Draft Environmental Impact Report

SCH# 2023060293

Volume 2

Appendices A – K

CarbonFrontier CCS Project
by Aera Energy, LLC *(PP23402)*

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Zone Change Case No. 3, Map 74
Zone Change Case No. 4, Map 75
Conditional Use Permit No. 9, Map 51
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Kern County
Planning and Natural Resources Department
Bakersfield, California

June 2024

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Appendix A
Notice of Preparation and Public Review

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A.1 Notice of Preparation/Initial Study

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Lorelei H. Oviatt, AICP, Director
2700 "M" Street, Suite 100
Bakersfield, CA 93301-2323
Phone: (661) 862-8600
Fax: (661) 862-8601 **TTY Relay 1-800-735-2929**
Email: planning@kerncounty.com
Web Address: http://kernplanning.com/

PLANNING AND NATURAL RESOURCES DEPARTMENT

Planning
Community Development
Administrative Operations

DATE: June 9, 2023

TO: See Attached Mailing List

FROM: Kern County Planning and Natural Resources Department
Attn: Cindi Hoover
2700 "M" Street, Suite 100
Bakersfield, CA 93301
(661) 862-8629; HooverC@kerncounty.com

SUBJECT: NOTICE OF PREPARATION (NOP) OF A DRAFT ENVIRONMENTAL IMPACT REPORT (EIR) FOR THE CARBONFRONTIER CARBON CAPTURE SEQUESTRATION (CCS) PROJECT BY AERA ENERGY, LLC.

The Kern County Planning and Natural Resources Department as Lead Agency (per CEQA Guidelines Section 15062) has determined that preparation of an Environmental Impact Report (per CEQA Guidelines 15161) is necessary for the proposed project identified below. The Planning and Natural Resources Department solicits the views of your agency as to the scope and content of the environmental information which is germane to your agency's statutory responsibilities in connection with the proposed project. Your agency may need to use the EIR prepared by our agency when considering your permit or other approval of the project.

You are invited to view the NOP and submit written comments regarding the scope and content of the environmental information in connection with the proposed project should you wish to do so. Due to the limits mandated by State law, your response must be received by **July 10, 2023 at 5:00 p.m**. Comments can be submitted to the Kern County Planning and Natural Resources Department at the address shown above or to HooverC@kerncounty.com. A Scoping Meeting will be held on **Friday, June 23, 2023 at 1:30 p.m.** at the address listed above.

PROJECT TITLE: CarbonFrontier CCS Project by Aera Energy, LLC (PP23402); PLN22-00137: ZCC No. 4, Map No. 51; ZCC No. 3, Map No. 74; ZCC No. 4, Map No. 75; CUP No. 9, Map No. 51; CUP No. 7, Map No. 74; CUP No. 7, Map No. 75; CUP No. 9, Map No. 96.

PROJECT LOCATION: The proposed project site is located within the Central Valley portion of unincorporated Kern County and is comprised of forty-seven (47) privately owned parcels and two (2) provisional parcels, within the administrative boundaries of the North and South Belridge oilfields. The North and South Belridge oilfields are contiguous and located west of Highway 33, approximately seven miles southwest of the community of Lost Hills (population 2,370) . Additionally, the proposed project is located within Sections 20, 21, 22, 26, 27, 28, 34, 35, and 36 of Township 27 South, Range 20 East; Sections 1, 2, and 12 of Township 28 South, Range 20 East; Sections 6, 7, 17, 18, 20, 27, 28, 29, 32, 33, and 34 of Township 28 South Range 21 East; and Sections 2, 3, and 4 of Township 29 South, Range 21 East of the Mount Diablo Base and Meridian (MDBM).

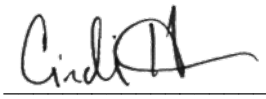
PROJECT DESCRIPTION: The project proponent is proposing to construct and operate a CCS project within the North and South Belridge oilfields. Implementation of the proposed project includes the following requests:

- Zone Classification Change (ZCC) from A-1 (limited Agriculture) to A (Exclusive Agriculture) on approximately 1,737 acres and from NR (Natural Resources – 20 acre minimum) to A (Exclusive Agriculture) on approximately 47 acres.
- Conditional Use Permit (CUP) to allow a CCS facility, associated Class VI geologic sequestration injection wells, and related improvements for storage of CO_2 on approximately 13,229 acres. CCS has been determined to be a storage operation under the Kern County Zoning Ordinance, Section 19.08.085 and Section 19.06.020. Therefore, CCS in either existing formation or tanks is an allowed use with a CUP in the following districts:
    - A District (Exclusive Agriculture)
    - M-2 District (Medium Industrial)
    - M-3 District (Heavy Industrial)

The proposed project would capture CO_2 from existing sources within the South Belridge oil field and transport it by pipeline to dedicated Class VI injection wells within the North Belridge oil field to be injected into identified geologically confined reservoirs for storage. The underground CCS formation is a depleted oil and gas reservoir with saline formation water. The CO_2 distribution pipelines, and associated infrastructure would be new construction. Implementation of the project would also require permits from the Federal Environmental Protection Agency (EPA) for up to nine (9) Class VI injection wells in compliance with the UIC Program for Class VI injection wells (40 CFR 146.81 et seq.).

The proposed project area has been identified as a location suitable for such storage and a potential to contribute to California's goals for carbon neutrality by 2045 by reducing industrial uses to no net contribution and potentially supporting direct removal of CO2 from the air. California executive order B-55-18 mandates that the state achieve carbon neutrality by 2045 and maintain net negative emissions thereafter. (https://livermorelabfoundation.org/2019/12/19/getting-to-neutral/).

Documents can be viewed online at: https://kernplanning.com/planning/notices-of-preparation/

Signature: 
Name: Cindi Hoover, Planning Division Chief

CarbonFrontier CCS Project (AERA)
Agency, Interested Party, & Tribal List

Justin Ong
266 Canyon Lakes Place
San Ramon CA 94582

City of Arvin
P.O. Box 548
Arvin, CA 93203

Bakersfield City Planning Dept
1715 Chester Avenue
Bakersfield, CA 93301

Bakersfield City Public Works Dept
1501 Truxtun Avenue
Bakersfield, CA 93301

California City Planning Dept
21000 Hacienda Blvd.
California City, CA 93515

Delano City Planning Dept
P.O. Box 3010
Delano, CA 93216

City of Maricopa
P.O. Box 548
Maricopa, CA 93252

City of McFarland
401 West Kern Avenue
McFarland, CA 93250

City of Ridgecrest
100 West California Avenue
Ridgecrest, CA 93555

City of Shafter
336 Pacific Avenue
Shafter, CA 93263

City of Taft
Planning & Building
209 East Kern Street
Taft, CA 93268

City of Tehachapi
Attn: John Schlosser
115 South Robinson Street
Tehachapi, CA 93561-1722

City of Wasco
764 E Street
Wasco, CA 93280

Inyo County Planning Dept
P.O. Drawer "L"
Independence, CA 93526

Kings County Planning Agency
1400 West Lacey Blvd, Bldg 6
Hanford, CA 93230

Los Angeles Co Reg Planning Dept
320 West Temple Street
Los Angeles, CA 90012

San Bernardino Co Planning Dept
385 North Arrowhead Avenue, 1st Floor
San Bernardino, CA 92415-0182

San Luis Obispo Co Planning Dept
Planning and Building
976 Osos Street
San Luis Obispo, CA 93408

Santa Barbara Co Resource Mgt Dept
123 East Anapamu Street
Santa Barbara, CA 93101

Tulare County Planning & Dev Dept
5961 South Mooney Boulevard
Visalia, CA 93291

Ventura County RMA Planning Div
800 South Victoria Avenue, L1740
Ventura, CA 93009-1740

U.S. Bureau of Land Management
Caliente/Bakersfield
35126 McMurtrey Avenue
Bakersfield, CA 93308

Federal Communications Comm
18000 Studebaker Road, #660
Cerritos, CA 90701

U. S. Fish & Wildlife Service
Division of Ecological Services
2800 Cottage Way #W-2605
Sacramento, CA 95825-1846

Environmental Protection Agency
Region IX Office
75 Hawthorn Street
San Francisco, CA 94105

U.S. Dept of Agriculture/NRCS
5080 California Avenue, Ste 150
Bakersfield, CA 93309-0711

State Air Resources Board
Stationary Resource Division
P.O. Box 2815
Sacramento, CA 95812

So. San Joaquin Valley Arch Info Ctr
California State University of Bkfd
9001 Stockdale Highway
Bakersfield, CA 93311

Caltrans/Dist 6
Planning/Land Bank Bldg.
P.O. Box 12616
Fresno, CA 93778

State Clearinghouse
Office of Planning and Research
1400 - 10th Street, Room 222
Sacramento, CA 95814

State Dept of Conservation
Director's Office
801 "K" Street, MS 24-01
Sacramento, CA 95814-3528

State Dept of Conservation
Geologic Energy Management Division
11000 River Run Boulevard
Bakersfield, CA 93311

State Dept of Conservation
Geologic Energy Management Division
801 "K" Street, MS 20-20
Sacramento, CA 95814-3530

Office of the State Geologist
Headquarters
801 "K" Street, MS 12-30
Sacramento, CA 95814

State Dept of Conservation
Office of Land Conservation
801 "K" Street, MS 18-01
Sacramento, CA 95814

California State University
Bakersfield - Library
9001 Stockdale Highway
Bakersfield, CA 93309

California Energy Commission
James W. Reed, Jr.
1516 Ninth Street
Mail Stop 17
Sacramento, CA 95814

California Fish & Wildlife
1234 East Shaw Avenue
Fresno, CA 93710

California Regional Water Quality
Control Board/Central Valley Region
1685 E Street
Fresno, CA 93706-2020

State Dept of Toxic Substance Control
Environmental Protection Agency
1515 Tollhouse Road
Clovis, CA 93612

Cal Environmental Protection Agency/
Dept of Toxic Substances Control, Reg 1
Attn: Dave Kereazis, Permit Div - CEQA
8800 Cal Center Drive, 2nd Floor
Sacramento, CA 95826

Kern County
Agriculture Department

Kern County Administrative Officer

Kern County Public Works Department/
Building & Development/Floodplain

Kern County Public Works Department/
Building & Development/Survey

Kern County
Env Health Services Department

Kern County Fire Dept (Put in FIRE BOX)
Regina Arriaga
Roxanne Routh
Jim Killam

Kern County Fire Dept
Aaron Duncan, Fire Chief

Kern County Library/Beale
Local History Room

Kern County Library/Beale
Andie Sullivan

Kern County Parks & Recreation

Kern County Sheriff's Dept
Administration

Kern County Library
Buttonwillow Branch
116 Buttonwillow Avenue
Buttonwillow, CA 93206

Kern County Public Works Department/
Building & Development/Development
Review

Kern County Public Works
Department/Operations &
Maintenance/Regulatory Monitoring &
Reporting

Taft City School Dist
820 North 6th Street
Taft, CA 93268

Wasco Union High School Dist
P.O. Box 250
Wasco, CA 93280

US EPA Region IX
Attn: David Albright
Manager Groundwater Protection Section
75 Hawthorne Street
San Francisco, CA 94105

Buttonwillow Union School Dist
42600 Highway 58
Buttonwillow, CA 93206

McKittrick School Dist
P.O. Box 277
McKittrick, CA 93251

Lost Hills Union School Dist
P.O. Box 158
Lost Hills, CA 93249

Kern High School Dist
5801 Sundale Avenue
Bakersfield, CA 93309

Kern County Superintendent of Schools
Attention School District Facility Services
1300 - 17th Street
Bakersfield, CA 93301

KernCOG
1401 19th Street - Suite 300
Bakersfield, CA 93301

Local Agency Formation Comm/LAFCO
5300 Lennox Avenue, Suite 303
Bakersfield, CA 93309

Kern County Water Agency
3200 Rio Mirada Drive
Bakersfield, CA 93308

San Joaquin Valley
Air Pollution Control District
1990 East Gettysburg Avenue
Fresno, CA 93726

West Side Mosquito
Abatement Dist.
P.O. Box 205
Taft, CA 93268

Adams, Broadwell, Joseph & Cardozo
Attention: Janet M. Laurain
601 Gateway Boulevard, Suite 1000
South San Francisco, CA 94080

Kern Audubon Society
Attn: Frank Bedard, Chairman
4124 Chardonnay Drive
Bakersfield, CA 93306

Los Angeles Audubon
926 Citrus Avenue
Los Angeles, CA 90036-4929

Center on Race, Poverty
& the Environment
Attn: Marissa Alexander
1999 Harrison Street – Suite 650
San Francisco, CA 94612

Center on Race, Poverty
& the Environmental/
CA Rural Legal Assistance Foundation
1012 Jefferson Street
Delano, CA 93215

Defenders of Wildlife/
Kim Delfino, California Dir
980 - 9th Street, Suite 1730
Sacramento, CA 95814

Native American Heritage Council
of Kern County
Attn: Gene Albitre
3401 Aslin Street
Bakersfield, CA 93312

Pacific Gas & Electric Co
Land Projects
650 "O" Street, First Floor
Fresno, CA 93760-0001

Sierra Club/Kern Kaweah Chapter
P.O. Box 3357
Bakersfield, CA 93385

Southern California Gas Co
35118 McMurtrey Avenue
Bakersfield, CA 93308-9477

Southern California Gas Co
Transportation Dept
9400 Oakdale Avenue
Chatsworth, CA 91313-6511

Verizon California, Inc.
Attention Engineering Department
520 South China Lake Boulevard
Ridgecrest, CA 93555

David Laughing Horse Robinson
P.O. Box 20849
Bakersfield, CA 93390

Leadership Counsel for Justice &
Accountability
1527 - 19th Street, Suite 212
Bakersfield, CA 93301

LIUNA
Attn: Danny Zaragoza
2201 "H" Street
Bakersfield, CA 93301

U.S. Bureau of Land Management
Caliente/Bakersfield
3801 Pegasus Drive
Bakersfield, CA 93308-6837

Gabe Pattee
113 Hwy 128
Geyserville, Ca 95441

North West Kern Resource Cons Dist
5080 California Avenue, Suite 150
Bakersfield, CA 93309

Defenders of Wildlife
Sophia Markowska
1212 Wagon Way
Gilroy, CA 95020

Lozeau Drury LLP
1939 Harrison Street, Suite 150
Oakland, CA 94612

CAL FIRE
PO Box 944246
Sacramento, CA 94244-246

Encompass Capital Advisors LLC
Attn: Todd Kantor
200 Park Avenue, 11th Floor
New York, NY 10166

California Energy Commission
Attn: Commissioner Douglas
715 P Street
Sacramento, CA 95814

California Public Utilities Commission
Attn: President Alice Reynolds
505 Van Ness Avenue
San Francisco, CA 94102

California Energy Commission
715 P Street
Sacramento, CA 95814

California Dept of Water Resources
San Joaquin Dist.
3374 East Shields Avenue, Room A-7
Fresno, CA 93726

California Dept of Water Resources
Div. Land & Right-of-Way
P.O. Box 942836
Sacramento, CA 94236

Encompass Capital Advisors LLC
Attn: Michael Osburn
200 Park Avenue, 11th Floor
New York, NY 10166

Kern County Fire Dept
Kain Linville, Fire Marshall

West Side Rec & Parks Dist
P.O. Box 1406
Taft, CA 93268

Rosedale-Rio Bravo Water Dist
P.O. Box 20820
Bakersfield, CA 93390-0820

Torres Martinez Desert Cahuilla Indians
Attn: Michael Mirelez,
Cultural Resources Coordinator
P.O. Box 1160
Thermal, CA 92274

San Manuel Band of Mission Indians
Attn: Ryan Nordness
Cultural Resources Analyst
26569 Community Center Drive
Highland, CA 92346

Twenty-Nine Palms Band of Mission Indians
Attn: Anthony Madrigal Jr.
Tribal Grants Administrator
46-200 Harrison Place
Coachella, CA 92236

Buttonwillow County Water Dist
P.O. Box 874
Buttonwillow, CA 93206

Tejon Indian Tribe
Kathy Morgan, Chairperson
1731 Hasti-acres Drive, Suite 108
Bakersfield, CA 93309

Livermore Lab Foundation
c/o UC Office of Institutional Advancement
1111 Franklin Street
Oakland, CA 94607

Tejon Indian Tribe
Attn: Collin Rambo
Cultural Resource Management Technician
1731 Hasti Acres Dr., Suite 108
Bakersfield, CA 93309

Twenty-Nine Palms Band of Mission Indians
Attn: Darrell Mike, Tribal Chairman
46-200 Harrison Place
Coachella, CA 92236

WZI, Inc.
1717 - 28th Street
Bakersfield, CA 93301

JB Energy Partners
Andrew Bremner
P.O. Box 82515
Bakersfield, CA 93308

LINN Energy, LLC
5201 Truxtun Avenue, Suite 100
Bakersfield, CA 93309

QK Inc,
Chris Mynk
5080 California Ave. Suite 220
Bakersfield, CA 93309

Chevron, USA
9525 Camino Media
Bakersfield, CA 93311

Stanford University
Energy Resources Engineering
Center of Carbon Storage
367 Panama Street
Stanford, CA 94305

Aera
Attn: Cindy Pollard
10000 Ming Avenue
Bakersfield, CA 93311

Exxon/Mobil Production Company
Attn: Troy Tranquada
12000 Calle Real
Goleta, CA 93117

CIPA
Attn: Trent Rosenlibe
1200 Discovery Drive, Suite 100
Bakersfield, CA 93309

Hathaway, LLC
Attn: Chad Hathaway
P.O. Box 81385
Bakersfield, CA 93380

IOPA
Attn: Les Clark
4520 California Avenue, Suite 230
Bakersfield, CA 93309

Stantec
Eric Snelling
180 Chorro Street
San Luis Obispo. CA 93401

Halliburton
Attn: Steve Pruett
34722 Seventh Standard Road
Bakersfield, CA 93314

Macpherson Oil Company
P.O. Box 5368
Bakersfield, CA 93388

WSPA
Attn: Suzanne Noble
1518 Mill Rock Way, Suite 103 Bakersfield, CA 93311

Seneca Resources Corporation
2131 Mars Court
Bakersfield, CA 93308

Venoco, Inc.
Attn: Ian Livett
6267 Carpentaria Avenue, Suite 100
Carpentaria, CA 93013

Kern Oil and Refining
7724 East Panama Lane
Bakersfield, CA 93307

Naftex Operating Company
P.O. Box 308
Edison, CA 93220

Mt Poso CoGen Company, LLC
100 Wilshire Boulevard, Suite 800
Santa Maria, CA 90401

E&B Natural Resources Management
1600 Norris Road
Bakersfield, CA 93309

San Joaquin Refining
3129 Standard Street
Bakersfield, CA 93308

Tricor Refining, LLC
1134 Manor Street
Bakersfield, CA 93308

GE Energy
13000 Jameson Road
Tehachapi, CA 93561

Ensign
7001 Charity Avenue
Bakersfield, CA 93308

Key Energy Services, Inc.
5080 California Avenue
Bakersfield, CA 93309

Hess Corporation
1675 Chester Avenue
Bakersfield, CA 93301

PCL Industrial Services
1500 Union Avenue
Bakersfield, CA 93307

PLCL Plus Int'l, Inc.
12418-B Rosedale Highway
Bakersfield, CA 93312

Vintage Production California
9600 Ming Avenue, Suite 300
Bakersfield, CA 93311

Sturgeon Services Int'l
3511 Gilmore Avenue
Bakersfield, CA 93308

Aera Energy
Jamie Swetalla
10000 Ming Avenue
Bakersfield, CA 93311

Kern Citizens for Energy
5001 California Avenue, Suite 211
Bakersfield, CA 93309

Weatherford Completions
Attn: Gregg Hurst
5060 California Avenue, Suite 1150
Bakersfield, CA 93309

Total Western
2811 Fruitvale Avenue
Bakersfield, CA 93308

Baker Hughes
3901 Fanucchi Way
Shafter, CA 93263

Schlumberger Oilfield Services
2157 Mohawk Street
Bakersfield, CA 93308

Nabors Completion & Production
3651 Pegasus Drive, Suite 101
Bakersfield, CA 93308

Golden Gate University School of Law
Environmental Law and Justice Clinic,
Attn: Lucas Williams, Susann Bradford
536 Mission Street
San Francisco, CA 94105

Center for Biological Diversity
Ann K. Brown
Open Government Coordinator
P.O. Box 11374
Portland, OR 97211-0974

California State University Bakersfield
Dr. Lynette Zelezny, Ph.D., M.B.A. President
Mail Stop: 33BCD
9001 Stockdale Highway
Bakersfield, CA 93311

Kern Economic Development Corp
Richard Chapman, President & CEO
2700 M Street, Suite 200,
Bakersfield, CA 93301

Dolores Huerta Foundation
Dolores Huerta, President
P.O. Box 2087
Bakersfield, CA 93303

Dolores Huerta Foundation
Camila Chavez, Executive Director
P.O. Box 2087
Bakersfield, CA 93303

Kern Community College District
Dr. Sonya Christian, Chancellor
2100 Chester Avenue
Bakersfield, CA 93301

Kern Community College District
Bonita Steele, Ed. D
Director, Programs and Program Development
2100 Chester Avenue
Bakersfield, CA 93301

City of Bakersfield
Mayor Karen Goh
Office of the Mayor
1501 Truxtun Avenue
Bakersfield, CA 93301

Governor's Office of Business and Economic Development
Dee Dee Myers, Senior Advisor & Director
1325 J Street, 18th Floor
Sacramento, CA 95814

California Natural Resources Agency Wade Crowfoot, Secretary for Natural Resources
715 P Street, 20th Floor
Sacramento, CA 95814

California Workforce Development Board
Tim Rainey, Executive Director
800 Capitol Mall, Suite 1022
Sacramento, CA 95814

California State Senate
Senator Melissa Hurtado, 14th District
State Capitol
Sacramento, CA 95814

Large Scale Solar Association
Shannon Eddy, Executive Director
2501 Portola Way
Sacramento, CA 95818

Kern County Farm Bureau
Patty Poire, Board President
1800 30th Street, Suite 390
Bakersfield, CA 93301

Kern County Farm Bureau
Romeo Agbalog, Executive Director
1800 30th Street, Suite 390
Bakersfield, CA 93301

Employers' Training Resource
Aaron Ellis, Assistant CAO
1600 East Belle Terrace
Bakersfield, CA 93307

Greater Bakersfield Chamber of Commerce
Nick Ortiz, President & CEO
1725 Eye Street
Bakersfield, CA 93301

International Brotherhood of Electrical Workers
Brian Holt, Business Manager/Financial Secretary
3921 Sillect Avenue
Bakersfield, CA 93308

Tejon Indian Tribe
Octavio Escobedo, Tribal Chair
P.O. Box 640
Arvin, CA 93203

Building Trades Council
Kern, Inyo, & Mono Counties, AFL-CIO
John Spaulding, Executive Secretary
200 West Jeffrey Street
Bakersfield, CA 93305-2434

Public Policy Institute of California PPIC Water Policy Center
Ellen Hanak, Vice President, Senior Fellow, and Director
500 Washington Street, Suite 600
San Francisco, CA 94111

Center for Biological Diversity
Victoria Bogdan Tejeda
1212 Broadway, Suite 800
Oakland, CA 94612

Stephen Reid
14223 Harborough Drive
Bakersfield, CA 93311

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2700 "M" Street, Suite 100□
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DATE: June 9, 2023

TO: Surrounding Property Owners within 1,000 Feet of Project Boundary; and Interested Parties

FROM: Kern County Planning and Natural Resources Department
2700 "M" Street, Suite 100
Bakersfield, CA 93311

SUBJECT: Notice of Preparation of an Environmental Impact Report – CarbonFrontier Carbon Capture Sequestration (CCS) Project by Aera Energy, LLC (PP23402).

Dear Sir or Madam:

The Kern County Planning and Natural Resources Department has determined that preparation of an Environmental Impact Report (EIR) is necessary for the proposed project identified below. The purpose of this letter is to notify interested parties and surrounding property owners within 1,000 feet of the project boundaries of this determination. A copy of the Initial Study/Notice of Preparation (IS/NOP) prepared for this proposed project is available for viewing at the following Kern County website:

https.//kernplanning.com/planning/notices-of-preparation/

The purpose of the IS/NOP is to describe the proposed project, specify the project location, and to identify the potential environmental impacts of the project so that Responsible Agencies and interested persons can provide a meaningful response related to potential environmental concerns that should be analyzed in the Environmental Impact Report.

You are invited to view the NOP and submit written comments regarding the scope and content of the environmental information in connection with the proposed project should you wish to do so. Due to the limits mandated by State law, your response must be received by **July 10, 2023 at 5:00 p.m.** Comments can be submitted to the Kern County Planning and Natural Resources Department at the address shown above or to HooverC@kerncounty.com. A Scoping meeting will be held on **Friday, June 23, 2023 at 1:30 p.m.** at the address listed above.

Please be advised that any comments received after the dates listed above will still be included in the public record for this project and made available to decision makers when this project is scheduled for consideration at a public hearing. Please also be advised that you will receive an additional notice in the mail once a public hearing date is scheduled for this project. You will also be provided additional opportunities to submit comments at that time.

PROJECT TITLE: CarbonFrontier CCS Project by Aera Energy, LLC (PP23402); PLN22-00137: ZCC No. 4, Map No. 51; ZCC No. 3, Map No. 74; ZCC No. 4, Map No. 75; CUP No. 9, Map No. 51; CUP No. 7, Map No. 74; CUP No. 7, Map No. 75; CUP No. 9, Map No. 96.

PROJECT LOCATION: The proposed project site is located within the Central Valley portion of unincorporated Kern County and is comprised of forty-seven (47) privately owned parcels and two (2) provisional parcels, within the administrative boundaries of the North and South Belridge oilfields. The North and South Belridge oilfields are contiguous and located west of Highway 33, approximately seven (7) miles southwest of the community of Lost Hills (population 2,370). Additionally, the proposed project is located within Sections 20, 21, 22, 26, 27, 28, 34, 35, and 36 of Township 27 South, Range 20 East; Sections 1, 2, and 12 of

Township 28 South, Range 20 East; Sections 6, 7, 17, 18, 20, 27, 28, 29, 32, 33, and 34 of Township 28 South Range 21 East; and Sections 2, 3, and 4 of Township 29 South, Range 21 East of the Mount Diablo Base and Meridian (MDBM).

PROJECT DESCRIPTION: The project proponent is proposing to construct and operate a CCS project within the North and South Belridge oilfields. Implementation of the proposed project includes the following requests:

- Zone Classification Change (ZCC) from A-1 (limited Agriculture) to A (Exclusive Agriculture) on approximately 1,737 acres and from NR (Natural Resources – 20 acre minimum) to A (Exclusive Agriculture) on approximately 47 acres.

- Conditional Use Permit (CUP) to allow a CCS facility, associated Class VI geologic sequestration injection wells, and related improvements for storage of CO_2 on approximately 13,229 acres. CCS has been determined to be a storage operation under the Kern County Zoning Ordinance, Section 19.08.085 and Section 19.06.020. Therefore, CCS in either existing formation or tanks is an allowed use with a CUP in the following districts:

    - A District (Exclusive Agriculture)
    - M-2 District (Medium Industrial)
    - M-3 District (Heavy Industrial)

The proposed project would capture CO_2 from existing sources within the South Belridge oil field and transport it by pipeline to dedicated Class VI injection wells within the North Belridge oil field to be injected into identified geologically confined reservoirs for storage. The underground CCS formation is a depleted oil and gas reservoir with saline formation water. The CO_2 distribution pipelines, and associated infrastructure would be new construction. Implementation of the project would also require permits from the Federal Environmental Protection Agency (EPA) for up to nine (9) Class VI injection wells in compliance with the UIC Program for Class VI injection wells (40 CFR 146.81 et seq.).

The proposed project area has been identified as a location suitable for such storage and a potential to contribute to California's goals of for carbon neutrality by 2045 by reducing industrial uses to no net contribution and potentially supporting direct removal of CO2 from the air. California executive order B-55-18 mandates that the state achieve carbon neutrality by 2045 and maintain net negative emissions thereafter. (https://livermorelabfoundation.org/2019/12/19/getting-to-neutral/).

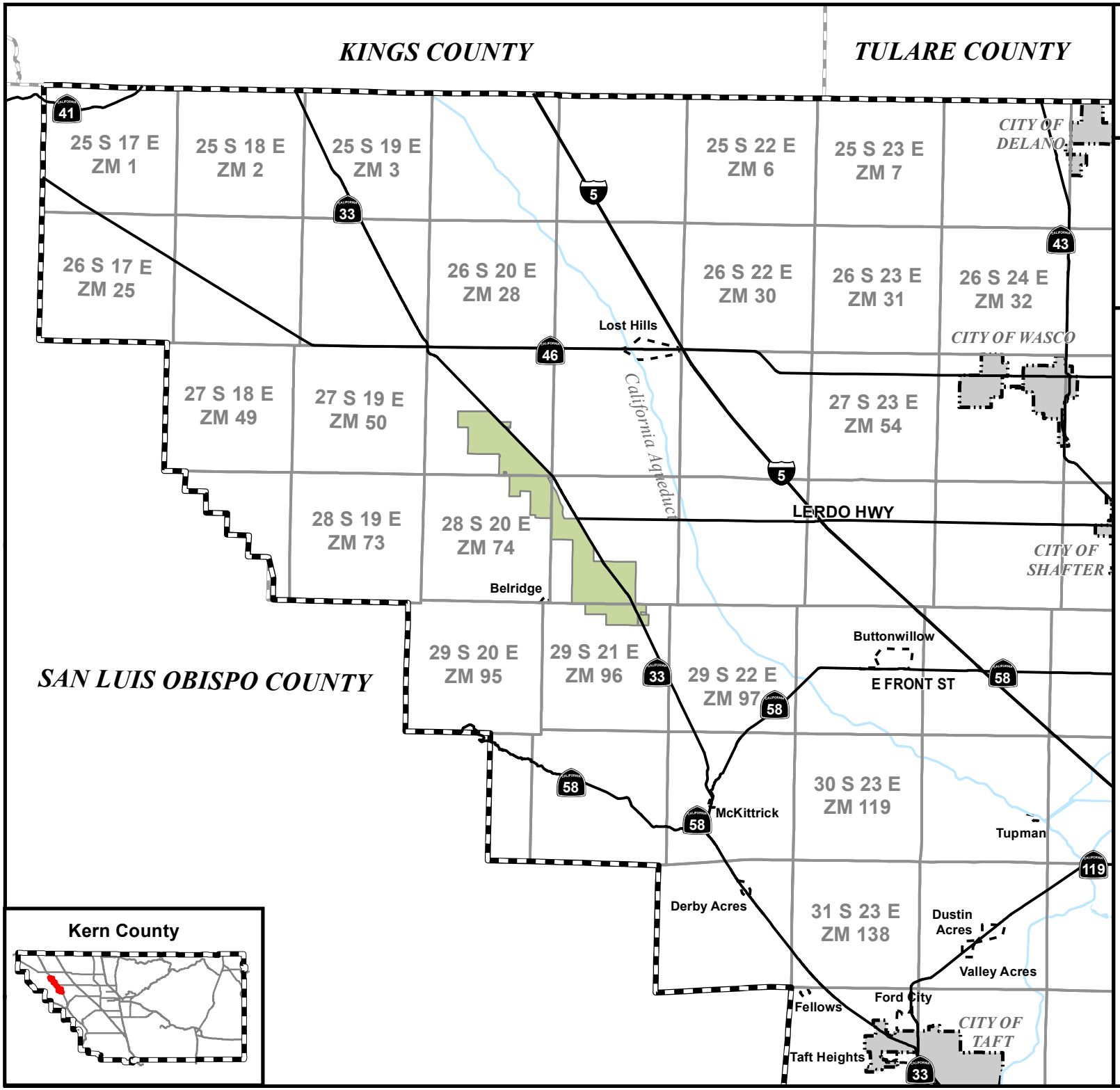
Should you have any questions regarding this project, or the Initial Study/Notice of Preparation, please feel free to contact me by phone at (661) 862-8629 or email HooverC@kerncounty.com.

Sincerely,

Cindi Hoover
Division Chief – Plan Development & Special Projects
Planning and Natural Resources Department

By: Keith Alvidrez, Planner I

Attachments: Figure 1 – Vicinity Map



ZCC 4, Map 51; ZCC 3, Map 74; ZCC 4, Map 75; CUP 9, Map 51; CUP 7, Map 74; CUP 7, Map 75; CUP 9, Map 96

Figure 1 - Regional Vicinity

CarbonFrontier Project
By: Aera Energy

- CarbonFrontier Project
- INTERSTATE
- NAMED ROAD
- STATE HWY
- Kern County Boundary
- Township/Range
- Water Bodies
- Water Courses
- City Limits
- Unincorporated Cities

T27S/R20E- Sec. 20- 22; 26-28; 34-36
T28S/R20E - Sec. 1-2 & 11
T28S/R21E- Sec. 6-7; 17-18; 20; 27-29; 32-34
T29S/R21E- Sec. 2-4

Created on: 6/5/2023

0 2.5 5 7.5 10 Miles

Kern County Planning & Natural Resources Department

CarbonFrontier CCS Project (AERA)
APN List

068 230 05 02 4
WHEELER ROBINSON A & JACQUELYN
APPELL TRUST
2006 ROSEMARY CT
MARTINEZ CA 94553

068 220 71 00 4
AERA ENERGY LLC
10000 MING AV
BAKERSFIELD CA 93311-1301

068 230 14 00 2
AERA ENERGY LLC
P O BOX 11164
BAKERSFIELD CA 93891-1647

068 220 09 00 5
BANUELOS ESAUL
16875 HWY 33
LOST HILLS CA 93249

085 230 48 00 6
BELRIDGE ENERGY RESOURCES INC
P O BOX 5566
BAKERSFIELD CA 93380-5566

068 220 35 00 0
BELRIDGE FARMS & PACKING LLC
PO BOX 11164
BAKERSFIELD CA 93389-1164

098 113 02 00 2
BELRIDGE WATER STORAGE DIST
P O BOX 1087
BAKERSFIELD CA 93302

085 130 40 00 3
BERRY PETROLEUM COMPANY LLC
11117 RIVER RUN BL
BAKERSFIELD CA 93311-8957

068 220 37 00 6
BLOEMER ESTATE LP
4948 ENGLE RD
BAKERSFIELD CA 93313-9707

068 220 73 00 0
CALIFORNIA RESOURCES PETROLEUM
CORPORATION
27200 TOURNEY RD STE 200
SANTA CLARITA CA 91355-4910

068 210 34 00 4
CATHER-HERLEY OIL CO
800 E WARDLOW RD
LONG BEACH CA 90807

068 210 63 00 8
CATHER-HERLEY OIL CO
P O BOX 7397
LONG BEACH CA 90807-7397

068 210 15 00 9
CHEVRON USA INC
P O BOX 1392
BAKERSFIELD CA 93302-1392

085 130 09 02 2
CONROY JOHN J
200 TECUMSEH WY
LOUDON TN 37774-2103

068 220 39 00 2
DIVERSIFIED ROYALTIES LTD
P O BOX 870849
MESQUITE TX 75187-0849

068 220 40 00 4
DIVERSIFIED ROYALTIES LTD
P O BOX 489
SEAGOVILLE TX 75159

085 230 36 00 1
E & B NATURAL RES MGMT CORP
1608 NORRIS RD
BAKERSFIELD CA 93308-2238

069 150 08 00 9
WONDERFUL CITRUS LLC
5001 CALIFORNIA AV STE 230
BAKERSFIELD CA 93309-0734

068 230 05 04 2
EPSTEIN SUSAN LEVINSON LIV TR
12014 SW 60TH AV
PORTLAND OR 97219-7008

085 110 24 04 7
JENKINS RICHARD & KATHLEEN FAMILY
TRUST
P O BOX 3001
ALPINE WY 83128-3001

068 200 30 00 9
KERN ENTERPRISES LLC
11108 TORBAY DR
BAKERSFIELD CA 93311-2924

068 210 19 00 1
LALEZARI EHSANALLAH & MAHNAZ
7606 BRAE ACRES CT
HOUSTON TX 77074-4123

085 230 03 00 5
LUNDIN WEBER CO LLC
1900 WASACH DR
LONGMONT CO 80504-3775

068 210 50 00 0
MARAHD PROP LLC
7404 CALLE SAGRADA
BAKERSFIELD CA 93309

068 220 49 00 1
MARIA JOAQUIN BASIN L L C
PO BOX 835
PINEHURST TX 77362

068 230 05 07 9
MITCHEL CARYL C CHARITABLE REM TR
1600 HUNTINGTON DR
SOUTH PASADENA CA 91030-4792

098 113 01 00 9
MOBIL OIL CORP
PO BOX 64106
SPRING TX 77387-4106

068 220 41 00 7
O DONNELL OIL & SECURITIES CO
1900 DALROCK RD
ROWLETT TX 75088-5526

085 110 06 00 9
ORYX ENERGY CO
P O BOX 1330
HOUSTON TX 77251-1330

068 220 20 03 3
PACIFIC GAS & ELECTRIC CO
1 MARKET PZ STE 400
SAN FRANCISCO CA 94105-1004

068 200 40 00 8
PAPENHAUSEN KATHLEEN CLANCY TR
PO BOX 1032
PEBBLE BEACH CA 93953-1032

085 130 09 01 3
RICE ROBERT J ET AL
P O BOX 82515
BAKERSFIELD CA 93380

068 220 18 00 1
SAN PABLO BAY PIPELINE COMPANY LLC
1801 CALIFORNIA ST STE 3600
DENVER CO 80202

068 220 58 00 7
SAN PABLO BAY PIPELINE COMPANY LLC
370 17TH ST STE 3100
DENVER CO 80202-5631

068 220 05 01 2
SENTINEL PEAK RESOURCES CAL LLC
1200 DISCOVERY DR STE 500
BAKERSFIELD CA 93309

068 210 13 00 3
SILL PROPERTIES INC
1508 18TH ST STE 320
BAKERSFIELD CA 93301

085 130 09 05 9
ST CLAIRE CATHERINE O
7110 SENALDA RD
LOS ANGELES CA 90068-2623

098 112 25 00 2
TORRANCE VALLEY PIPELINE CO LLC
100 CONGRESS AV STE 1900
AUSTIN TX 78701-2750

068 220 30 00 5
VALLEY AG HOLDING LLC
3908 W CALDWELL AV
VISALIA CA 93277

068 200 15 00 6
WONDERFUL NUT ORCHARDS LLC
6801 E LERDO HW
SHAFTER CA 93263-9610

085 230 24 00 6
WEST AMERICAN ENERGY CORP
P O BOX 22016
BAKERSFIELD CA 93390-2016

068 210 27 00 4
WESTERVELT ECOLOGICAL SERV LLC
1400 NE JACK WARNER PKWY
TUSCALOOSA AL 35404

068 210 51 00 3
WESTERVELT ECOLOGICAL SERV LLC
600 N MARKET BL STE 3
SACRAMENTO CA 95834

Notice of Completion & Environmental Document Transmittal

Mail to: State Clearinghouse, P. O. Box 3044, Sacramento, CA 95812-3044 (916) 445-0613
For Hand Delivery/Street Address: 1400 Tenth Street, Sacramento, CA 95814

SCH # _____

Project Title: CarbonFrontier CCS Project by Aera Energy, LLC

Lead Agency: Kern County Planning and Natural Resources Department — Contact Person: Cindi Hoover

Mailing Address: 2700 "M" Street Suite 100 — Phone: (661) 862-8629

City: Bakersfield — Zip: 93301 — County: Kern

Project Location: County: Kern — City/Nearest Community: City of Taft, Community of Lost Hills

Cross Streets: Lerdo Highway and State Highway 33 — Zip Code: 93249 / 93251

Lat. / Long.: 35.49980° N, -119.75522° W (NAD 83) — Total Acres: 13,229

Assessor's Parcel No.: Multi — Section: Multi — Twp.: Multi — Range: Multi — Base: SBB&M

Within 2 Miles: State Hwy #: SR-33 — Waterways: N/A

Airports: N/A — Railways: N/A — Schools: N/A

Document Type:

CEQA: ☒ NOP ☐ Early Cons ☐ Neg Dec ☐ Mit Neg Dec ☐ Draft EIR ☐ Supplement/Subsequent EIR (Prior SCH No.) _____ ☐ Other _____

NEPA: ☐ NOI ☐ EA ☐ Draft EIS ☐ FONSI

Other: ☐ Joint Document ☐ Final Document ☐ Other _____

Local Action Type:

☐ General Plan Update ☐ General Plan Amendment ☐ General Plan Element ☐ Community Plan
☐ Specific Plan ☐ Master Plan ☐ Planned Unit Development ☐ Site Plan
☒ Rezone ☐ Prezone ☒ Use Permit ☐ Land Division (Subdivision, etc.)
☐ Annexation ☐ Redevelopment ☐ Coastal Permit ☐ Other: _____

Development Type:

☐ Residential: Units _____ Acres _____
☐ Office: Sq.ft. _____ Acres _____ Employees _____
☐ Commercial: Sq.ft. _____ Acres _____ Employees _____
☐ Industrial: Sq.ft. _____ Acres _____ Employees _____
☐ Educational _____
☐ Recreational _____

☐ Water Facilities: Type _____ MGD _____
☐ Transportation: Type _____
☐ Mining: Mineral _____
☐ Power: Type _____ MW _____
☐ Waste Treatment: Type _____ MGD _____
☐ Hazardous Waste: Type _____
☒ Other: Carbon Capture and Sequestration (CCS)

Project Issues Discussed in Document:

☒ Aesthetic/Visual
☒ Agricultural Land
☒ Air Quality
☒ Archeological/Historical
☒ Biological Resources
☐ Coastal Zone
☒ Drainage/Absorption
☒ Economic/Jobs
☐ Fiscal
☒ Flood Plain/Flooding
☒ Forest Land/Fire Hazard
☒ Geologic/Seismic
☒ Minerals
☒ Noise
☒ Population/Housing Balance
☒ Public Services/Facilities
☒ Recreation/Parks
☒ Schools/Universities
☒ Septic Systems
☒ Sewer Capacity
☒ Soil Erosion/Compaction/Grading
☒ Solid Waste
☒ Toxic/Hazardous
☒ Traffic/Circulation
☒ Vegetation
☒ Water Quality
☒ Water Supply/Groundwater
☒ Wetland/Riparian
☒ Wildlife
☒ Growth Inducing
☒ Land Use
☒ Cumulative Effects
☒ Other GHG, Wildfire, Tribal Cultural Resources, Energy

Present Land Use/Zoning/General Plan Designation: Oil and Gas Exploration and Production / A (Exclusive Agriculture), A-1 (Limited Agriculture, NR (20) (Natural Resources – 20 acre min) / 8.1 (Intensive Agriculture), 8.3 (Extensive Agriculture), 8.4 (Mineral and Petroleum), 8.1/2.5 (Intensive Agriculture – Flood Hazard Overlay), 8.3/2.5 (Extensive Agriculture – Flood Hazard Overlay), 8.4/2.5 (Mineral and Petroleum – Flood Hazard Overlay).

Project Description: The CarbonFrontier CCS Project, as proposed by AERA Energy, LLC would develop an approximate 13,229 acre carbon capture and sequestration field, associated Class VI geologic sequestration injection wells, and related improvements for storage of Carbon Dioxide (CO_2). The proposed project would capture CO_2 from existing sources within the South Belridge oil field and transport it by pipeline to dedicated Class VI injection wells within the North Belridge oil field to be injected into identified geologically confined reservoirs for storage. The underground CCS formation is a depleted oil and gas reservoir with saline formation water. The CO_2 distribution pipelines, and associated infrastructure would be new construction.

Implementation of the proposed project includes the following requests:

- Zone Classification Change (ZCC) from A-1 (limited Agriculture) to A (Exclusive Agriculture) on approximately 1,737 acres and from NR (Natural Resources – 20 acre minimum) to A (Exclusive Agriculture) on approximately 47 acres.

- Conditional Use Permit (CUP) to allow a CCS facility, associated Class VI geologic sequestration injection wells, and related improvements for storage of CO_2 on approximately 13,229 acres. CCS has been determined to be a storage operation under the Kern County Zoning Ordinance, Section 19.08.085 and Section 19.06.020. Therefore, CCS in either existing formation or tanks is an allowed use with a CUP in the following districts:

    - A District (Exclusive Agriculture)
    - M-2 District (Medium Industrial)
    - M-3 District (Heavy Industrial)

Implementation of the proposed project would also require permits from the Federal Environmental Protection Agency (EPA) for up to nine (9) Class VI injection wells in compliance with the UIC Program for Class VI injection wells (40 CFR 146.81 et seq.).

The proposed project area has been identified as a location suitable for such storage and a potential to contribute to California's goals for carbon neutrality by 2045 by reducing industrial uses to no net contribution and potentially supporting direct removal of CO2 from the air. California executive order B-55-18 mandates that the state achieve carbon neutrality by 2045 and maintain net negative emissions thereafter. (https://livermorelabfoundation.org/2019/12/19/getting-to-neutral/).

Reviewing Agencies Checklist

Lead Agencies may recommend State Clearinghouse distribution by marking agencies below with and "**X**".
If you have already sent your document to the agency, please denote that with an "**S**".

S Air Resources Board	X Office of Emergency Services
_____ Boating & Waterways, Department of	_____ Office of Historic Preservation
_____ California Highway Patrol	_____ Office of Public-School Construction
X CalFire	_____ Parks & Recreation
S Caltrans District # 6	_____ Pesticide Regulation, Department of
S Caltrans Division of Aeronautics	_____ Public Utilities Commission
_____ Caltrans Planning (Headquarters)	S Regional WQCB # Central
_____ Central Valley Flood Protection Board	S Resources Agency
_____ Coachella Valley Mountains Conservancy	_____ S.F. Bay Conservation & Development Commission
_____ Coastal Commission	_____ San Gabriel & Lower L.A. Rivers and Mtns Conservancy
_____ Colorado River Board	_____ San Joaquin River Conservancy
S Conservation, Department of	_____ Santa Monica Mountains Conservancy
_____ Corrections, Department of	_____ State Lands Commission
_____ Delta Protection Commission	_____ SWRCB: Clean Water Grants
_____ Education, Department of	X SWRCB: Water Quality
S Energy Commission	_____ SWRCB: Water Rights
S Fish & Game Region # Fresno	_____ Tahoe Regional Planning Agency
_____ Food & Agriculture, Department of	S Toxic Substances Control, Department of
_____ General Services, Department of	S Water Resources, Department of
_____ Health Services, Department of	
_____ Housing & Community Development	_____ Other _____
_____ Integrated Waste Management Board	_____ Other _____
X Native American Heritage Commission	

Local Public Review Period (to be filled in by lead agency)

Starting Date June 9, 2023 Ending Date July 10, 2023

Lead Agency (Complete if applicable):

Consulting Firm: _____	Applicant: _____
Address: _____	Address: _____
City/State/Zip: _____	City/State/Zip: _____
Contact: _____	Phone _____
Phone: _____	

Signature of Lead Agency Representative: _____ **/s/** _____ **Date:** 6/9/2023

Cindi Hoover, Division Chief

Authority cited: Section 21083, Public Resources Code. Reference: Section 21161, Public Resources Code.

NOTICE OF PREPARATION/INITIAL STUDY CHECKLIST

CarbonFrontier
Carbon Capture and Sequestration
by Aera Energy, LLC

Zone Change Classification No. 4, Map No. 51; Zone Change Classification No. 3, Map No. 74;
Zone Change Classification No. 4, Map No. 75; Conditional Use Permit No. 9, Map No. 51;
Conditional Use Permit No. 7, Map No. 74; Conditional Use Permit No. 7, Map 75;
Conditional Use Permit No. 9, Map 96

PLN22-00137
(PP23402)

LEAD AGENCY:

Kern County Planning and Natural Resources Department
2700 M Street, Suite 100
Bakersfield, CA 93301-2370

Contact: Cindi Hoover
(661) 862-8629
hooverc@kerncounty.com

June 2023

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1.3. Project Description 7
1.4. Project Objectives 9
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INTRODUCTION

Pursuant to the California Environmental Quality Act (CEQA), the Kern County Planning and Natural Resources Department (County) will initiate the preparation of an Environmental Impact Report (EIR) for the CarbonFrontier Project in the unincorporated area of western Kern County, California.

1. Project Description

1.1. Project Location

The CarbonFrontier Project (proposed project) is a proposal by Aera Energy, LLC (project proponent) to construct and operate a carbon capture and sequestration (CCS) field on approximately 13,229 acres of privately owned land. CCS facilities would be composed of four (4) carbon dioxide (CO_2) capture facilities, up to nine (9) injection wells, up to eight (8) monitoring wells, CO_2 pipelines, and the surface projection of the CO_2 sequestration field capable of storing up to 43 Million Metric Tons (MM Mt) of CO_2.

The proposed project site is located within the Central Valley portion of unincorporated Kern County and is comprised of forty-seven (47) privately owned parcels and two (2) provisional parcels, within the administrative boundaries of the North and South Belridge oilfields. The North and South Belridge oilfields are contiguous and located west of Highway 33, approximately seven miles southwest of the community of Lost Hills (population 2,370).

The proposed project is located within Sections 20, 21, 22, 26, 27, 28, 34, 35, and 36 of Township 27 South, Range 20 East; Sections 1, 2, and 12 of Township 28 South, Range 20 East; Sections 6, 7, 17, 18, 20, 27, 28, 29, 32, 33, and 34 of Township 28 South Range 21 East; and Sections 2, 3, and 4 of Township 29 South, Range 21 East of the Mount Diablo Base and Meridian (MDBM). The proposed project area can be seen in Figure 1 – Regional Vicinity.

Primary access to the project site would be from Oasis Road, a private road, accessed from Seventh Standard Road, west of Highway 33, which can be seen in Figure 2 – Local Vicinity. The access road connects to a network of existing dirt roads within the field; depending on the final locations of the injection wells and accessory facilities and infrastructure, new internal access roads may be constructed. These new roads would most likely be compacted dirt roads as well.

1.2. Environmental Setting

The proposed project site is situated in the western extent of the valley region in unincorporated Kern County. The County's geography includes, among other features, mountainous area, agricultural lands, and deserts. Kern County is California's third largest County in land area and encompasses approximately 8,200 square miles with the current estimated population being 914,193 residents.

As previously discussed, the project site is located within the administrative boundary of the South and North Belridge oilfields. Combined, the two oilfields cover an area approximately thirteen (13) miles long and three (3) miles wide. The oil fields are predominantly developed with oil and gas production and accessory facilities and infrastructure. The primary operator within both oilfields is Aera Energy, LLC. The proposed CO_2 capture facilities would be located within the developed portion of the South Belridge oilfield. The proposed injection wells, monitoring wells and CO_2 sequestration field would be located in the North Belridge oilfield. Pipelines would transect both fields. The infield pipelines would primarily be

installed above ground, except where the pipelines would cross main access roads (below ground) within the oil field properties. The CO_2 sequestration field would be comprised of 2,636 acres of land in which CO_2 would be injected and stored underground in a depleted oil and gas reservoir.

The proposed project parcels are not designated by the California Department of Conservation (DOC) as Prime Farmland, Farmland of Statewide Importance, or Unique Farmland. However, the proposed project site has two (2) parcels (APN: 068-220-26 and 085-210-42) subject to Farmland Security Zone (FSZ) contracts and three (3) parcels subject to Williamson Act Land Use Contracts; one (1) parcel (APN: 068-210-13) designated as non-prime; one (1) parcel (APN: 068-200-33) designated as mixed; and one (1) parcel (APN: 085-220-37) designated as prime, as shown in *Figure 3 – Active Land Use Contract*. Furthermore, twenty-four (24) parcels are included within the boundaries of Agriculture Preserve numbers 5 and 2, as shown in Figure 4 – Agricultural Preserve.

The proposed project site is within the San Joaquin Valley Air Basin, under the regulatory authority of the San Joaquin Valley Air Pollution Control District. The Federal Emergency Management Agency (FEMA) delineates flood hazard areas on its Flood Insurance Rate Maps (FIRMs). A majority of the proposed project site is designated as Zone "X" on the FIRMs, which indicates the site is not in an area of flood hazard, as shown in Figure 5 – Flood Hazard. However, portions of the proposed pipeline routes are located within the FIRMs and are designated as Zone "A" flood hazard area, which indicates the site has a 1% chance of flooding. There are no State-designated Alquist-Priolo Earthquake Fault Zones within the proposed project site. No portion of the project site is identified as a wetland area on the National Wetlands Inventory.

Additionally, the proposed project site is not located within a Kern County-designated mineral recovery zone, however, the majority of the North and South Belridge oilfields are designated by the Kern County General Plan for Mineral and Petroleum exploration and extraction. Please see *Figure 6 – Existing General Plan Designations.* Most parcels within the proposed project boundary have a zone classification of A (Exclusive Agriculture), with the exception of five parcels which have a zone classification of A-1 (Limited Agriculture) and a portion of one (1) parcel which currently has a zone classification of NR (20) (Natural Resources – 20 acre minimum) as shown in *Figure 7 – Existing Zoning Classifications.* The project proponent has requested a zone classification change to A (Exclusive Agriculture) on parcels with a current zone classification of A-1 (Limited Agriculture) or NR (20) (Natural Resources – 20 acre minimum) *Figure 8 – Proposed Zoning Classifications.*

Table 1: Project Assessor Parcel Numbers, Existing Map Code Designation, Existing and Proposed Zoning, & Acreages, below identifies the individual parcels, their respective assessor parcel numbers (APN), acreages, and existing general plan and zoning designations.

Table 1: Project Assessor Parcel Numbers, Existing Map Code Designation, Existing and Proposed Zoning, & Acreages

APN	Existing Map Code Designations	Existing Zoning	Proposed Zoning	Section Township Range	Acres	Land Use Contract/ Designation	Agriculture Preserve
068-210-13	8.3	A	A	S20/T27S/R20E	240	Nonprime	Preserve 5
068-210-35	8.3/8.4	A	A	S21/T27S/R20E	120	N/A	Preserve 5
068-210-34	8.3	A	A	S21/T27S/R20E	40	N/A	Preserve 5
068-210-19	8.3	A	A	S21/T27S/R20E	120	N/A	Preserve 5
068-200-30	8.4	A	A	S22/T27S/R20E	44.80	N/A	Preserve 5
068-200-37	8.4	A	A	S22/T27S/R20E	37.23	N/A	Preserve 5
*068-200-41	8.4	A	A	S22/T27S/R20E	66.84	N/A	Preserve 5
068-200-33	8.3/8.4	A	A	S22/T27S/R20E	192.34	Mixed	Preserve 5
068-220-55	8.4	A	A	S34/T27S/R20E	152.36	N/A	Preserve 5
068-220-42	8.4/8.1	A	A	S36/T27S/R20E	123.60	N/A	Preserve 5
*068-220-39	8.4	A	A	S36/T27S/R20E	26.17	N/A	Preserve 5
068-220-37	8.4	A	A	S36/T27S/R20E	18.52	N/A	Preserve 5
068-210-18	8.3/8.4	A	A	S21/T27S/R20E	360	N/A	N/A
068-200-16	8.4	A-1	A	S22/T27S/R20E	40	N/A	N/A
068-230-04	8.3/8.4	A-1	A	S28/T27S/R20E	640	N/A	N/A
068-220-01	8.4	A	A	S27/T27S/R20E	640	N/A	N/A
068-220-36	8.4	A	A	S26/T27S/R20E	324.10	N/A	N/A

068-220-25	8.4	A-1	A	S34/T27S/R20E	40	N/A	N/A
068-220-26	8.4	A	A	S34/T27SR20E	118.85	FSZ	Preserve 5
068-220-13	8.4	A	A	S35/T27S/R20E	640	N/A	N/A
068-220-44	8.4	A	A	S36/T27S/R20E	78.29	N/A	Preserve 5
068-220-08	8.4	A	A	S36/T27S/R20E	80	N/A	N/A
085-110-10	8.4/2.5	A-1	A	S2/T28S/R20E	554.84	N/A	N/A
085-110-13	8.4	A	A	S1/T28S/R20E	160	N/A	N/A
085-110-14	8.4	A	A	S12/T28S/R20E	160	N/A	N/A
085-110-16	8.4	A	A	S12/T28S/R20E	80	N/A	N/A
085-110-32	8.4	A	A	S12/T28S/R20E	382.33	N/A	N/A
085-110-50	8.4/2.5	A-1	A	S1/T28S/R20E	462.54	N/A	N/A
085-190-27	8.1/8.4	A	A	S6/T28S/R21E	64.77	N/A	N/A
085-190-28	8.1/8.4	A	A	S7/T28S/R21E	309.82	N/A	N/A
085-210-43	8.4/2.5	A	A	S18&17/T28S/R21E	530.22	N/A	N/A
085-210-40	8.1/2.5	A	A	S18/T28S/R21E	135.30	N/A	N/A
085-210-42	8.1/2.5	A	A	S17/T28S/R21E	313.16	FSZ	Preserve 5
085-210-18	8.4/2.5	A	A	S20/T28S/R21E	619.15	N/A	N/A
085-230-05	8.4	A	A	S29/T28S/R21E	640	N/A	N/A
085-230-26	8.4/8.1/2.5	A	A	S28/T28S/R21E	493.18	N/A	N/A
085-230-07	8.4/2.5	A	A	S33/T28S/R21E	631.36	N/A	N/A

085-230-09	8.4/2.5	A/NR (20)	A	S32/T28S/R21E	636.36	N/A	N/A
085-230-25	8.1/8.4	A	A	S28/T28S/R21E	139.79	N/A	Preserve 5
085-220-36	8.1/2.5	A	A	S27/T28S/R21E	274.99	N/A	Preserve 5
085-220-37	8.1/2.5	A	A	S27/T28S/R21E	366.45	Prime	Preserve 5
085-220-19	8.1/2.5	A	A	S27/T28S/R21E	14.77	N/A	Preserve 5
085-220-21	8.4/2.5	A	A	S34/T28S/R21E	287.87	N/A	N/A
085-220-22	8.4/2.5	A	A	S34/T28S/R21E	336.16	N/A	N/A
098-111-01	8.4	A	A	S3/T29/R21E	315.78	N/A	Preserve 2
098-111-03	8.4/8.3	A	A	S3/T29S/R21E	320	N/A	Preserve 2
098-112-01	8.4	A	A	S2/T29S/R21E	277.07	N/A	Preserve 2
098-112-02	8.4	A	A	S2/T29S/R21E	276.98	N/A	Preserve 2
098-120-10	8.4/8.3	A	A	S4/T29S/R21E	317.04	N/A	Preserve 2

** Provisional Parcel*

Kern County General Plan Map Code Designations:
2.5 (Flood Hazard Overlay)
8.1 (Intensive Agriculture)
8.3 (Extensive Agriculture)
8.4 (Mineral and Petroleum)

Kern County Zoning District:
A (Exclusive Agriculture); A-1 (Limited Agriculture); NR (20) (Natural Resource, Min 20 Acre Parcel Size)

Land Use Contract/Designation:
Williamson Act Land Use Contract Designations: Mixed; Prime; Non-Prime
Farmland Security Zone (FSZ)Contract

Surrounding Land Uses

Table 2, Existing Project Site and Surrounding Properties, Existing Land Use, General Plan Map Code Designations, and Zoning, identifies the existing land use, the existing general plan land use designation,

and the existing zone classification within the proposed project site. Additionally, such conditions are described for adjacent lands to the north, east, south, and west of the proposed project site.

Table 2: Existing Project Sites and Surrounding Properties, Existing Land Use, General Plan Map Code Designations, and Zoning

Location	Existing Land Use	Existing General Plan Map Code Designations	Existing Zoning
Project Site	Oil and Gas Exploration and Production	8.1 (Intensive Agriculture) 8.3 (Extensive Agriculture) 8.4 (Mineral and Petroleum) 8.1/2.5 (Intensive Agriculture / Flood Hazard Overlay) 8.3/2.5 (Extensive Agriculture / Flood Hazard Overlay) 8.4/2.5 (Mineral and Petroleum / Flood Hazard Overlay)	A (Exclusive Agriculture) A-1 (Limited Agriculture) NR (20) (Natural Resources – 20 acre min)
North	Oil and Gas Exploration and Production, Undeveloped Land, Agriculture	8.3 (Extensive Agriculture)	A (Exclusive Agriculture)
East	Agriculture	8.1/2.5 (Intensive Agriculture / Flood Hazard Overlay) 8.1 (Intensive Agriculture) 8.3 (Extensive Agriculture)	A (Exclusive Agriculture)
South	Oil and Gas Exploration and Production	8.4 (Mineral and Petroleum) 8.4/2.5 (Mineral and Petroleum / Flood Hazard Overlay)	A (Exclusive Agriculture)
West	Oil and Gas Exploration and Production, Undeveloped Land	8.3 (Extensive Agriculture) 8.3/2.5 (Extensive Agriculture / Flood Hazard Overlay) 8.4 (Mineral and Petroleum) 8.4/2.5 (Mineral and Petroleum / Flood Hazard Overlay)	A (Exclusive Agriculture) A-1 (Limited Agriculture)

The surrounding land uses of the proposed project site include oil and gas exploration and production, grazing, and agricultural lands. The closest sensitive receptor to the proposed project site includes one residence approximately 400 feet from the project boundary, and approximately 3,970 feet from the nearest proposed injection well, located east of State Route 33 and adjacent to the North Belridge oilfield. The

nearest schools are Lost Hills Elementary School and A.M. Thomas Middle School located at 20979 Lobos Court approximately six (6) miles northeast of the proposed project site. Additionally, the nearest recreational facility is the Lost Hills Wonderful Park located approximately seven (7) miles northeast of the proposed project site.

The proposed project would be served by the Kern County Sheriff's Office (KCSO) for law enforcement and public safety, Kern County Fire Department (KCFD) for fire protection, and Kern County Medical Emergency Service for emergency medical and rescue services. The nearest KCSO substation that would serve the project is located in the City of Taft at 315 N. Lincoln Street. Additionally, fire protection and emergency medical service would be provided by the KCFD fire station (Station No. 26) located at 14670 Lost Hills Road in the community of Lost Hills.

The proposed project is not located within an Airport Sphere of Influence (SOI), per the Kern County Airport Land Use Compatibility Plan (ALUCP). The nearest airport is the Buttonwillow Airport approximately 14 miles southeast of the proposed project site.

1.3. Project Description

Aera Energy, LLC is proposing to construct and operate a CCS project within the North and South Belridge oilfields. The proposed project requires a Zone Classification Change (ZCC) from A-1 (limited Agriculture) to A (Exclusive Agriculture) on approximately 1,737 acres, from NR (Natural Resources – 20 acre minimum) to A (Exclusive Agriculture) on approximately 47 acres and a Conditional Use Permit (CUP) to allow a CCS capture facility, associated Class VI geologic sequestration injection wells, and related improvements for storage of CO_2 on approximately 13,229 acres. The proposed project CUP boundary is shown in Figure 9 – Proposed Project CUP Boundary.

The project would capture CO_2 from existing sources within the South Belridge oil field and transport it by pipeline to dedicated Class VI injection wells within the North Belridge oil field to be injected into identified geologically confined reservoirs for storage. The underground CCS formation is a depleted oil and gas reservoir with saline formation water, situated at a depth of approximately 8,500', more than a mile below potential underground sources of drinking water. Prior to project commencement, oil and gas production activities would cease within the underground CCS formation where CO_2 would be stored. The CO_2 distribution pipelines, and associated infrastructure would be new construction and sized to accept CO_2 from existing sources within the South Belridge oil field. This area has been identified as a location suitable for such storage and the potential to contribute to California's goals for carbon neutrality by 2045 by reducing industrial uses to no net contribution and potentially supporting direct removal of CO_2 from the air. California executive order B-55-18 mandates that the state achieve carbon neutrality by 2045 and maintain net negative emissions thereafter.(https://livermorelabfoundation.org/2019/12/19/getting-to-neutral/).

Implementation of the project would require permits from the Federal Environmental Protection Agency (EPA) for up to nine (9) Class VI injection wells in compliance with the Underground Injection Control (UIC) Program for Class VI injection wells (40 CFR 146.81 et seq.). Area of Review (AOR) modeling has been performed to define the anticipated limits of the CCS field. The Area of Review is the region surrounding the geologic sequestration project where Underground Sources of Drinking Water (USDWs) may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and displaced fluids, and is based on available site characterization, monitoring, and operational data as set

forth in 40 CFR 146.84 (Underground Injection Control (UIC) Program Class VI Implementation Manual for UIC Program Directors, EPA 816-R-18-001, January 2018).

All employee facilities needed for the proposed project would be provided by the existing Aera Belridge facilities. Over the life of the proposed project, the CO_2 capture facilities would require on average approximately 918 acre feet per year (AFY). This preliminary estimate is based on seasonal high temperatures and the average daily water use is expected to be less than 26,000 barrels per day.

The proposed project would primarily use produced water from the Belridge oilfield. Fresh water would be minimally used for utility purposes including, but not limited to fire protection, lavatories, showers, equipment cleaning, dust control, grading, compaction, and only used in the process if sufficient water is available under existing water rights. Fresh water would be sourced from existing State Water Project entitlements with the Belridge Water Storage District and from existing Aera-owned groundwater wells located in the Buena Vista Water Storage District. Water treatment facilities would be installed at the CO_2 capture facilities to treat produced water. Pipelines for water would be constructed and installed primarily aboveground connecting the new water treatment facilities to existing water distribution pipelines and water injection wells.

Electrical demand for the proposed project is estimated to be up to 49 megawatts (MW), which will be provided by the existing Section 32 Cogeneration facility and existing utility electrical service connections. If project energy demands are forecasted to exceed existing self-generation and electrical service capacity, a supplemental load request would be pursued with the utility provider and may warrant upgrades to power distribution infrastructure.

The proposed project would capture CO_2 from existing Tulare and Diatomite reservoir produced gas streams (Pre-Combustion) and emissions from flue gas emissions from existing stationary sources (Post-Combustion) within the South Belridge oilfield, described in more detail below, and transport the CO_2 through pipelines to the North Belridge oilfield for injection at dedicated UIC Class VI injections wells.

Pre-Combustion

Produced natural gas from existing operations will be directed to a dedicated CO_2 capture facility to be located near Gas Plant 32 (GP 32) in Section 32, Township 28 South, Range 21 East of the Mount Diablo Base and Meridian. The CO_2 capture facility would include three steel towers up to 120 feet in height and between 2 to 12 feet in diameter. Other equipment within the facility will include heat exchangers, transfer pumps, compressors, and a storage area for process chemicals.

A physical solvent or a traditional amine absorption process would be used to remove the CO_2 from the produced gas stream. In the CO_2 capture facility, the produced gas stream would be passed through an absorber column where the absorbent would chemically react with and bind over 90 percent of the incoming CO_2. The rich absorbent carrying the CO_2 would be piped to a regenerator column and through the combination of reduced pressure and applied heat the CO_2 would be released from the absorbent and captured in nearly pure concentration. Following the CO_2 release, the reconstituted absorbent would be recycled back to the absorber column. The captured CO_2 would then be cooled, compressed, and pumped by pipeline to the permitted Class VI injection wells to be stored in the underground CCS sequestration field located within the North Belridge oilfield.

Post-Combustion

Three post-combustion CO_2 capture facilities would be constructed to remove CO_2 from the exhaust streams at three existing facilities. The post-combustion CO_2 capture facilities would be located at the Section 32 Cogeneration facility, Steam Generation Site 2868, and Steam Generation Site 2972 within the South Belridge oil field. The CO_2 capture and processing facilities would include the separation, dehydration, compression, and cooling of CO_2 from flue gas emissions at the existing stationary sources. The post-combustion CO_2 capture facilities would use a similar chemical process as described above for the pre-combustion facility. The remaining flue gas would continue to be vented to the atmosphere as allowed under the facilities current permits issued by the San Joaquin Valley Air Pollution Control District.

Proposal

Implementation of the proposed project includes the following requests:

(a) Zone Classification Changes (ZCC), as follows:

- A-1 (Limited Agriculture) to A (Exclusive Agriculture) on approximately 1,737.38 acres comprised of five (5) parcels;
- NR (20) (Natural Resources – 20 gross acres) to A (Exclusive Agriculture) on approximately 47 acres comprised of a portion of one (1) parcel.

(b) Conditional Use Permit (CUP) to allow for the construction and operation of a Carbon capture and sequestration field, within the A (Exclusive Agriculture) Zone District. Carbon Capture and Sequestration (CCS) has been determined to be a storage operation under the Kern County Zoning Ordinance, Section 19.08.085 and Section 19.06.020. Therefore, CCS in either existing formations or tanks is an allowed use with a Conditional Use Permit (CUP) in the following districts:

- A District (Exclusive Agriculture)
- M-2 District (Medium Industrial)
- M-3 (Heavy Industrial)

1.4. Project Objectives

The project proponent has defined the following objectives for the proposed project:

- Construct and operate facilities and infrastructure to capture, transport, inject, and permanently sequester up to 43 MM Mt of CO_2 in a safe, secure, and economically feasible manner for storage, not enhanced recovery;
- Minimize new disturbance by siting and designing project facilities and infrastructure within the existing developed oil field footprint;
- Reduce the carbon intensity of Aera's produced oil and gas by capturing CO_2 from produced gas and stationary sources;
- Generate environmental, social, and economic benefits for Kern County and the State of California by implementing low carbon technologies, developing CCS infrastructure, and providing living-wage jobs in the region; and

- Contribute to California's goal to achieve carbon neutrality by 2045 (Executive Order B-55-18) by integrating carbon capture in existing operations as well as ending oil and gas production from select reservoirs and repurposing them for the permanent storage of CO_2.

1.5. Proposed Discretionary Actions/Required Approvals

The Kern County Planning and Natural Resources Department as the CEQA Lead Agency (per CEQA Guidelines Section 15052) has discretionary responsibility for the CarbonFrontier Project owned by AERA ENERGY, LLC. To implement this project, the project proponent may need to obtain discretionary and ministerial permits/approvals including, but not limited to, the following:

- Federal
    - Environmental Protection Agency Underground Injection Control – Class VI Permit
    - U.S. Fish and Wildlife Service (USFWS) Section 10 Incidental Take Permit and Habitat Conservation Plan (if required).
    - United States Army Corps of Engineers Section 404 Permit (if required)
    - Pipeline Approval – U.S. Department of Transportation – Pipeline and Hazardous Materials Safety Administration (if required)
- State
    - California Department of Fish and Wildlife (CDFW)
        - Section 2081 Incidental Take Permit (State-listed endangered species) (if required)
        - Section 1602 Lake or Streambed Alteration Agreement (if required)
    - Central Valley Water Quality Control Board (RWQCB)
        - Waste Discharge Requirements
        - Regional Water Quality Certification (401 Permit) (if required)
        - National Pollution Discharge Elimination System (NPDES) Construction General Permit
        - General Construction Stormwater Permit (Preparation of a SWPPP) (if required)
    - California Department of Transportation (Caltrans)
        - Right-of-Way Encroachment Permit (if required)
        - Permit for Transport of Oversized Loads (if required)
    - California Department of Conservation - Geological Energy Management Division (CalGEM)
        - Well Abandonment Permit (if required)

- Local
    - Kern County
        - Certification of Final Environmental Impact Report
        - Adoption of Mitigation Monitoring and Reporting Program
        - Adoption of 15091 Findings of Fact and 15093 Statement of Overriding Considerations
        - Approval of Zone Classification Change
        - Approval of Conditional Use Permits
        - Approval of Kern County Grading (if required)
        - Approval of Kern County Building Permits
        - Approval of Fire Safety Plan
    - San Joaquin Valley Air Pollution Control District
        - Approval of Fugitive Dust Control Plan
        - Authority to Construct (ATC)
        - Permit to Operate (PTO)

The preceding discretionary actions/approvals are potentially required and do not necessarily represent a comprehensive list of all possible discretionary permits/approvals required. Other additional permits or approvals from responsible agencies may be required for the proposed project.

In addition, although not required to implement the proposed project, the project proponent may seek a determination from the California Air Resources Board for Permanence Certification under the Low Carbon Fuel Standard's CCS Protocol.

Figure 1 – Regional Vicinity

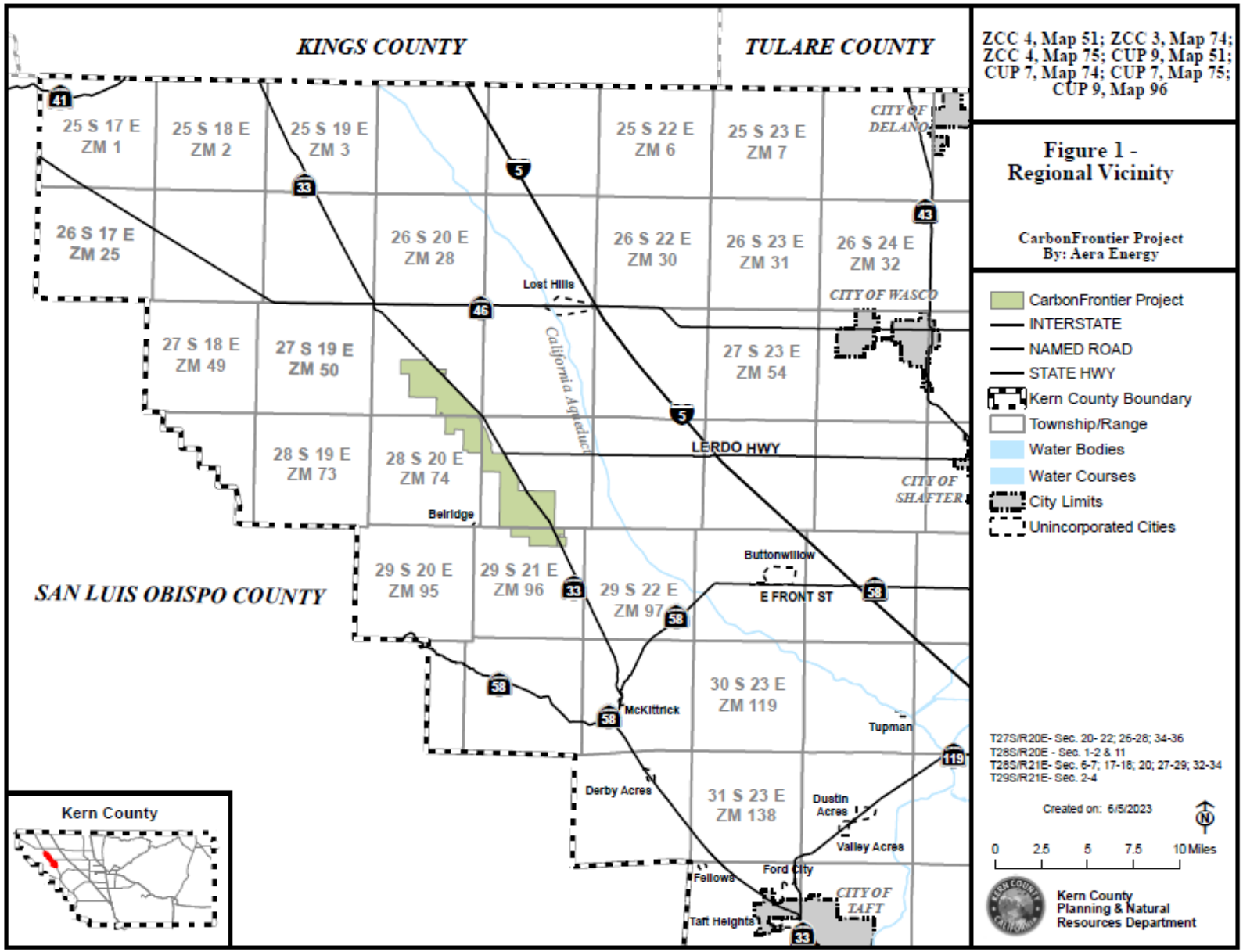


Figure 2 – Local Vicinity

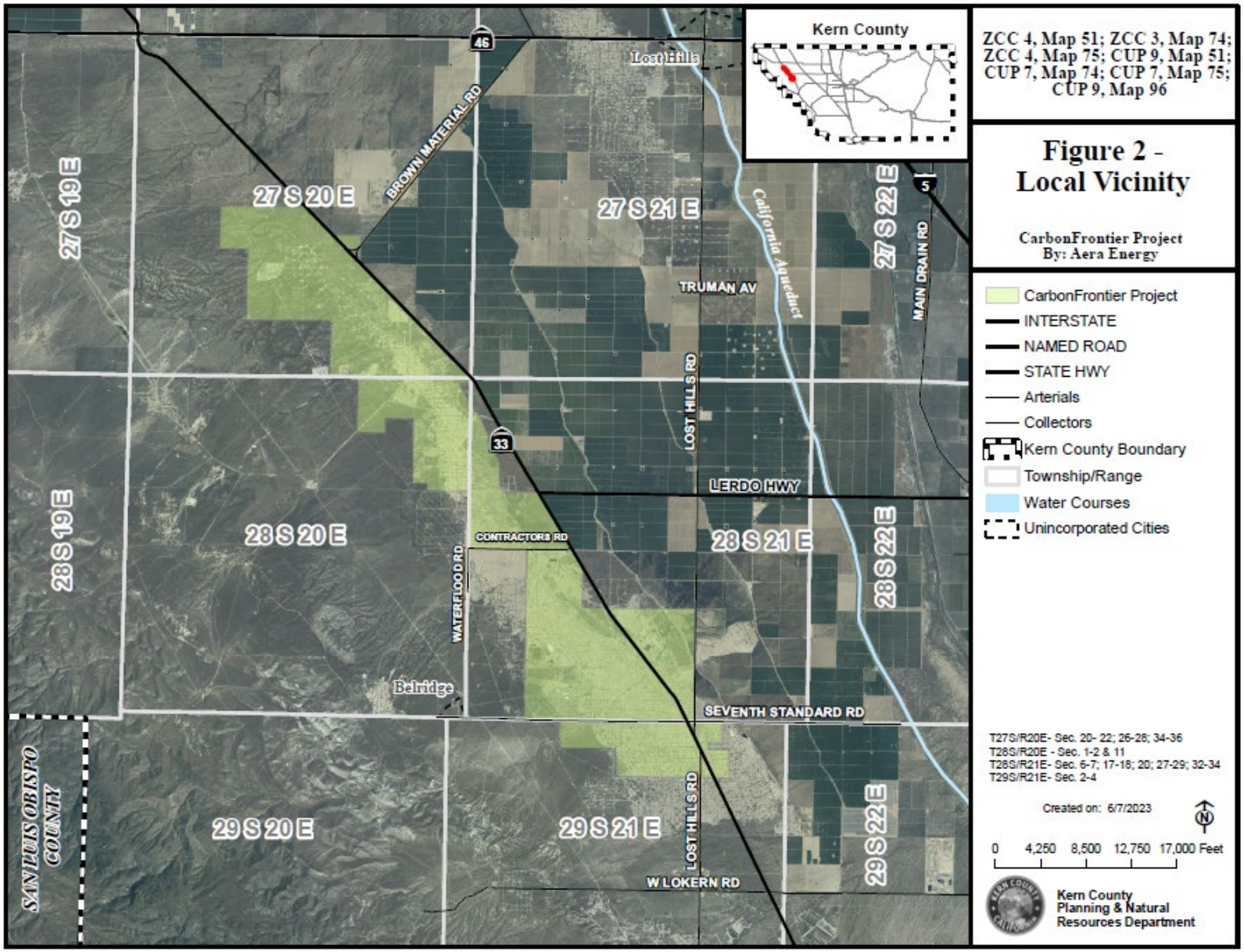


Figure 3 – Active Land Use Contract

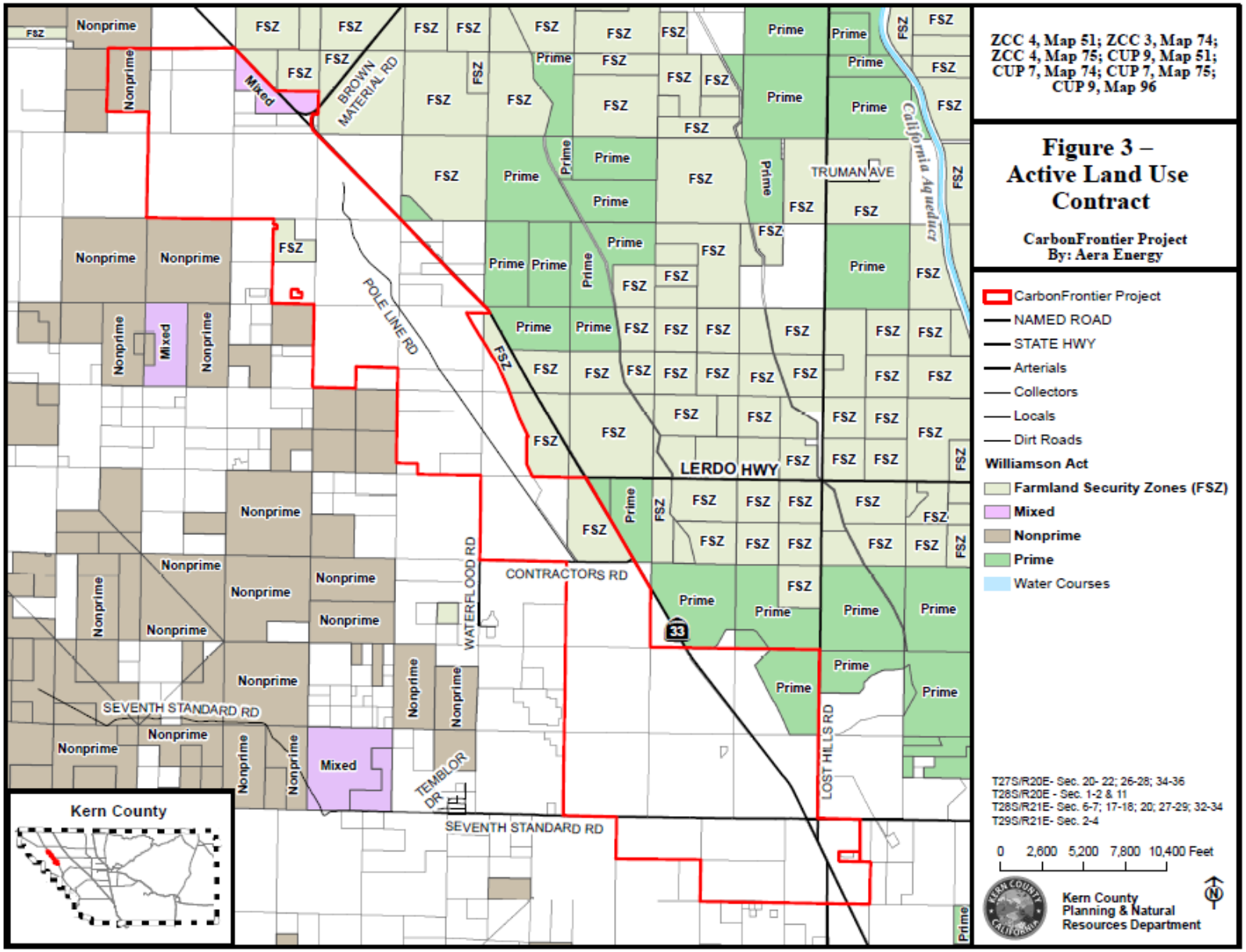


Figure 4 – Agricultural Preserve

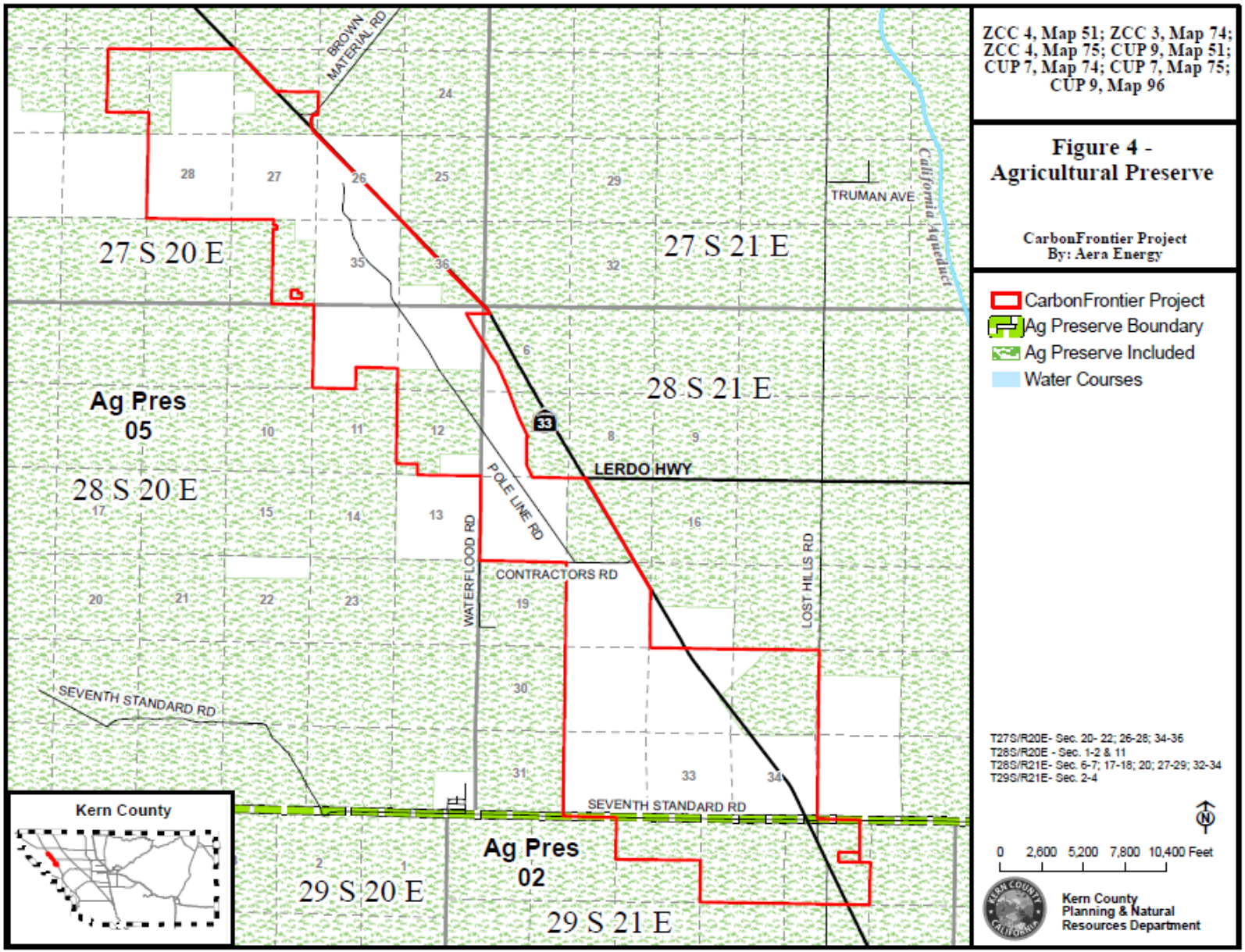


Figure 5 – Flood Hazard

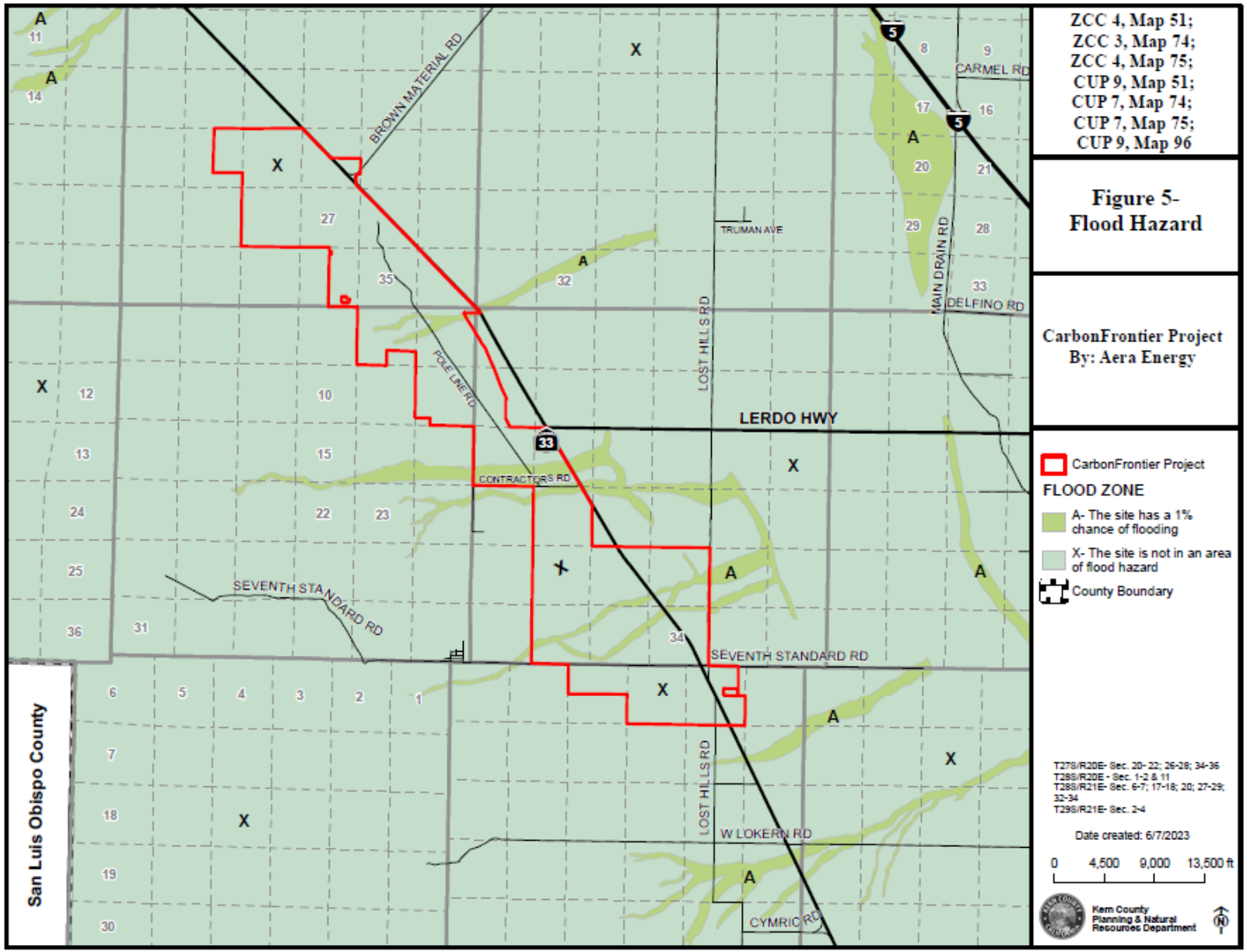


Figure 6 – Existing General Plan Designations

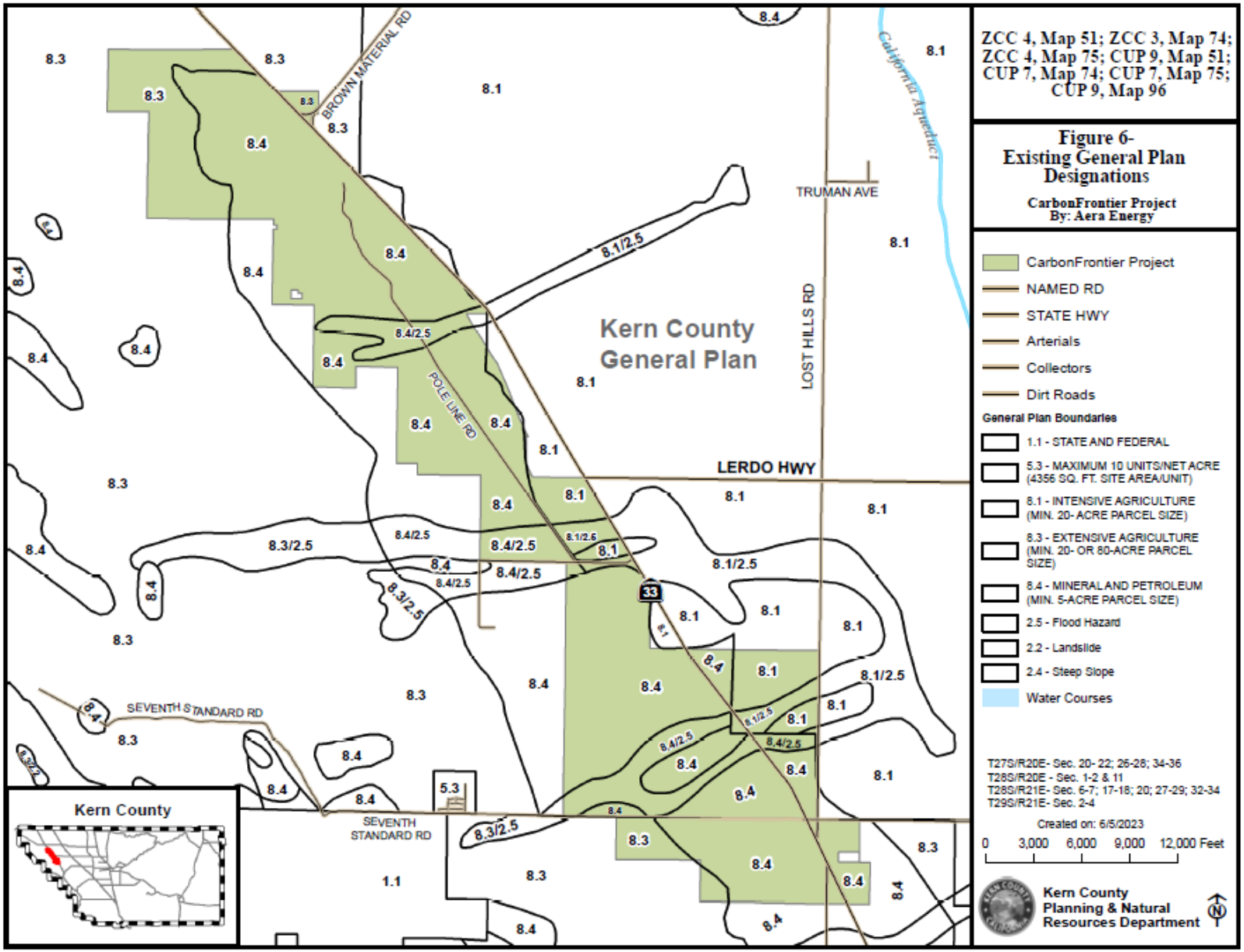


Figure 7 – Existing Zone Classification

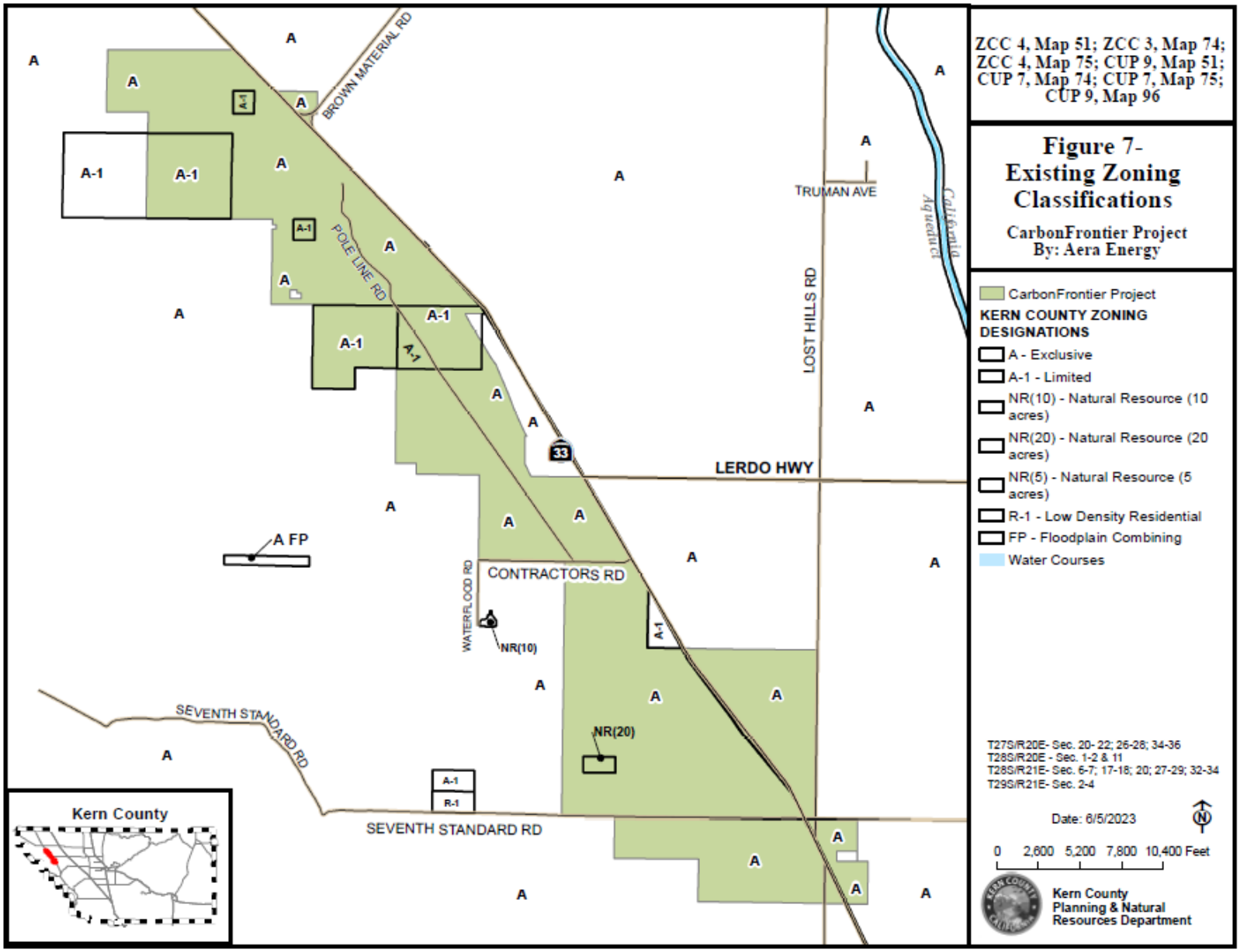


Figure 8 – Proposed Zoning Classifications

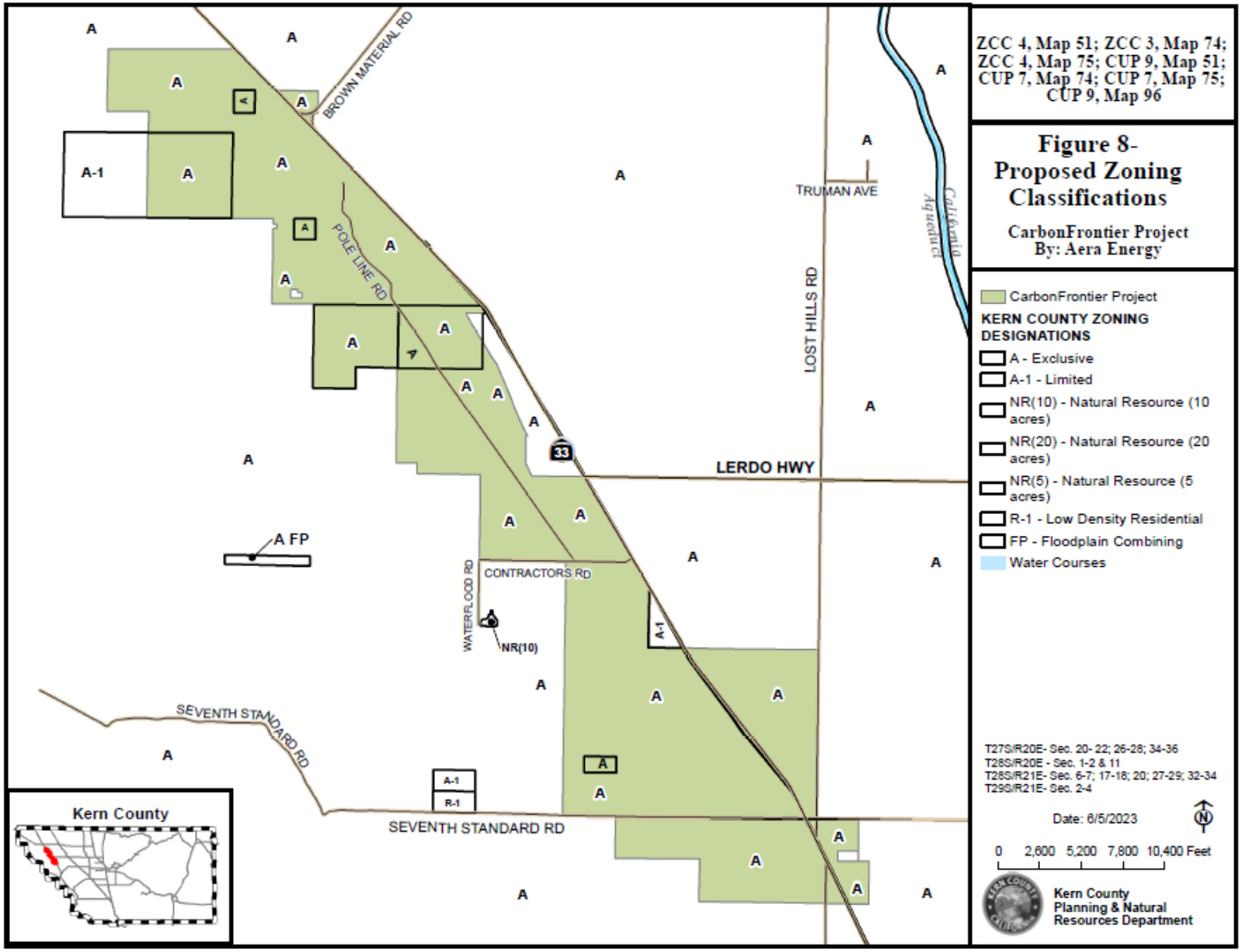
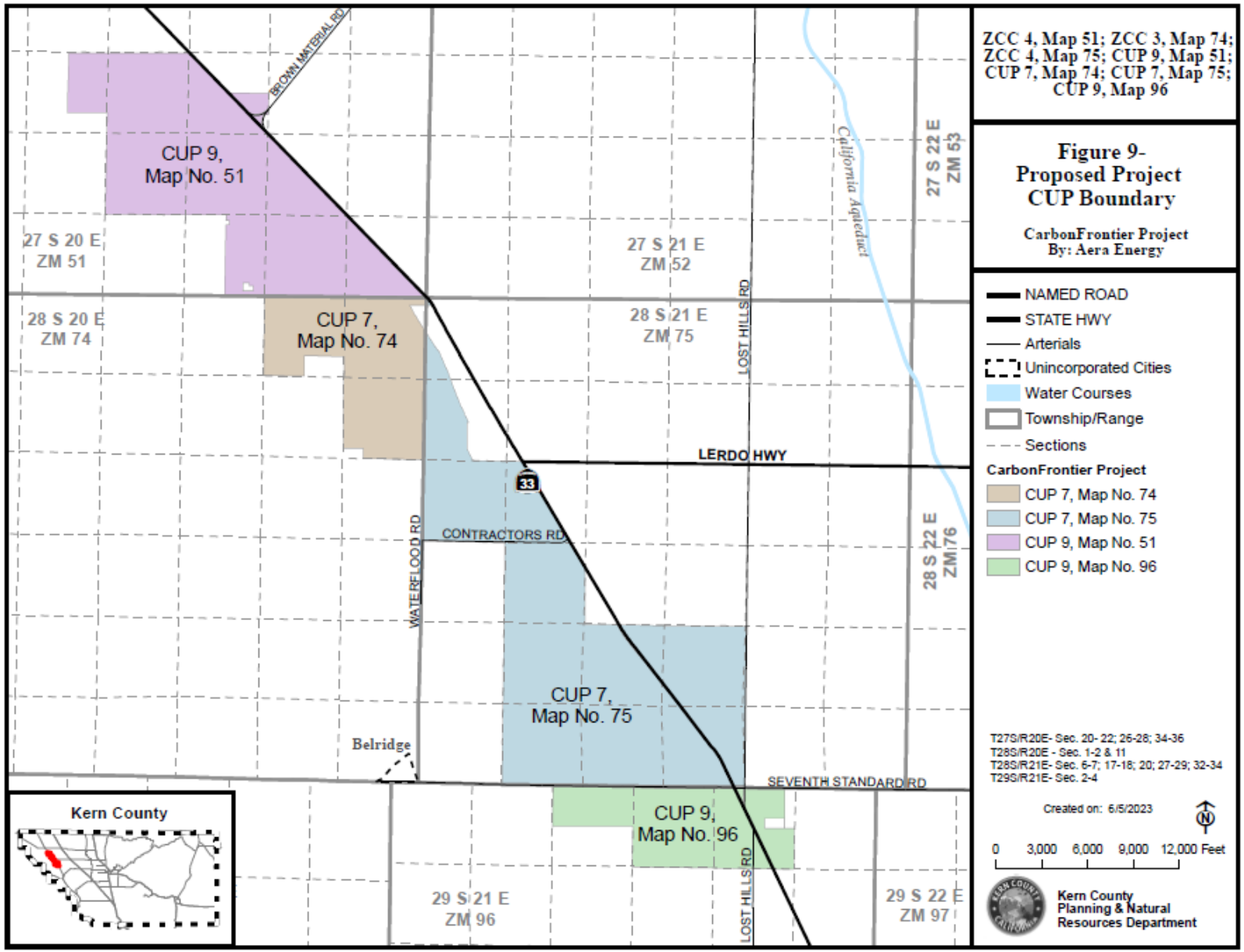


Figure 9 – Proposed Project CUP Boundary



2. Kern County Environmental Checklist Form

2.1. Environmental Factors Potentially Affected

In accordance with CEQA Guidelines, the County intends to prepare an Environmental Impact Report (EIR) to evaluate potential environmental effects of the project and to propose mitigation measures to reduce any significant effects identified.

The environmental factors checked below would be potentially affected by this project, involving at least one impact that is a "potentially significant impact" as indicated by the Kern County Environmental Checklist. As such, the analysis contained within the EIR will focus on these issue areas.

☒ Aesthetics	☒ Agricultural and Forestry Resources	☒ Air Quality
☒ Biological Resources	☒ Cultural Resources	☒ Energy
☒ Geology and Soils	☒ Greenhouse Gas Emissions	☒ Hazards and Hazardous Materials
☒ Hydrology and Water Quality	☒ Land Use and Planning	☒ Mineral Resources
☒ Noise	☒ Population and Housing	☒ Public Services
☒ Recreation	☒ Transportation and Traffic	☒ Tribal Cultural Resources
☒ Utilities/Service Systems	☒ Wildfire	☒ Mandatory Findings of Significance

2.2. Determination

(To be completed by the Lead Agency)

Based on this initial evaluation:

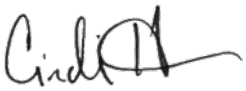
☐ I find that the proposed project COULD NOT have a significant effect on the environment, and a NEGATIVE DECLARATION will be prepared.

☐ I find that although the proposed project could have a significant effect on the environment, there will not be a significant effect in this case because revisions in the project have been made by or agreed to by the project proponent. A MITIGATED NEGATIVE DECLARATION will be prepared.

☒ I find that the proposed project MAY have a significant effect on the environment, and an ENVIRONMENTAL IMPACT REPORT is required.

☐ I find that the proposed project MAY have a "potentially significant impact" or "potentially significant unless mitigated" impact on the environment, but at least one effect (a) has been adequately analyzed in an earlier document pursuant to applicable legal standards, and (b) has been addressed by mitigation measures based on the earlier analysis as described on attached sheets. An ENVIRONMENT IMPACT REPORT is required, but it must analyze only the effects that remain to be addressed.

☐ I find that although the proposed project could have a significant effect on the environment, because all potentially significant effects (a) have been analyzed adequately in an earlier EIR or NEGATIVE DECLARATION pursuant to applicable standards, and (b) have been avoided or mitigated pursuant to that earlier EIR or NEGATIVE DECLARATION, including revisions or mitigation measures that are imposed upon the proposed project, nothing further is required.

Signature: 	Date: 6/9/2023
Printed Name: Cindi Hoover	Title: Division Chief

A.2 Notice of Preparation Comment Letters

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CENTER for BIOLOGICAL DIVERSITY
Because life is good.

CENTRAL CALIFORNIA
ENVIRONMENTAL JUSTICE NETWORK

July 3, 2023

Kern County Planning and Natural Resources Department
Cindi Hoover
2700 "M" Street, Suite 100
Bakersfield, CA 93301
hooverc@kerncounty.com

Re: Notice of Preparation of a Draft Environmental Impact Report: – CarbonFrontier Carbon Capture Sequestration (CCS) Project by Aera Energy, LLC (PP23402)

Dear Kern County Planning and Natural Resources Department:

The Center for Biological Diversity and the Central California Environmental Justice Network (CCEJN) submit these comments on the Notice of Preparation (NOP) of an Environmental Impact Report (EIR) for the CarbonFrontier Carbon Capture Sequestration Project by Aera Energy, LLC (PP23402) (hereinafter, the project, or the Aera CCS project). The proposed project involves capturing carbon dioxide (CO_2) from sources in the South Belridge oil field and transporting it in as-yet undisclosed number of pipelines to up to nine injection wells in the North Belridge oilfield with the capacity to store 43 million metric tons (MM Mt).

As a threshold matter, our organizations disagree with the premise that carbon capture and sequestration (CCS) should play a role in achieving our state's goal of reaching near-zero emissions by midcentury in order to limit global warming to 1.5°C. CCS regularly over-promises and under-delivers on its carbon capture benefits all while keeping dirty industries like fossil fuels alive, making it a false solution that diverts attention and resources from transitioning to clean, renewable energy. Instead of approving carbon storage, the County should phase out fossil fuel development to prevent catastrophic climate change and environmental injustice.

If the County continues to consider the project, as explained in detail below, it must first commit to providing the public with at least 90 days to review and comment on the draft EIR (DEIR), hearings, and translations of relevant project materials.

Specific to the DEIR, the County must adequately analyze and mitigate the project's full array of potential impacts to the environment. Transporting compressed CO_2 is extremely risky to people and the environment, as any leak can lead to serious injury or death to those even miles away. The State has not yet clarified regulatory authority over carbon pipelines, nor has it written regulations addressing carbon pipeline safety standards. In addition, storing carbon underground can contaminate drinking water and trigger earthquakes. Even if the applicant has modeled the injected carbon's area of review (AoR), this could change based on the application process for wells with EPA. The County must wait until EPA's review of the Class VI permits is complete and the permits are issued so that the full array of project activities are known and can be

assessed. Finally, because the project will prolong use of fossil fuels and unacceptably endanger and impact the environment, the County should deny the requested conditional use permit.

I. The Kern County Planning Department Should Provide the Public with At Least 90 Days for Comment and at Least Two Hearings on the Draft EIR.

While we recognize that the present comment period is on the NOP for the EIR, for the reasons described below, we urge the County to offer at least 90 days for public comment once the draft EIR is released.[1] The County should also hold at least two public hearings once the draft EIR is available.[2] We also request that the County translate the EIR and other key documents—including press releases, summaries, and presentations—into Spanish, Punjabi and any other language translation requested by county residents. In light of the significant Spanish- and Punjabi- speaking populations throughout Kern County, the County should also provide Spanish, Punjabi, or other language interpretation requested at any public meetings.

There are several reasons why more time to comment public hearings is necessary. First, it is likely that the Aera CCS EIR will be only the first or second CEQA review of a CCS project in state history, and the public must have ample time to review, consider, and comment on such an activity of statewide significance.

Second, CCS projects produce an array significant public safety and environmental impacts and risks, such as groundwater contamination, dangerous releases of compressed CO_2, earthquakes, and air pollution.[3] The public needs more than 30 days to review an EIR discussing such a wide array of significant impacts that could result from deployment of technology that is new to the state.

Third, the proposed project location is near highly-impacted, vulnerable, and overburdened residents of the San Joaquin Valley. The input, questions, and perspectives of those who will be most affected by the proposed projects must be heard, and allowing only 30 days for review and comment on the EIR—or requiring residents to seek a comment extension and wait for an answer—does not serve this purpose.

It is therefore imperative that the County provide at least 90 days for public comment throughout the CEQA process, hold at least two hearings on the draft EIR, and translate all materials and hearings.

II. The EIR Should Consider Other Alternatives that Would Advance the State's Carbon Neutrality Goals While Protecting Communities and the Environment.

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[1] Cal. Code Regs. tit. 14, § 15087(d) (directing that the public be given "*at least* 30 days" for comment).
[2] *Id.* § 15087(i).
[3] Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geologic Sequestration (GS) Wells – Final Rule, 75 Fed. Reg. 77230, 77234 (Dec. 10, 2010) (to be codified at 40 C.F.R. Pts 124, 144, 145, 146, 147); Miss. Emergency Mgmt. Agency, *Pipeline Ruptures in Yazoo County, Dozens Rushed to the Hospital*, Miss. Emergency Mgmt. Agency (Feb. 23, 2020), https://www.msema.org/news/pipe-ruptures-in-yazoo-county-dozens-hospitalized/; Vinca, A. et al., Bearing the Cost of Stored Carbon Leakage, 6 Frontiers in Energy Rese. Art. 40 (2018), https://www.frontiersin.org/articles/10.3389/fenrg.2018.00040/full; Zoback, Mark D. et al., Earthquake triggering and large-scale geologic storage of carbon dioxide, 109 PNAS 10164 (2012), https://www.pnas.org/content/109/26/10164.

The EIR must identify and consider alternatives to the project that would avoid impacts to environmental justice communities near the project and protect the air, water, and species of Kern County. One of the primary purposes of the project appears to be "contribution to the goals of California for carbon neutrality by 2045." A much better way to achieve these goals, however, is to phase out oil and gas extraction at the Belridge oil fields. The County should analyze this as a project alternative.

Phasing out oil production in the Belridge oil fields would be especially impactful because South Belridge is one of the top five highest carbon-intensity oil fields in California, contributing 12% of the estimated upstream emissions from California-sourced oils.[4] North Belridge ranks as number 22 for statewide GHG emissions from oil fields.[5]

Phasing out operations in the oil fields, replacing oil production with renewable energy, and developing a just transition program for oil workers has significant potential to advance GHG reduction goals while creating jobs that are better shielded from the market contractions of a fading industry.[6]

III. More Information is Required to Properly Describe the Project and Analyze its Impacts Under CEQA.

The NOP does not adequately describe the project, including its associated network of pipelines. The EIR must include a much more detailed description to enable decision-making that considers environmental consequences and environmental characteristics.[7] Under CEQA, a project description must represent the "whole of an action" to be undertaken by the lead agency; "an accurate project description is necessary for an intelligent evaluation of the potential environmental effects of a proposed activity."[8] Moreover, the project description and analysis must include "future action" that is "a reasonably foreseeable consequence of the initial project" and would "be significant in that it will likely change the scope or nature of the initial project or its environmental effects."[9]

For example, the NOP only provides that the project would "capture CO_2 from existing sources within the South Belridge oil field and transport it by pipeline to dedicated Class VI injection wells within the North Belridge oil field to be injected into identified geologically confined reservoirs for storage," and that "infield pipelines would primarily be installed above ground, except where the pipelines would cross main access roads (below ground)" (emphasis added). This is insufficient. Courts have routinely held that EIRs must include information about

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[4] Fleming, John, Killer Crude: How California Produces Some of the Dirtiest, Most Dangerous Oil in the World, Center for Biological Diversity (2021) at 6, https://www.biologicaldiversity.org/programs/climate_law_institute/pdfs/June-2021-Killer-Crude-Rpt.pdf.

[5] *Id.* at 21.

[6] Pollin, Robert et al., A Program for Economic Recovery and Clean Energy Transition in California, Political Economy Research Institute (2021) at Chapter 7.

[7] Cal. Code Regs. tit. 14 § 15124.

[8] *San Joaquin Raptor/Wildlife Rescue Ctr. v. Cnty of Stanislaus*, 27 Cal. App. 4th 713, 730 (1994).

[9] *Laurel Heights Improvement Ass'n v. Regents of Univ. of Cal.*, 47 Cal. 3d 376, 396 (1988), as modified on denial of reh'g (Jan. 26, 1989).

the associated transportation method and its impacts.[10] The location of project components will dictate environmental impacts and their significance. The DEIR must disclose exactly how many miles of pipeline will be constructed, where the pipelines will be located, what the pipelines will be made of (since CO_2 pipelines are extremely dangerous and prone to corrosion), the distance of pipelines to sensitive receptors, and any emergency preparedness measures.[11] The DEIR must then analyze the potential impacts of these pipelines, including the impact of potential leaks, as well as how certain weather events that are happening with increasing frequency—such as extreme temperature fluctuations and flooding—could heighten the risk of leaks..

In addition to information about the project's pipelines, other aspects of the project that must be better defined and analyzed in the EIR include:

1. The number and location of injection wells (which is particularly important for identifying potentially-impacted species and historic sites);
2. The carbon injection rate (the NOP lists only the amount of carbon injection over the life of the project, but not the injection rate, yearly estimates, or expected life of the project);
3. The sources of carbon;
4. The properties of the carbon to be injected (particularly since the carbon will come from different sources);
5. The type of chemicals that will be used, as well as where and how they will be stored; and
6. The quantity, location, and impact of the construction of "new internal access roads."

And while the County has indicated that "[t]ransport of CO2 by pipeline is covered by Kern County Oil and Gas Ordinance and related [Supplemental Recirculated Environmental Impact Report ("SREIR")] (2020/2021) and requires an Oil and Gas Conformity Review permit for construction and operation,"[12] the County will not be able to rely on the SREIR for an analysis of the pipeline's impacts. If upheld, the SREIR "addresses County jurisdictional activities that occur as ancillary activities *in support of oil and gas production* in these areas, including, for example, electric transmission lines, pipelines, and access roads."[13] There is no evidence that a CO_2 pipeline transporting carbon to be stored long term in the oil field would support oil and gas *production*, meaning the SREIR is inapplicable.

Further, the County must consider and reconcile its project description with the information Aera is providing EPA for the project's Class VI permits. For example, according to

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[10] *See, e.g., Santiago County Water Dist. v County of Orange* (1981) 118 Cal.App.3d 818, 830 (EIR for a sand and gravel mine that failed to describe or analyze the construction of water pipelines that would be needed for mining operations); *Whitman v Board of Supervisors* (1979) 88 Cal.App.3d 397, 414 (EIR for an exploratory oil well should have analyzed the impacts associated with a proposed oil pipeline).
[11] Pipeline Safety Trust, "The State of Federal Carbon Dioxide Transmission Pipeline Safety Regulations as it Relates to Carbon Capture, Utilization, and Sequestration within the U.S" (March 2022), https://pstrust.org/wp-content/uploads/2022/03/3-23-22-Final-Accufacts-CO2-Pipeline-Report2.pdf.
[12] Oviatt, Lorelei, to File, Determination on Zoning Classification for Carbon Capture and Sequestration Section 19.08.085 Alternative to Determination of Similar Use (June 21, 2021).
[13] Kern County Oil and Gas Draft SREIR, Project Description (2020), https://psbweb.co.kern.ca.us/UtilityPages/Planning/EIRS/OG_SREIR/aVol1/Oil_Gas_SREIR_Oct%202020_Vol%201_03.0_Project%20Description.pdf at 3-13.

EPA the project will capture 3.6 million metric tons of CO_2/year for seven years, meaning the project will inject roughly 27 MM Mt total of captured CO_2.[14] In contrast, the NOP says the project will inject and sequester 43 MM Mt of CO_2. There must be some explanation and accounting for these vastly different numbers.

IV. The County Must Take a Hard Look at the Environmental Impacts of the Whole Project.

The NOP rightly finds that the project has the potential to contribute to significant impacts. A thorough assessment of the project's water quality, habitat and wildlife, environmental justice and public health, seismicity, climate change, and other impacts is necessary to inform the County's decision-making process and afford the fullest protection of communities and the environment.

The DEIR must analyze the whole of the project, including injection and pipeline activities. Even though the Aera CCS Project will require injection permits from EPA, the up to nine injection wells are a critical part of the project's impacts, and must be analyzed together (along with the pipeline) in the DEIR. This likely means that the DEIR cannot be complete until the EPA Class VI permits are issued.

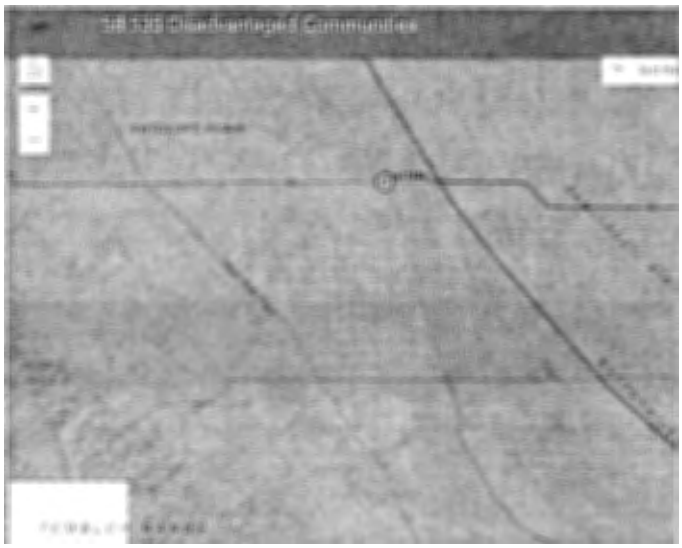
A. Environmental Justice and Sensitive Receptors

Kern County must consider how the environmental and public health burdens of the project might disproportionately impact certain vulnerable and historically-harmed populations.[15] The White House Environmental Justice Advisory Council has called CCS projects a "type[] of project that will *not* benefit a community," noting that "it would be unreasonable to have any climate investment working against historically harmed communities."[16] Simply because a project is touted as a climate solution does not mean the County can assume it will benefit nearby disadvantaged communities.

The proposed project location is described as the North and South Belridge oil fields, approximately seven miles southwest from the community of Lost Hills (population 2,370)." The community of Buttonwillow (pop. 1,443) is approximately 14 miles southeast of the project site. These communities are designated as "disadvantaged" by the California EPA because they fall within the top 25% scoring areas from CalEnviroScreen—the higher the score, the higher the

[14] EPA Region 9, Class VI applications – Aera, available at https://www.epa.gov/uic/uic-permits-epas-pacific-southwest-region-9.
[15] Cal. Dep't of Justice, Environmental Justice at the Local and Regional Level Legal Background (May 8, 2012), https://oag.ca.gov/sites/all/files/agweb/pdfs/environment/ej_fact_sheet_final_050712.pdf.
[16] WHEJAC, Interim Final Recommendations at 55, 58 (May 13, 2021), https://www.epa.gov/sites/default/files/2021-05/documents/whejac_interim_final_recommendations_0.pdf (emphasis original).

level of pollution burden relative to other California census tracts.[17] Lost Hills is currently in the 86th percentile for pollution burden;[18] Buttonwillow is in the 96th percentile.[19]



Above: SB 535 Disadvantaged Communities in the Vicinity of the Project Area

More broadly, Kern County and communities near the project area have a high percentage of residents of color, that are linguistically isolated, and/or that have less than a high school education. In Lost Hills, over 60% of residents did not complete high school, and 90% of adults' primary language is Spanish.[20] The poverty level in Lost Hills is more than 1.5 times the rate of poverty in the rest of California.[21] In Buttonwillow, nearly 40% of residents were born in Latin America, and 35% of residents live below the poverty line.[22] It is critical that the EIR address the environmental justice impacts of the project and incorporate mitigation measures to address the high levels of pollution and emissions at sensitive receptors surrounding the project.

Further, the DEIR must fully consider how dangerous CO_2 leaks can be. The NOP notes that the nearest sensitive receptor to the proposed project site is a residence only 400 feet from the project boundary, and approximately 3,970 feet from the nearest proposed injection well. The nearest schools are Lost Hills Elementary School and A.M. Thomas Middle School, approximately six miles northeast of the proposed project site. The residence and schools are at risk of serious harm if there is a leak of compressed CO_2, which is an asphyxiant that is heavier than atmospheric air, meaning it does not disperse easily and can travel and harm people even

[17] Cal. Office of Envtl Health Hazard Assessment, *SB 535 Disadvantaged Communities*, https://oehha.ca.gov/calenviroscreen/sb535 (last visited Mar. 23, 2022).
[18] Cal. Office of Envtl Health Hazard Assessment, *SB 535 Disadvantaged Communities Map*, Census Tract 6029004500, https://oehha.ca.gov/calenviroscreen/sb535 (last visited June 26, 2023).
[19] *Id.*, Census Tract 6029003700 (last visited June 26, 2023).
[20] CensusReporter, Lost Hills, https://censusreporter.org/profiles/16000US0644280-lost-hills-ca/ (last visited June 26, 2023).
[21] *Id.*
[22] CensusReporter, Buttonwillow, https://censusreporter.org/profiles/16000US0609332-buttonwillow-ca/.

miles away.[23] This was the case in 2020 with Satartia, Mississippi when a CO2 pipeline ruptured and caused dozens to be hospitalized and hundreds evacuated.[24] Because compressed CO2 prevents combustion vehicle engines from working, residents had a difficult time escaping in their cars, and emergency vehicles had a difficult time accessing those who were "near death and foaming at the mouth" from carbon dioxide exposure.[25] These are serious risks Kern County must take seriously and analyze in the DEIR, for both nearby receptors as well as on-site workers.

B. Seismicity and Carbon Leakage

California is one of the most seismically active states in the U.S. and earthquakes pose a risk in the project area. Studies link CO_2 injection to earthquakes.[26] For example, a 2012 study concluded that large-scale geologic storage of CO_2 carries has a "high probability" of triggering earthquakes, finding that "[b]ecause even small- to moderate-sized earthquakes threaten the seal integrity of CO_2 repositories, in this context, large-scale CCS is a risky, and likely unsuccessful, strategy for significantly reducing greenhouse gas emissions."[27] A 2013 study found a strong correlation between earthquakes and CO_2 injection for enhanced oil recovery.[28] The full range of foreseeable seismic impacts should therefore be evaluated in the DEIR, particularly given the evidence that injection activities have been linked to earthquakes.

Relatedly, Aera proposes to inject the captured carbon into a "depleted oil and gas reservoir with saline formation water." The DEIR must analyze the potential for leaks due to abandoned oil and gas wells throughout the oil field, which could cause (on their own, or in combination with seismic events) CO_2 to leak up through the surface and both undermine climate goals and create public safety harms.

C. Climate Change & Air Pollution

CEQA requires that EIRs consider a project's reasonably foreseeable indirect impacts on the environment,[29] which includes indirect greenhouse gas (GHG) emission impacts. An

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[23] Pipeline Safety Trust, "The State of Federal Carbon Dioxide Transmission Pipeline Safety Regulations as it Relates to Carbon Capture, Utilization, and Sequestration within the U.S" (March 2022), https://pstrust.org/wp-content/uploads/2022/03/3-23-22-Final-Accufacts-CO2-Pipeline-Report2.pdf.
[24] Zegart, Dan, *The Gassing of Satartia*, Huffington Post (August 26, 2021), https://www.huffpost.com/entry/gassing-satartia-mississippi-co2-pipeline_n_60ddea9fe4b0ddef8b0ddc8f.
[25] *Id.*
[26] Zoback, Mark D. et al., "Earthquake triggering and large-scale geologic storage of carbon dioxide," 109 PNAS 10164 (2012), https://doi.org/10.1073/pnas.1202473109; Gan, Wei & Cliff Frohlich, Gas injection may have triggered earthquakes in the Cogdell oil field, Texas, 110 *PNAS* 18786 (2013), https://doi.org/10.1073/pnas.1311316110; Foulger, Gillian R. et al., Global review of human-induced earthquakes, 178 Earth-Science Reviews 438 (2018), https://doi.org/10.1016/j.earscirev.2017.07.008; Sano, Yuji et al., Groundwater anomaly related to CCS-CO2 injection and the 2018 Hokkaido Eastern Iburi Earthquake in Japan, 8 Frontiers in Earth Science 611010 (2020), https://doi.org/10.3389/feart.2020.611010.
[27] Zoback, Mark D. & Steven M. Gorelick, Earthquake triggering and large-scale geologic storage of carbon dioxide, 109 PNAS 10164 (2012), https://doi.org/10.1073/pnas.1202473109.
[28] Gan, Wei & Cliff Frohlich, Gas injection may have triggered earthquakes in the Cogdell oil field, Texas, 110 *PNAS* 18786 (2013), https://doi.org/10.1073/pnas.1311316110.
[29] Cal. Code Regs., tit. 14, § 15064(d).

environmental review must evaluate these impacts to the extent doing so is feasible and the effects are not speculative.[30] CEQA Guidelines Appendix G requires lead agencies to evaluate whether "the project [would] generate greenhouse gas emissions, either directly or indirectly, that may have a significant impact on the environment."[31]

In the DEIR, Kern County must not only analyze GHG emissions from the construction, operation, and maintenance of the injection wells, it also must analyze and mitigate emissions associated with transporting the carbon, and with any production of carbon and associated air emissions (along with any non-captured fuel that is generated and later combusted) that would not have otherwise occur in the absence of the project providing an incentive and location for sequestration—these emissions are reasonably foreseeable and significant consequences of the project.

Kern County must also disclose and analyze the amount (or percentage) of carbon the Aera CCS Project claims it will capture. The NOP says that the project's amine absorption processes will "react with and bind over 90 percent of the incoming CO_2." The DEIR must account for the CO_2 that is not captured in the amine processes. In addition, CCS projects historically have over-promised and under-delivered on their carbon capture promises.[32] For example, Chevron's natural gas-and-CCS project promised 80% capture, but after five years, achieved less than half of that.[33] A Stanford study found that the energy penalty of CCS can be up to 25% (meaning, whatever the capture promise is must be reduced by the energy penalty to calculate the true capture benefit) and concluded that CCS can increase air pollution and is not efficient at reducing carbon in the atmosphere.[34]

On the air pollution issue, the Jacobson study concluded that even if a project could achieve 100 percent capture from the capture equipment, "it is still worse, from a social cost perspective, than replacing a coal or gas plant with a wind farm because carbon capture never reduces air pollution and always has a capture equipment cost."[35] The DEIR must therefore consider what equipment is being used to capture carbon and address air pollution, and not assume that just because the project proposes to capture emissions that this will eliminate air pollution.

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[30] *See id.* § 15145.
[31] CEQA Guidelines, Appendix G.
[32] IEEFA, The carbon capture crux: Lessons learned (Sept. 2022), https://ieefa.org/resources/carbon-capture-crux-lessons-learned.
[33] Guardian UK, Gas giant Chevron falls further behind on carbon capture targets for Gorgon gasfield (July 15, 2022), https://www.theguardian.com/environment/2022/jul/16/gas-giant-chevron-falls-further-behind-on-carbon-capture-targets-for-gorgon-gasfield.
[34] Jacobson, Mark Z., The health and climate impacts of carbon capture and direct air capture, Energy & Envtl Sci. , Vol. 12 (2019), https://pubs.rsc.org/en/content/articlelanding/2019/ee/c9ee02709b/unauth#!divAbstract; *see also* Stanford News, Stanford study casts doubt on carbon capture (Oct. 25, 2019), https://news.stanford.edu/2019/10/25/study-casts-doubt-carbon-capture/.
[35] Stanford News, Stanford study casts doubt on carbon capture (Oct. 25, 2019), https://news.stanford.edu/2019/10/25/study-casts-doubt-carbon-capture/.

Finally, the project NOP says that "flue gas would continue to be vented to the atmosphere as allowed under the facilities current permits." The DEIR must disclose the pollutants contained in this flue gas and the amounts likely to occur.

D. Water Quality

Kern County currently faces severe water pollution,[36] and the project threatens to make the problem worse if injected carbon migrates from the injection sites. The County must obtain the information from EPA concerning the nine Class VI injection wells (permitted under the federal Safe Drinking Water Act) in order to fully disclose and analyze the project's impacts to water quality.

Further, the NOP estimates that the project will use "less than 26,000 barrels per day" of water, which is estimated to mostly derive from Belridge oilfield produced water. The DEIR must disclose and analyze what exactly it means to use produced water in CCS operations, and what the risks are of spills, leaks, and contamination from these practices.

E. Chemicals

The NOP says the project will involve a "storage area for process chemicals" because "a physical solvent or a traditional amine absorption process would be used to remove the CO2 from the produced gas stream." The DEIR must disclose and analyze the volume of chemicals that will be stored onsite, how those chemicals will get to the project location, plans for disposal, and impacts from possible leaks and spills on the environment and worker safety.

F. Species and Habitat

The project's construction and operation of the injection wells and other project components, including transportation and carbon capture, are likely to adversely impact biological resources in the Belridge/Lost Hills area.

Under the California Endangered Species Act, all state agencies "shall seek to conserve endangered species and threatened species."[37] And, "state agencies should not approve projects as proposed which would jeopardize the continued existence of any endangered species or threatened species . . . if there are reasonable and prudent alternatives available."[38] The federal Endangered Species Act[39] also affords protections to imperiled species in the Belridge area. The area of the project overlaps with the habitats of numerous federally managed species and habitats.

The list below includes the species that, according the U.S. Fish and Wildlife Service, could be affected by activities in the project location.[40] Of course, the EIR also must consider impacts to species that will be impacted by ancillary transportation and construction activities that extend beyond the oilfield boundaries.

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[36] *King & Gardiner Farms, LLC v. Cty. of Kern*, 45 Cal. App. 5th 814, 833, 259 Cal. Rptr. 3d 109, 125 (2020), *as modified on denial of reh'g* (Mar. 20, 2020).
[37] Cal. Fish & Game Code § 2055, et seq.
[38] *Id.* § 2053.
[39] 7 U.S.C. § 136; 16 U.S.C. § 1531 et seq.
[40] U.S. Fish & Wildlife Service, Information for Planning and Conservation (IPaC) database, available at https://ecos.fws.gov/ipac/ (last visited on June 26, 2023).

- Buena Vista Lake Ornate Shrew / Endangered
- Giant Kangaroo Rat / Endangered
- San Joaquin Kit Fox / Endangered
- Tipton Kangaroo Rat / Endangered
- California Condor / Endangered
- Blunt-nosed Leopard / Endangered
- Monarch Butterfly / Candidate
- Vernal Pool Fairy Shrimp / Threatened
- California Jewelflower / Endangered
- Kern Mallow / Endangered
- San Joaquin Wooly-threads / Endangered

In addition to the federally listed species named above, the County must consult with the California Department of Fish and Wildlife (CDFW) on state listed species. According to 2022 documents on the North and South Belridge oil fields from CDFW, the oil fields contain potentially suitable habitat within the well pad footprints and/or adjacent to the wells that can serve as refugia, denning, breeding, foraging, and dispersal habitat for the following species: the blunt-nosed leopard lizard (*Gambelia sila*), the giant kangaroo rat (*Dipodomys ingens*), the San Joaquin kit fox (*Vulpes macrotis mutica*), the Swainson's hawk (*Buteo swainsoni*), the San Joaquin antelope squirrel (*Ammospermophilus nelsoni*), the State Candidate for Listing Temblor legless lizard (*Anniella alexanderae*) and Crotch bumble bee (*Bombus crotchi*), the California jewelflower (*Caulanthus californicus*), and the State species of special concern short-nosed kangaroo rat (*Dipodomys nitratoides brevinasus*), burrowing owl (*Athene cunicularia*), American badger (*Taxidea taxus*), western spadefoot (*Spea hammondi*), LeConte's thrasher (*Toxostoma lecontei*), loggerhead shrike (*Lanius ludovicianus*), San Joaquin coachwhip (*Masticophis flagellum ruddocki*), California glossy snake (*Arizona elegans occidentalis*), legless lizard (*Anniella spp.*), and coast horned lizard (*Phrynosoma blainvilli*) as well as State Watch List species prairie falcon (*Falco mexicanus*) and California horned lark (*Eremophila alpestris actia*), other nesting birds, and potential impacts to streams.[41] This list should not been taken as exhaustive or a replacement for consultation with relevant agencies.

V. The Planning Department Must Analyze the Potential Cumulative Impacts, Including from Other CCS Projects Proposed for the Area.

CEQA requires that EIRs analyze cumulative impacts, including impacts created or compounded as a result of the combination of the project evaluated in the EIR together with other closely related past, present, and reasonably foreseeable projects.[42] A project has "cumulatively considerable" impacts when its effects are "considerable when viewed in connection with the effects of" related projects.[43]

There are several closely related, foreseeable CCS projects proposed for Kern County and the surrounding areas. The Planning Department must take these projects (listed below, though this list should not be viewed as authoritative, as more projects may exist) and any other related and foreseeable projects into account when evaluating the cumulative impacts of the Aera

[41] CDFW, Special Status Species Information for the North and South Belridge Oil Fields (Nov 1, 2022), on file.
[42] Cal. Code Regs., tit. 14, § 15355.
[43] Cal. Pub. Res. Code § 21083(b); *see also* Cal. Code Regs § 15355(b)(2).

CCS proposal. This evaluation must include considering the impacts to public safety from the dangers of compressed carbon pipelines, injection, and storage (including leaks).

Proposed CCS projects in the project area include:

1. Elk Hills Carbon TerraVault 1 – a project (under CEQA review by Kern County) to take local industrial sources of CO_2 by a combination of truck, pipeline and/or rail to the dedicated Class VI injection wells in the Elk Hills oil field;[44]
2. Delano bioenergy with carbon capture and sequestration – a project to convert woody biomass into electricity or transportation fuel in Delano, CA (Kern County);[45]
3. Mendota bioenergy with carbon capture and sequestration — a project to convert biomass into transportation fuel and sequester the carbon in Class VI storage wells near Mendota, CA (Fresno County);[46]
4. San Joaquin Renewables – a project to convert orchard biomass into natural gas for transportation fuel and sequester the carbon in Class VI storage wells near McFarland, CA (Kern County);[47] and
5. Elk Hills Carbon TerraVault 26R – a project to capture CO2 from oil field operations, direct air capture, and a newly constructed hydrogen facility for injection into the Elk Hills oil field.[48]
6. Direct Air Capture hub in Kern County – a project to capture CO_2 from the atmosphere and sequester it for storage in Kern County.[49]

Consideration of each CCS project in isolation is not permissible under CEQA. The Planning Department must also consider the CCS project in light of Kern County's oil and gas ordinance, which, if upheld in court, would accelerate oil and gas development over the next two decades, allowing up to 43,000 new wells. CO_2 injection activities will add to the air quality, water quality, and public health risks from drilling and injecting for traditional production in communities that are already overburdened.

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[44] CEQAnet, Carbon TerraVault 1 by California Resources Corporation, https://ceqanet.opr.ca.gov/2022030180. California Resources Corporation has noted in investor presentations that it sees the Elk Hills project as just the first in a series of CCS projects to take advantage of the company's inventory of deep wells and depleted reservoirs, including in the Elk Hills oilfield. California Resources Corporation, Carbon Storage Update (Oct. 6, 2021) at 9 (describing goals of first injection by 2025, 200 MMT permitted by 2025, 5 MMTPA injection by 2027), 13-15, 29.

[45] *See* Cox, John, *Idle biomass plant near Delano would reopen under carbon burial proposal*, Bakersfield.com, Dec. 4, 2021, https://www.bakersfield.com/news/idle-biomass-plant-near-delano-would-reopen-under-carbon-burial-proposal/article_40b1cedc-54b1-11ec-bb81-9b8ecd1354ae.html.

[46] *See* Clean Energy Systems, *Mendota Bioenergy with Carbon Capture and Sequestration Project (BECCS)*, https://www.cleanenergysystems.com/MendotaBECCS (last visited Mar. 31, 2022).

[47] *See* San Joaquin Renewables, *About the Project*, https://sjrgas.com/the-project/ (last visited Mar. 31, 2022).

[48] EPA Region 9, Class VI permits, https://www.epa.gov/uic/uic-permits-epas-pacific-southwest-region-9.

[49] Cox, John, *Consortium lools to apply for $800 in federal support for carbon management,* Bakersfield.com (Oct. 29, 2022), https://www.bakersfield.com/news/consortium-looks-to-apply-for-800m-in-federal-support-for-carbon-management/article_08c45aaa-571f-11ed-a5de-777d8e9ae532.html.

VI. Instead of Creating Carbon Storage, the County Must End Fossil Fuel Development to Prevent Catastrophic Climate Change and Halt Further Environmental Injustices.

From the outset, we reject the premise that CCS is a necessary—or even appropriate—approach to addressing the climate crisis and pollution burdens borne by frontline communities. Further, the proposed project *itself* will emit GHGs, even if it purports to capture and store other sources' climate-harming emissions. As such, the proposed project is inconsistent with California's goals to reduce emissions and protect vulnerable residents.

CCS is a false climate solution championed by polluting industries—such as the biomass and fossil fuel industries—to enable business-as-usual operations, all while diverting resources from the needed transition to clean, cheaper renewable energy. In fact, CCS is *not* required under Intergovernmental Panel on Climate Change pathways to limit temperature rise to 1.5°C and avert climate catastrophe.[50] At the state level, CCS is also not necessary for California to achieve its climate goals, and deploying CCS would be inconsistent with state orders directing that policies and programs undertaken to achieve carbon neutrality must "improve air quality and support the health and economic resiliency of . . . particularly low-income and disadvantaged communities."[51]

After billions of dollars of investment and decades of development, CCS projects around the world have consistently failed to meet their GHG emission reduction promises. In July 2021, Chevron, operator of Australia's only commercial-scale CCS project, admitted that its self-described "world's biggest CCS project" failed to meet its five-year target of sequestering 80% CO_2,[52] instead only sequestering 30%.[53] In the U.S., CCS equipment on the Petra Nova coal-

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[50] The IPCC-modeled pathway with the best chance of keeping warming at or below the target of 1.5°C makes no use of fossil fuels with carbon capture and storage (CCS) or bioenergy with carbon capture and storage (BECCS). IPCC, Summary for Policymakers in Global Warming of 1.5°C: An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty (2018) [hereinafter IPCC SR1.5] at 14, Section C.1.1., Figure SPM 3b (Pathway 1); *see also* IPCC SR1.5, at Ch. 2.3.3 and Table 2.SM.12. *See also* Center for International Environmental Law, Confronting the Myth of Carbon Free Fossil Fuels at 2, https://www.ciel.org/wp-content/uploads/2021/07/Confronting-the-Myth-of-Carbon-Free-Fossil-Fuels.pdf [hereinafter *CIEL CCS Report*].

[51] California Executive Department, Executive Order B-55-18 (2018), https://www.ca.gov/archive/gov39/wp-content/uploads/2018/09/9.10.18-Executive-Order.pdf.

[52] Mazengarb, Michael, *Chevron admits failure of $3 billion CCS facility in Western Australia*, Inst. For Energy Econ. & Fin. Analysis (July 19, 2021), https://ieefa.org/chevron-admits-failure-of-3-billion-ccs-facility-in-western-australia/.

[53] Milne, Peter, *Chevron's five years of Gorgon carbon storage failure could cost $230 million,* Sydney Morning Herald, Nov. 11, 2021, https://www.smh.com.au/environment/climate-change/chevron-s-five-years-of-gorgon-carbon-storage-failure-could-cost-230-million-20211110-p597uf.html; Morton, Adam, *'A shocking failure': Chevron criticized for missing carbon capture target at WA gas project,* Guardian, July 18, 2021, https://www.theguardian.com/environment/2021/jul/20/a-shocking-failure-chevron-criticised-for-missing-carbon-capture-target-at-wa-gas-project.

fired powerplant in Texas achieved only a 50% CO_2 capture rate,[54] before being shut down indefinitely for being uneconomic. And these real-world failures of CCS projects do not even take into account the *lifecycle* emissions of CCS projects. One Stanford study of the lifecycle emissions associated with Petra Nova CCS project found that "the [CCS] equipment captured the equivalent of only 10-11% of the emissions they produced, averaged over 20 years."[55]

When the lifecycle GHG impacts of carbon capture and storage are taken into account, any purported climate benefits evaporate. For one, carbon capture is incredibly energy intensive, reducing the net GHG benefits.[56] Second, there is always a risk that CO_2 transported via pipeline, rail, or truck, and then stored underground, could leak back to the atmosphere.[57] Researchers estimate that a minor leakage of stored CO_2 could reduce the benefit of CCS by up to 35%.[58] Third, lifecycle studies of CCS projects show that CCS "reduces only a small fraction of carbon emissions, and it usually increases air pollution."[59] A Stanford study recommended replacing fossil fuels with renewables such as wind or solar, rather than encouraging and investing in CCS.[60]

CONCLUSION

In conclusion, the Aera CCS DEIR must take a hard look at the potential environmental impacts associated with the whole of the project, and Kern County should ultimately deny Aera's application for a conditional use permit. The project is dangerous and subverts California's progress toward a carbon free future. At the very least, the County must delay preparation of a

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[54] Schlissel, David, *IEEFA op-ed: Reality of carbon capture not even close to proponents' wishful thinking*, Inst. For Energy Econ. & Fin. Analysis (Aug. 8, 2019), https://ieefa.org/reality-of-carbon-capture-not-even-close-to-proponents-wishful-thinking/.

[55] Jacobson, Mark Z., The health and climate impacts of carbon capture and direct air capture, 12 Energy Envt. Sci. 3567 (2019), https://pubs.rsc.org/en/content/articlelanding/2019/ee/c9ee02709b/unauth#!divAbstract. This research also considered the social cost of carbon capture—in other words, the resulting air pollution, potential health problems, economic costs and overall contributions to climate change—and concluded that these costs are similar to or higher than a fossil fuel plant *without* carbon capture, meaning "it is always better to use the renewable electricity instead to replace coal or natural gas electricity or to do nothing." *Id.*

[56] Butler, Clark, Carbon Capture and Storage Is About Reputation, Not Economics, Inst. For Energy Econ. & Fin. Analysis at 4 (2020), https://ieefa.org/wp-content/uploads/2020/07/CCS-Is-About-Reputation-Not-Economics_July-2020.pdf.

[57] The 2015-16 Aliso Canyon natural gas blowout released over 97,000 metric tons of methane, effectively doubling the Los Angeles basin's methane emission rate. Conley. S. et al., Methane emissions from the 2015 Aliso Canyon blowout in Los Angeles, CA, 351 Science 1317 (2016), https://science.sciencemag.org/content/351/6279/1317.

[58] Vinca, A. et al., Bearing the Cost of Stored Carbon Leakage, 6 Frontiers in Energy Res. Art. 40 (2018), https://www.frontiersin.org/articles/10.3389/fenrg.2018.00040/full.

[59] Jacobson, Mark Z., The health and climate impacts of carbon capture and direct air capture, 12 Energy Envt. Sci. 3567 (2019), https://pubs.rsc.org/en/content/articlelanding/2019/ee/c9ee02709b/unauth#!divAbstract.

[60] *Id.* ("There is a lot of reliance on carbon capture in theoretical modeling, and by focusing on that as even a possibility, that diverts resources away from real solutions. It gives people hope that you can keep fossil fuel power plants alive. It delays action. In fact, carbon capture and direct air capture are always opportunity costs.").

DEIR until EPA Region 9 releases the nine Class VI permits Aera is seeking for carbon injection and storage so that the County has complete information about the project's activities.

Thank you for your consideration of these important issues in determining the scope and content of the DEIR. Please do not hesitate to contact us if you have any questions.

Respectfully submitted,

Center for Biological Diversity
Victoria Bogdan Tejeda, Staff Attorney
vbogdantejeda@biologicaldiversity.org

Liz Jones, Senior Staff Attorney

Central California Environmental Justice Network
Nayamin Martinez, MPH
Executive Director

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Clark Butler, IEEFA Guest Contributor
July 2020

Institute for Energy Economics and Financial Analysis
IEEFA.org

Carbon Capture and Storage Is About Reputation, Not Economics

Supermajors Saving Face More Than Reducing Emissions

Executive Summary

The Australian Government proposes to broaden the scope of its Climate Solutions Fund[1] to include the ability to invest in carbon capture, use and storage (CCS or CCUS) projects.

This expansion of scope is essential if CCS projects are to be undertaken as CCS projects:

- are prohibitively expensive compared to other greenhouse gas emissions mitigation options, such as renewable energy and energy storage technologies;
- offer no financial return for investors; and
- have a dubious track-record. Even the Global CCS Institute - a booster organisation for CCS - acknowledges in its 2019 *Global Status of CCS* report that CCS is at best a minor contributor to decarbonisation, addressing up to 9% of greenhouse gas (GHG) emissions by 2050.[2]

There isn't one example of a CCS project anywhere in the world that offers a financial justification for investing in CCS.

In the absence of a carbon price, CCS will never provide a return on investment.

European oil companies—in particular, Equinor, Shell and Total—are investing in CCS, notwithstanding the lack of return, because it is an important part of their decarbonisation narrative and supports their aims to be seen as "responsible" energy companies.

There isn't one example of a CCS project anywhere in the world that offers a financial justification for investing in CCS.

The Australian Labor Party's recent statement that it remains "open to CCS" but insists that CCS must *not* be funded by the Clean Energy Finance Corporation (CEFC) nor the Australian Renewable Energy Agency (ARENA), makes sense. These bodies

[1] Australian Government. Clean Energy Regulator. Climate Solutions Fund.
[2] Global CCS Institute. Global Status of CCS 2019.

are intended to facilitate the increased flow of finance into the commercialisation and deployment of Australian based renewable energy, energy efficiency and low carbon technologies."[3] With CCS, there is no flow of finance into the CCS sector because there is no business case. With a carbon price, this might change: the market could then decide how much to invest in CCS projects.

Despite the Minerals Council of Australia's recent hollow statement about the Paris Agreement in its "Climate Action Plan"[4], decarbonisation of electricity, electrification of mining, and the use of green hydrogen in minerals processing will be the contributions its' members make to combating increasing emissions, rather than the limited benefits afforded by CCS.

There is no flow of finance into the CCS sector because there is no business case.

CCS, Carbon Sinks and a Carbon Price

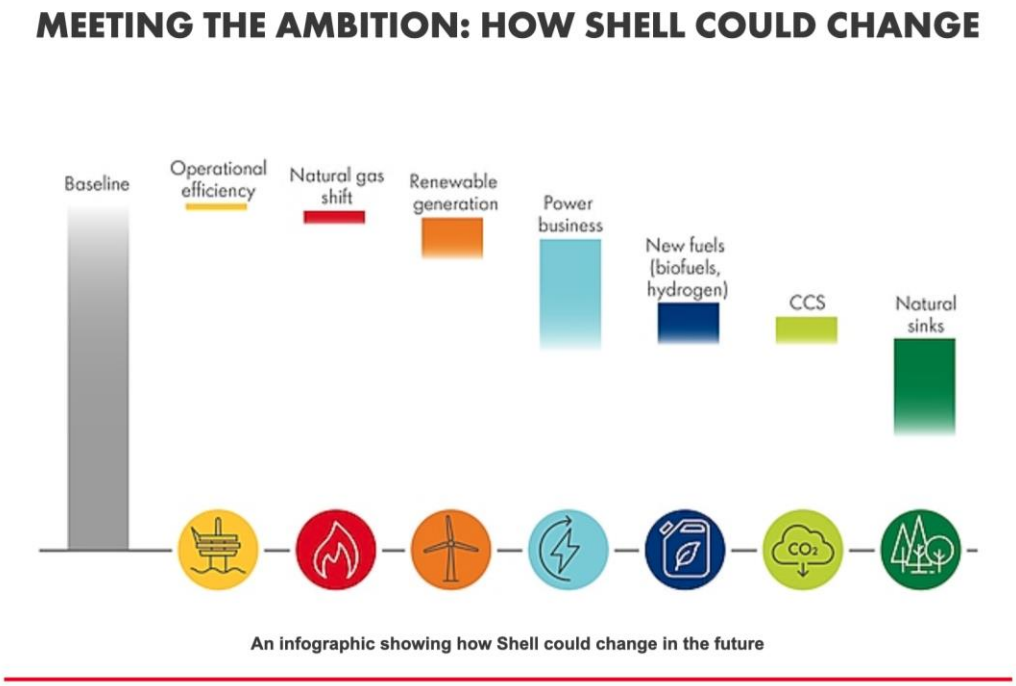
Oil majors Total and Shell have both emphasised the role that CCS, carbon sinks and a carbon price play in their ability to meet their long-term net-zero objectives.

Figure 1 shows directionally how Shell could meet its goal. Although this is not intended to be a precise chart, it is noteworthy the proportion of the reduction attributed to "natural sinks" (i.e., planting trees) and CCS.

Patrick Pouyanné, Chairman and CEO of Total, has stated, "We have the technology to capture and reinject carbon. The real question is how to do it in a way that is economically sustainable. That brings us back to the issue of carbon pricing."[5] In relation to CCS for coal-fired power generation, Pouyanné has said, "… I know that people advocate… for clean coal, but frankly, clean coal means a lot of CCS, and I would like to see where the CCS technologies are."[6]

[3] CEFC. CEFC Investment Policies.
[4] Minerals Council of Australia, Climate Action Plan, 2020.
[5] CNBC. Total gives itself 15 years to make its products 15 percent less carbon intensive. 20 October 2018.
[6] CSIS. A Conversation with Patrick Pouyanné, Chairman and CEO of Total S.A. 17 May 2018.

Figure 1: Shell's Path to Decarbonisation



Source: Shell.

IEEFA supports the idea that a carbon price is essential to achievement of large-scale carbon emission reductions. However, the fact that both companies' CEOs refer to this almost as a precondition to their climate goals invites scepticism about their commitment to unilateral action on CCS. Each company currently spends an immaterial percentage of annual capital expenditure on CCS[7], so it is arguable that CCS is little more than a helpful marketing message to support their boarder decarbonisation ambitions.

It is arguable that CCS is little more than a helpful marketing message.

What is Carbon, Capture and Storage?

Carbon capture, use and storage (CCS or CCUS) encompasses an integrated suite of technologies that can prevent large quantities of carbon dioxide (CO_2) from being released into the atmosphere as a consequence of using fossil fuels.

This technology has been applied in a wide range of industries since 1972 when several natural-gas processing plants in the Val Verde area of Texas began

[7] None of their investments are quantified in annual reports.

employing carbon capture to supply CO_2 for enhanced oil recovery (EOR) operations. Since then, more than 200 million tonnes of CO_2 have been captured and injected deep underground.

The net emissions impact of CCS must include emissions from the energy used in the process (up to 20% more than an operation without CCS) and the emissions from any oil extracted using EOR.

CCS Involves Three Major Steps:

1. **Capture**: The separation of CO_2 from other gases produced at large industrial process facilities such as coal and natural-gas-fired power plants, steel mills, cement plants and refineries.

2. **Transport**: Once separated, the CO_2 is compressed and transported via pipelines, trucks, ships or other methods to a suitable site for geological storage.

3. **Storage**: CO_2 is injected into deep underground rock formations, usually at depths of one kilometre or more, depleted oil or gas fields, deep saline aquifer formations or other forms of underground caverns, though it could apply to any form of storage.

The 'usage' component includes applications of the carbon in industrial processes such as the manufacture of synthetic diesel, biofuels, solvents and polymers.

A Good Idea but…

CCS is an excellent idea: if greenhouse gasses can be prevented from entering the atmosphere, we can continue traditional fossil fuel activities without worrying about the devastating effects of the changing climate.

The Global CCS Institute report quotes Lord Nicholas Stern, Bill Gates and other experts in the fields of climate, engineering and finance all emphasising the crucial role CCS has to play in addressing rising emissions.

There Are Some Key Problems However:

- Storage solutions can and do leak methane;

- The energy cost involved in the process materially reduces its net benefit; and,

- It doesn't make any economic sense, absent a whole-of-economy price on carbon emissions, supported by carbon border taxes (as proposed by the European Union).

What Can Go Wrong… and Does

Transportation and storage are two key areas of concern.

'Captured' carbon must be separated, transformed and, in most cases, transported to the sequestration site. The energy used in this process and the leakages that can occur during transportation and handling can materially reduce the net impact of the CCS process.[8]

Further, the underground storage into which the carbon is injected is not always secure. Wells have weaknesses and gaps. Fracking causes long-term subterranean instability, and seismic activity could dislodge even the most carefully stored carbon. Leaks in the Aliso Canyon natural gas storage facility in 2015 "released 97,100 metric tons of methane to the atmosphere,"[9] doubling the methane emission rate of the entire Los Angeles basin.

The underground storage into which carbon is injected is not always secure.

According to geologists, leaks should not be a practical concern for carbon dioxide (CO_2) storage if the CCS process is carefully implemented. However, further research concludes that the consequences of a minor leakage could reduce the benefit of CCS by up to 35%.[10]

The fossil gas industry has failed to systematically cap, sterilise and monitor abandoned gas wells over the last few decades, so methane leakage is massively underreported and largely ignored (thanks to regulatory capture and constant defunding of EPA departments). Further, the industry resists accepting liability for leakages.

The Economics of CCS Are Wrong

Whilst the technical issues of CCS can probably be addressed with engineering solutions over time, the more significant problem is a financial one.

CCS is an expensive process that generates very little revenue. Aside from limited pricing signals from emissions trading systems, there is no financial reason to invest in CCS. Consequently, there are no commercially viable examples of CCS anywhere in the world.

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[8] IEEFA. Volkswagen lied about emissions from their vehicles, and the gas industry is also lying about their emissions. March 2020.
[9] Science. Methane emissions from the 2015 Aliso Canyon blowout in Los Angeles, CA. 18 March 2016.
[10] Frontiers in Energy Research. Bearing the Cost of Stored Carbon Leakage. 15 May 2018.

The traditional financial justification for doing CCS is for enhanced oil recovery (EOR). With oil prices currently well below breakeven for oils sands extraction, this does not begin to cover the costs of CCS.

With costs in the order of US$4,200 per kilowatt[11] for a power plant equipped with CCS, even if it works, CCS is a poor investment, multiples of the cost of new renewable energy even when the addition cost of firming is included.

There are no commercially viable examples of CCS anywhere in the world.

It is no surprise that the few operating CCS plants globally are government subsidised.

Playing With Someone Else's Money

Shell

Royal Dutch Shell promotes CCS as a key factor in its new, bold emission reductions strategy: to bring down its net carbon footprint of products by 50% by 2050. As a then new CEO in 2014, Ben van Beurden told the audience in a keynote speech at Columbia University that CCS could remove up to 90% of emissions from power generation. In 2015, Shell promised investment in CCS, coinciding with the opening of the Quest CCS facility in Canada. At every AGM since, van Beurden has returned to CCS as a key part of the solution.

To date, Shell has two CCS projects: Quest in Alberta, Canada, funded by the Albertan and Canadian governments and operated by Shell; and Gorgon in Western Australia, a project in which the project principals (Shell and Chevron) are financially motivated *not* to operate the CCS plant. The Gorgon plant has failed to meet its targets every year, notwithstanding a $60 million subsidy from the Western Australian government.

Shell's actual outlay in CCS over the years remains to be seen. Its overall investment in renewables is well behind its stated targets.[12] Any progress Shell demonstrates in removing carbon from the atmosphere using CCS (1m tonnes per annum at Quest and up to 4m tonnes at Gorgon) should be seen in light of Shell's total emissions of 656 million tonnes per annum (80Mt scope 1 and 2; 576Mt scope 3).[13]

Total SA

Total SA has also promised massive investment in CCS to remove up to 5 million tonnes of CO_2 per annum (8% of Total's scope 1 and 2 GHG emissions and 1% of

[11] EIA. PetroNova is one of two carbon capture and sequestration power plants in the world. 31 October 2017.
[12] NS Energy. "Royal Dutch Shell could be set to miss out on its green energy targets". 3 January 2020.
[13] Shell. Shell Sustainability Report 2019.

scope 1/2/3 emissions).[14]

Total SA is an investor in Equinor's Sleipner CO_2 storage as well as, with Shell and Equinor, the larger Nordic project under development, Northern Lights.[15]

Equinor

Equinor, the Norwegian state oil and gas producer, has been investing in CCS since 1996, mainly because Norway has had a carbon price since 1991. Its Sleipner CO2 storage and Snøhvit CO2 storage facilities have cumulatively captured and stored around 22 million tonnes of CO2. Compared to the rest of the fossil fuel industry, this is considerable achievement but this pales into insignificance when one considers that Equinor is responsible for over 330m tonnes of CO2-e emissions every year (scope 1, 2 and 3). With the carbon price, there is a modest economic return on its CCS operations but the impact on emissions is immaterial in the scheme of Equinor's contribution to global warming. By way of comparison, Equinor's scope 3 emissions increased by 26 million tonnes per annum from 2014 to 2018.[16]

Capturing Carbon at Power Stations Proves Fraught

CCS is more problematic in relation to power stations.

Boundary Dam in Saskatchewan, Canada and Petro Nova in Texas are the only power stations to implement a CCS retrofit that were completed in North America this past decade.

Boundary Dam, owned by the Saskatchewan utility, SaskPower, cost C$1.3bn to the retrofit, was years behind schedule, and operated at less than 50% capacity when it finally commenced.[17] Only one power unit has been retrofitted and SaskPower made a decision not to apply the technology to the other units.

Kemper was to be the shining example of 'clean' coal. The cost blew out to US$7.5bn, and the project was abandoned.

Petro Nova cost US$1bn, at approximately $4,200/KW, and captures 33% of emissions from one unit (654MW).[18] The carbon was intended to be supplied for enhanced oil recovery (EOR) but the price has fallen dramatically since the initial modelling was done and the project is a financial failure. It receives a $50/t subsidy

[14] Total. Integrating Climate into our Strategy. 2019.
[15] Northern Lights. About the Project.
[16] Equinor. Six ways our oil and gas expertise is energising renewables.
[17] Renew Economy. The Fallout from SaskPower's Boundary Dam debacle. 12 November 2015.
[18] EIA. Petron ova is one of two carbon capture and sequestration power plants in the world. 31 October 2017.

from the U.S. Government—effectively a carbon price—to keep it running at this minimal level.

Kemper was to be the shining example of 'clean' coal. A massive new coal-fired power station in Mississippi—possibly the largest project ever in the state—promised jobs and cheap, clean electricity. The $2.4bn estimated cost ($4,100/KW) blew out to US$7.5bn and the project was abandoned.[19]

There is no business case for gas CCS other than as a corporate social responsibility initiative, and there is no business case for coal CCS at all.

Conclusion

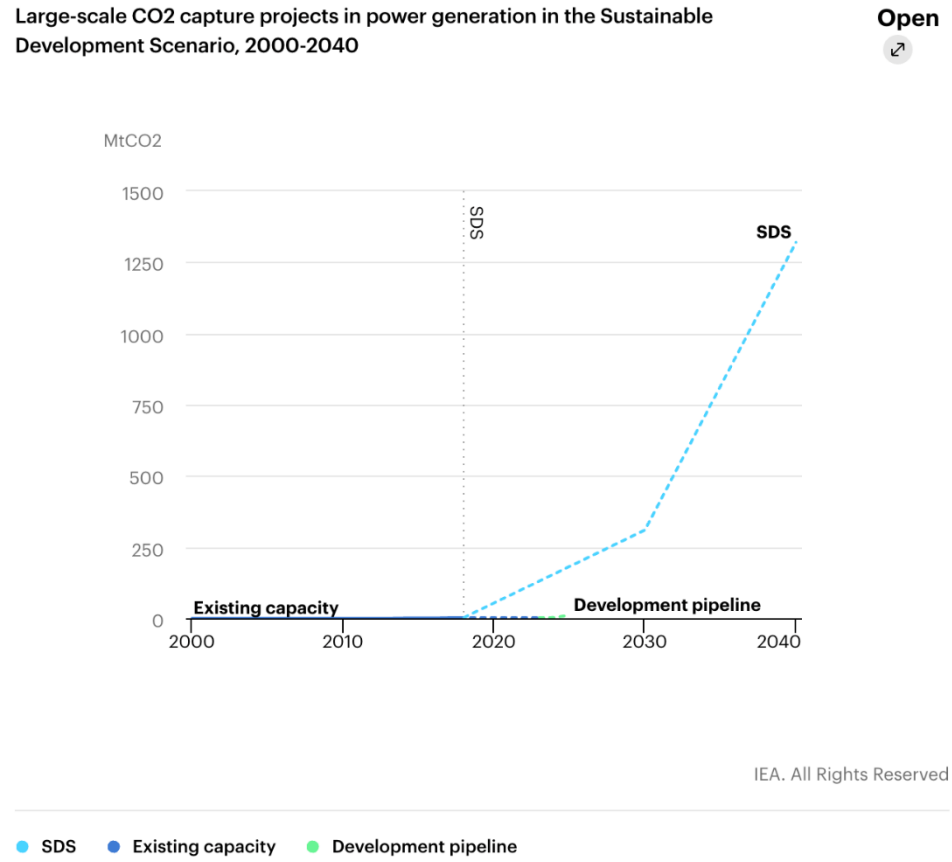
The IEA identifies CCS as mitigating up to 9% of GHG emissions by 2050 but notes:

> *"With only two large-scale CCUS power projects in operation at the end of 2018 and a combined capture capacity of 2.4 million tonnes of CO2 (MtCO2) per year, CCUS in power remains well off track to reach the 2030 Sustainable Development Scenario (SDS) level of 350 MtCO2 per year.*
>
> *As CCUS applied to power is at an early stage of commercialisation, securing investments will require complementary and targeted policy measures such as tax credits or grant funding. Support for innovation needs to target cost reductions and broaden the portfolio of CCUS technologies."*[20]

Figure 2 highlights the IEA's assessment of the huge gap between aspiration and reality in relation to power CCS.

[19] EIA. Petron ova is one of two carbon capture and sequestration power plants in the world. 31 October 2017.
[20] IEA. Tracking Power 2019.

Figure 2: IEA Highlights the Gap Between CCS Ambition and Reality



Source: IEA.

If the Australian Government wishes to encourage the development of CCS in Australia, in both gas and power, a carbon price would be a much better policy than the subsidisation of uneconomic CCS project proposals.

About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

About the Author

Clark Butler

Clark Butler is an IEEFA guest contributor, and a corporate adviser with a background in the technology and finance sectors. In additional to being a director of and investor in technology and data companies, he is exploring technology and financing solutions to encourage investment in renewable energy solutions. clark.butler@ironbarkgroup.com

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Confronting the Myth of Carbon-Free Fossil Fuels



Why Carbon Capture Is Not a Climate Solution

The world is confronting a climate emergency. Avoiding climate catastrophe requires immediate and dramatic reductions in greenhouse gas (GHG) emissions that are possible only with a significant investment of public resources in proven mitigation measures, beginning with eliminating fossil fuel use and halting deforestation. Carbon capture and storage (CCS) and carbon capture, utilization, and storage (CCUS) will not address these core drivers of the climate crisis or meaningfully reduce GHG emissions, and should not distract from real climate solutions.

CCS and CCUS technologies are not only *unnecessary* for the rapid transformation required to keep warming under 1.5°C, they *delay* that transformation, providing the fossil fuel industry with a license to continue polluting. This brief argues that carbon capture technologies:

- Do not remove carbon from the atmosphere, and in fact worsen the climate crisis when used to boost oil production.
- Have not been proven feasible or economic at scale and can only contain a fraction of source emissions.
- Prolong dependence on fossil fuels and delay their replacement with renewable alternatives.
- Create environmental, health, and safety risks for communities saddled with CCS infrastructure, such as pipelines and underground storage.

CCS Isn't Carbon Negative, or Even Carbon Neutral

CCS and CCUS refer to processes that collect or "capture" carbon dioxide generated by high-emitting activities — such as coal- and gas-fired power production or plastics manufacturing — and then transport those captured emissions to sites where they are either used for industrial processes or stored underground.[1]

CCS does not *remove* carbon from the atmosphere, although it is often erroneously conflated with "CO_2 removal" or "negative emission" technology. At best, CCS prevents some emissions caused by the combustion of carbon-based fuels from reaching the atmosphere — provided that the captured gases are not later released.

In practice, however, CCS masks the harmful carbon emissions from the underlying source, enabling that source to continue operating rather than being replaced altogether, while creating additional risks, impacts, and costs associated with the CCS infrastructure itself. Moreover, the injection of captured carbon into oil wells to enhance oil recovery — the most pervasive use of CCS today — exacerbates global warming by boosting oil production and prolonging the fossil fuel era.[2]

Large-Scale CCS is Neither Viable Nor Necessary

The unproven scalability of CCS technologies and their prohibitive costs mean they cannot play any significant role in the rapid reduction of global emissions necessary to limit warming to 1.5°C. Despite the existence of the technology for decades and billions of dollars in government subsidies to date, deployment of CCS at scale still faces insurmountable challenges of feasibility, effectiveness, and expense.

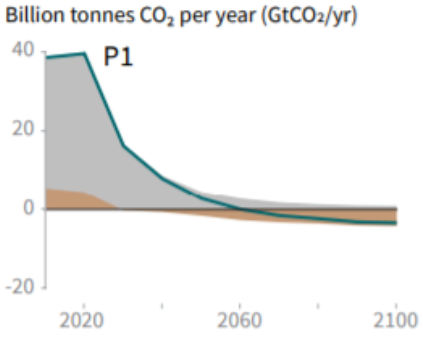
Existing CCS facilities capture less than 1 percent of global carbon emissions. The 28 CCS facilities currently operating globally have a capacity to capture only 0.1 percent of fossil fuel emissions, or 37 megatons of CO_2 annually. Of that capacity, just 19 percent, or 7 megatons, is being captured for actual geological sequestration.[3] The vast majority, as discussed ahead, is being used to produce more oil.

CCS pilot projects have repeatedly overpromised and underdelivered. The Petra Nova carbon capture facility installed at a coal-fired power station near Houston, Texas, in 2017 illustrates the failure of CCS to deliver meaningful emissions reductions and the folly of deploying CCS in service of fossil fuel extraction and use.

During its operation, the CCS system only captured 7 percent of the power plant's total CO_2 emissions, well below the company's promises to reduce CO_2 emissions by 90 percent.[4] The captured carbon from Petra Nova had been used for enhanced oil recovery, but the 2020 collapse in oil price and demand rendered this uneconomic. The CCS operation and the gas plant used to power it have been shut down indefinitely, leaving the coal-fired plant as emissions-intensive as ever.[5]

The surest approach to avoiding climate catastrophe does not involve CCS. According to the Intergovernmental Panel on Climate Change (IPCC), the emissions reduction pathway with the best chance of keeping warming at or below 1.5°C makes *limited to no* use of engineered carbon capture technologies. This pathway involves a rapid phaseout of fossil fuels along with limited carbon removal by *natural sources* such as reforestation

FIGURE 1
IPCC 1.5°C Pathway 1



P1: A scenario in which social, business, and technological innovations result in lower energy demand up to 2050 while living standards rise, especially in the global South. A down-sized energy system enables rapid decarbonisation of energy supply. Afforestation is the only CDR option considered; neither fossil fuels with CCS nor BECCS are used.

Graphic Source: IPCC

and enhanced soil carbon uptake.[6] The IPCC points to "uncertainty in the future deployment of CCS,"[7] and cautions against reliance on the technology, given "concerns about storage safety and cost"[8] and the "non-negligible risk of carbon dioxide leakage from geological storage and the carbon dioxide transport infrastructure."[9]

In January 2021, the 1,500 member-organizations of Climate Action Network (CAN) International adopted a shared position statement that the largest network of climate organizations worldwide "does not consider currently envisioned CCS applications as proven sustainable climate solutions." The organizations warned that CCS "risks distracting from the need to take concerted action across multiple sectors in the near-term to dramatically reduce emissions." Accordingly, CAN urged that "[a]ll government subsidies, loans, grants, tax credit, incentives, and financial support for fossil fuels and technologies that use or otherwise support the continued use of fossil fuels, including CCS, should be phased out as soon as possible."[10]

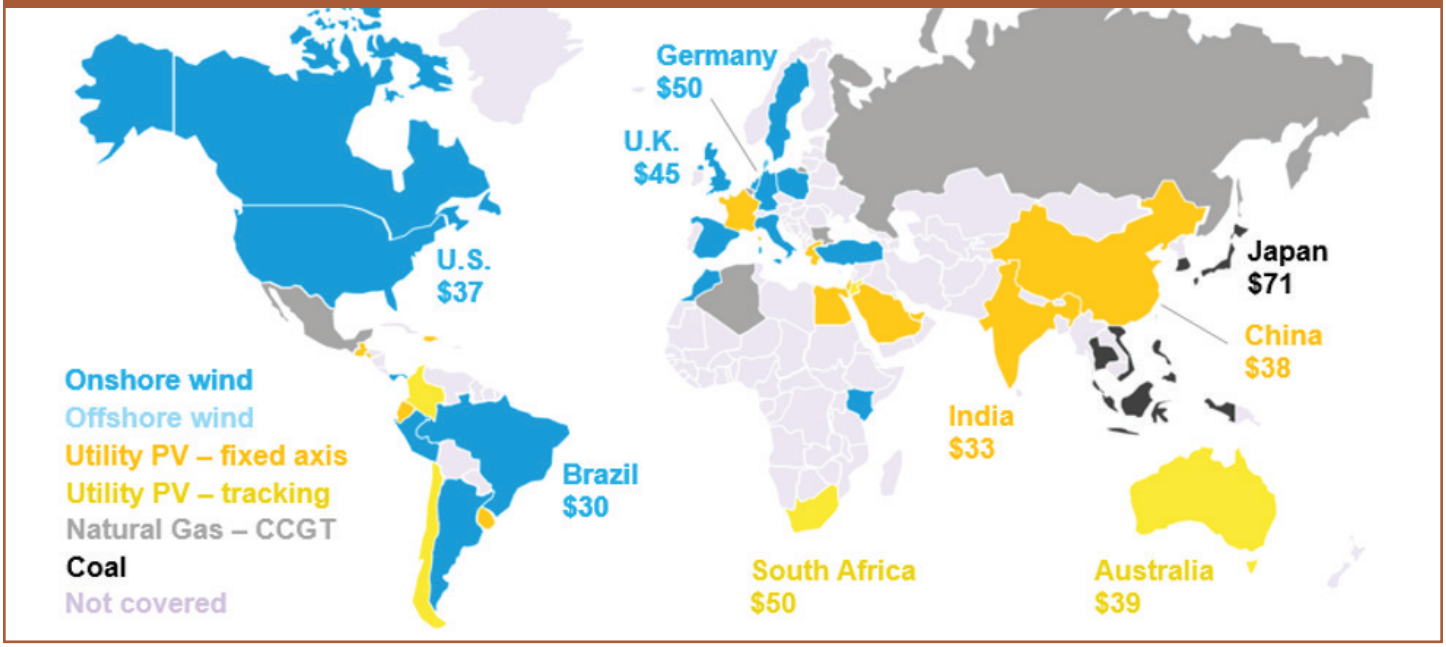
A 1.5°C pathway is possible without CCS. By transitioning the transportation, industry, and building sectors to 100 percent clean, renewable energy through rapid electrification and phase out of fossil fuels, and enhancing natural carbon sequestration through improved land management and restoration, it is possible to keep warming at or below 1.5° C *without* CCS.[11]

Clean energy is also cheaper energy. Plummeting renewable energy costs are rapidly making electrification with clean sources like solar and wind less expensive than producing power with fossil fuels.[12] A 2020 analysis by Bloomberg New Energy Finance found that solar and wind are already the cheapest energy sources for two-thirds of the world's population. Rapidly declining costs make renewable energy cheaper than continuing to operate existing coal and gas facilities in many places.[13]

Similarly, plummeting costs are quickly making battery storage a cheaper option for ensuring grid reliability than new gas peaker plants.[14] The US Energy Information Administration (EIA) projects that renewables will account for 71 percent of new US electricity generating capacity in 2021.[15]

The failure to account for the energy transition's market and technological disruptions to coal- and gas-fired power plants means not only that they are outcompeted

FIGURE 2
Cheapest Source of New Bulk Electricity Generation by Country



Source: *BloombergNEF.* Note: Levelized cost of energy (LCOE) calculations exclude subsides or tax credits. Graph shows benchmark LCOE for each country in US dollars per megawatt-hour. CCGT: Combined-cycle gas turbine.



Photo by Fabrice Duprez via Pixabay

by alternatives and systematically overvalued,[16] but also that "the overwhelming majority of these conventional facilities will become financially unviable and their assets stranded over the next decade or so."[17] Tacking CCS onto these soon-to-be stranded power plants is as economically ill-founded as it is environmentally unsound.

From a purely economic perspective, CCS does not make sense. Economists and energy analysts note that CCS projects are "prohibitively expensive compared to other GHG emissions mitigation options, such as renewable energy and energy storage technologies."[18] Adding CCS onto a fossil-fueled power plant inevitably makes operating the underlying source more expensive. As the authors of the energy transition study summarized above observed, "Coal and gas power plants with integrated carbon capture and storage (CCS) are doubly mispriced (overvalued)."[19] With coal- and gas-fired power stations already becoming more costly than renewable alternatives, adding CCS simply makes them even less economic and even less necessary.

A recent assessment of the economic viability of using CCS with gas-fired power plants demonstrates this reality, noting that mature carbon capture technologies are poorly suited to gas and pose an even larger energy penalty for fossil gas than for coal.[20] For a new-build gas-fired plant, CCS could more than double the construction costs and increase the cost of energy produced (known as levelized cost of energy) by up to 61 percent.[21]

As a result, CCS is not economic for gas-fired power plants even when it takes full advantage of existing federal subsidies, as discussed below, and when the captured carbon is used to produce more oil.[22] The authors of the study proposed a solution of injecting even more federal funding into CCS.

The simpler, surer, and cheaper solution is to end this and similar subsidies for the fossil fuel economy and invest the savings in accelerating the transition to clean energy.

Even for the Hard-to-Decarbonize Industrial Sector, CCS Is Not the Answer

The industrial sector accounted for 27 percent of US GHG emissions in 2019.[23] As the rationale for wide CCS deployment in the energy sector rapidly fades, CCS proponents are increasingly arguing that CCS will be needed to reduce emissions in heavy-emitting industries like steel, cement, petrochemicals, and aluminum. While the challenges to decarbonizing these industries are real, the potential for CCS to contribute to major emission reductions is routinely and often dramatically overstated. All too frequently, the advocacy for industrial CCS overlooks or downplays considerations like cost, alternatives to fossil fuel inputs, and the risks posed by transporting and storing captured carbon underground.

Applying CCS to high-emitting industrial activities, like petrochemical, steel, or cement manufacturing, is not economical. GHG emissions from these industries come from a diverse array of sources, including electricity consumption, on-site fossil fuel combustion, and process emissions, which make installing and operating CCS even more complex and generally more costly than it is in the power sector.

A recent analysis co-authored by a Chevron researcher highlights how these costs and complexities weaken the case for significant CCS deployment in the industrial sector. Beginning with a candidate pool of more than 1,500 US industrial facilities identified by the Environmental Protection Agency, the researchers immediately eliminated nearly 700 facilities, accounting for roughly half of all US industrial emissions, because the industries involved — including oil, gas, and coal production — "are not suitable for carbon capture retrofit."[24] By contrast, a transition away from fossil fuels would dramatically curtail such emissions.

From the remaining 656 facilities, the researchers identified only 123 facilities, less than 10 percent of the 1,500 facilities in the initial pool, that could capture carbon economically, even with full use of available federal subsidies and enhanced oil recovery.[25] And among that handful of facilities, many major sources of GHG emissions could not be captured.

For example, the petroleum refining industry is the largest source of industrial emissions other than fossil fuel production itself, yet less than 19 percent of refinery emissions were amenable to carbon capture. For metals processing, including steel, only a quarter of process emissions were amenable to CCS.[26] In total, the researchers identified only 68.5 metric tons of CO_2 per year from industrial process emissions that could be economically captured,[27] representing just 8 percent of all industrial emissions in the US.

Even this figure significantly overstates the potential of CCS in the industrial sector because the analysis excluded the indirect energy inputs that account for the largest single component of industrial sector emissions.[28] The authors did so on the grounds that the energy provided comes from the electrical grid, meaning associated emissions can be reduced more directly through other means, such as renewable energy.

Renewable sources for electricity and heat can dramatically reduce industrial emissions. Most industrial sector emissions are created by burning fossil fuels to produce the electricity and heat that power

FIGURE 3
Breakdown of the Number of Facilities and Their Emissions by Industrial Sector, Type of Emissions, and CO_2 Capture Potential

	refining[a]	chemicals	bioethanol	metals	minerals	pulp & paper	total
All Facilities in the Continuous U.S. Non-Suppliers of CO_2							
number of facilities	123	360	174	289	369	214	**1529**
total emissions [$MtCO_2$-eq/yr]	163	138	60	93	114	38	**606**
SC[b] [$MtCO_2$-eq/yr]	101	70	19	55	30	28	**303**
PE[b] [$MtCO_2$-eq/yr]	57	68	41[c]	37	84	10	**297**[c]
Facilities Considered for Carbon Capture Retrofit							
Number of facilities	97	104	174	118	163	0	**656**
total emissions [$MtCO_2$-eq/yr]	163	82	60	73	96	0	**473**
SC[b] [$MtCO_2$-eq/yr]	107	39	19	45	15	0	**225**
PE[b] [$MtCO_2$-eq/yr]	56	39	39	27	81	0	**242**
captured emissions [$MtCO_2$/yr]	40	26	37	19	72	0	**195**
Facilities Qualifying for the 45Q Tax Credit							
number of facilities	75	62	155	37	129	0	**458**
captured emissions [$MtCO_2$/yr]	39	24	36	17	71	0	**188**

[a]Refining category includes the emissions from the refining process and the hydrogen production at refineries. [b]SC = emissions from stationary combustion; PE = process emissions. [c]Process emissions from the ethanol industry are not reported by the EPA, the total process emissions reported by the EPA would thus equal to 256 $MtCO_2$/yr. In addition, this number excludes emissions from wastewater treatment and landfills that are not studied for point-source carbon capture in this work. Details are available in the Supporting Information.



Photo by HHakim via iStockphoto

manufacturing processes. Thus, decarbonizing the electricity grid by shifting to renewable sources provides the most direct route to slashing emissions in these industries. For example, the World Economic Forum estimates that 60 percent of carbon emissions from electricity-intensive aluminum production could be eliminated simply by producing that electricity from renewable sources.[29] In March 2021, a report by the International Aluminum Institute agreed that decarbonizing electricity grids provides the surest, most direct, and likely most cost-effective pathway to significant emission reductions in this energy-intensive industry.[30]

As currently equipped, the industrial sector uses fossil fuels not only for electricity, but for the heat that fuels industrial processes. Fossil fuel combustion for that heat accounts for about 58 percent of US industrial emissions and about 10 percent of overall global GHG emissions.[31] Electricity from clean power sources like solar and wind has the potential to provide low-carbon heat to many industrial systems.[32]

Concentrated solar thermal systems, for example, use solar energy for generating heat. One company has demonstrated this system works for reaching temperatures of more than 1,000°C.[33] From the heat used in kilns during the process of making cement,[34] to the high energy demand from electricity that goes into producing aluminum,[35] clean sources of electricity could displace fossil fuels consumed in a growing array of industrial processes, dramatically curtailing the largest single source of industrial GHG emissions and, with it, the purported benefits of CCS deployment in those industries.

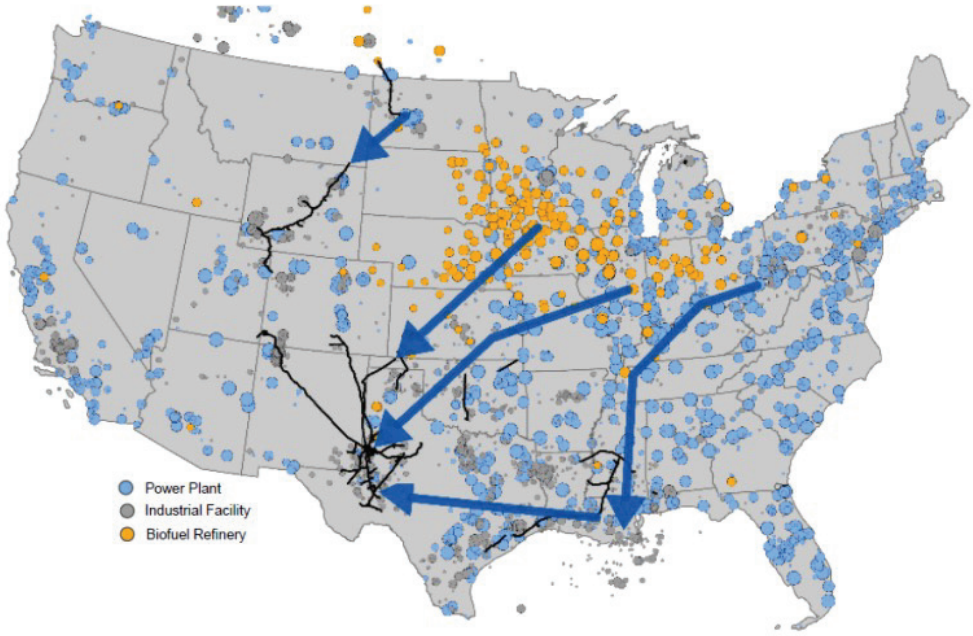
CCS obscures the role of reduction, reuse, and recycling in lowering industrial emissions. Proponents of industrial CCS routinely ignore that one of the most effective ways to reduce industrial emissions from high-emitting sectors like steel, aluminum, and plastics is to reuse existing materials, increase recycling rates, and produce less of the virgin material that is the major driver of emissions. This contrast is particularly notable in the case of plastics and petrochemicals, where the fracking boom of the last decade has driven a massive buildout of new plastics infrastructure even as communities around the world recognize that we need to reduce, not increase, our production and use of disposable plastics.

Even for aluminum, which is already heavily recycled, increasing the recycling of scrap metal could avoid 200 million tons of GHG emissions per year.[36] Replacing virgin steel with increased use of scrap metal or direct reduced iron also has high potential to reduce emissions from steel production — potential that should be tapped, given that CCS technology for steel remains immature and economically unproven, according to industry analysis.[37]

Applying CCS to industrial sources requires massive infrastructure buildout. Even assuming carbon can be captured effectively and economically from an industrial process, that does not assure it can be safely sequestered. The geographic distribution of CO_2 storage sites is a limiting factor for CCS deployment in industry.[38] The overwhelming majority of industrial facilities including those in high-emitting industries like cement, steel, and aluminum, were sited to ensure access to critical

FIGURE 4

Map of CO_2-Emitting Facilities Compared to Viable Geological Storage Sites



Elizabeth Abramson, Regional Carbon Capture and Transport Opportunities for Storage in Louisiana. Presentation to "Developing CCUS Projects in Louisiana and the Gulf Coast" (USDOE/USEA/GCCSI) November 17, 2020. *https://www.globalccsinstitute.com/wp-content/uploads/2020/11/PPT-LA_Day-1-and-Day-2.pdf* at slide 42.

resources like steam, electricity, water, and end markets, not carbon storage.

Accordingly, only a small fraction of existing or proposed facilities in these sectors are located in areas suitable for CO_2 storage. Storing carbon captured from such facilities would demand a vast network of new pipelines, some running hundreds of miles, and carrying hazardous CO_2 through populated areas.

Transporting carbon to storage sites and injecting it underground involves further risks and costs. As discussed more fully below, this reality means that the growing risks of carbon capture will be borne disproportionately by the few communities already living near concentrations of both heavy industry and potential storage or injection sites.

CCS Perpetuates Fossil Fuel Systems and Impacts

By design, CCS enables an underlying emissions-generating activity to continue — by capturing some of the CO_2 it would otherwise emit. The promise of CCS is being used to rationalize — and subsidize — continued investment in fossil fuel infrastructure that would lock in emissions of CO_2 and other pollutants for decades to come.

Even in its idealized form, CCS only prevents a fraction of emissions from the underlying source. At every stage of their lifecycle, including extraction, refining, transport, use, and disposal, fossil fuels release a wide array of pollutants, many of which pose known or suspected hazards to humans and the environment. For example, a study released in February 2021 by Harvard University and University College London researchers found that fine particulate matter (PM2.5) from burning fossil fuels is responsible for millions of deaths worldwide. In 2018, approximately one in five deaths overall, or 8.7 million premature deaths, were linked to PM2.5 pollution from fossil fuels.[39]

CCS does nothing to address these hazards.[40] Indeed, by requiring greater use of fossil fuels to power the CCS process itself, CCS may actually exacerbate them. In the energy sector, there is compelling evidence that the negative climate, environmental, and health impacts of adding carbon capture to fossil fuels are substantially

greater than simply replacing fossil fuels altogether with clean alternatives.[41] As discussed more fully above, the deployment of industrial CCS raises similar concerns.

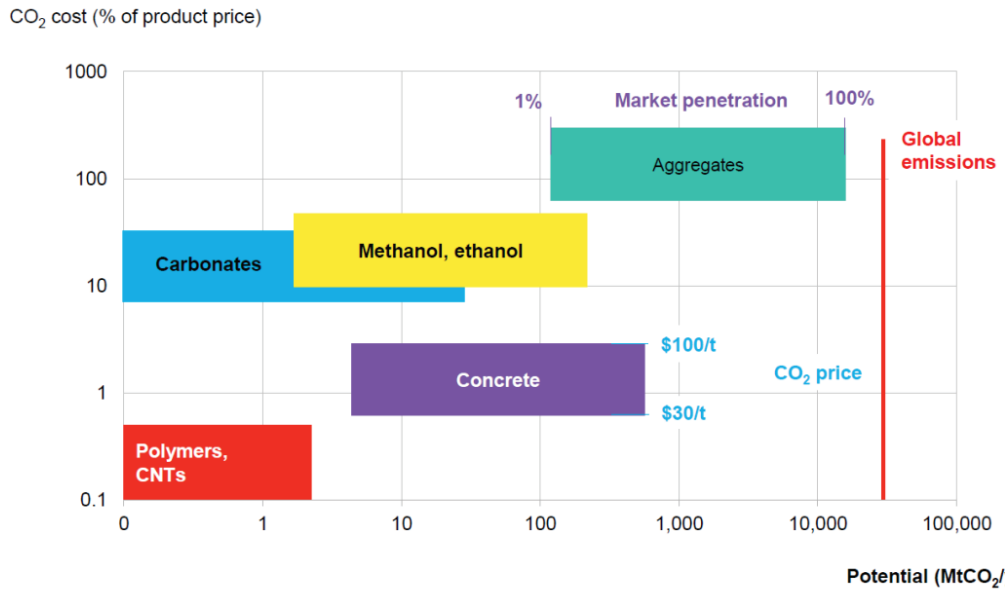
Using captured carbon to produce still more fossil fuels accelerates the climate crisis. At present, carbon capture is not economically viable without enhanced oil recovery or the production of combustible fuels, making the technology inseparable from the fossil economy. Enhanced oil recovery (EOR) is a technique through which CO_2 — either from natural sources or captured carbon — is injected into underground oil reservoirs to boost oil and gas production from old wells. In essence, CO_2 waste products from a fossil fuel-burning activity are used to generate more fossil fuels, propping up the unsustainable fossil fuel energy system.

More than 80 percent of all CCS capacity deployed to date has been used for EOR.[42] And the majority of CCS projects in active development also incorporate EOR. The US Department of Energy estimates this could result in up to 48 billion additional barrels of oil used in the US alone by 2030.[43] This is disastrous from a climate mitigation perspective, since it will result in more oil extracted and more carbon emissions from the oil burned. The emissions impact from burning oil produced with CO_2 + EOR is currently excluded from lifecycle analyses touting the technology.[44] While the resulting CO_2 emissions may be invisible to carbon accountants, their presence in the atmosphere and their impact on the climate remains real and significant.

Proponents of CCUS argue that "[t]he most efficient strategy to reduce the concentration of CO_2 in the atmosphere is to convert it to useful chemicals and fuels."[45] But such proposals confront a fundamental challenge: global emissions of CO_2 are orders of magnitude greater than global demand for CO_2 in products. In 2018, the world emitted more than 37 billion tons of CO_2 and other GHGs from fossil fuel combustion for energy and industry.[46] By contrast, it used just 230 million tons of CO_2 for commercial purposes — equal to just 0.5 percent of total annual emissions. Two uses alone — EOR and fertilizer production — account for more than 85 percent of all CO_2 consumed globally.[47] All other commercial and industrial uses combined account for just 20 million tons of CO_2 each year, a mere drop in the bucket.

The touted uses of CO_2 are also unviable. Using captured carbon to produce combustible fuels, including via EOR, defeats any climate mitigation purpose, as the fuels release the carbon back into the atmosphere. Transforming CO_2 into chemicals requires massive

FIGURE 5
CO_2 Utilization Markets and Sensitivity to CO_2 Prices



BNEF Executive Factbook 2021 at 56: https://assets.bbhub.io/professional/sites/24/BNEF-2021-Executive-Factbook.pdf

amounts of energy, which is why only a handful of commercialized chemicals use CO_2 in significant quantities.[48] Technologies for embedding captured carbon in plastics, for example, are currently confined to laboratory environments, and neither technologically nor economically proven at scale.[49] Just as importantly, using captured carbon to increase production of plastics — which are themselves made from fossil fuels — would compound the plastics crisis while doing little to address the climate crisis.[50] Proposals to store captured carbon in concrete are no more promising. Storing 1 pound of CO_2 requires 100 times its weight in concrete when embedded in cement mix and over 1,000 times its weight when embedded in standard concrete blocks.[51] Embedding coal combustion wastes or industrial slag in concrete does not eliminate smokestack emissions and increases risks of toxic leaching from the treated materials.[52] Just as using captured carbon to produce more oil increases emissions, embedding industrial wastes into new products does nothing to curb emissions from the activity that generated the waste.

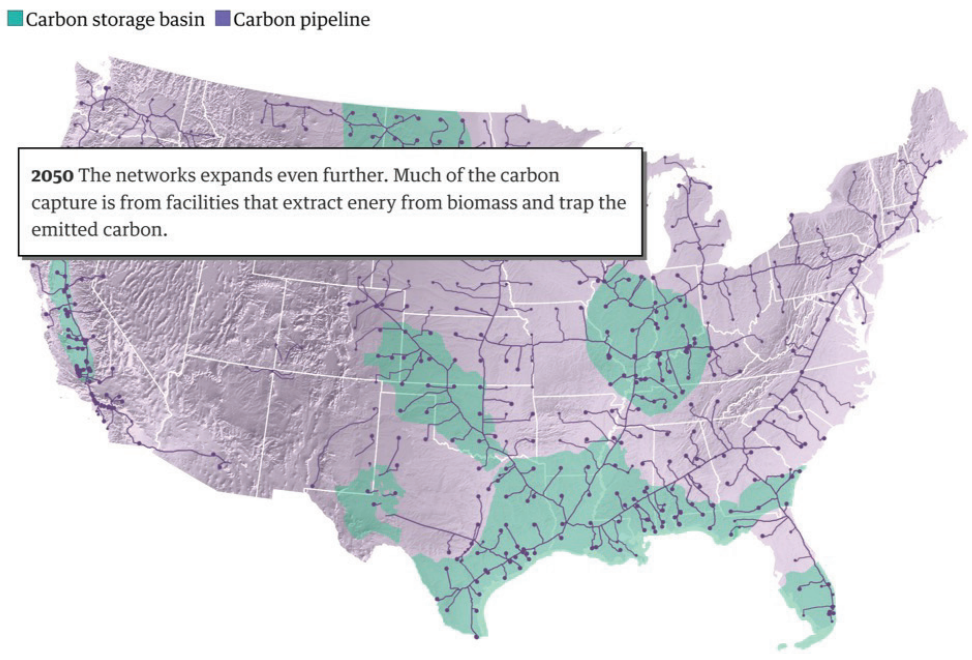
CCS subsidies end up in oil industry pockets. The tax credit for CCS projects (under Section 45Q of the US Internal Revenue Code, which Congress extended in December 2020) is the main federal policy support for CCS. Its biggest beneficiaries are oil companies that claim the credit for injecting carbon into underground oil deposits to produce more oil, through EOR.[53] The tax credit thus functions as a fossil fuel subsidy.[54]

Moreover, the lack of adequate monitoring of CCS activities means claimed credits may be based on little more than hot air, not on stored carbon.[55] For example, an investigation by the US Treasury's Inspector General for Tax Administration found that fossil fuel companies improperly claimed nearly $900 million in tax credits under Section 45Q.[56]

The push for carbon capture and storage primarily benefits the fossil fuel industry. The most vocal and active proponents of CCS are oil and gas, petrochemical, and utility companies. They tout the necessity and promise of carbon capture to protect a business model that is contributing to climate catastrophe.[57]

In addition to investing directly in carbon capture ventures, companies in the fossil fuel industry promote

FIGURE 6
Map of Proposed US CO_2 Pipeline Network



Oliver Milman, Alvin Chang & Rashida Kamal, The race to Zero: can America reach net-zero emissions by 2050. The Guardian (March 15, 2021). https://www.theguardian.com/us-news/2021/mar/15/race-to-zero-america-emissions-climate-crisis

CCS advocacy, research, and policy through an array of corporate consortia, industry-government working groups, and funding partnerships with universities. For example, the Global CCS Institute, an international think tank dedicated to accelerating CCS deployment, includes various coal, oil and gas, and energy and utility companies as members, and a handful of national and sub-national governments.[58] Corporate polluters benefit from promoting CCS, while the environmental and community impacts of scaling up the CCS industry are too often ignored.

CCS Poses a Growing and Poorly Understood Threat to Communities & the Environment

Scaling up the technology and infrastructure required to capture, compress, transport, and store CO_2 entails significant risks.[59] Whether paired with fossil fuel power plants or industrial manufacturing, CCS technology demands massive infrastructure buildout. In terms of scale, it is estimated the CCS industry and associated infrastructure would need to be two to four times larger by 2050 than the current global oil industry.[60] As the IPCC has noted, extensive deployment of CCS "will require a large network of pipelines."[61] To date, the heavy environmental footprint and safety and health hazards[62] associated with CCS infrastructure have been largely overlooked.[63]

The transportation of compressed CO_2 raises a host of health and safety concerns. Especially when moved over long distances and/or through heavily populated areas, piping CO_2 poses risks similar to those associated with fossil fuel pipelines, from land disturbance and water contamination to the danger of explosions and other accidents. These risks are rarely disclosed or discussed in public discussion of CCS.

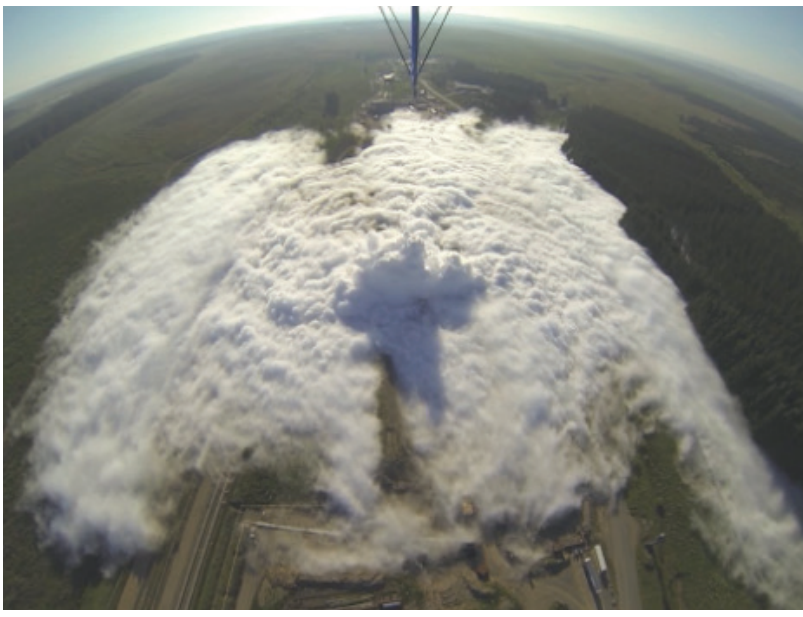
Effective transport through pipelines requires that CO_2 be shipped at very high pressure and extremely low temperatures, demanding pipelines capable of withstanding those conditions. The presence of moisture or contaminants can make this condensed CO_2 corrosive to the steel in those pipelines, increasing the risk of leaks, ruptures, and potentially catastrophic running fractures.

Because of the intense pressures involved, explosive decompression of a CO_2 pipeline releases more gas, more quickly, than an equivalent explosion in a gas pipeline.[64] Video recordings of pipeline failure tests under controlled conditions demonstrate that even a modest rupture can spread freezing CO_2 over a wide area within seconds.[65] The emergence of a running pipeline rupture could extend impacts the entire length of a pipeline segment.[66]

As a paper published by the Institution of Chemical Engineers Symposium cautions: "The combination of the massive amount of CO_2 released in a relatively short period of time, the resulting dense cloud followed by solid discharge and its slow sublimation will pose a major challenge to safety practitioners when dealing with the hazards associated with the failure of pressurized CO_2 pipelines."[67]

The IPCC recognizes that "carbon dioxide leaking from a pipeline forms a potential physiological hazard for humans and animals."[68] These risks take several forms.

The explosive rupture of a pipeline and its associated shockwave pose immediate physical risks to nearby people and property. In areas closest to the pipeline, a release of CO_2 can quickly drop temperatures to minus 60°C, coating the surrounding area with super-cold dry ice.[69] At high concentrations, CO_2 is a toxic gas and an



CO_2 cloud from a rupture test performed at DNV GL Spadeadam, Photo: DNV GL



Photo Credit: Mississippi Emergency Management Agency

asphyxiant capable of causing "rapid 'circulatory insufficiency', coma and death."[70] And potential contaminants in CO_2 streams, such as hydrogen sulfide (H_2S) can dramatically compound these risks.[71]

Accidents are inevitable as CO_2 pipelines are increasingly built in populated areas. In February 2020, a 24-inch high-pressure pipeline containing carbon dioxide and sulfur dioxide ruptured in Yazoo County, Mississippi. According to the Mississippi Emergency Management Agency, more than 300 residents were evacuated and[46] dozens were hospitalized.[72] The pipeline owner, Denbury Enterprises, operates hundreds of miles of CO_2 pipelines in the Gulf Coast and Rocky Mountain regions. At least two Denbury pipelines run through the heavily polluted petrochemical corridor known as Cancer Alley,[73] predominately populated by communities of color.

These safety hazards and environmental risks fall disproportionately on marginalized communities. Fossil fuel and petrochemical infrastructure, and the threats to health and public safety that infrastructure creates, already overburden Black, Brown, and Indigenous communities. The deployment of CCS threatens to significantly increase these risks, particularly in the regions being most heavily targeted for new CCS buildouts.

Both the Gulf Coast of Texas and Cancer Alley in southern Louisiana have been widely touted as potential epicenters for industrial CCS development due to existing concentrations of oil, gas, and petrochemical infrastructure, along with oil fields and salt domes that are the most viable injection and storage sites.[74] CCS proposals in other regions also focus on areas where energy and industrial infrastructure are concentrated, which are typically in or adjacent to poor neighborhoods and communities of color. The expansion of CCS would add a significant new source of pollution and safety risks in Black, Brown, and Indigenous communities already suffering the disproportionate and deadly impacts of environmental racism.

Conclusion

CCS and CCUS are not only unnecessary, ineffective, uneconomic, and unsafe; the technologies are also exceptionally risky, prop up the fossil fuel industry and carbon-intensive industrial activities, and distract from the urgent task of transitioning away from fossil fuels at a time when the US and the world must dramatically accelerate that transition. These technologies, and the dangerous myth they perpetuate of climate-safe fossil fuels, have no place in US climate policies and financing. Such policies should focus instead on phasing out fossil fuels and implementing proven climate mitigation strategies on an urgent, comprehensive basis, reflecting their fundamental importance for this and all future generations.

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CIEL
CENTER for INTERNATIONAL ENVIRONMENTAL LAW

1101 15th Street NW, #1100, Washington, DC 20005
15 rue des Savoises, 1205 Geneva, Switzerland
www.ciel.org

Confronting the Myth of Carbon-Free Fossil Fuels: Why Carbon Capture Is Not a Climate Solution was prepared by Dana Drugmand and Carroll Muffett of the Center for International Environmental Law (CIEL), with editorial assistance from Nikki Reisch, Steven Feit, and Cate Bonacini.

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In conclusion, pure H^- conduction was realized in the $La_{2-x-y}Sr_{x+y}LiH_{1-x+y}O_{3-y}$ system. The present success in the construction of an all-solid-state electrochemical cell exhibiting H^- diffusion confirms not only the capability of the oxyhydride to act as an H^- solid electrolyte but also the possibility of developing electrochemical solid devices based on H^- conduction.

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ACKNOWLEDGMENTS

This research was supported by JST, PRESTO, and Grant-in-Aid for Young Scientists (A) no. 15H05497 and (B) no. 24750209; Grant-in-Aid for Challenging Exploratory Research nos. 15K13803, 23655191, and 25620180; and Grant-in-Aid for Scientific Research on Innovative Areas nos. 25106005 and 25106009, from the Japan Society for the Promotion of Science. Synchrotron and neutron radiation experiments were carried out as four projects approved by the Japan Synchrotron Radiation Research Institute (JASRI) (Proposal no. 2013A1704), the Japan Proton Accelerator Research Complex (J-PARC) (Proposal no. 2010A0058), the Spallation Neutron Source (SNS) in the Oakridge National Laboratory (Proposal no. IPTS5808), and the Neutron Scattering Program Advisory Committee of IMSS, KEK (Proposal no. 2014S10). A part of neutron experiments (Proposal no. 2014S10) was performed at BL09 Special environment neutron powder diffractometer (SPICA) developed by the Research and Development Initiative for Scientific Innovation of New Generation Batteries (RISING) project of the New Energy and Industrial Technology Development Organization (NEDO). Supercomputing time on the Academic Center for Computing and Media Studies (ACCMS) at Kyoto University is gratefully acknowledged. Further information regarding the materials and methods is included in the supplementary materials. G.K., A.W., M.H., and R.K. have filed for a patent application with the Japan Patent Office under no. JP2015-22868 on the H^- conductive oxyhydride system and its manufacture.

SUPPLEMENTARY MATERIALS

www.sciencemag.org/content/351/6279/1314/suppl/DC1
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29 June 2015; accepted 20 January 2016
10.1126/science.aac9185

GAS INFRASTRUCTURE

Methane emissions from the 2015 Aliso Canyon blowout in Los Angeles, CA

S. Conley,[1,2]*† G. Franco,[3] I. Faloona,[2] D. R. Blake,[4] J. Peischl,[5,6] T. B. Ryerson[6]†

Single-point failures of natural gas infrastructure can hamper methane emission control strategies designed to mitigate climate change. The 23 October 2015 blowout of a well connected to the Aliso Canyon underground storage facility in California resulted in a massive release of natural gas. Analysis of methane and ethane data from dozens of plume transects, collected during 13 research-aircraft flights between 7 November 2015 and 13 February 2016, shows atmospheric leak rates of up to 60 metric tons of methane and 4.5 metric tons of ethane per hour. At its peak, this blowout effectively doubled the methane emission rate of the entire Los Angeles basin and, in total, released 97,100 metric tons of methane to the atmosphere.

Large volumes of processed natural gas are stored underground to accommodate variability in energy demand on diurnal to seasonal time scales. Underground storage facilities constitute strategic gas reserves in many countries worldwide, with a volume equal to 10% of global annual consumption (*1*). Roughly 86% of stockpiled natural gas in the United States is stored at high pressure in depleted subsurface oil reservoirs (*2*). The Aliso Canyon storage facility, a depleted subsurface oil reservoir in the San Fernando Valley 40 km northwest of Los Angeles, CA, has a total capacity of 168 billion standard cubic feet (SCF) (4.79×10^9 m^3) at standard temperature and pressure, of which only 86 billion SCF (2.5×10^9 m^3; the "working capacity") is routinely accessed for commercial use (*2*). It is the fourth largest facility of its kind in the United States, accounting for 2.1% of the total U.S. natural gas storage in 2014 (*2*). Processed natural gas is composed primarily of methane (CH_4), a powerful greenhouse gas, and ethane (C_2H_6), both of which can lead to background tropospheric ozone production; at sufficiently high concentrations, natural gas leaks pose an explosion hazard and, if inhaled, can induce nausea, headaches, and impaired coordination. Exposure to odorants that are added to natural gas, which are typically sulfur-containing compounds such as tetrahydrothiophene [$(CH_2)_4S$] and 2-methylpropane-2-thiol [*t*-butyl mercaptan; $(CH_3)_3CSH$] can cause short-term loss of the sense of smell, headaches, and respiratory tract irritation. Major natural gas leaks therefore can have adverse impacts on climate, air quality, and human health.

On 23 October 2015, a major natural gas leak of indeterminate size was reported in the Aliso Canyon area and was later identified as originating from SS-25, one of 115 wells connected to the subsurface storage reservoir. The SS-25 well began oil production in 1954 and was converted to a gas storage well in 1973 (*3*). Seven unsuccessful attempts to close the leak have been reported. A relief well intercepted the leaking pipe at a depth of ~2600 m, below the subsurface breach; heavy fluid injection (a "bottom kill") temporarily halted the leak on 11 February 2016, and cement injection sealed the well on 18 February 2016 (*4*).

We deployed a chemically instrumented Mooney aircraft in 13 flights from 7 November 2015 to 13 February 2016. We measured CH_4 and C_2H_6 to quantify the atmospheric leak rate and to assess air quality downwind of the leaking well (*5*). Ground-based whole-air sampling (WAS) with stainless steel canisters on 23 December 2015, followed by laboratory analysis, provided information on the chemical speciation of the leaking hydrocarbon mixture. We used the continuous airborne data and the ground-based WAS canister

[1]Scientific Aviation, 3335 Airport Road, Boulder, CO 80301, USA. [2]Department of Land, Air, and Water Resources, University of California–Davis, Davis, CA 95616, USA. [3]Research and Development Division, California Energy Commission, Sacramento, CA 95814, USA. [4]Department of Chemistry, University of California–Irvine, Irvine, CA 92617, USA. [5]Cooperative Institute for Research in Environmental Sciences, University of Colorado–Boulder, Boulder, CO, 80309, USA. [6]Earth System Research Laboratory, National Oceanic and Atmospheric Administration (NOAA), Boulder, CO, 80305, USA.
***Corresponding author. E-mail: sconley@scientificaviation.com** †These authors contributed equally to this work.

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data to fingerprint the plume's chemical composition, quantify the atmospheric leak rate, and document trends in the leak rate over time.

The airborne chemical data showed the continuing transport on northerly winds of exceptionally high concentrations of CH_4 and C_2H_6 into the densely populated San Fernando Valley, a few kilometers south of the leaking well (Fig. 1). The plume C_2H_6-to-CH_4 enhancement ratio (ER) derived from linear least-squares regression fits to the 23 December 2015 continuous airborne data is identical, within total uncertainties propagated by quadrature addition of errors (*6*), to the plume ER derived from WAS canister data taken at the surface on the same day (Fig. 2A).

The hydrocarbon composition of WAS canister samples taken at surface locations in the San Fernando Valley (Fig. 1) on 23 December 2015 (*5*) is consistent with a leak of pipeline-quality processed natural gas with a hydrocarbon composition of ~95% CH_4, ~4% C_2H_6, and ~0.3% propane (C_3H_8) (table S1). Plume enhancements of natural gas liquids (ethane, propane, and butanes) and condensates (pentanes and longer-chain hydrocarbons that are liquid at ambient temperature and pressure) were detected (table S1) and were probably responsible for reports of oily deposits on surfaces in downwind residential areas. Trace enhancements of benzene, toluene, ethylbenzene, and xylene isomers (the so-called BTEX compounds) were also detected at ratios of 0.001% or lower relative to CH_4 (table S1).

Benzene is a known human carcinogen (*7*); thus, population exposure to benzene from the Aliso Canyon leak has received particular attention. Composition data from the WAS canisters indicate a benzene-to-CH_4 enhancement ratio of $(5.2 \pm 0.1) \times 10^{-6}$ (uncertainties throughout are ±1 SEM), which is broadly consistent with an ER of ~7×10^{-6} found in highly concentrated samples that were collected ~3 m downwind of the SS-25 well site (*8*). Together, these samples suggest minimal variation over time in the benzene composition of the leaking gas. Publicly available benzene data, reported in near-daily 12-hour air samples (*9*), were often below the detection limit of 1 nmol/mol [or 1 part per billion (ppb)] of the contract laboratories used for the analyses, but these data also show a relatively constant ER over time. Plume benzene enhancements can be estimated from the abundant CH_4 data by multiplying plume CH_4 enhancements by the benzene-to-CH_4 ER determined using the research-grade WAS canister samples. Sulfur-containing odorants were not measured, but concentrations above the odor threshold can be estimated similarly (Fig. 1) from observed CH_4 enhancements by assuming an industry-standard value of ~5 parts per million (ppm) of total odorant in processed natural gas (*10*).

Continuous airborne CH_4 and C_2H_6 data were taken on each flight between 11 AM and 3:30 PM (local time) with a resolution of 30 m along-track during repeated crosswind transects at multiple altitudes from 60 to 1400 m above ground. These data define the horizontal and vertical extent of the leaking natural gas plume on each flight (Fig. 1 and fig. S1). The flights provided highly spatially resolved data from which an atmospheric mass flux can be accurately calculated (*11*) within well-defined uncertainties (*12*). Plumes from nearby landfills have low concentrations of CH_4, are easily identified by their lack of co-emitted C_2H_6, and were eliminated from further analysis. Background levels of CH_4 and C_2H_6 were measured during aircraft transects on multiple flights immediately upwind, confirming the SS-25 well as the dominant source of enhanced natural gas to the region. Operational restrictions on aircraft flight patterns were imposed by the elevated terrain at the leak site, the highly controlled airspace of the San Fernando Valley, and the proximity to approach corridors of the nearby Van Nuys Airport (Fig. 1). These restrictions were overcome by performing crosswind transects at multiple altitudes immediately downwind of the leak site,

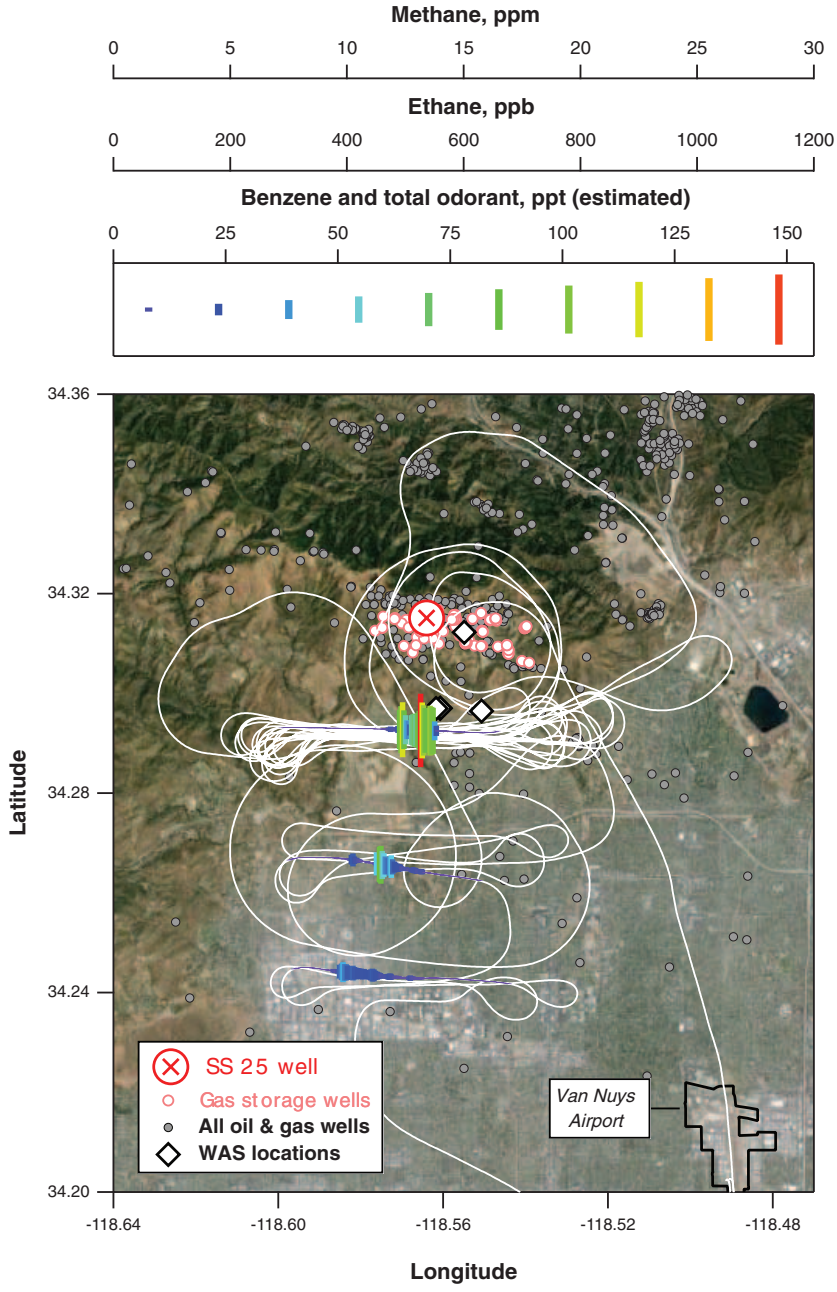


Fig. 1. Aliso Canyon gas plume transport into populated areas. Airborne chemical data illustrate plume transport into the San Fernando Valley; data from 10 November 2015 are shown. Plume enhancements above the local background (colored markers) from example transects are plotted along the flight track (white line) and can be scaled using the legends at top to yield measured CH_4, measured C_2H_6, estimated benzene based on the WAS benzene-to-CH_4 ER, and estimated total odorant (assuming 5 ppm in the leaking gas). Benzene and total odorant are in parts per trillion by volume (ppt).

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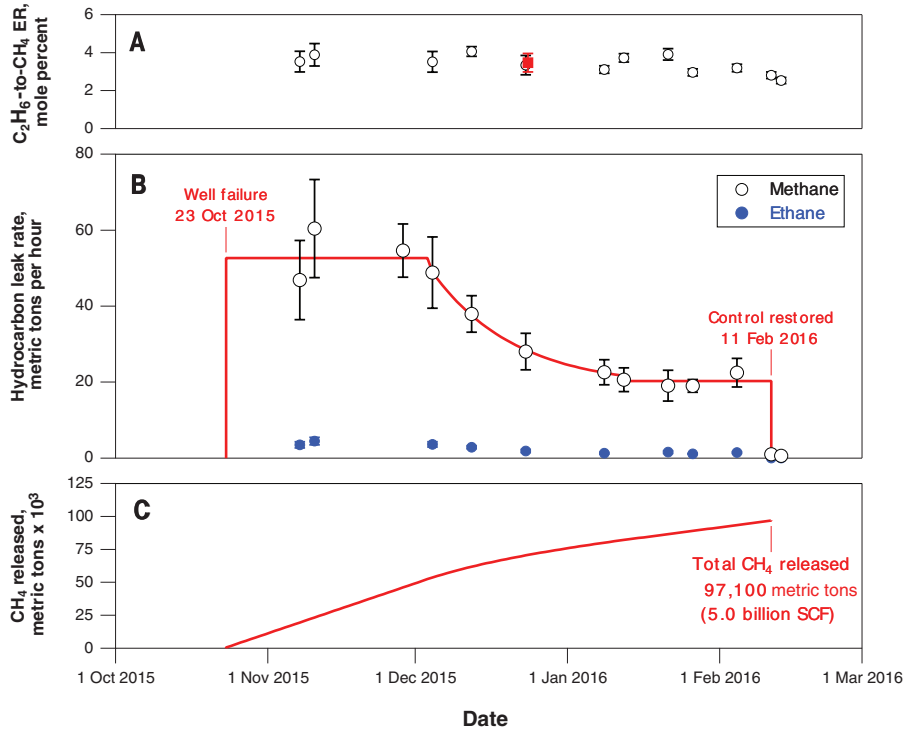


Fig. 2. Time series of the Aliso Canyon natural gas leak. (**A**) Plume C_2H_6-to-CH_4 ERs from airborne measurements (open circles) and ground-based WAS measurements (red square). (**B**) Leak rates (in metric tons per hour) of CH_4 (open circles) and C_2H_6 (blue circles), determined from airborne measurements. The red line is a fit to the airborne CH_4 data, assuming an average leak rate from the blowout (day 0) to day 43, an exponential decrease between days 43 and 80, and an average leak rate thereafter to day 112, when control was restored. (**C**) The total amount of CH_4 released (in metric tons), calculated from the fit in (B). Error bars indicate ±1 SEM.

which enabled accurate reconstruction of a vertical concentration profile, even before the plume had completely mixed throughout the full vertical extent of the atmospheric boundary layer (*5*).

The chemical data show that the airborne sampling captured the full vertical extent of the lofted plumes on each flight day (fig. S1). Atmospheric mass fluxes calculated from the chemical data from each transect collected downwind (*5*) suggest an average leak rate of 53 ± 3 metric tons of CH_4 and 3.9 ± 0.3 metric tons of C_2H_6 per hour for the first six weeks of the leak, decreasing thereafter (Fig. 2B and table S2). The decreasing trend, which began around the first week of December 2015 (Fig. 2B and table S2), is consistent with decreasing reservoir pressure in response to the withdrawal of gas through other storage wells connected to the subsurface reservoir, which was done in a deliberate effort to slow the leak (*13*). The lack of a decrease in the leak rate after the first week of January 2016 is consistent with the cessation of withdrawals to maintain a minimum working pressure in the reservoir, which supplied natural gas to customers in the greater Los Angeles basin throughout the leak duration.

These data demonstrate that the blowout of a single well in Aliso Canyon temporarily created the largest known anthropogenic point source of CH_4 in the United States (*14*), effectively doubling the leak rate of all other sources in the Los Angeles basin combined (*15, 16*). Further, at its peak, this leak rate exceeded that of the next largest point source in the United States—an underground coal mine in Alabama—by over a factor of 2 (*14*) and was a factor of 10 larger than the CH_4 leak rate reported from the Total *Elgin* rig blowout in the North Sea in 2012 (*17*). The Aliso Canyon CH_4 leak rates were comparable to the total CH_4 emission rates of entire oil and gas production regions in the United States [e.g., the Barnett shale, 76 metric tons per hour (*18*); the Haynesville shale, 80 metric tons per hour (*19*); the Fayetteville shale, 39 metric tons per hour (*19*); and the northeastern Marcellus shale, 15 metric tons per hour (*19*)].

Our aircraft flights after the "bottom kill" confirmed the cessation of flow from the SS-25 well on 11 February 2016 and revealed a residual leak rate of <1 metric ton of CH_4 per hour (Fig. 2B and table S2), consistent with nonzero leak rates observed at other natural gas, oil, and petrochemical facilities nationwide (*16*, *18*–*24*). These data show that over its 112-day duration, the Aliso Canyon natural gas leak released a total of 97,100 metric tons (5.0 billion SCF) of CH_4 (Fig. 2C) and 7300 metric tons (0.2 billion SCF) of C_2H_6 to the atmosphere, which is equal to 24% of the CH_4 and 56% of the C_2H_6 emitted each year from all other sources in the Los Angeles basin combined (*16*).

This CH_4 release is the second largest of its kind recorded in the United States, exceeded only by the 6 billion SCF (115,000 metric tons) of natural gas released in the 2004 collapse of an underground storage facility in Moss Bluff, TX, and greatly surpassing the 0.1 billion SCF (1900 metric tons) of natural gas leaked from an underground storage facility near Hutchinson, KS, in 2001 (*25*). Aliso Canyon will have the largest climate impact by far, however, given that an explosion and subsequent fire during the Moss Bluff release combusted most of the leaked CH_4, immediately forming CO_2. The total release from Aliso Canyon will substantially affect the State of California greenhouse gas (GHG) emission targets for the year (*26*) and is equivalent to the annual energy sector CH_4 emissions from medium-sized European Union nations (*27*). The radiative forcing from this amount of CH_4, integrated over the next 100 years, is equal to that from the annual GHG emissions of 572,000 passenger cars in the United States (*28*). The volume of CH_4 released represents only 3% of the total capacity of the Aliso Canyon storage facility, raising the possibility of substantial additional emissions if the leaking SS-25 well had not been sealed, or if the remaining natural gas had not been withdrawn through other wells, before the reservoir was completely exhausted to the atmosphere.

The agreement reached at the 21st Conference of the Parties (COP21) to the UN Framework Convention on Climate Change (*29*) includes specific requirements for the Parties to account for anthropogenic GHG emissions with accuracy and completeness. In the post-COP21 world, rapid evaluation of episodic GHG release events, such as the Aliso Canyon blowout, will be an essential contribution to meeting these requirements.

Our analysis quantifies a massive CH_4 release using a rapid, direct, and repeatable method with known accuracy. As such, results from this method serve as reference values for less direct and timely estimates that use retrievals of surface (*30, 31*), airborne (*32*), and/or satellite remote sensing observations (*33*). For example, our airborne method offers a priori estimates of the Aliso Canyon leak rates that can be used for inverse modeling analysis of continuous in situ CH_4 monitoring data from fixed ground sites (*15, 34*). This incident highlights the utility of rapid-response airborne chemical sampling in providing an independent, time-critical, accurate, and spatially and temporally resolved leak rate, as well as in ascertaining the source location and plume chemical composition. Such information can help to document human exposure, formulate optimal well-control intervention strategies, quantify the efficacy of deliberate control measures, and assess the climate and air quality impacts of major unanticipated chemical releases to the atmosphere (*35, 36*).

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ACKNOWLEDGMENTS

The first two Scientific Aviation flights were funded by the California Energy Commission through University of California–Davis project #201401201. Subsequent flights were funded by the Southern California Gas Company, the operator of the Aliso Canyon storage facility. I.F. was supported in part by the California Agricultural Experiment Station (Hatch project CA-D-LAW-2229-H). J.P. and T.R. were supported in part by the NOAA Climate Program Office and the NOAA Atmospheric Chemistry, Carbon Cycle, and Climate program. We acknowledge the contributions of M. Trainer for scientific input and K. Aikin and S. Wolter for time-critical technical support. The views expressed here are those of the authors and do not constitute endorsement by their funding agencies. Data used in this report are posted at esrl.noaa.gov/csd/scientificaviation.

SUPPLEMENTARY MATERIALS

www.sciencemag.org/content/351/6279/1317/suppl/DC1
Materials and Methods
Figs. S1 and S2
Tables S1 and S2
References (*37*–*44*)

11 January 2016; accepted 17 February 2016
Published online 25 February 2016
10.1126/science.aaf2348

BIOCHEMISTRY

Fine-tuning of a radical-based reaction by radical *S*-adenosyl-L-methionine tryptophan lyase

Giuseppe Sicoli,[1,2] Jean-Marie Mouesca,[1,2] Laura Zeppieri,[3] Patricia Amara,[3] Lydie Martin,[3] Anne–Laure Barra,[4] Juan C. Fontecilla-Camps,[3] Serge Gambarelli,[1,2]* Yvain Nicolet[3]*

The radical *S*-adenosyl-L-methionine tryptophan lyase NosL converts L-tryptophan into 3-methylindolic acid, which is a precursor in the synthesis of the thiopeptide antibiotic nosiheptide. Using electron paramagnetic resonance spectroscopy and multiple L-tryptophan isotopologues, we trapped and characterized radical intermediates that indicate a carboxyl fragment migration mechanism for NosL. This is in contrast to a proposed fragmentation-recombination mechanism that implied Cα–Cβ bond cleavage of L-tryptophan. Although NosL resembles related tyrosine lyases, subtle substrate motions in its active site are responsible for a fine-tuned radical chemistry, which selects the Cα–C bond for disruption. This mechanism highlights evolutionary adaptation to structural constraints in proteins as a route to alternative enzyme function.

Nosiheptide, produced by *Streptomyces actuosus*, is a highly modified, sulfur-rich, polythiazolyl macrocyclic peptide antibiotic (*1*). This compound exhibits highly potent activity against multidrug-resistant strains of several gram-positive pathogens (*2*–*5*). Originating from a 13-residue-long, ribosomally synthesized peptide, nosiheptide contains a central tetra-substituted pyridine ring, five thiazole rings, and an unusual indolic acid (*6*, *7*). The latter is produced by the tryptophan lyase (NosL) enzyme, which converts L-tryptophan to the methylindolic acid (MIA) precursor that is subsequently inserted into the thiopeptide (*8*, *9*). NosL belongs to the radical *S*-adenosyl-L-methionine (SAM) protein superfamily, which uses a reduced $[Fe_4S_4]^+$ cluster and SAM to initiate a 5′-deoxyadenosyl radical (5′-dA•)–based reaction (*10*). Homologous tyrosine lyases (CofH, ThiH, and HydG) cleave the Cα–Cβ bond of tyrosine, producing a *p*-cresyl radical and dehydroglycine (DHG) (*11*–*15*).

Because of the prevalence of tyrosyl and tryptophanyl radicals in proteins, it was initially proposed that the H-atom abstraction from L-tyrosine and L-tryptophan by the highly reactive 5′-dA• should take place at the L-tyrosine phenol group and at the L-tryptophan indole nitrogen, respectively (*9*, *12*, *14*). However, a recent NosL structure in complex with L-tryptophan (*16*) indicates that the H-atom abstraction takes place at the amino nitrogen atom (Fig. 1A). Biochemical studies confirmed that this abstraction in NosL is the first step in the conversion of L-tryptophan into MIA. NosL can perform β-scissions from the amino-centered radical intermediate at either Cα–Cβ or Cα–C when using L-tryptophan analogs (*17*, *18*). These observations suggest a relative propensity of NosL for substrate promiscuity that, combined with slight differences in

[1]Université Grenoble–Alpes, Institut Nanosciences et Cryogénie (INAC)–Service de Chimie Inorganique et Biologique (SCIB)/Laboratoire de Résonance Magnétique (LRM), F-38000 Grenoble, France. [2]Commissariat à l'Energie Atomique et aux Energies Alternatives (CEA), INAC-SCIB/LRM, F-38000 Grenoble, France. [3]Metalloproteins Unit, Institut de Biologie Structurale, CEA, CNRS, Université Grenoble-Alpes, 71, Avenue des Martyrs, 38044 Grenoble Cedex 9, France. [4]Laboratoire National des Champs Magnétiques Intenses, UPR CNRS 3228, F-38048 Grenoble, France.
***Corresponding author. E-mail: yvain.nicolet@ibs.fr (Y.N.); serge.gambarelli@cea.fr (S.G.)**

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Science
AAAS

Methane emissions from the 2015 Aliso Canyon blowout in Los Angeles, CA

S. Conley, G. Franco, I. Faloona, D. R. Blake, J. Peischl and T. B. Ryerson (February 25, 2016)

Science **351** (6279), 1317-1320. [doi: 10.1126/science.aaf2348] originally published online February 25, 2016

Editor's Summary

The magnitude of a major methane leak

The Aliso Canyon underground gas storage facility outside Los Angeles, CA, houses enormous natural gas reserves. One well at the site experienced a blowout in late October 2015 and began leaking gas until it was sealed in February 2016. Over the course of 13 flights in the region, Conley *et al.* sampled the air column and determined daily release rates of methane (a powerful greenhouse gas) and ethane throughout the leak. The methane release rates were nearly double that of the entire Los Angeles region combined. Thus, single vulnerabilities can have major implications for state and federal climate policy.

Science, this issue p. 1317

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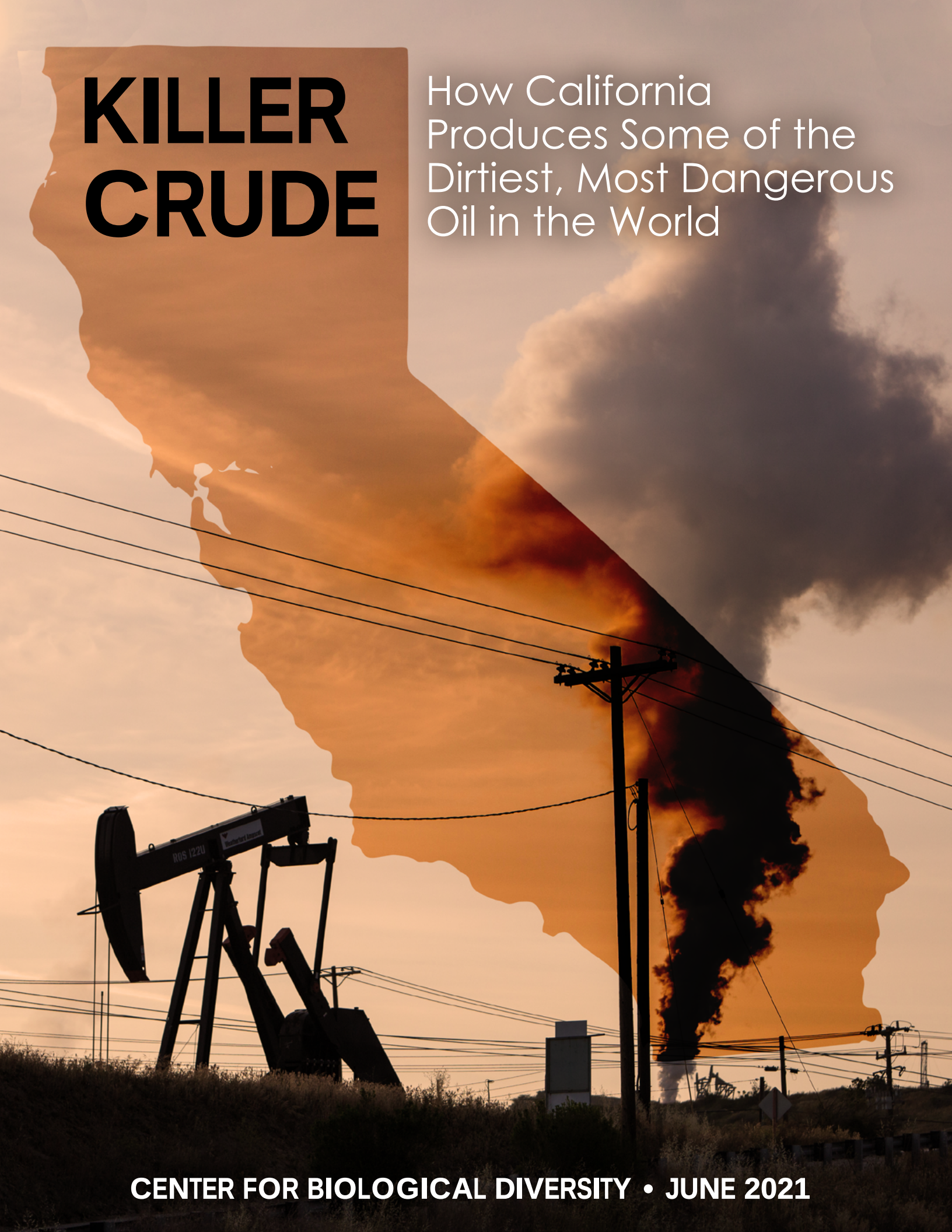
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KILLER CRUDE

How California Produces Some of the Dirtiest, Most Dangerous Oil in the World



CENTER FOR BIOLOGICAL DIVERSITY • JUNE 2021

KILLER CRUDE: HOW CALIFORNIA PRODUCES SOME OF THE DIRTIEST, MOST DANGEROUS OIL IN THE WORLD

Written by Center for Biological Diversity Staff

Lead Author: John Fleming, Ph.D.

Contributing Team: Hollin Kretzmann, Nyshie Perkinson, Kassie Siegel, Patrick Sullivan and Shaye Wolf, Ph.D.

Cover photo by Drew Bird Photography

JUNE 2021

Published by Center for Biological Diversity:
biologicaldiversity.org



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Executive Summary

Despite California's reputation as a global climate leader, California-sourced oils are now among the most climate-damaging in the world and are rapidly becoming even more so. This report analyzes the state's oil production and refining to show the dramatic increase in California oil's carbon intensity over roughly the past decade. It finds that California-sourced oils have gone from bad to worse and are now dirtier than oils refined here from other states and global regions including the Middle East, South America, Africa, Canada and Mexico.

California has a huge impact as the nation's seventh-largest producer of crude oil and the third-largest oil refiner. In 2020 California oil companies produced more than 144 million barrels of crude oil, and state regulators issued more than 1,900 permits for new oil wells. This takes our state in the wrong direction at a critical juncture, as the scientific consensus tells us that we must phase out fossil fuel extraction to keep global heating below 1.5 degrees Celsius and prevent climate catastrophe.

Our findings on the worsening carbon intensity of California oil give state leaders an even greater opportunity — and responsibility — to confront ongoing health harms, climate damage and environmental racism by ending new oil and gas approvals and immediately banning fracking in the state. In April 2021 Gov. Gavin Newsom ordered state regulators to ban fracking by 2024 and study the phaseout of California oil production by 2045, but the climate and health crises demand action now, not decades in the future.

We studied upstream carbon intensity values (from exploration to refinery gate) provided by the California Air Resources Board for all oils refined in California. We found that the average carbon intensity of all oil refined in California is increasing, but the average carbon intensity of just the oil produced in California is increasing far faster. The carbon intensity of California-sourced oil is growing at twice the rate of all oils refined in California, and nearly three times the rate of oils produced outside of California (Figure E1). By 2019 the average carbon intensity of California-sourced crudes was more than one-and-a-half times greater than that of crudes produced outside of California.

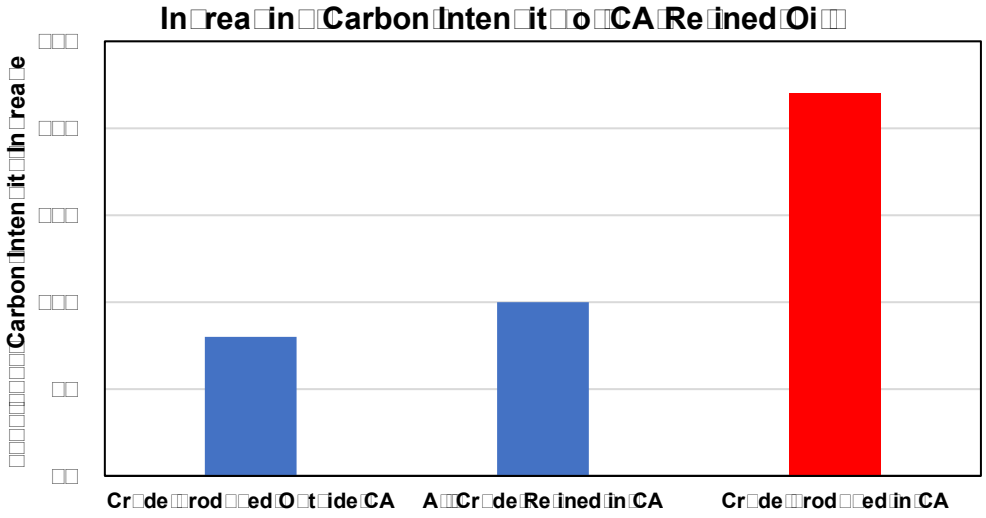


Figure E1: Increase in average carbon intensity between 2012 and 2019 for: (1) crude produced outside CA; (2) all crude refined in CA; (3) crude produced in CA.

Further evidence of California-sourced oil's outsized carbon footprint can be found in its contribution to the average carbon intensity of California-refined oil. California oil was 31% of all oil refined in California between 2012 and 2019 but was responsible for 39% of upstream carbon emissions.

Thus, on average, California oil emits more carbon dioxide per barrel than the rest of the global supply refined in California. So, although California oil production is declining, the increase in carbon intensity is helping to cancel out the climate benefits of declining production.

We also found that oil produced and refined in California is more climate-damaging than the notoriously dirty Canadian tar sands crude refined here. In 2019 the average upstream carbon intensity of California-sourced oil exceeded that of Canadian tar sands crude refined in California, with 98 kg CO_2eq/barrel for California oil and 90 kg CO_2eq/barrel for Canadian tar sands crude.

To avoid the worst dangers of climate change, the world must transition away from fossil fuels. No jurisdiction is better suited than California to lead the way in phasing out dirty oil and gas production. For California this means an end to approvals for new oil and gas wells and an immediate ban on fracking and related extreme techniques that only amplify the damage from extraction.

While a full phaseout of in-state production will take some time, it needs to be much faster than Gov. Newsom's 2045 target. A health-and-safety buffer should also be implemented immediately to prevent oil and gas drilling in communities and to protect public health and safety from air pollution and other harms of oil and gas extraction. Without taking these steps, California cannot protect the climate or the state's most vulnerable communities.



San Ardo Oil Field by Loco Steve/Flickr

Introduction: California's Oil Production Undermines Its Climate, Environmental Justice and Public Health Goals

Despite California's image as a leader on climate and the environment, the state's oil industry contributes heavily to dangerous climate-heating pollution. California is the nation's seventh-largest producer of crude oil and the third-largest oil refiner.[1] In 2020, California oil companies produced more than 144 million barrels of crude oil, while Gov. Newsom's state regulators issued more than 1,900 permits for new oil wells.[2] The flood of permits for new oil wells runs directly counter to the imperative to phase out fossil fuel extraction to prevent the worst climate damages. It also perpetuates the environmental justice and health crises caused by oil and gas extraction in California.

Overwhelming scientific consensus has shown that without deep and rapid emissions reductions, global warming will exceed 1.5 degrees Celsius compared to preindustrial levels, resulting in catastrophic damage around the world.[3] Every fraction of additional warming above 1.5 degrees will worsen these harms, threatening lives, livelihoods, the environment and global security for this and future generations. Because 75% of global greenhouse gas emissions and 85% of U.S. emissions come from fossil fuels,[4] phasing out fossil fuel extraction and combustion is of urgent necessity to avert climate catastrophe.

Unfortunately, today the world faces a fossil fuel "production gap" of tremendous proportions: Producers currently plan to extract far more fossil fuels than a livable planet will allow.[5] There is enough oil, gas and coal in already developed fields and mines globally — that is, places where the infrastructure is built and the capital is sunk — to far exceed the carbon budget for 1.5 degrees C if these reserves were all produced and burned.[6] This means that meeting global climate goals

requires an immediate halt to the approval of new fossil fuel projects and a phaseout of existing oil, gas and coal extraction *before* the reserves in existing fields and mines are fully depleted.[7]

Nowhere in the world is better suited than California, with its wealthy, diverse economy and vibrant clean energy sector, to lead the way in a rapid phaseout of oil and gas extraction. To date, however, progress has been slow and insufficient. Gov. Newsom's order for regulators to study how to phase out oil extraction by 2045 could allow another two and a half decades of toxic inaction.

To make matters worse, much of the remaining oil in California's largest oilfields is heavy and carbon intensive.[8] The "heaviness" of an oil is defined by its API gravity, which is a measure of the oil's density. A crude oil is "light" if it has an API gravity of more than 31.1 degrees, "medium" if it has an API gravity from 22.3 to 31.1 degrees, "heavy" if it has an API gravity from 10 to 22.3 degrees and "extra heavy" if under 10 degrees. In 2018, 68% of California's crude oil production was heavy.[9] Heavy oils are especially climate-damaging because they often require energy-intensive techniques such as hydraulic fracturing, waterflood, steamflood and cyclic steam to extract. This greater energy demand results in greater greenhouse gas emissions as well as greater health and safety risks.

The heaviness of oil contributes to its carbon intensity, with heavier oils tending to be more carbon intensive. Carbon intensity is a value that estimates the emissions from the production, processing and transport of crude oil. Our study of carbon intensity values for oil refined in California, provided by the California Air Resources Board, shows that California-sourced oils are especially dirty in a global context and that their carbon intensity is rapidly increasing.

Oil and gas production in California has also caused an environmental justice and public health crisis in California. Eighteen percent of the state's population lives within a mile of at least one oil or gas well.[10] The highest-density oil and gas extraction areas are predominantly located near low-income communities and communities of color.[11] These communities are disproportionately exposed to the health harms associated with oil and gas extraction such as cancer,[12] respiratory illnesses[13] and pregnancy complications. Two recent studies focused on California specifically found associations between proximity to oil and gas production and preterm birth and low birth weight.[14] A recent Harvard study found that an estimated 34,000 Californians died prematurely in one year because of fossil fuel pollution.[15]

California's failure to rein in the dirty oil extraction within its own borders, using increasingly energy-intensive and dangerous techniques, completely undermines its climate, health and justice goals.

Study Description

California refines crude oil from countries around the world, including (as of 2019) Angola, Argentina, Brazil, Canada, Colombia, Ecuador, Equatorial Guinea, Ghana, Iraq, Kuwait, Mexico, Nigeria, Oman, Peru, Russia, Saudi Arabia, Trinidad and United Arab Emirates. California also refines oil from other U.S. states including Alaska, New Mexico, North Dakota, Texas and Utah, along with oil from federal offshore sources. The remaining oil refined in California comes primarily from its own 158 major oilfields.

California's 2019 oil production was only 27% of the total 600 million barrels refined in California.[16] In 2019, 13% of the oil refined in California was from other U.S. states, predominantly Alaska, New Mexico, North Dakota, Utah and Wyoming. Notably, the oils refined from these states were all light based on API gravity.[17] Similarly, oil refined in California from the Middle East (mainly Saudi Arabia, Iraq and Kuwait), constituting 26% of oil refined in California in 2019 and the dominant foreign source, was light.[18]

The only significant foreign source of heavy oil refined in California is South America (mainly Ecuador, Colombia and Brazil), constituting 22% of oil refined in 2019.[19] Oils from Canada and Mexico, including the infamous Canadian tar sands oils, are comparable in heaviness to California oils, but as less than 5% of the total oil refined in California in 2019, they are a relatively small source.[20]

For oil refined in California, the Oil Production Greenhouse gas Emissions Estimator (OPGEE) is the model used to estimate the emissions from oil from different sources, or the carbon intensity, extending from initial oil exploration to the arrival of the oil at the refinery gate.[21]

Since 2012 the California Air Resources Board (CARB) has provided carbon intensity estimates for all oils refined in California, measured in grams CO_2 per megajoule (g/MJ — grams of CO_2 eq produced per MJ of energy derived from oil).[22] The carbon intensity values are attributed to the production and transport of the crude oil supplied as petroleum feedstock to California refineries, so emissions that occur during the refining process or thereafter are not considered. Carbon intensity (CI), as a measure of greenhouse gas emissions derived from a given crude, is one way to quantify the relative harms of different crudes to the climate.

Using the carbon intensity values of the various refined oils, CARB calculates an average carbon intensity for a given year by doing a weighted average based on the volume of oil from a given source:

$$Average\ carbon\ intensity = \frac{(Crude\ Vol.\#1 * CI\ \#1) + (Crude\ Vol.\#2 * CI\ \#2) + (Crude\ Vol.\#3 * CI\ \#3) + \cdots}{Total\ Volume\ of\ Oil\ Refined\ in\ CA}$$

where "crude vol." is the amount of oil from a given source and "CI" is the corresponding carbon intensity of that oil.

For our study, we used the same method and CARB's own average carbon intensity values of individual crudes to determine the average carbon intensity of different subsets of oil refined in California, including the average carbon intensity of only oils produced in California and only oils produced outside of California. The following is an example calculation of the average carbon intensity of oil from California oilfields:

$$Average\ carbon\ intensity\ of\ CA\ oil = \frac{(Crude\ Vol.\ CA\ \#1 * CI\ CA\ \#1) + (Crude\ Vol.CA\ \#2 * CI\ CA\ \#2) + (Crude\ Vol.CA\ \#3 * CI\ CA\ \#3) + \cdots}{Total\ Volume\ of\ Oil\ Produced\ and\ Refined\ in\ CA}$$

where "crude vol. CA" is the amount of oil from a given California oilfield and "CI CA" is the corresponding carbon intensity of that oil.

Using a conversion factor of 5,813.4 MJ per barrel as an approximation,[23] all carbon intensity values in the following analysis were converted from grams CO_2 per megajoule to kilograms CO_2eq per barrel (kg CO_2eq/bbl). With carbon intensity in terms of barrels and using values for barrels of oil production, upstream emissions from oil refined in California between 2012 and 2019 were also estimated.



Oil field in Bakersfield by Babette Plana/Flickr


San Ardo Oil Field by Drew Bird Photography

Results

The carbon intensity of oil produced in California has increased 22% since 2012, increasing the overall carbon intensity of all crude refined in the state.

The average carbon intensity of all crudes refined in California has gone up 10% between 2012 and 2019, increasing from an average of 66 kg CO_2eq/barrel in 2012 to 73 kg CO_2eq/barrel in 2019. This is an increase of about 1.5% per year. Meanwhile, for just the crudes extracted from California oilfields, the average carbon intensity has gone up 22% between 2012 and 2019, increasing from 81 kg CO_2eq/barrel in 2012 to 98 kg CO_2eq/barrel in 2019. This is an increase of about 3.1% per year or double the rate of increase for the carbon intensity of all oils refined in California. For all crudes not produced in California, the average carbon intensity has gone up 8% between 2012 and 2019, increasing from 59 kg CO_2eq/barrel in 2012 to 64 kg CO_2eq/barrel in 2019. This is an increase of about 1.2% per year, or about half the increase observed for crudes produced in California (Table 1, Figure 1).

So, although the average carbon intensity of all oil refined in California is increasing, the average carbon intensity of California-produced oil is increasing far faster: twice the rate of all oils refined in California, and nearly three times the rate of oils originating outside of California. This complements an earlier estimate that the carbon intensity of California crudes on a per barrel basis increased by 39% between 2000 and 2017.[24]

Year	All Crude Refined in CA	CA-Produced Crude	Crude Produced Outside CA
2012	66.04	80.57	58.89
2013	66.10	80.63	58.72
2014	65.05	82.26	56.45
2015	70.11	86.97	61.80
2016	70.57	87.55	62.67
2017	69.35	87.72	62.32
2018	71.80	97.20	62.96
2019	72.78	98.07	63.66

Table 1: Average carbon intensity (CI) of oil refined in California between 2012 and 2019 in units of kg CO_2eq/barrel: (1) all crude refined in CA; (2) CA-produced crude; (3) crude produced outside CA.

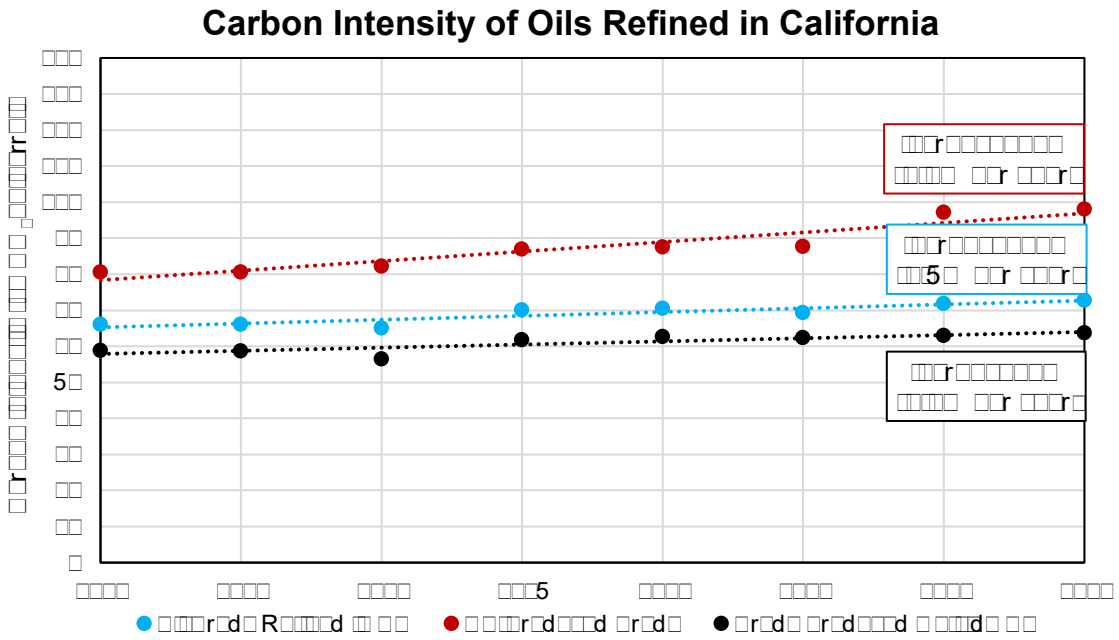


Figure 1: Increase in average carbon intensity over time for: (1) all crude refined in CA; (2) CA-produced crude; (3) crude produced outside CA.

<u>The high carbon intensity of California-sourced oils can be traced to just a few key California oilfields.</u>

As of 2019, California had 158 major oilfields, but five oilfields contributed more to California's average carbon intensity and upstream emissions than all others combined. These five fields in order of decreasing contribution are Midway-Sunset, South Belridge, Cymric, Kern River and San Ardo. Between 2012 and 2019, Midway-Sunset contributed 22% of the estimated upstream emissions from California-sourced oils; South Belridge contributed 12%; Cymric contributed 10%; Kern River contributed 9% and San Ardo contributed 8%. The remaining 39% was contributed by the other 153 major California oilfields (Figure 2):

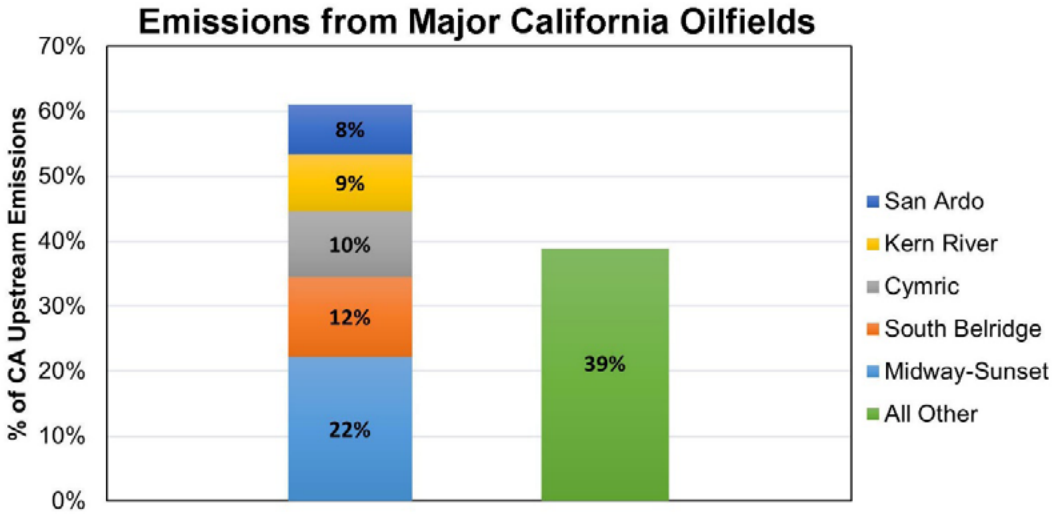


Figure 2: The top 5 California fields in terms of their contributions to the average carbon intensity and upstream emissions of California-sourced oils between 2012 and 2019. "All other" refers to all California oilfields outside of the top 5.

The contribution of specific oilfields to the average carbon intensity of California-sourced oils is strongly linked to total oil production (Figure 3), with Midway-Sunset, Kern River, South Belridge and Cymric being in the top five for contributing to California-sourced oils' average carbon intensity and the top five for California oil production. San Ardo, though in the top five for its contribution to California carbon intensity, ranks eighth in terms of oil production. The discrepancy is due to the relatively high carbon intensity of San Ardo oil.

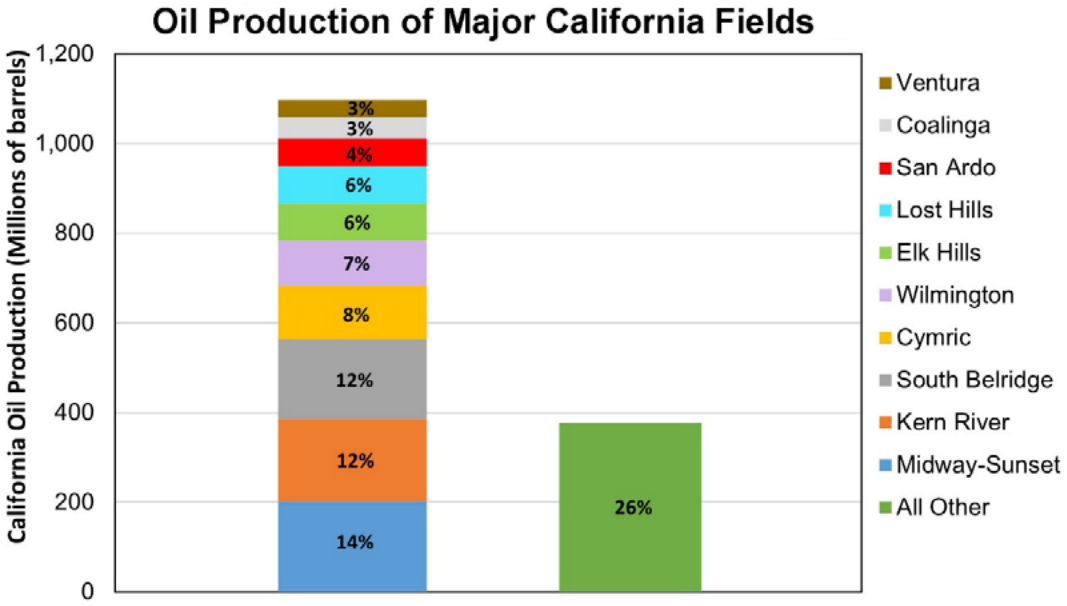


Figure 3: California's top 10 oilfields in terms of cumulative oil production between 2012 and 2019. Percent values displayed represent the percent of total California oil production. "All other" refers to all California oilfields outside of the top 10.

In terms of their contribution to the average carbon intensity of California-sourced oils, none of the top five California oilfields are in the top five for individual carbon intensity, although all are in the top 20 (Figure 4). This highlights the importance of both carbon intensity and production volume in determining the contribution of any given oilfield to the average carbon intensity and upstream emissions.

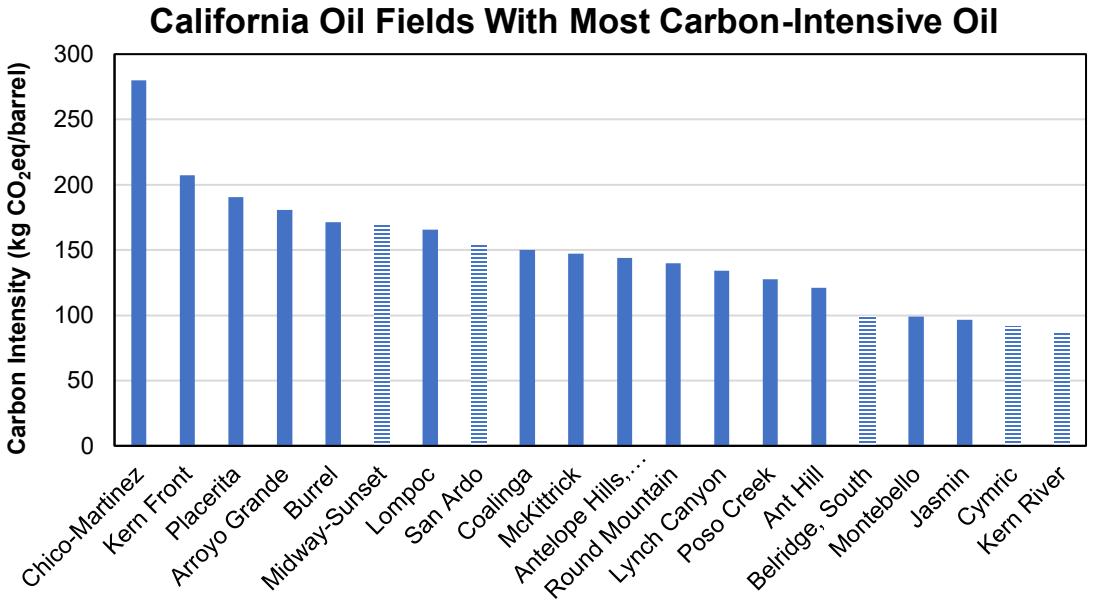
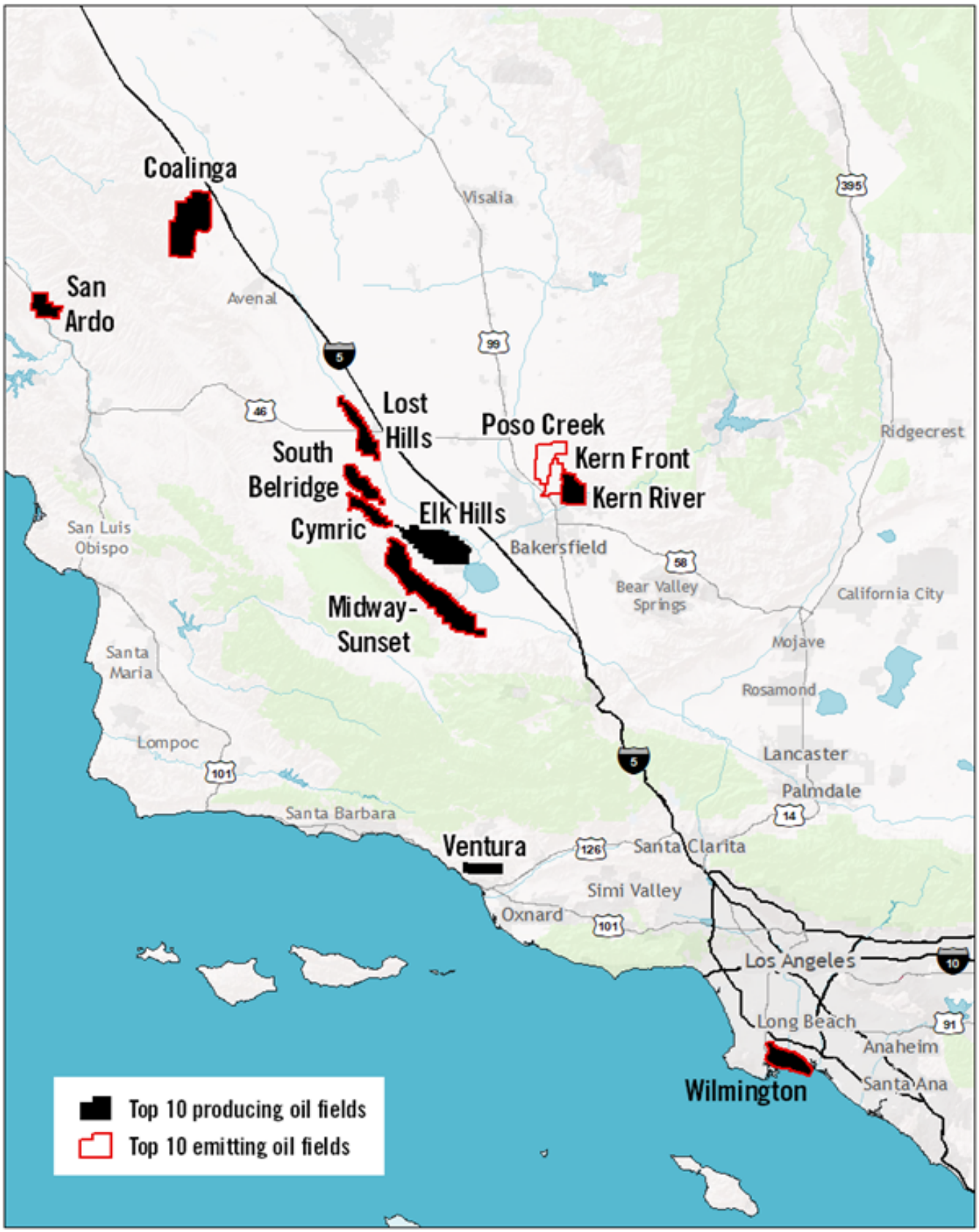


Figure 4: California's top 20 oilfields based on carbon intensity in 2019. The top 5 based on their contribution to the total upstream emissions of California-sourced oils are distinguished with horizontal stripes.

Top 10 Most Productive California Oilfields vs. Top 10 Carbon Dioxide Emitters

It's no surprise that California's top oil-producing fields also tend to contribute the most to California oil's upstream carbon dioxide emissions. Eight of the top 10 emitters are also in the top 10 for oil production. That means the fields producing the most oil also produce some of the dirtiest and most damaging crude, worsening California's overall contribution to dangerous global heating.



California oil is now more carbon intensive than notoriously dirty Canadian tar sands crude.

Our 2017 study found that three quarters of oil produced in California was as climate-damaging as Canadian tar sands crude, which is infamous for being exceptionally dirty.[25] This report shows that California oil has become more carbon intensive since that time.

In 2019 the average upstream carbon intensity of California oil exceeded that of Canadian tar sands crude with about 98 kg CO_2eq/barrel for California oil and about 90 kg CO_2eq/barrel for Canadian tar sands crude refined in California. Moreover, between 2012 and 2019, the average carbon intensity of Canadian tar sands crude refined in California declined, while the average carbon intensity of California-sourced oil increased (Figure 5). This may be due to California refineries refining proportionally less of the dirtiest Canadian oils over time.

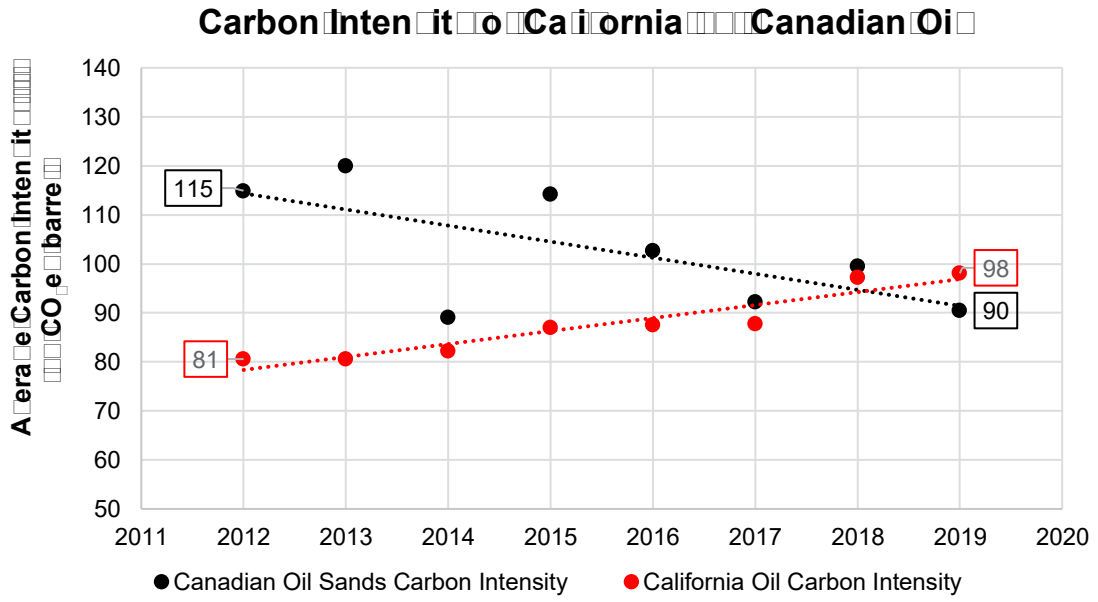


Figure 5: Change in average carbon intensity over time of Canadian oil sands crude vs. California-sourced oil. Here, average carbon intensity and average upstream emissions are interchangeable.

The last point is evidenced by the difference in the range of carbon intensities of Canadian crudes between 2012 and 2019. In 2012, the range was 44 to 142 kg CO_2eq/barrel, whereas in 2019 it was 47 to 171 kg CO_2eq/barrel. Even though the range shifted up in 2019, indicating dirtier oil streams being refined from Canada, the overall average carbon intensity was less in 2019 than in 2012, meaning a smaller proportion of these dirtier oils were refined.


Tar sands in Alberta
by Dru Oja Jay, Dominion

The increase in carbon intensity of California-sourced oils is partially canceling out the benefits of the decline in California oil production.

California's oil production has been in long-term decline since 1985 (Figure 6):

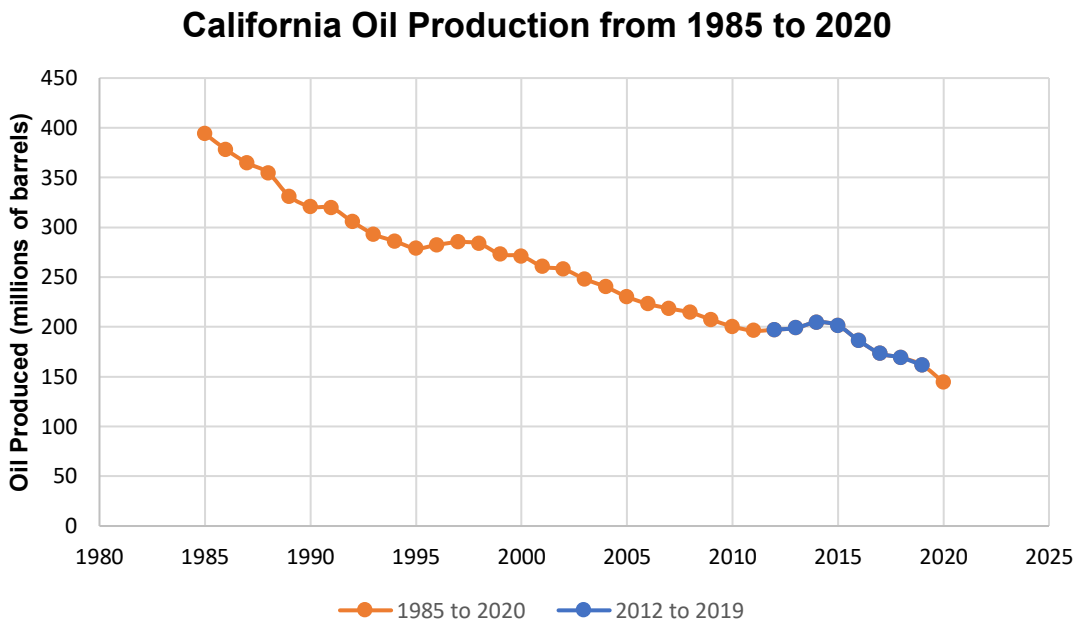


Figure 6: California oil production from 1985 to 2020.[26]

This trend holds in the 2012 to 2019 timeframe of our analysis, with the first three years holding a relatively steady annual amount of oil production, and 2015 to 2019 seeing declines in both oil production and upstream emissions from California-sourced oils (Figure 7).

However, the rate of decline in oil production from 2015 to 2019 exceeded the rate of decline in upstream emissions. While oil production declined by 22% between 2015 and 2019, upstream emissions only declined by 13%. If we compare 2012 and 2019, oil production was 20% less in 2019 than in 2012, whereas upstream emissions were only 3% less. Both cases make clear that the increase in carbon intensity of California-sourced oils is partially canceling out the climate benefits of California's oil-production decline.

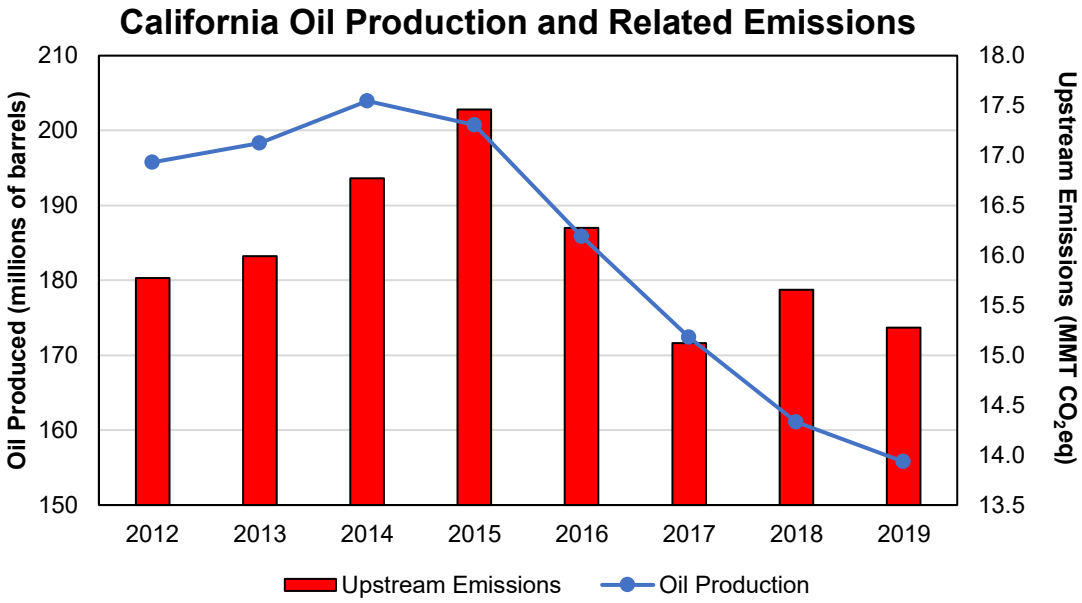


Figure 7: Upstream emissions from California-sourced oils vs. California oil production between 2012 and 2019.

For example, upstream emissions in 2015 were about 18.1 MMT CO_2eq. So if upstream emissions declined by 22% between 2015 and 2019, as oil production did, then emissions in 2019 would be about 14.1 MMT CO_2eq. Instead upstream emissions in 2019 were 15.8 MMT CO_2eq, or about 1.7 MMT CO_2eq more. Assuming this value is 20% of lifecycle emissions (upstream emissions + midstream refining emissions + downstream end use emissions; assumption addressed in more detail in the Discussion), then the lifecycle emissions would be about 8.5 MMT CO_2eq more, or an additional 2% of California's total emissions (based on a 2018 estimate of California total emissions).

Thus, increasing carbon intensity is reducing California's potential progress on reducing greenhouse gas emissions. To maximize emissions reductions, policymakers should both reduce oil production and eliminate enhanced oil-recovery techniques that increase the carbon intensity of California oils.



San Ardo Oil Field by Drew Bird Photography

Discussion

A phaseout of California oil production does not require an increase in imports.

Proponents of business-as-usual oil extraction in California often say that limiting oil production in California will require an increase in imports from parts of the world where oil is produced with fewer environmental safeguards. This is simply incorrect.

A 2018 study found that the decline in production that would result if California stopped approving new oil wells would be approximately equal to the decline in oil consumption forecast by the California Air Resources Board's (CARB's) "Scoping Plan" to reduce greenhouse gas emissions (Figure 8).[27] Ending the approval of new oil wells and accelerating the ongoing decline in the state's oil production would, therefore, not require an increase in imports.

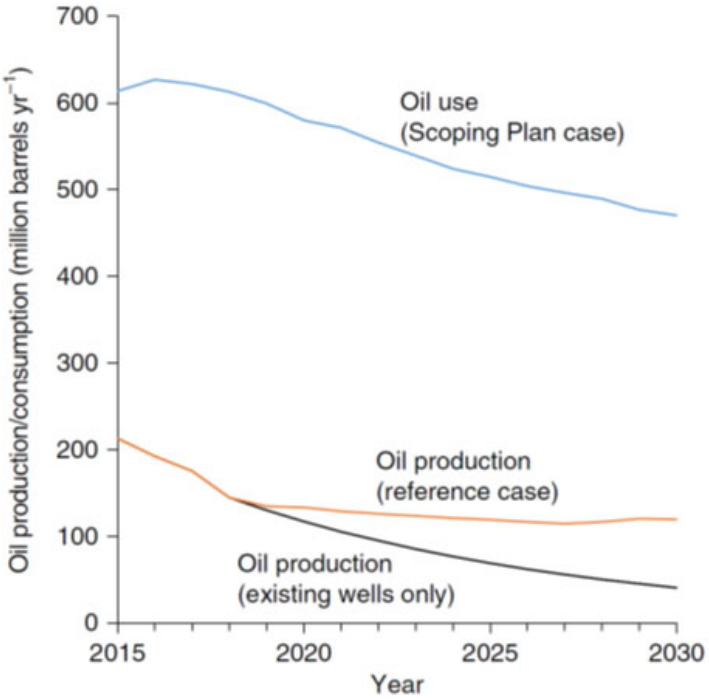


Figure 8: California's projected decline in oil production and consumption. (1) Reference scenario (orange line): developed by the U.S. Energy Information Administration, the state's annual oil production decline trajectory if it continues issuing new drilling permits; (2) No new wells (black line): production drawdown if California stopped issuing drilling permits; (3) Scoping Plan scenario (blue line): estimate of future oil use based on California's Scoping Plan (for gasoline, diesel and liquefied petroleum gas), the federal government (for residual and other oil), and the federal government and the California Energy Commission (for jet fuel). Figure and data from Erickson, P. et al. (2018).[28]

An update to the findings of the 2018 study using data from a 2020 CARB-commissioned study that charted three pathways for California carbon neutrality by 2045 strengthens this conclusion. Under CARB's "Balanced" and "Zero Carbon Energy" scenarios, the decline in California oil demand between 2020 and 2030 would exceed the decline in oil production if the state stopped issuing permits for new oil wells.[29] Thus, under California's current climate policies, California can and should simultaneously reduce in-state oil production and oil imports.

In 2020 oil production in California dropped to 144 million barrels, or by 10.6% compared to 2019.[30] According to state regulators, only 138 new wells were drilled, despite the issuance of permits for nearly 2,000 new wells.[31] Meanwhile, imports dropped by 27% from 433 million barrels to 316 million barrels.[32]

These declines are largely because of less oil consumption during the COVID-19 pandemic, but this further emphasizes the point that as California oil demand decreases, declines in production from halting new oil well permits would not need to be compensated for with increases in imports. With decreasing demand, in a no-new-permits scenario, both production and imports would decline, leading to a global decline in fossil fuel reliance.

However, research by Communities for a Better Environment reveals a troubling trend: In recent years California refineries have increased their production of gasoline for *export* to Pacific Rim countries, maintaining demand for imports despite falling oil use within the state.[33] If California allows this trend to continue, then it will continue to prop up imports. This emphasizes the need for the state to pursue a just transition that winds down all phases of the fossil fuel lifecycle, including refining.

A phaseout of oil extraction in California would not only get rid of an exceptionally dirty source of crude, but it would also lead to an overall global reduction in oil production and decrease in global carbon emissions. This is because every barrel of California oil left in the ground will reduce overall oil supply, resulting in a net decrease of about half a barrel of oil consumption globally.[34] Thus, actions taken in California to curb oil production will have global ramifications.

California's oil and gas regulatory failures have worsened the state's public health and environmental justice crises.

The oil industry's argument that production limits here will cause more production in places with weaker environmental safeguards is not only wrong, but also morally reprehensible because it minimizes California's regulatory failures and the public health and environmental justice crises caused by in-state oil production.

California's long-term regulatory failures are shocking and include the following:

- California is virtually the only major oil-producing state with no minimum setback distance between wells and homes, schools or other sensitive receptors, despite the grave health harms from oil and gas pollution.
- An EPA audit in 2011 found widespread failures in enforcing state regulations pertaining to the safety of oil and gas-related underground injection projects.[35]
- The California Geologic Energy Management Division (CalGEM) admitted in 2015 that thousands of oil and gas wells were improperly injecting wastewater into California's protected underground sources of drinking water, leading to the widespread contamination of the state's water supplies.[36] Half a decade later, the state has reneged on multiple commitments to remedy the situation and our water supplies are still being sacrificed to the oil industry.[37]
- California's lax waste-disposal laws allow oil industry wastewater to be dumped into unlined pits, which has led to multiple additional instances of groundwater contamination.[38]
- Loosening regulations on steam injection pressure led to multiple large-scale spills in Central California in 2019. CalGEM has yet to collect any fines for a 1.3-million-gallon spill in the Cymric oilfield,[39] and a separate spill of over 4 million gallons is still ongoing.[40] These spills contaminate the environment and threaten wildlife.
- Reports uncovered that multiple regulators had financial interests in oil companies,[41] and numerous top agency officials have gone on to work for the industry.
- Dozens of injection projects were approved under "dummy" files that had no underlying review for the project.[42]
- CalGEM has brought virtually no enforcement actions in response to illegal pollution.[43]
- CalGEM also has failed to comply with the environmental review and public participation requirements of the California Environmental Quality Act, despite acknowledging the environmental harms of extraction.[44]

California's regulatory record on oil and gas does not justify claims that it has the toughest environmental regulations in the world. On the contrary, it highlights the urgent need to phase out dangerous and dirty fossil fuel production in the state.

Lifecycle emissions make California oils' climate harms even more pronounced.

The carbon intensity values provided by the Air Resources Board only consider upstream emissions from oil, or the emissions from extracting and transporting oil up to the refinery gate. However, every step of the fossil fuel life cycle produces greenhouse gas pollution, including midstream refining and downstream combustion.

While we take comparisons of the upstream data from CARB as representative of the relative "dirtiness" of different oils refined in California, the overall climate impact of oils refined in California depends on the total lifecycle emissions. The emissions from midstream and downstream processes typically exceed upstream emissions. This is apparent when considering previously reported lifecycle emissions of California's top five oils in terms of upstream emissions — Midway-Sunset, South Belridge, Cymric, Kern River and San Ardo (Table 2):[45]

Field	2017 Upstream Emissions ($kg CO_2eq/bbl$)	2017 Lifecycle Emissions ($kg CO_2eq/bbl$)	% Upstream Emissions
Midway-Sunset	146	725	20%
South Belridge	86	690	12%
Cymric	112	600	19%
Kern River	56	650	9%
San Ardo	159	760	21%

Table 2: For California's top oilfields in terms of upstream emissions, listed are the upstream emissions estimates from 2017, most recent lifecycle emissions estimates from 2017, and upstream emissions per barrel as a percentage of lifecycle emissions per barrel.

Comparing the 2017 (the year with the most recent lifecycle emissions data) upstream and lifecycle emissions of the top five fields, we find that midstream and downstream processes constitute a greater proportion of emissions than upstream processes. Taking the above five fields as an example, upstream emissions are most often around 20% of the total lifecycle emissions. This agrees with an estimate by the Stockholm Environmental Institute in which factoring in upstream emissions increases the total emissions per barrel of oil by at least 25%,[46] which would likewise make upstream emissions about 20% of the total.

Putting this into perspective, California's total CO_2eq emissions across all sectors in 2018 was 425 MMT CO_2eq. In just 2018, upstream emissions from California-sourced oil were about 16 MMT CO_2eq. Assuming upstream emissions are about 20% of total lifecycle emissions, lifecycle emissions from California-sourced oil in 2018 would be about 80 MMT CO_2eq, which would make them almost 20% of California's total emissions in 2018 (Table 3).

Year	Oil Production (bbl)	Upstream Emissions (MMT CO_2eq)	Lifecycle Emissions (MMT CO_2eq)	Total CA Emissions (MMT CO_2eq)	% Upstream Emissions	% Lifecycle Emissions
2012	196	15.8	78.9	451.6	3.5%	17%
2013	198	16.0	80.0	447.6	3.6%	18%
2014	204	16.8	83.9	443.4	3.8%	19%
2015	201	17.5	87.3	440.8	4.0%	20%
2016	186	16.3	81.4	429.2	3.8%	18%
2017	172	15.1	75.6	424.5	3.6%	18%
2018	161	15.7	78.3	425.3	3.7%	18%
2019	156	15.3	76.4	--	--	--

Table 3: For the years 2012 to 2019, listed are barrels of California oil production, estimated California upstream emissions, estimated lifecycle emissions assuming upstream emissions are 20% of lifecycle emissions, and total California emissions across sectors. Using those values, upstream and lifecycle emissions as a percentage of total California emissions were calculated and listed.

The importance of considering lifecycle emissions is even more apparent when looking at the carbon intensity of California's refining itself. As follows from California both producing and accepting some of the dirtiest oil for refining, California's refining processes are exceptionally dirty.

Because California refines the heaviest crude on average, California refineries emit more CO_2eq per barrel of crude refined than those in any other major U.S. refining region. For 2013 to 2017, the average carbon intensity of California refining was 59.3 kg CO_2eq/barrel, whereas the U.S. average over the same time was 49.3 kg CO_2eq/barrel. Some individual refineries in California have refining carbon intensities as high as 79 kg CO_2eq/barrel.[47]

California-sourced oil's excessive upstream emissions burden not only California's population but the entire planet with some of the world's dirtiest refining.

California's Gas Production is More Climate-Damaging Than Coal And Threatens Public Health and Safety.

While California is the seventh-largest oil producer and third-largest oil refiner, it ranks 14th in U.S. fossil gas production, with nearly 200 billion cubic feet produced in 2019. California's gas production, however, is also exceptionally dirty, dangerous and carbon intensive.

A recent report from the California Energy Commission assumes fossil gas as part of California's energy mix well into the future, treating it as a bridge fuel. However, methane — a superpollutant 87 times more powerful than CO2 at warming the climate over a 20-year period — leaks during all phases of oil and gas production.

If the methane leakage rate is greater than 2.4% of the gas produced, then the climate damage from the methane leakage cancels out any climate benefit that gas achieves over coal at the smokestack over a 20-year period.

Therefore, depending on the overall leakage rate, fossil gas provides little or no climate benefit over coal: In fact, fossil gas may even be worse.

A recent analysis found that the methane leakage rate in the San Joaquin Valley is 4.8%, making gas sourced from this region not only worse than coal on a 20-year timescale, but also the worst in the continental United States.

In addition to its role as a major climate pollutant, gas production also threatens public health and safety. The 2015 gas leak disaster at the Aliso Canyon gas storage facility near Los Angeles resulted in 109,000 metric tons of methane entering our atmosphere—the largest-known methane release in U.S. history.

The Aliso Canyon disaster boosted statewide greenhouse gas emissions, set back emissions-reduction goals and sickened nearby residents with symptoms including dizziness, headaches, nausea, eye, nose and throat irritation, nose bleeds and likely long-term effects yet to be identified. Clearly the risks of keeping gas infrastructure in place far exceed any benefits.

Though California's dirty oil is the focus of the present study, it must be considered in the context of California's overarching dirty fossil fuel industry. The continued extraction of both exceptionally dirty oil and gas only makes a stronger case for the rapid phaseout of fossil fuels to mitigate substantial climate and public health harms.

Conclusion

Because climate change is driven primarily by fossil fuel production and combustion, most of the world's fossil fuels must stay in the ground to avoid the worst dangers of climate change. Worldwide, there are more than enough fossil fuels in already developed production fields to far exceed targets to limit warming to 1.5 degrees C or even 2 degrees C.[48] New fossil fuel development and infrastructure is thus unsafe and unjustified, and fossil fuel production must be phased out globally within the next several decades. With one of the world's wealthiest economies and some of the world's dirtiest oil, California needs to lead the way in ending fossil fuel production.

To address the climate damage, health harms and environmental injustice caused by its increasingly dirty oil production, Gov. Newsom should direct his regulators to end approvals for new oil and gas wells and other fossil fuel projects and commit to a plan to phase out existing extraction far faster than 2045. Newsom should also act now, not in 2024, to ban fracking and related extreme techniques that amplify the damage from extraction. Newsom should immediately implement a health-and-safety buffer to prevent oil and gas drilling in communities and protect public health and safety from the air pollution and other harms of oil and gas extraction. Without taking these crucial steps, California cannot protect the climate or the state's most vulnerable communities.



Inglewood Oil Field by Gary Kavanagh

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Appendix

California-sourced oil is the primary contributor to the average carbon intensity of all oil refined in California.

Although California oil was about 31% of all oil refined in California between 2012 and 2019, it was responsible for about 39% of the carbon intensity, or about 39% of the emissions leading up to the refinery gate (upstream emissions).

Calculated using the carbon intensity values provided by CARB, it is estimated that upstream emissions of oils refined in California between 2012 and 2019 were about 343 million metric tons CO_2eq (MMT CO_2eq). It follows that oil not produced in California constituted about 69% of all oil refined in California but was responsible for only 61% of the emissions leading up to the refinery gate.

As a reference, if all oils refined in California had the same carbon intensity, then their contribution to the total emissions leading up to the refinery gate would be the same as their contribution to the total volume of oil refined in California. So, a contribution to the carbon intensity that is more than the contribution to total oil refined indicates a carbon intensity above the overall average. In turn, a contribution to the carbon intensity that is less than the contribution to the total volume of oil refined indicates a carbon intensity below the overall average. This further indicates that, on average, California oil is more polluting per barrel than the rest of the global supply refined in California.

This fact holds when considering just the oil produced in the U.S. that is refined in California. Oil produced in the U.S., including oil produced in California, constitutes 46% of the oil refined in California, but 54% of the upstream emissions. However, if broken down further, oil produced in the U.S. *excluding* oil produced in California constitutes 15% of the oil refined in California but 16% of the upstream emissions.

In other words, the contribution of U.S. oil, including California, to upstream emissions is 1.2 times its contribution to the total production. The contribution of U.S. oil, excluding California, to upstream emissions is 1.05 times. And the contribution of California oil to the total upstream emissions is 1.3 times its contribution to the total production. So, normalized to production, oil produced in California contributes more to the upstream emissions for California-refined oils than other U.S. oils (Figure 9).

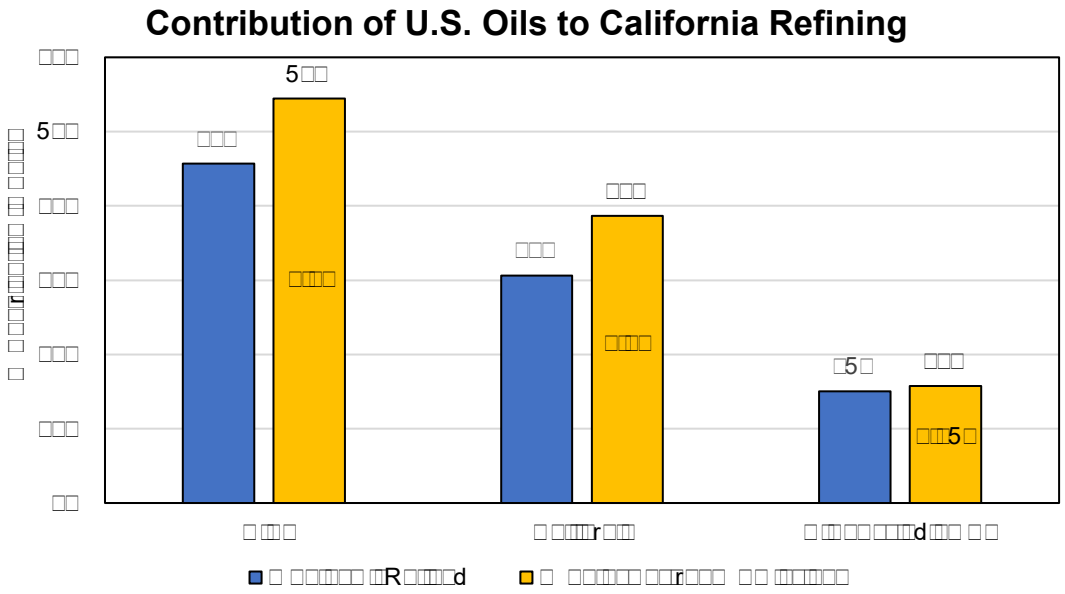


Figure 9: For U.S.-sourced oil including California, California-sourced oil, and U.S.-sourced oil excluding California, the volume of oil as a percentage of all oil refined in CA (% Total Oil Refined) vs. oil as its percent contribution to the total upstream emissions of all oil refined in CA (% Total Upstream Emissions). Also labeled on the orange bars is the multiple by which a given region's contribution to the total upstream emissions compares to its contribution to the total oil refined. Here, the contribution to average carbon intensity and the contribution to upstream emissions are interchangeable.

There is strong overlap between California fields employing enhanced oil recovery techniques and those with the most upstream emissions.

Enhanced oil recovery techniques such as cyclic steam and steamflooding are known to be energy-intensive compared to conventional oil extraction with the result being greater associated greenhouse gas emissions. In California, 19 fields have cyclic steam wells (Figure 10) while 18 fields have steamflood wells (Figure 11), with significant overlap of the two groups.

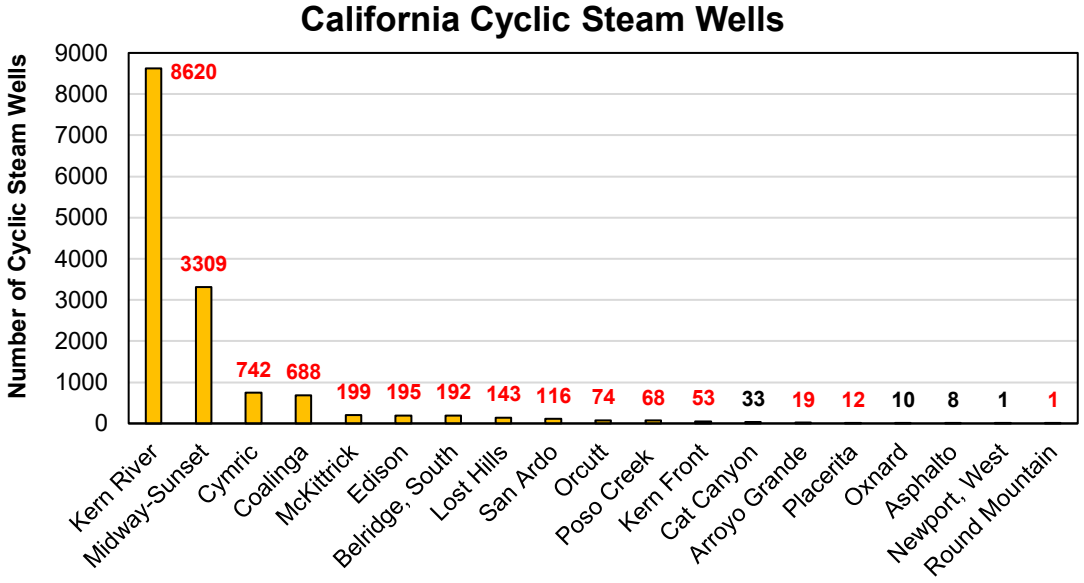


Figure 10: Cyclic steam wells in California based on 2020 data. The number of cyclic steam wells in each oilfield is labeled. The oilfields that are also in the top 20 for upstream emissions have red labels.

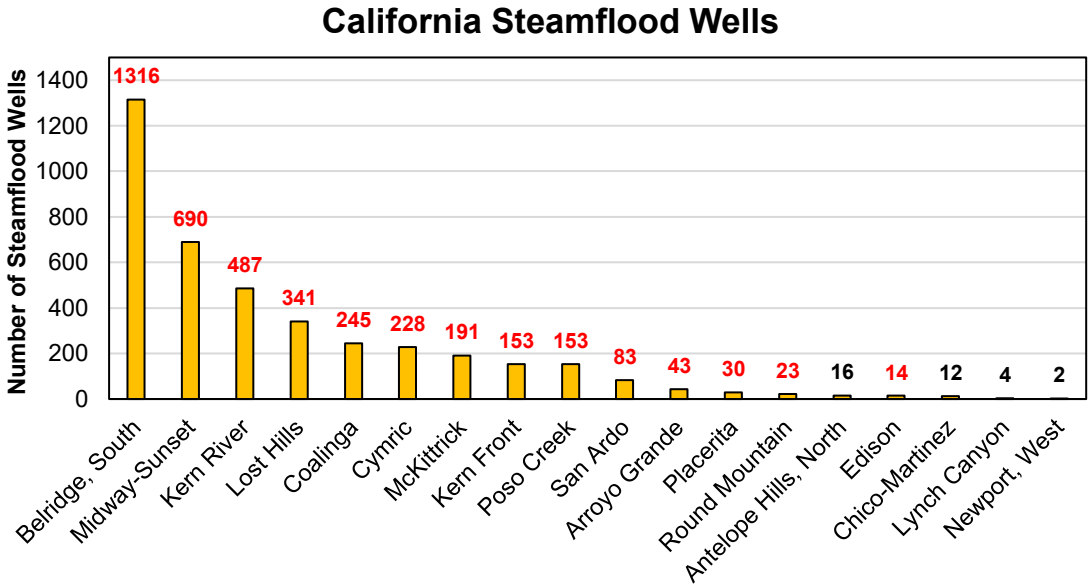


Figure 11: Steamflood wells in California based on 2020 data. The number of steamflood wells in each oilfield is labeled. The oilfields that are also in the top 20 for upstream emissions have red labels.

Notably, of the 19 oilfields with cyclic steam wells, 15 rank in the top 20 for their contribution to upstream emissions from California-sourced oils. Of the 18 oilfields with steamflood wells, 14 rank in the top 20 for their contribution to upstream emissions. Also, four of the top five oilfields in terms of upstream emissions rank highly in terms of numbers of steam wells: Kern River, Midway-Sunset, and Cymric are 1, 2, and 3, respectively, for number of cyclic steam wells while South Belridge, Midway-Sunset, and Kern River are 1, 2, and 3, respectively, for number of steamflood wells. The top five oilfields for upstream emissions (the four mentioned, plus San Ardo) together have 70% of California's steamflood wells and 90% of California's cyclic steam wells, or 85% of California's total steam wells (cyclic steam + steamflood).

There is significant overlap in California between fracking permits, enhanced oil recovery and the most carbon-intensive oil extraction.

In 2020, 1,929 oil and gas drilling permits were issued in California with 1,052 of them, or 55%, going to the top five fields contributing the most to greenhouse gas emissions. Of the top five fields, South Belridge received the most with 351, then Midway-Sunset with 346, Cymric with 221, Kern River with 111 and San Ardo with 23.

Of the total permits, 1,359 were for oilfields in the top 20 for carbon intensity (Figure 6).

Finally, of the total permits, 65 were for cyclic steam wells and 64 were for steamflood wells. Out of the 129 total cyclic steam and steamflood well permits, 78 permits, or 60%, were for fields in the top five for greenhouse gas emissions.

In 2020, 84 permits for fracking were issued with 24, or 29%, for South Belridge. Another 36, or 43%, were issued for Lost Hills Oil Field. Lost Hills has not been previously mentioned, but it is noteworthy as number seven in terms of oilfield greenhouse gas emissions. The remaining permits were granted to North Belridge which is number 22 in terms of oilfield greenhouse gas emissions.

As is the case with existing enhanced oil recovery wells, the oilfields being granted oil and gas drilling and fracking permits are those that already contribute the most to California oil's greenhouse gas emissions, hence maintaining a vicious cycle.

Earth-Science Reviews 178 (2018) 438–514

Contents lists available at ScienceDirect

Earth-Science Reviews

journal homepage: www.elsevier.com/locate/earscirev

Invited review

Global review of human-induced earthquakes

Gillian R. Foulger[a,*], Miles P. Wilson[a], Jon G. Gluyas[a], Bruce R. Julian[a], Richard J. Davies[b]

[a] Department of Earth Sciences, Durham University, Durham DH1 3LE, UK
[b] School of Civil Engineering and Geosciences, Newcastle University, Newcastle upon Tyne NE1 7RU, UK

ABSTRACT

The Human-induced Earthquake Database, *HiQuake*, is a comprehensive record of earthquake sequences postulated to be induced by anthropogenic activity. It contains over 700 cases spanning the period 1868–2016. Activities that have been proposed to induce earthquakes include the impoundment of water reservoirs, erecting tall buildings, coastal engineering, quarrying, extraction of groundwater, coal, minerals, gas, oil and geothermal fluids, excavation of tunnels, and adding material to the subsurface by allowing abandoned mines to flood and injecting fluid for waste disposal, enhanced oil recovery, hydrofracturing, gas storage and carbon sequestration. Nuclear explosions induce earthquakes but evidence for chemical explosions doing so is weak. Because it is currently impossible to determine with 100% certainty which earthquakes are induced and which not, *HiQuake* includes all earthquake sequences proposed on scientific grounds to have been human-induced regardless of credibility. Challenges to constructing *HiQuake* include under-reporting which is ~30% of M ~4 events, ~60% of M ~3 events and ~90% of M ~2 events. The amount of stress released in an induced earthquake is not necessarily the same as the anthropogenic stress added because pre-existing tectonic stress may also be released. Thus earthquakes disproportionately large compared with the associated industrial activity may be induced. Knowledge of the magnitude of the largest earthquake that might be induced by a project, M_{MAX}, is important for hazard reduction. Observed M_{MAX} correlates positively with the scale of associated industrial projects, fluid injection pressure and rate, and the yield of nuclear devices. It correlates negatively with calculated inducing stress change, likely because the latter correlates inversely with project scale. The largest earthquake reported to date to be induced by fluid injection is the 2016 M 5.8 Pawnee, Oklahoma earthquake, by water-reservoir impoundment the 2008 M ~8 Wenchuan, People's Republic of China, earthquake, and by mass removal the 1976 M 7.3 Gazli, Uzbekistan earthquake. The minimum amount of anthropogenic stress needed to induce an earthquake is an unsound concept since earthquakes occur in the absence of industrial activity. The minimum amount of stress *observed* to modulate earthquake activity is a few hundredths of a megapascal and possibly as little as a few thousandths, equivalent to a few tens of centimeters of water-table depth. Faults near to failure are pervasive in the continental crust and induced earthquakes may thus occur essentially anywhere. In intraplate regions neither infrastructure nor populations may be prepared for earthquakes. Human-induced earthquakes that cause nuisance are rare, but in some cases may be a significant problem, e.g., in the hydrocarbon-producing areas of Oklahoma, USA. As the size of projects and density of populations increase, the potential nuisance of induced earthquakes is also increasing and effective management strategies are needed.

1. Introduction

Natural processes that modulate the spatial and temporal occurrence of earthquakes include tectonic stress changes, migration of fluids in the crust, Earth tides, surface ice and snow loading, heavy precipitation, atmospheric pressure changes, sediment unloading and groundwater loss (e.g., Kundu et al., 2015). Such processes perturb stress on faults by only small amounts but, since rock failure in earthquakes is a critical process, nucleation of each event is ultimately brought about by a final, incremental change in stress. It is thus unsurprising that anthropogenic activity that perturbs stress in the crust, even slightly, can modulate seismicity. In most cases such effects probably go unnoticed (Section 7.1) but as industrial projects proliferate and grow in scale the number of cases where a link is obvious is increasing.

Mining- and dam-induced earthquakes have been recognized for several decades. Now concern is growing about earthquakes induced by hydraulic fracturing for shale-gas extraction and waste-water disposal

* Corresponding author.
E-mail address: g.r.foulger@durham.ac.uk (G.R. Foulger).

http://dx.doi.org/10.1016/j.earscirev.2017.07.008
Received 5 January 2017; Received in revised form 19 July 2017; Accepted 23 July 2017
Available online 26 July 2017
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by injection into boreholes. Seismicity may also increase in hydrocarbon reservoirs as they enter their late phases of production. The full extent of human activities that may induce earthquakes is, however, wider than generally appreciated. We conducted an extensive search to build as complete a catalog as possible of cases of induced seismicity reported to date. Our work expands previous reviews that include a general overview by McGarr et al. (2002), lists by Nicol et al. (2011) and Suckale (2009), and a review of 198 M ≥ 1 events by Davies et al. (2013). Our new database of human-induced earthquakes, *HiQuake*, contains over 700 cases of anthropogenic projects postulated to induce earthquake activity. It is publically available at www.inducedearthquakes.org (Wilson et al., 2017).

We constructed *HiQuake* by searching for case histories in published papers, conference abstracts, books, reports and the world-wide web, and through personal communications. The credibility of individual cases varies from extremely low to overwhelming, with most cases in between. There is no rigorous way of quantifying the likelihood that a particular claim for human induction is correct, and many arguments for anthropogenesis are presented as tentative by authors and challenged by other researchers, e.g., the 1983 M_W 6.2 Coalinga, California, event (Section 3.3.2). There is thus no rigorous way of defining a "credibility cut-off" below which a case history should be excluded from the database. For this reason we adopted the only reliable policy which was to include all cases without regard to plausibility. *HiQuake* thus lists all projects proposed on scientific grounds (not religious or moral) to have induced earthquakes and judgment regarding the credibility of any individual case is the responsibility of the user. *HiQuake* therefore comes with a caveat emptor. It is up to the database user to judge the strength of arguments for anthropogenic induction of any particular case included. For convenience, details of our information sources are included in the database.

In this paper we present the basics of relevant, fundamental, but sometimes-misunderstood background issues. Following this we give examples of seismicity postulated to be related to:

a) Surface operations,
b) Extraction of mass from the subsurface,
c) Introduction of mass into the subsurface, and
d) Explosions.

We sub-divide each category. In some cases, categorization is tentative because more than one anthropogenic process preceded or was ongoing at the time of the earthquakes, e.g., fluid extraction and injection are often conducted simultaneously in hydrocarbon reservoirs. Finally, we summarize features of the database and comment on related issues with which scientists are currently grappling.

1.1. Intraplate earthquakes

Plate tectonic theory in its simplest form considers plates to be rigid and expects most large earthquakes to occur in plate boundary zones. The fact that intraplate earthquakes occur, and may be large, is prima facie evidence that the plates are not rigid but also deform in their interiors. Intraplate stress changes cyclically as stress diffuses through them following the great[1] earthquakes and volcanic events that sum to bring about what geologists model as smooth plate movements (Foulger et al., 1992; Heki et al., 1993). The configuration of plate boundaries is geometrically unstable and evolving. For example, in Europe the formation of extensional features such as the Rhine Graben (Germany) is likely a consequence of southerly migration of the collision zone between Africa and Europe ("slab roll-back"). Intraplate European seismicity is probably related to the same process (Fig. 1) (Nielsen et al., 2007).

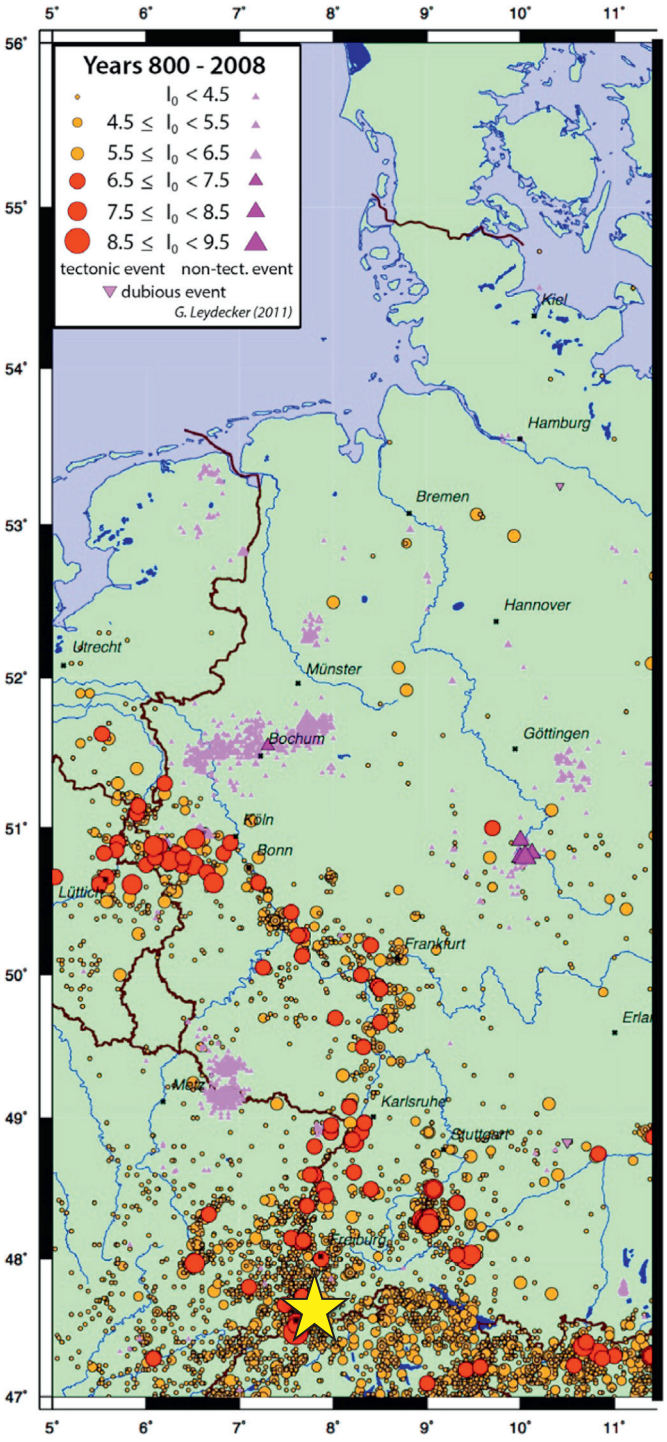


Fig. 1. Map of central Europe showing historical earthquakes with different epicentral intensities from 800 CE (from Stein et al., 2015). Yellow star: city of Basel, Switzerland.

Intraplate seismicity is commonly assumed to be spatially stable so future earthquakes occur where events have occurred in the past. This assumption has recently been re-visited as a result of geodetic work done in the New Madrid Seismic Zone, USA (e.g., Newman et al., 1999; Stein et al., 2009). There, it is generally expected that future large earthquakes will follow the damaging 1811–1812 sequence of four M ≥ 7 earthquakes (e.g., Johnston and Schweig, 1996). As a result, significant resources have been invested in earthquake hazard mitigation. Recent GPS surveying has, however, failed to detect any ongoing

[1] Earthquakes are classified as Great (8 or more), Major (7–7.9), Strong (6–6.9), Moderate (5–5.9), Light (4–4.9) and Minor (3–3.9).

strain build-up (Stein et al., 2009). This led to the proposal that the spatial distribution of intraplate earthquakes in general is not stationary and that the locations of past large earthquakes are not a good predictors of future earthquakes (Liu and Stein, 2016). Wrong forecasts of the location of future large earthquakes may lead to inefficient deployment of hazard-reduction resources and thus have significant implications for public safety.

A non-stationary spatial pattern of seismicity accords with evidence that the crust is critically stressed in most intraplate regions. Stress measurements made in boreholes commonly show that stress is close to the depth-dependent strength of the crust as estimated by laboratory experiments (e.g., Brudy et al., 1997; Zoback and Healy, 1984). The ambient pore pressure is generally close to hydrostatic, the crust is pervasively faulted, and faults that are well oriented for slip in the ambient stress field are commonly close to failure. This is consistent with observations that human-induced seismicity may occur, and even be large, in regions that have been historically aseismic.

1.2. Induced, triggered, stimulated, and nuisance earthquakes

Many if not all earthquakes induced by human activity release more stress than artificially added to the crust. McGarr et al. (2002) suggested the terms "induced" for earthquakes where the stress change caused by human activity is comparable to the shear stress causing a fault to slip, "triggered" where the anthropogenic stress change is much smaller, and "stimulated" where there are insufficient data to make the distinction.

It is beyond dispute that in many cases seismic strain energy released in earthquakes is many orders of magnitude larger than that introduced into the crust by the industrial activity. In this paper, however, we use the term "induced" for all earthquakes related to human activity because:

a) All earthquakes probably release some pre-existing strain energy and are thus likely to be "triggered". Only where rock is entirely unstressed initially could this not be so and that is not possible in a heterogeneous, gravitating half-space. Even nuclear tests, which are purely explosive sources, trigger the release of some regional tectonic stress as shown by shear components in their focal mechanisms (e.g., Toksöz and Kehrer, 1972).
b) The amount of tectonic strain energy loaded into the crust that is relieved seismically, on what time-scale, and the amount released aseismically are poorly understood. In rapidly deforming regions aseismic deformation can be measured geodetically (e.g., Heki et al., 1997) and surface subsidence is commonly observed above producing reservoirs (e.g., the Wilmington Oilfield, California; Kovach, 1974; Nagel, 2001). Only a fraction of the total strain energy is relieved seismically but it is difficult to determine what this fraction is. Surface geodetic data have low sensitivity to fault motion at depth. Estimates of the percentage of strain energy dissipated aseismically vary from ~20% to 1000% of that released seismically (Villegas-Lanza et al., 2016). The recent under-prediction of the magnitude of the 2011 M_W 9 Tohoku-oki, Japan, earthquake which killed >18,000 people and did incalculable economic damage, showed that our assumptions regarding the length of the "seismic cycle" may be incorrect. Even large earthquakes may not relieve all the stress on a fault so our ability to estimate long-term stress buildup in the crust is limited. The same considerations hold true for industrial projects. If the timescale of energy release is underestimated, and with it the size of the largest expected earthquake (which dominates the energy budget because of the fractal nature of earthquake magnitudes), the maximum expected earthquake magnitude (M_{MAX}) may be underestimated.
c) It is at best impractical and at worst fundamentally impossible to determine how much of the strain energy released in a seismic event pre-existed. Even in cases where the energy released is comparable to that industrially added (e.g., McGarr, 1991), much of the latter may have been relieved by aseismic deformation such as ground subsidence or inflow of water at depth. These processes may themselves trigger earthquakes or load adjacent regions to seismic failure (e.g., Guglielmi et al., 2015).

We use the term "induced" neutrally, and without implications for the origin of the total seismic stress change, in accord with the usage of the Committee on Induced Seismicity Potential (Hitzman, 2013). That committee uses the term "induced" to mean "earthquakes related to human activities".[2]

We use the term "nuisance" earthquakes for those that cause societal inconvenience. This inconvenience may be physical or psychological. It includes objectionable damage to infrastructure or the environment, public concern, annoyance or distress about ground shaking, noise or environmental effects such as hydrological changes. Clearly no seismological parameter, e.g., magnitude or intensity of ground shaking, can quantify nuisance because it is dependent on the culture of those affected. Nuisance earthquakes are those that need health-and-safety management. That requires an evidence base to which it is hoped the present review will contribute.

1.3. Factors involved in the nucleation of earthquakes

Shear slip on fault planes, with or without crack-opening or closing components, is the most common earthquake source process. Factors involved in nucleation, i.e. the onset of motion, include:

- the coefficient of friction on the fault plane;
- compressive normal stress on the fault plane;
- pore pressure in the fault zone; and
- shear stress on the fault.

According to the widely used Coulomb Theory, the shear stress required for failure τ is

$$\tau = \tau_0 + \mu(\sigma_n - p) \quad (1)$$

where τ_0 is the cohesion, μ is the coefficient of friction, σ_n is the normal stress across the fault, and p is the pore pressure in the fault zone (e.g., McGarr et al., 2002). The onset of an earthquake may thus result from reduction of the cohesion or normal stress on the fault plane or increase in the shear stress or pore pressure.

The loss or gain of overlying mass, introduction of fluid into a fault zone, or the imposition of vertical and/or horizontal stress by other means, e.g., stress transfer from nearby earthquakes, can bring a fault closer to failure. Where there are rapid temperature changes, e.g., where cold water is injected into geothermal areas, thermal effects may also be a significant.

Both the addition and removal of material industrially is associated with earthquakes. Removal of water from aquifers (Section 3.1) and rock from mines (Section 3.2) may reduce the confining stress on fault planes. Introduction of water via reservoir impoundment (Section 2.1.1) or injection (Section 4.1) may alter the fluid pressure in fault zones. Cessation of groundwater pumping, e.g., out of mines, may result in influx of groundwater and increase in pore pressure (Section 4.1.7). Addition of solid mass at the surface may also alter hydrological

[2] *"Some researchers (e.g., McGarr et al., 2002) draw a distinction between "induced" seismicity and "triggered" seismicity. Under this distinction, induced seismicity results from human-caused stress changes in the Earth's crust that are on the same order as the ambient stress on a fault that causes slip. Triggered seismicity results from stress changes that are a small fraction of the ambient stress on a fault that causes slip. Anthropogenic processes cannot "induce" large and potentially damaging earthquakes, but anthropogenic processes could potentially "trigger" such events. In this report we do not distinguish between the two and use the term "induced seismicity" to cover both categories."* Quoted from Hitzman, M. W. (Ed.) (2013), Induced Seismicity Potential in Energy Technologies x + 248 pp., National Academies Press, Washington, D.C.

conditions (Section 2.1.2).

Theories for the mechanism of induced earthquakes include the asperity model of Pennington et al. (1986) which suggests that fluid extraction results in differential compaction or aseismic fault motion, increasing stress on locked faults. This stress is eventually relieved when asperities break. The poroelastic model of Segall (1985, 1992) suggests that declining pore pressures resulting from fluid extraction cause contraction of the reservoir rocks and stress build-up. *Ad hoc* theories for individual earthquakes may provide candidate explanations *a posteriori*. However, developing a method that can reliably predict *a priori* which industrial projects will induce earthquakes and which not remains a work in progress.

1.4. Earthquake locations

Earthquakes in the *HiQuake* database span the period 1868 to 2017. Seismological technology has improved vastly during this period, but even today the standard of monitoring is non-uniform. Many projects may not be monitored at all until nuisance seismicity begins. In contrast, others may be monitored by dense seismic networks installed well in advance to obtain a pre-operational baseline (e.g., Cladouhos et al., 2013). As a result, data in *HiQuake* such as locations, magnitudes and focal mechanisms are non-uniform in quality.

Inaccurate hypocentral locations hamper efforts to associate earthquakes with operations, especially if the errors are larger than the separation between boreholes or producing horizons. An example is the case of the Crooked Lake, Alberta, earthquake sequences, thought to have been induced by shale-gas hydrofracturing (Section 4.1.6) (Schultz et al., 2015). A pre-operational seismic baseline was not available for medium-magnitude earthquakes, there was little information on local crustal structure, and most of the seismic data were from stations > 100 km away. As a result, it is unclear whether the lack of spatial correlation of some events with operations is real or a consequence of inaccurate locations.

The largest source of hypocentral uncertainty is imperfect knowledge of crustal structure. This factor is not included in the error estimates computed by many commonly used hypocenter-location programs which typically base uncertainty estimates on root-mean-square arrival-time residuals, assuming no errors in the crustal model used. Such residuals may be unrealistically small for systematically mislocated hypocenters. Advanced earthquake location methods using relative locating ("double-differencing"; Waldhauser and Ellsworth, 2000) or waveform cross-correlation (Got et al., 1994) can improve the accuracy of locations *relative to one another* but do not reduce systematic errors in the absolute locations. Accurate depths may be out of reach if geometrically strong data are unavailable. Errors in hypocentral depth are typically 2–3 times the error in horizontal (epicentral) location. Insufficient stations and sparse networks are also hindrances (Section 4.2.1).

Obtaining accurate local crustal velocity models in the neighborhood of small-scale industrial projects may be challenging. Information may be limited to well-logs, global or national crustal models, or models from analogous geological areas (e.g., Schultz et al., 2015). Such models are not adequate for reducing location uncertainties to sub-hectometer (100 m) levels. Ideally, high-quality crustal models based on active-source seismic surveying and/or one- and three-dimensional inversions of local earthquake data will be available. Projects will be monitored by dense networks of seismic stations with stations every 1–2 km^2. Experimental designs of this kind can return locations accurate to about a hectometer. Reducing errors still further requires calibration shots (Foulger and Julian, 2014).

In order to inform discussions regarding whether earthquakes are induced or natural, a pre-operation baseline is required. For this purpose, seismic networks must be deployed prior to commencement of operations. An effort to establish such a baseline for the entire UK prior to possible expansion of shale-gas hydrofracturing was recently made by Wilson et al. (2015).

1.5. Earthquake magnitudes

Magnitudes given for earthquakes often differ by up to a whole magnitude unit because:

- Traditional scales such as local magnitude (M_L) use measurements of the amplitudes of certain seismic phases recorded on seismic stations. Amplitudes are a poor measure of the size of an earthquake because they are influenced by factors such as the orientation of the fault that slipped and source-to-station crustal structure. Because of these and other factors, measurements at different stations may yield different magnitudes for the same earthquake.
- Different magnitude scales such as M_L and surface-wave magnitude (M_s) use different types of seismic waves, resulting in both systematic and random differences in the magnitudes calculated. For example, shallow earthquakes excite stronger surface waves than deep earthquakes, so M_S underestimates the sizes of deeper earthquakes compared with M_L.
- Seismological practice is notoriously non-standard in respect of magnitudes, and local magnitude scales and practices often depart considerably from those originally defined. Many local seismic stations and networks use their own customized magnitude scales, often constructed by calibrating them using a few earthquakes measured in common with the nearest permanent or calibrated station. That station may in turn have been calibrated in the same way. M_L technically refers to recordings made on Wood-Anderson seismographs, but such instruments are now rare. As a result, magnitudes reported from one seismic network may not be comparable to those reported from another, even if the same magnitude scale has, in theory, been used.

It is beyond the scope of this paper to render all magnitudes to a single scale and in this paper we therefore do not discriminate between magnitude types reported. We record the information currently available in the *HiQuake* database, e.g., M_L (local magnitude), m_b (body-wave magnitude), M_S (surface-wave magnitude), M_d (duration magnitude) and M_W (moment magnitude). Where magnitude type is not specified we use the notation M. Where several different estimates are published, we preferentially cite M_W. If M_W is not available, and more than one other magnitude has been published, we cite the largest. Rendering all the magnitudes to M_W is a task for future work.

1.6. Earthquake counts

The total number of earthquakes detected for a sequence depends on the density of seismic monitoring. This may change with time, e.g., if additional seismic stations are installed after nuisance seismicity has begun. Earthquakes are a fractal phenomenon, and their numbers increase by about an order of magnitude for each reduction in magnitude unit. If earthquake counts are to be meaningfully compared, they must thus be related to a common low-magnitude cut-off threshold.

The numbers of earthquakes induced may be of interest where monitoring networks are stable since this parameter may serve as a sensitive strainmeter. As a result, earthquake counts have been particularly useful for monitoring active volcanoes. The availability of many earthquakes is an advantage for purposes such as tracking injected fluids. From the point of view of potential damage the earthquakes of most relevance are the relatively few large-magnitude events and possibly only the largest (M_{MAX}).

1.7. The database

The approach we used to construct the database is described in detail by Wilson et al. (2017). Challenges intrinsic to the task included:

Table 1
Data recorded in the database.

Column contents
Country
Project name
Project type (subclass)
Longitude
Latitude
Project end date
Project start date
End date of seismicity or monitoring
Start date of seismicity or monitoring
Magnitude type
Delay time
Date of largest earthquake
Depth of largest earthquake
Distance of largest earthquake from induction activity
Year of largest earthquake
Lithology/resource
Distance of furthest earthquake from induction activity
Depth of induction activity
Typical depth of earthquakes
Previous seismicity
Tectonic setting
Injection/extraction rate
Dam height
Total volume or mass injected/extracted
Units of injection/extraction rate
Maximum wellhead pressure during injection
Units of total volume or mass injected/extracted
Stress change postulated to have induced earthquake
Change in reservoir pressure
Bottom-hole temperature
Area of project
References
Notes
References used by Davies et al. (2013)
Project type

- Incomplete reporting (Section 7.1);
- Ambiguous reporting, e.g., “Seismicity is not reported”;
- Lack of reported data, e.g., operational parameters not given;
- Uncertainty regarding whether or not the earthquakes were induced, e.g., some postulated associations are based simply on short-term temporal correlations or weak spatial correlations unsupported statistically and possibly coincidences. We dealt with this by including all cases (Section 1);
- Multiple possible induction processes ongoing simultaneously, e.g., hydrocarbon extraction and wastewater injection;
- Non-uniformity of magnitude reporting (Section 1.5). We report M_W if available, and if not the largest other magnitude;
- Lack of suitable networks to detect earthquakes. For some studies, instruments were installed only after the onset of seismicity (Section 1.4);
- Poor location accuracies (Section 1.4).

A list of database column headings is given in Table 1. The full *HiQuake* database is available as an Excel spreadsheet and references as an EndNote library at http://www.inducedearthquakes.org.

1.8. Earthquakes and belief systems

Public attitudes to induced earthquakes may have major implications for industrial projects, but human reactions to earthquakes may not be based on science. Because of their apparently chaotic and spontaneous nature, and lack of obvious direct causes, earthquakes have for millennia been explained in terms of folklore, religion, and other belief systems (e.g., Harris, 2012). This includes Chinese, Russian and Japanese folklore and the religions of the ancient Greeks and Polynesians. All three mainstream Abrahamic religions–Christianity, Islam and Judaism–are based on ancient texts that attribute earthquakes to shortfalls in human moral behavior.

Recent cases where belief-system-based explanations for earthquakes have had significant societal impacts include:

- In 2015, the Malaysian government attributed a M_W 6.0 earthquake that killed 18 people to tourists posing nude on Mt. Kinabalu, one of the country's sacred mountains.
- In 2014 local people in the Altai Mountains, Siberia, attributed earthquakes to the removal of the mummified remains of a 5th-century BC noblewoman for archaeological research.
- In 2010, the American evangelist Pat Robertson attributed the devastating M_W 7.0 Haiti earthquake to an alleged “pact to the Devil” made by escaped slaves to ensure success of the successful 1791–1804 anti-slavery insurrection on the island.

These examples illustrate the importance of public information and outreach when planning industrial projects that might induce earthquakes.

2. Surface operations

2.1. Adding mass

Earthquakes have been postulated to have been induced by three kinds of surface-mass addition. These are water impoundment behind dams (168 cases), erecting heavy buildings (1 case), and engineering coastal sediments (1 case).

The earliest report of earthquakes induced by water reservoir impoundment is from Reservoir Mead, Nevada and Arizona, USA (Carder, 1945). Several probable water-reservoir-induced earthquakes have resulted in fatalities and extensive property damage. The largest earthquake claimed to have been induced in this way is the 2008 M ~8 Wenchuan, China, earthquake, which has been associated with impoundment of the reservoir behind the Zipingpu dam. Reports of earthquakes induced by erecting heavy buildings and engineering coastal sediments are, in comparison, rare.

2.1.1. Water impoundment behind dams

A well-studied example is that of the Koyna Dam, India (Fig. 2). A detailed overview of this case, along with a review of reservoir-induced earthquakes, is given by Gupta (2002). The 103-m-high Koyna Dam was raised in 1962 and contains a reservoir up to 75 m deep and 52 km long. Five years after it was completed, a sequence of earthquakes with magnitudes up to M_S 6.3 occurred causing ~200 deaths and slightly damaging the dam. The largest earthquake nucleated at shallow depth, probably < 5 km, and its epicenter was ~10 km downstream from the dam. Earthquake activity has continued subsequently, correlating to some extent with water level in the reservoir (Fig. 3) (Talwani, 1995). A M > 5 event occurs there about every four years.

A second notable example is the Nurek dam, Tadjikistan (Keith et al., 1982; Leith et al., 1981; Simpson and Soboleva, 1977; Simpson and Negmatullaev, 1981). Building of this dam began in 1961 and, at 317 m, it is currently the highest in the world. It contains a reservoir ~10 km^3 in volume (Fig. 4). The largest earthquake to have occurred there to date is the 1972 M_S 4.6 event (Simpson and Negmatullaev, 1981). Seismicity is ongoing and there is evidence for correlation with periods of increase in water depth (Fig. 5).

The largest-volume reservoir in the world is 1.64×10^{11} m^3 and is contained by the 111-m-high Aswan dam, Egypt. Earthquakes induced there are thought to occur in two depth intervals i.e. ~0–10 km and ~15–25 km (Figs. 6 and 7). This vertical separation is postulated to indicate two different processes/environments of induction (Awad and Mizoue, 1995). The largest earthquake observed there to date is the 1981 M 5.7 earthquake, thought to have nucleated in the deeper zone.

A rare case where induced seismicity damaged the dam itself is that

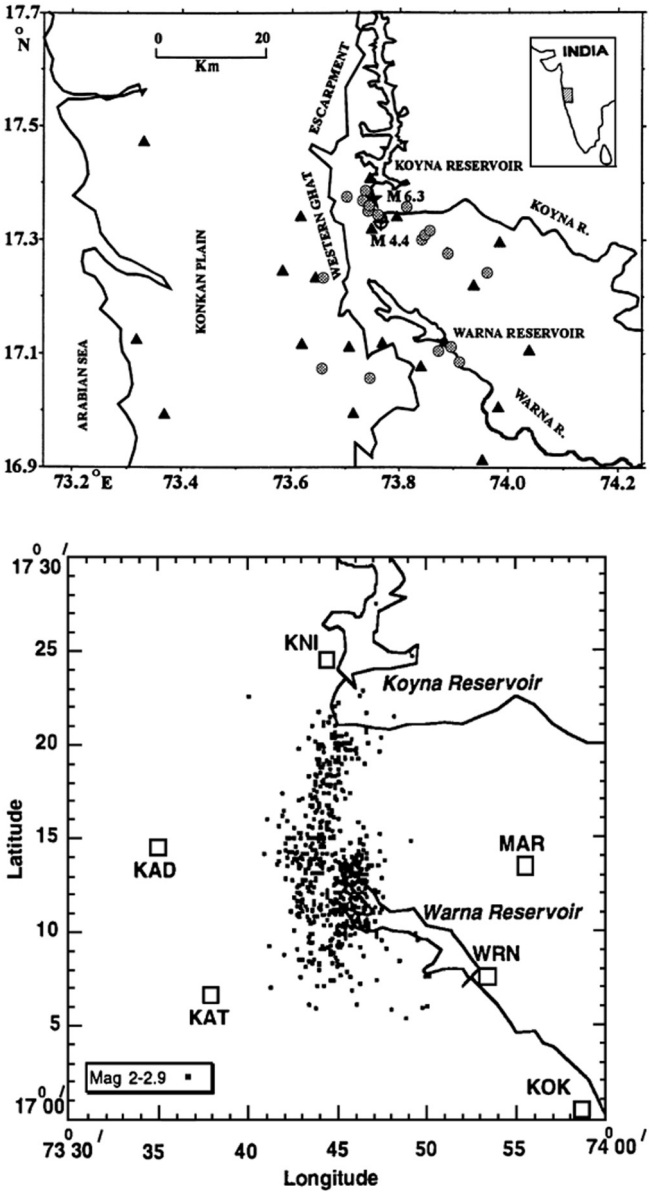


Fig. 2. Top: Map of Koyna area, India, showing the dam, reservoir, seismic stations (triangles) and boreholes (dots). Bottom: Same area showing earthquakes with M 2–2.9 for the period October 1993 to December 1994.
(From Gupta (2002).)

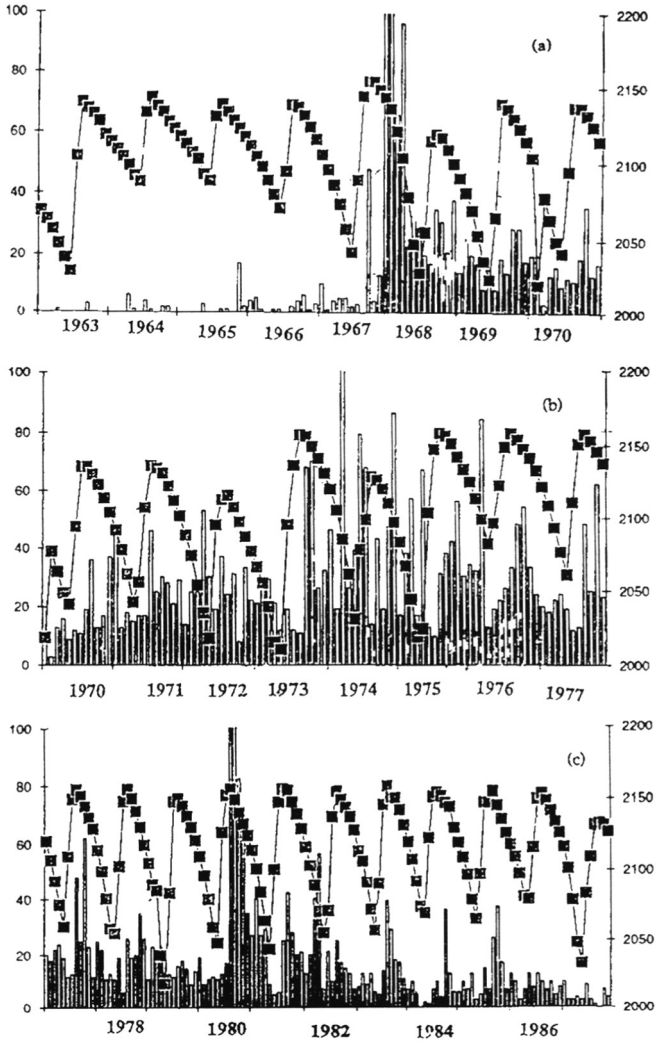


Fig. 3. Number of earthquakes in the region of the Koyna dam, India, for the period 1963–1986 (left axes), along with reservoir water level (right axes, in m).
(From Talwani (1995).)

of the 105-m-high Xinfengjian Reservoir, China. Impoundment of the 1.39×10^{10} m^3 volume reservoir began in 1959 and seismic activity started a month later. A M_S 6.1 earthquake occurred in 1962 which caused minor cracking of the dam.

A case of particular interest is that of the May 2008 M_W ~8 Wenchuan, China, earthquake (Fig. 8). This earthquake was so large relative to the height of the nearby Zipingpu dam (156 m) and the volume of the reservoir (~10^9 m^3) that it is controversial whether it was induced or not. It occurred ~20 km from the dam within months of full reservoir impoundment. The earthquake caused ~90,000 deaths, collapsed roads and bridges, and serious damaged >100 towns.

The activated zone lies at the transition between the low-strain-rate (<10^{-10}/year), stable Sichuan Basin and the tectonically active Tibet plateau where strain rates are >10^{-8}/year. The transition is marked by the multi-stranded Longmenshan fault zone which accommodates thrust and strike-slip motion. Paleoseismic work suggests an earthquake recurrence time of ~7000 years for M 7–8 earthquakes (Klose, 2012).

Prior to impoundment of the reservoir there had been ~40 recorded earthquakes per month in the vicinity of the dam. In October 2005, seismicity increased as impoundment started and the water level rose rapidly by ~80 m. The water level peaked in October 2006 at ~120 m above pre-impoundment levels. Earthquake activity surged to ~90 events per month but reduced thereafter (Fig. 9).

The 2008 M_W ~8 mainshock nucleated at ~16 km depth and thrust motion propagated up toward the surface beneath the reservoir. Rupture transitioned to strike-slip motion and propagated laterally along the fault in both directions, rupturing >300 km of the Longmenshan thrust belt with an average slip of 2.4 m, peaking at 7.3 m. The source time function, which lasted 90 s, indicated that failure occurred in five sub-events that sequentially released 9%, 60%, 8%, 17% and 6% of the total moment (Fig. 9) (Zhang et al., 2008, Yong Zhang, personal communication). The average stress drop during the earthquake was 18 MPa, peaking at 53 MPa. Like other great earthquakes, this event owed its large size to progressive activation of adjacent fault segments in a chain of sub-events.

The increase in shear and normal stresses, caused by the reservoir, that were orientated to encourage slip on the fault were no more than a few kPa (Klose, 2012). This is small, even compared with the stress changes associated with Earth tides (Section 7.3). Klose (2012) suggests that the additional stress modulated the timescale on which the earthquake occurred, advancing it in time by ~60 years. It has been much disputed whether such a small stress perturbation was sufficient

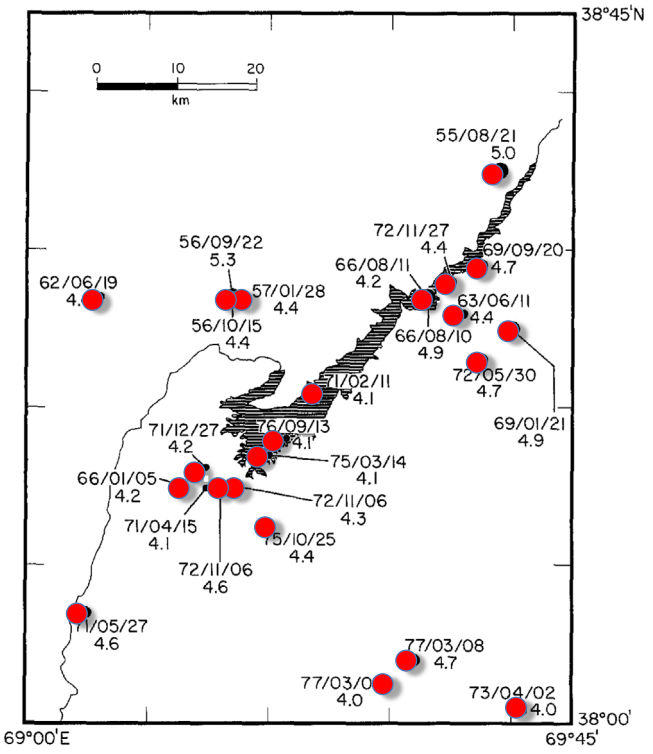


Fig. 4. Map of Nurek dam and reservoir, Tadjikistan, showing earthquakes with M ≥ 4.0 for 1955–1979.
(From Simpson and Negmatullaev (1981).)

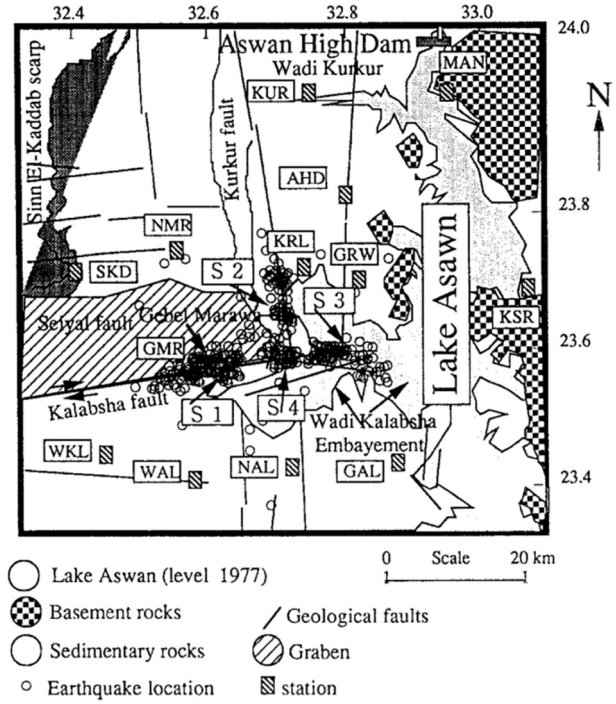


Fig. 6. Map showing Lake Aswan, Egypt, and epicenters of induced earthquakes. (From Awad and Mizoue (1995).)

to trigger such a large earthquake. A more relevant question is whether the reservoir could have induced the initial M_W ~7.5 sub-event, since it is that sub-event which started the cascade of segment failures that grew the earthquake to M_W ~8.

An unusual dam-related seismic sequence occurred in association with the Beni Haroun hydraulic complex in the Mila region, 30 km west of the city of Constantine, Algeria (Semmane et al., 2012). This complex comprises a main dam 120 m high and a reservoir with a capacity of ~10^9 m^3. It is connected by pipelines to the secondary Oued Athmania reservoir, ~15 km south of the main dam (Fig. 10). A 6-km section of pipeline passes through a mountain as a lined tunnel 1.4–3.6 m in diameter. To reach this part of the pipeline water is pumped up ~600 m higher than the Beni Haroun reservoir. The pipeline has a capacity of 600,000 m^3/day.

In 2007, a sequence of earthquakes up to M_d 3.9 occurred. It is thought to have been induced by leakage into the ground of ~400,000 m^3 of water as it was being pumped between the reservoirs. More than 7200 earthquakes were recorded over a ~2-month period. The water leaked from the tunnel via defective joints and penetrated deep into the ground via fractures, faults and karst cavities. Earthquakes started within days of the leakage (Fig. 10). The area had no prior record of such swarm activity and installation of the complex

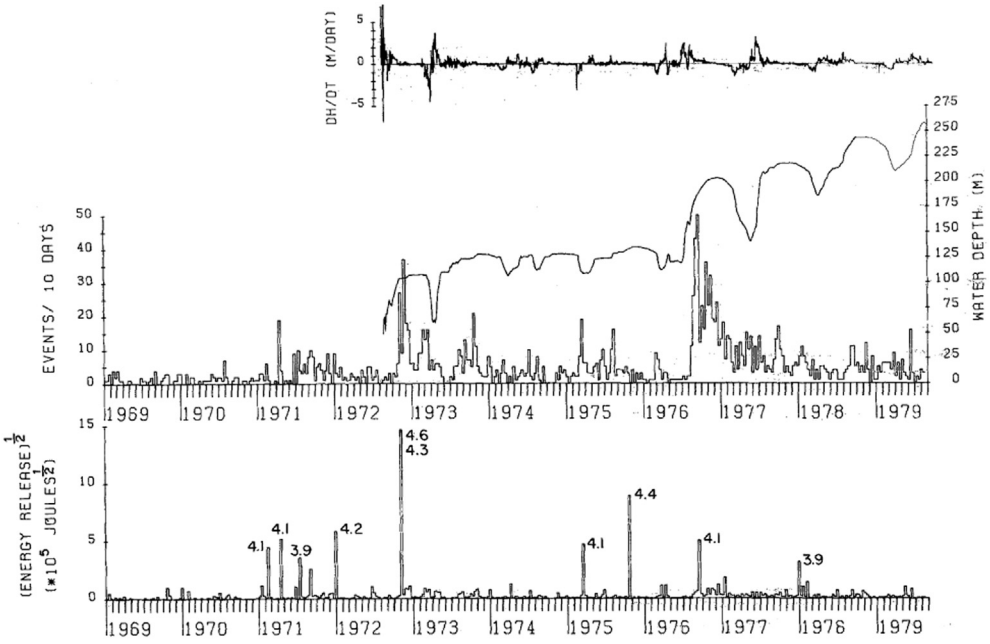


Fig. 5. Water depth and seismicity for 1969–1979 in the vicinity of Nurek dam, Tadjikistan.
(From Simpson and Negmatullaev (1981).)

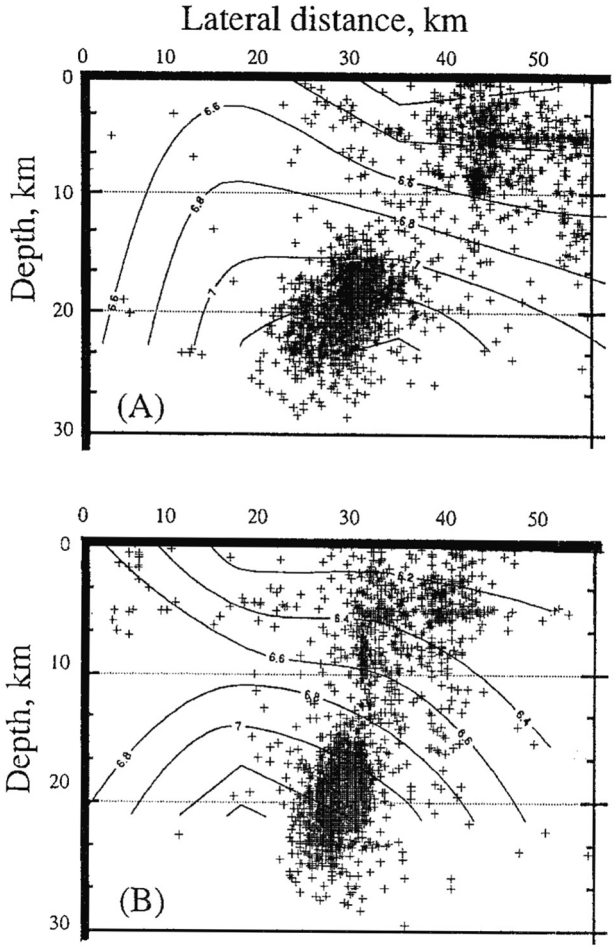


Fig. 7. Cross sections showing hypocentral distribution of earthquakes postulated to have been induced by impoundment of Lake Aswan.
(From Awad and Mizoue (1995).)

in 2000 had not been associated with an increase in seismicity. The events did no damage but were heard loudly and alarmed local people unaccustomed to earthquakes (Semmane et al., 2012).

The Colorado River, USA, contains numerous dams. The two largest are the 220-m-high Glen Canyon dam, a concrete arch that impounds Reservoir Powell, Arizona, and the Hoover dam, ~600 km further downstream, that impounds Reservoir Mead, mostly in Nevada. Glen Canyon dam is built in Mesozoic sedimentary rocks whereas the Hoover dam is built in Tertiary volcanics, part of the tectonically active basin-range province. In keeping with expectations, the latter is seismogenic but the former is not (Fig. 11).

Currently, attention is focused on the 181-m-high Three Gorges dam, China. Its 4×10^{10} m^3 water reservoir was fully impounded in 2010 and power generated came online in 2012. Total generation capacity is 22,500 MW. The area lies in a seismogenic region that includes two major fault lines. The reservoir is not the largest in the world, but earthquakes are already being reported with a M_L 4.6 event occurring in 2014.[3]

2.1.2. Erecting tall buildings

Lin (2005) suggested that erection of the ~500-m high Taipei 101 building, Taiwan, influenced the pattern of seismicity in the immediate neighborhood of the building. This 7×10^8 kg building increased stress on the ground at its base by ~0.47 MPa. In the eight-year period prior to building, nine earthquakes with $M_L \leq 2.0$ occurred whereas during the eight-year period that spanned construction and followed it, 20 earthquakes up to M 3.8 occurred. Earthquakes were unusually frequent during the construction period (Fig. 12).

This is the only published case to date proposing earthquakes were induced by erecting a heavy building. Taiwan lies in a convergent plate boundary zone where the Philippine Sea plate subducts beneath the Eurasian plate at the Manila trench. As a consequence it is seismically active.

This case raises the question of whether other such examples exist, e.g., in Japan. The building that is currently the tallest in the world, the 825-m-high Burj Khalifa, Dubai, weighs less than the Taipei 101 building, at only 4.5×10^8 kg. There are no known reports of changes in earthquake activity from the New York or Tokyo regions where large buildings are common, though to our knowledge the issue has not been studied in detail.

2.1.3. Coastal land gain

Klose (2007b) suggested that the 2007 M_L 4.2 Folkestone, Kent, UK, earthquake was triggered by geo-engineering of shingle accumulation in the harbor since 1806. There is substantial coastal land loss as a result of erosion to the southwest and northeast of Folkestone, but land gain by artificial shingle accumulation in Folkestone harbor has been ongoing for ~200 years. An estimated total of $\sim 2.8 \times 10^9$ kg had accumulated by 2007, four times the mass of the Taipei 101 building. This altered the stress by an estimated 0.001–0.03 MPa at 2 km depth. The earthquake epicenter lay ~1 km (epicentral error ~ 5 km) from the shingle, and nucleated at shallow depth.

2.2. Surface operations: removing mass

Operations that remove mass from the surface and are reported to induce earthquakes are limited to quarrying. *HiQuake* contains 16 such cases. The largest earthquake that has been associated with quarrying is the 2013 M 6.1 Kuzbass, Siberia, event (Emanov et al., 2014; Yakovlev et al., 2013). It occurred in the Bachatsky open-cast coal mine which is 10 km long, 2.2 km wide, excavated up to 320 m deep, and produces $> 9 \times 10^6$ t of coal per year. The earthquake collapsed buildings in local communities and was felt in neighboring provinces.

Moderate earthquake activity had been detected in the mine in early 2012 when a M_L 4.3 event and associated aftershocks occurred. A dense local seismic network was installed, and recorded a low level of small earthquakes with magnitudes up to ~M_L 2. Event magnitudes increased with time, and 15 months later a M_L 3.9 event occurred followed a month later by the M 6.1 mainshock.

2.3. Surface operations: summary

The impoundment of water in reservoirs behind dams induces earthquakes in abundance and accounts for 168 (24%) of all cases in *HiQuake*. Ignoring natural lakes where dams have made minor changes to the water level, reservoirs are up to 8502 km^2 in area (Lake Volta, behind the Akosombo Dam, Ghana). Earthquakes may thus be induced throughout relatively large regions.

Eight cases of induced earthquakes with M > 6 have been proposed, associated with the dams at Zipingpu (China), Lake Hebgen (USA) (Klose, 2013), Polyphyto (Greece), Koyna (India), Kariba (Zambia/Zimbabwe), Kremasta (Greece), Hsingfengkiang (China) and Killari (India). In China there are 348 reservoirs with volumes exceeding 0.1 km^3. Of these, 22 (6.3%) are reported to be seismogenic.

Gupta (2002) reviews theories for the mechanism of triggering. Stresses induced by reservoirs at the depths where earthquakes occur are small, perhaps of the order of 0.1 MPa. This is much smaller than the 1–10 MPa stress drops that are typical in earthquakes. They are, nevertheless, larger than seismogenic Earth tidal stresses (Section 7.3). The mechanism of induction may be that the surface load alters

[3] https://journal.probeinternational.org/2014/04/07/three-gorges-dam-triggers-frequent-seismic-activities/.

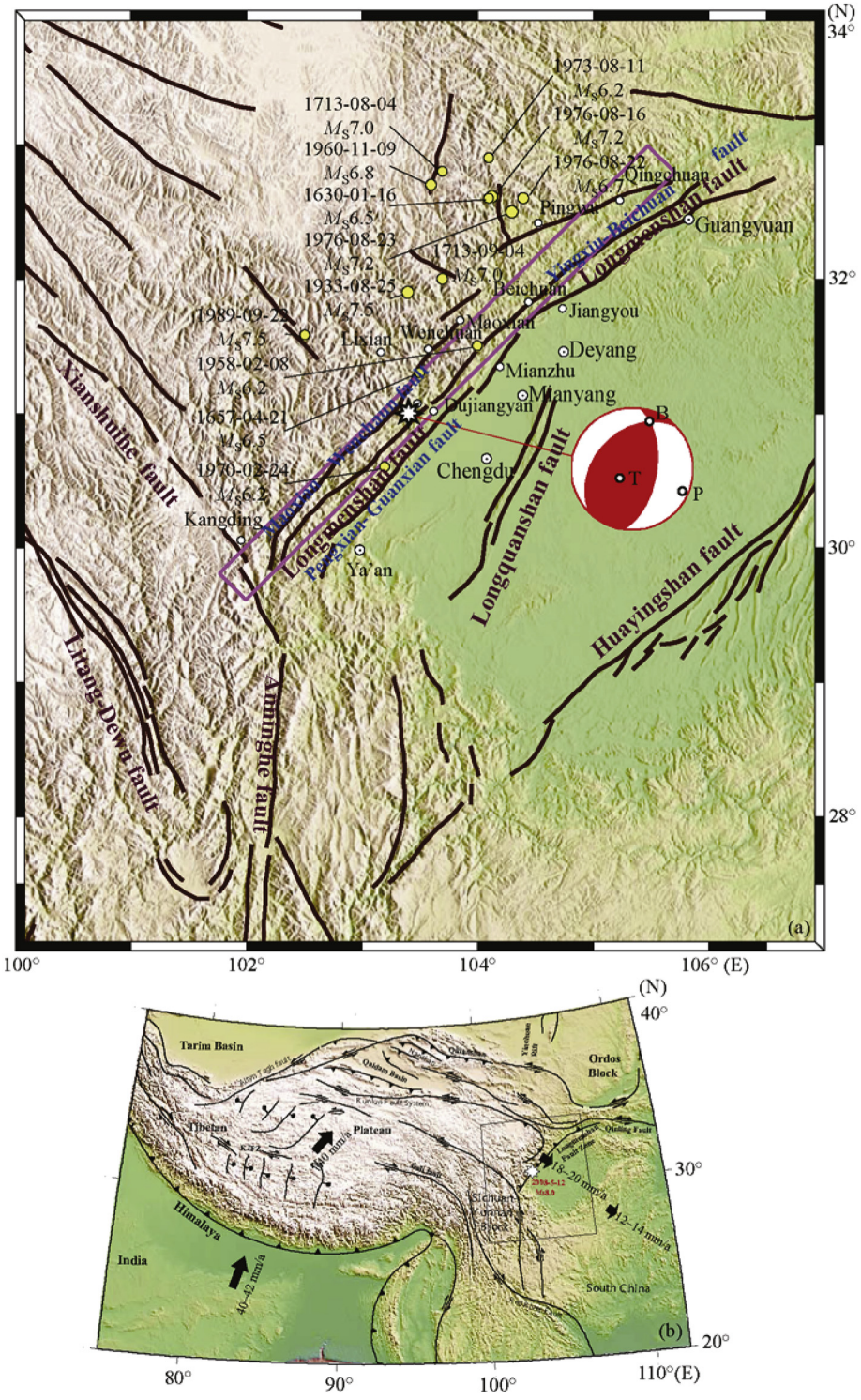


Fig. 8. Top: Area of the 2008 M_W ~8 Wenchuan, China, earthquake. Star: location of nucleation point of the mainshock; lines: main faults of the Longmenshan fault zone; yellow circles: historical earthquakes; white circles: main cities; lilac rectangle: projection of the fault plane that slipped; beach ball: lower hemisphere projection of the focal mechanism of the mainshock. Bottom: regional tectonic setting.
(From Zhang et al. (2008).)

hydraulic conditions at depth, causing fluid to migrate into fault zones and increase pore pressure. This may also explain the seismicity postulated to have been induced by the Taipei 101 building, Taiwan (Section 2.1.2) and shingle accumulation at Folkstone, UK (Section 2.1.3).

3. Extraction from the subsurface

3.1. Groundwater extraction

Five cases of earthquakes associated with artificial lowering of the water table have been postulated. The 2011 M_W 5.1 Lorca, Spain, event, suggested to have been induced by groundwater extraction (Fig. 13) (González et al., 2012), caused extensive damage to the town of Lorca, seriously damaging both modern and historic buildings, killing nine people and injuring several hundred (Fig. 14).

The region lies in a transpressive shear zone containing thrust- and strike-slip faults, in the Nubia-Eurasia plate boundary. The M_W 5.1 mainshock nucleated on the Alhama de Murcia fault at unusually shallow depth (~3 km). This fault has generated several large earthquakes over the past few centuries. Geodetic data from radar interferometry and GPS surveying constrained co-seismic deformation that

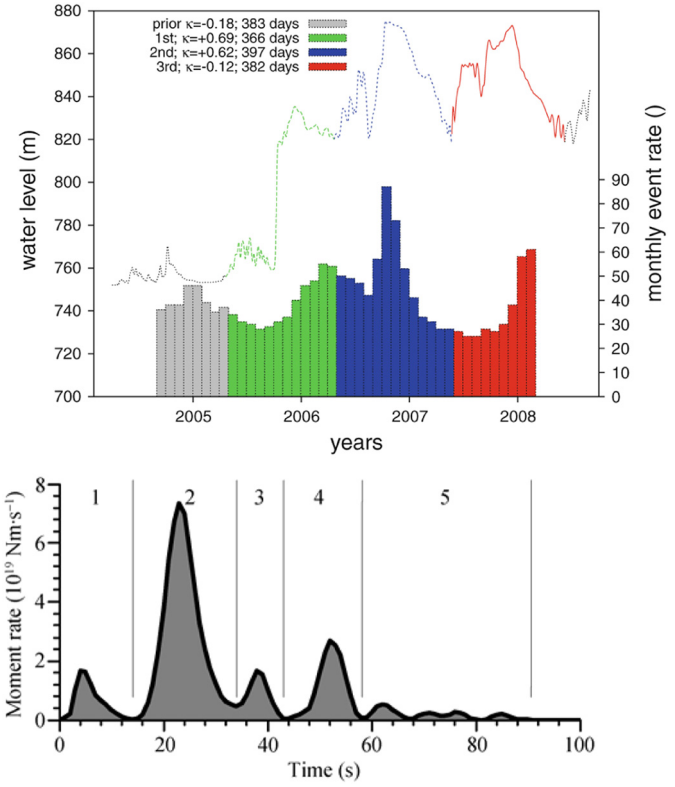


Fig. 9. Top: Water level change in the Zipingpu, China, water reservoir and earthquake event rate in the vicinity prior to the May 2008 M_W ~8 Wenchuan earthquake (from Klose, 2012). Bottom: Source time function of the 2008 great Wenchuan, China earthquake (from Zhang et al., 2008).

was consistent with slip of up to ~15 cm on a ~10 × 10 km section of the fault in the depth interval ~ 1–4 km (Fig. 15).

To the southeast, groundwater pumping 1960–2010 had lowered the water table by > 250 m. The surface had concurrently subsided by > 10 cm/year, totaling > 2 m. Significant environmental effects had occurred as a result (Fig. 16).

A slip deficit of up to ~12 cm had probably accumulated in the Alhama de Murcia fault since the previous large earthquake on the fault segment ~200 years earlier. Calculated Coulomb stress changes induced by water removal were consistent with a crustal unloading process that enabled tectonically accumulated stress to be released in the 2011 event. González et al. (2012) concluded that cumulative long-term hydraulic unloading, coupled with the location and type of the fault with respect to the depleting aquifer, contributed to the stress conditions that precipitated the earthquake.

Other cases of induced seismicity of this kind include the 2015 M_W 7.8 Gorkha, Nepal, earthquake which has been linked to groundwater depletion beneath the Indo-Gangetic Plain to the south (Kundu et al., 2015). This thrust earthquake caused ~8000 deaths and ~$10 billion of economic loss, ~50% of the Gross Domestic Product of Nepal.

The Indo-Gangetic Plain is the most intensely irrigated region in southeast Asia and has the highest population density. It covers ~2.5×10^6 km^2 and is home to ~0.5 billion people. Groundwater is extracted at a rate of ~23×10^{12} m^3/year, the largest rate of groundwater loss on Earth (Fig. 17). This load is being removed from the footwall of the Main Himalayan Thrust and encourages slip in the fault zone in a similar way to the Lorca case (Fig. 18) (Kundu et al., 2012).

The Coulomb failure stress change has been ~0.003–0.008 MPa since 1960 (Kundu et al., 2012). This is at the lower limit of that induced by Earth tides (Section 7.3) but is comparable to the natural rate of stress accumulation on the Main Himalayan Thrust of ~0.001–0.002 MPa/year. Dewatering of the Indo-Gangetic Plain is thus accelerating stress accumulation on the Main Himalayan Thrust by 4.5–20%.

Groundwater beneath the San Joaquin Valley, California, has been depleted by ~1.6×10^{11} m^3 over the past ~150 years (Amos et al., 2014; McGarr, 1991). The most rapid depletion occurs during the summer agricultural growing months and the most rapid natural recharge during the winter and spring. Annual fault-normal seasonal stress variations on the San Andreas fault zone from this source are ~0.001 MPa, encouraging earthquakes in summer and autumn. The stress rate is similar to that calculated for the Main Himalayan Thrust from dewatering the Indo-Gangetic Plain and the predicted seasonality in seismicity is seen in earthquakes with M > 1.25.

A similar process was suggested to modulate seismicity in the Gran Sasso chain in the central Apennines, Italy (Bella et al., 1998). There, tunneling for construction of a highway 1970–1986 significantly changed the hydrology of natural springs. Changes in the spatial pattern of local seismicity, an increase in seismic rate, and the occurrence of three M > 3 events were postulated to be linked to the hydraulic changes. Klose (2007a) attributes the 1989 M_L 5.6 Newcastle, New South Wales, Australia, event to the dewatering of deep coal mines.

3.2. Mining

Mine excavations perturb stresses in surrounding rocks and may reduce some components from values initially of the order of 100 MPa to atmospheric (0.1 MPa). The resulting stress differences can exceed the strength of competent rocks and cause earthquakes. These are traditionally known as “rock bursts” or “coal bumps”.

Lately, excellent seismic data have been recorded on dense, multi-component arrays installed for hazard mitigation purposes. Propagation paths are often short, pass through homogeneous rock, and data are free from the effects of the weathered surface layer that degrade surface observations. Significant advances in understanding the source physics of earthquakes have been achieved using these data. It has been shown that many mining-induced earthquakes have net implosive source mechanisms, consistent with partial closure of the artificial voids created by the removal of mass (e.g., Feignier and Young, 1992; Kusznir et al., 1982; Rudajev and Sileny, 1985; Wong and McGarr, 1990; Wong et al., 1989). Miller et al. (1998a, Section 3.4) give a detailed review of this.

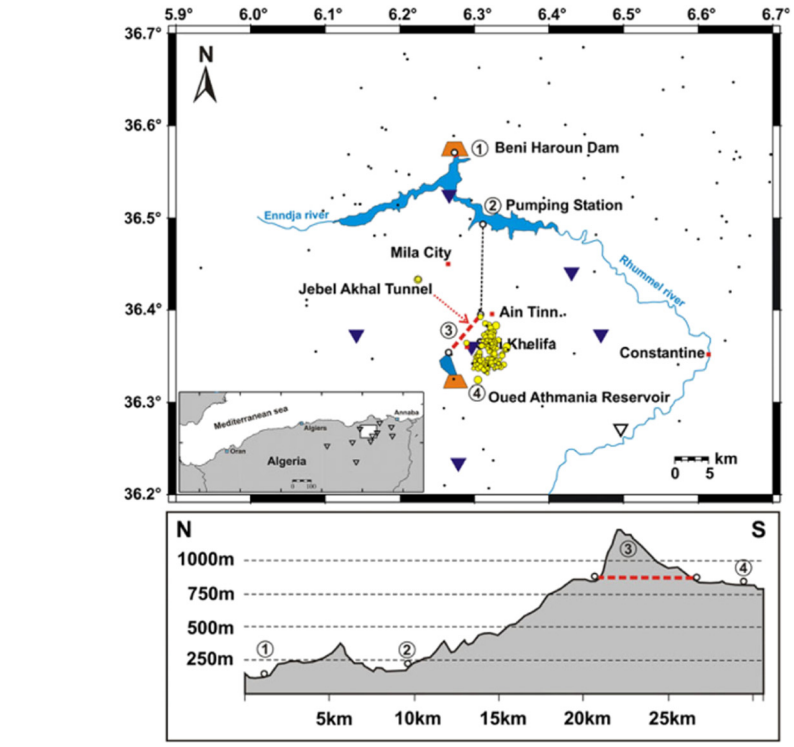
3.2.1. Traditional mining

Mining seismicity may be disproportionately serious because of the large loss of life and resources caused. This includes environmental damage such as surface subsidence which may render buildings beyond repair. Mitigating mining-induced seismicity is a major technical challenge, and might become a limiting factor to the industry (e.g., Tang et al., 2010).

During the ~50-year period 1949–1997, over 2000 coal bursts occurred in 33 mines in China, killing several hundred people and costing > 1300 days in lost production (Tang et al., 2010). In 2007 some 102 coal mines and 20 other mines reported seismicity (Fig. 19). Seven of these were associated with events of M > 4.0 and 27 with events of M ≥ 3.0 (Li et al., 2007). Earthquakes are shallow, occurring at 0–7 km depth. The largest coal mining event that has occurred in China is the 1977 M_L 4.3 event at Taiji mine, Beipiao, Liaoning (Li et al., 2007).

Coal mining in China is increasing in depth of extraction and volume removed, and the problem of mining-induced seismicity is increasing also (Figs. 20 and 21). The demand for coal and other minerals requires, in the absence of other solutions, that this trend continues. The problem of mining-induced earthquakes may thus grow unless management solutions are found.

Perhaps the most spectacular case of mining-induced seismicity occurred in 1989 in the Volkershausen Ernst Thaelmann/Merkers potash mine, Germany. An event with M_L 5.6 (Bennett et al., 1994; Knoll,



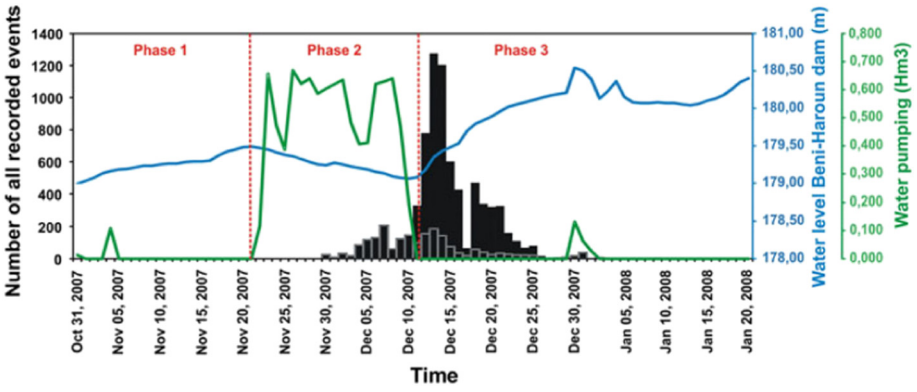


Fig. 10. Map of hydraulic system in Mila region, Algeria. Top: Water transport system (dashed lines) from Beni Haroun dam to Oued Athmania reservoir. Red dashed line: tunnel through Mt. Jebel Akhal; black dots: seismicity for 2006–2007; triangles: seismic stations; yellow dots: epicenters of earthquakes postulated to have been induced. Middle: topographic profile of hydraulic system. Bottom: Number of earthquakes recorded, water level in Beni Haroun dam, and volumes of water pumped vs. time around the seismogenic period. Black histogram: events recorded; gray histogram: events recorded by the network, discarding a temporary station deployed in the epicentral area for 17 days during the swarm. This exemplifies the effect of varying the number of seismic stations. (From Semmane et al. (2012).)

1990) was associated with the collapse of ~3200 pillars throughout an area of ~6 km^2 in the depth range 850–900 m. A large part of the local town of Düren was devastated, damaging several hundred buildings and totally destroying 19. Three people were killed and several injured. The event was probably multiple, with three main sub-events of M_L 4.4, 5.1 and 5.5. The M_L 5.5 sub-event was attributed partly to fluid waste injection which increased pore pressure by ~0.3–1.1 MPa, and this may have initiated an earthquake which led to collapse of the pillars (Knoll, 1990).

A case that involved litigation over the cause of a fatal mine-related earthquake is the 2007 M_W 4.1 Crandall Coal Mine, Utah, event. Nine miners and rescuers were killed by a gallery collapse. The cause of the collapse was variously attributed to triggering by a natural earthquake or unsafe back-stripping mining practices. The seismic moment tensor of the event was not consistent with shear slip on a fault, as expected for a natural earthquake, but with a rapidly closing crack, as expected for a gallery collapse (Fig. 22) (Dreger et al., 2008). The following year, the US Mine Safety and Health Administration levied fines totaling $1.85

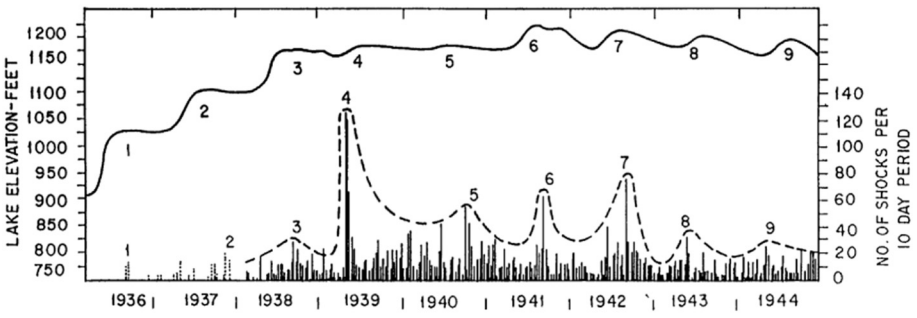


Fig. 11. Earthquakes and water level at Reservoir Mead, Arizona, which is impounded behind Hoover dam. (from Gupta (2002).)

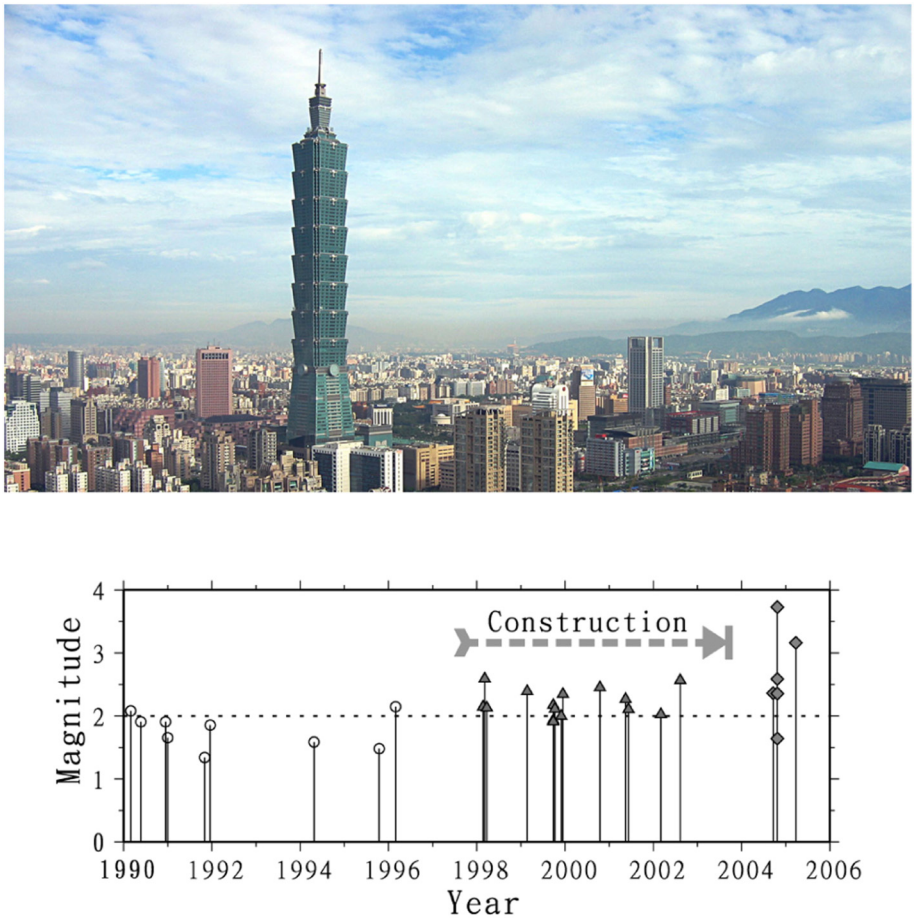


Fig. 12. Top: The Taipei 101 building, Taiwan (http://inhabitat.com/taipei-101-worlds-tallest-green-building/green-taipei-101-1). Bottom: Earthquake history for a 16-year period spanning the construction of the building. (From Lin (2005).)

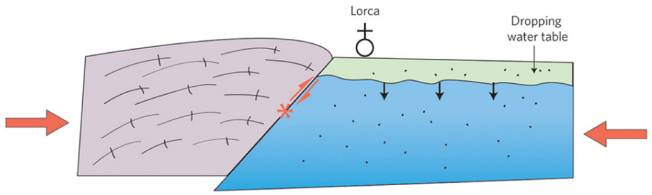


Fig. 13. Schematic figure showing the mechanism proposed by González et al. (2012) for inducing the 2011 M_W 5.1 Lorca, Spain, earthquake. (From Avouac (2012).)

million for unsafe mining practices at Crandall Coal Mine.

The UK has a long history of mining dating from the Neolithic period that includes flint, lead, copper, coal, tin and gold (Fig. 23). During the 19th and 20th centuries coal mining reached its peak and in 1913, ~ 3 x 10^8 t were extracted from 3024 mines. Some of these were excavated to depths of ~1200 m and extended several kilometers offshore beneath the North Sea.[4,5] *HiQuake* includes the largest earthquake recorded in each major UK coalfield.

Wilson et al. (2015) reviewed UK earthquakes to determine a national baseline for seismicity in advance of possible future shale-gas hydrofracturing. They used the earthquake database of the British Geological Survey. Of the ~8000 onshore British earthquakes in that catalog for 1970–2012 they estimated ~21% to have been anthropogenic, the majority caused by coal mining (Fig. 24). Coal production and earthquakes correlate (Fig. 25) (Wilson et al., 2015). A large reduction in seismicity accompanied a fall in production during the 1984–85 miners' strike. The economic cost of that strike is estimated to have been several billion pounds, from which it can be calculated that mitigation of each earthquake with $M_L \geq 1.5$ cost ~£10 million. The earthquake rate recovered in line with coal production when the strike ended in 1985.

The region most renowned for large mining-induced earthquakes is South Africa. There, two of the world's richest ore bodies are mined–the gold-bearing conglomerates of the Witwatersrand Basin and the platinum-bearing pyroxenites of the Bushveld Complex. Both bodies extend to depths of several kilometers, and mining depths exceed 3.5 km (Durrheim, 2010). The current regional stress field is extensional but tectonically inactive. Mining-induced earthquakes are accompanied by collapses of up to ~1 m in the vertical that contract galleries in the form of horizontal tabular voids for up to several kilometers of their lengths. Earthquakes up to m_b 5.6 have occurred (President Brand mine, Welkom, in 1994).

The problem of induced seismicity in South Africa became apparent early in the 20th century when mining penetrated to several hundred meters depth. It is now a major issue and great efforts are made to mitigate the risk. These include development of the safest possible mining techniques, optimal design of equipment, and seismological monitoring. Fatality rates have been reduced but still number several tens of deaths per year (e.g., Amidzic et al., 1999; Boettcher et al., 2015; deBruyn and Bell, 1997; Durrheim, 2010; Durrheim et al., 2013; Durrheim et al., 2006; Heesakkers et al., 2005; Jaku et al., 2001; Julià et al., 2009; Kozlowska et al., 2015; Lippmann-Pipke et al., 2011; Milev and Spottiswoode, 2002; Richardson and Jordan, 2002; Wright et al., 2003; Yabe et al., 2015; Ziegler et al., 2015).

An example is a M_L 4.0 event that occurred in Western Deep Levels East gold mine in 1996. It nucleated in complex geology ahead of

[4] https://www.gov.uk/government/statistical-data-sets/historical-coal-data-coal-production-availability-and-consumption-1853-to-2011.

[5] http://www.dmm.org.uk/mindex.htm.



Fig. 14. Destruction in the church of Santiago resulting from the 2011 M_W 5.1 Lorca, Spain, earthquake (https://en.wikipedia.org/wiki/2011_Lorca_earthquake).

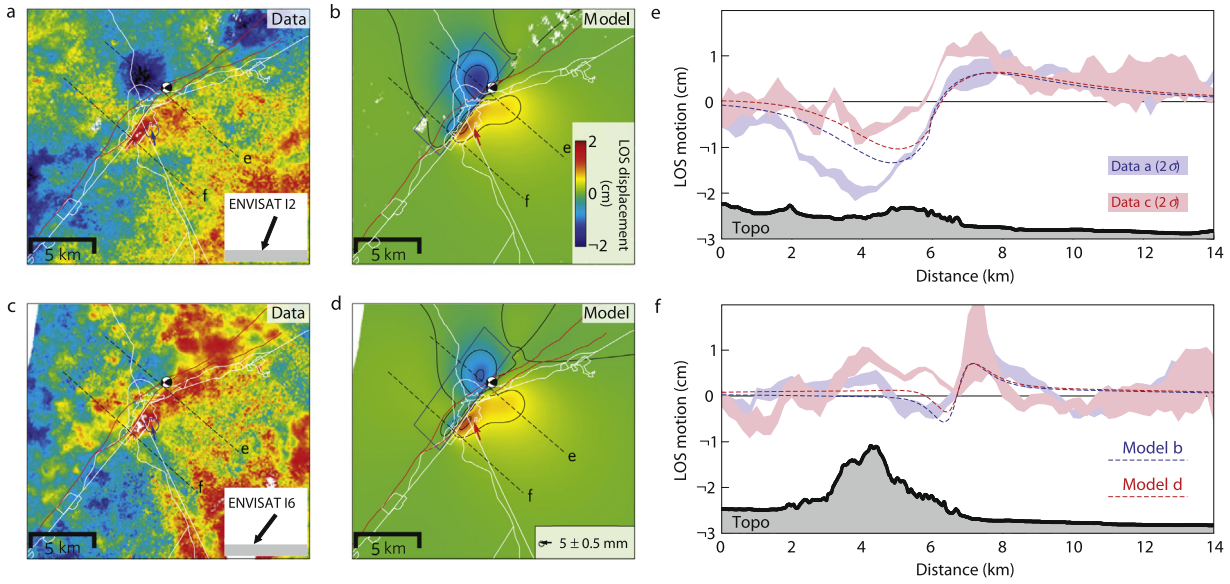


Fig. 15. (a–d): Ground deformation data and model for the 2011 M_W 5.1 Lorca, Spain, earthquake. (a and c): Descending line-of-sight (LOS) displacement map and horizontal GPS vector; (b and d): distributed slip model predictions. Insets in a and c indicate LOS angle, positive values away from the satellite. Blue rectangle: fault surface projection; dashed lines: profile locations; (e and f): observed and simulated data along two profiles, and local topography.
(From González et al. (2012).)

mining and extensively damaged the area. Work had involved removing a large pillar left by earlier, smaller-scale mining. This damaging earthquake had a significant impact and resulted in improved seismicity management strategies (Amidzic et al., 1999).

An even larger event, with M_L 5.3, occurred in the Klerksdorp district, South Africa, in 2005. It seriously damaged the nearby town of Stilfontein, injuring 58 people. Two mineworkers in a nearby gold mine were killed and thousands of others were evacuated. This earthquake was attributed to stress loading by past mining (Durrheim et al., 2006). It highlighted the problem of poor documentation of historic mining activities, a difficulty faced by all nations with long traditions of mining. It also showed that earthquakes induced by one industrial project can endanger others nearby. Its delayed occurrence illustrates that seismic hazard may remain a problem after mine closure.

McGarr (1992a) used the exceptionally high-quality data collected on the state-of-the-art monitoring networks installed in deep South African gold mines to derive full moment tensors for 10 Witwatersrand mining-induced earthquakes with M 1.9–3.3. The earthquakes were of two types. Seven involved substantial coseismic volumetric reduction combined with normal faulting and three had no significant volumetric component. Those with volumetric components probably involved interaction between a mine stope and a shear fault (McGarr, 1992a).

These conclusions were confirmed by later workers. Julià et al. (2009) obtained focal mechanisms for 76 mine tremors with M 0.5–2.6 at the deep AngloGold Ashanti Savuka gold mine. These events were recorded on 20 high-frequency geophones in the mine. The largest

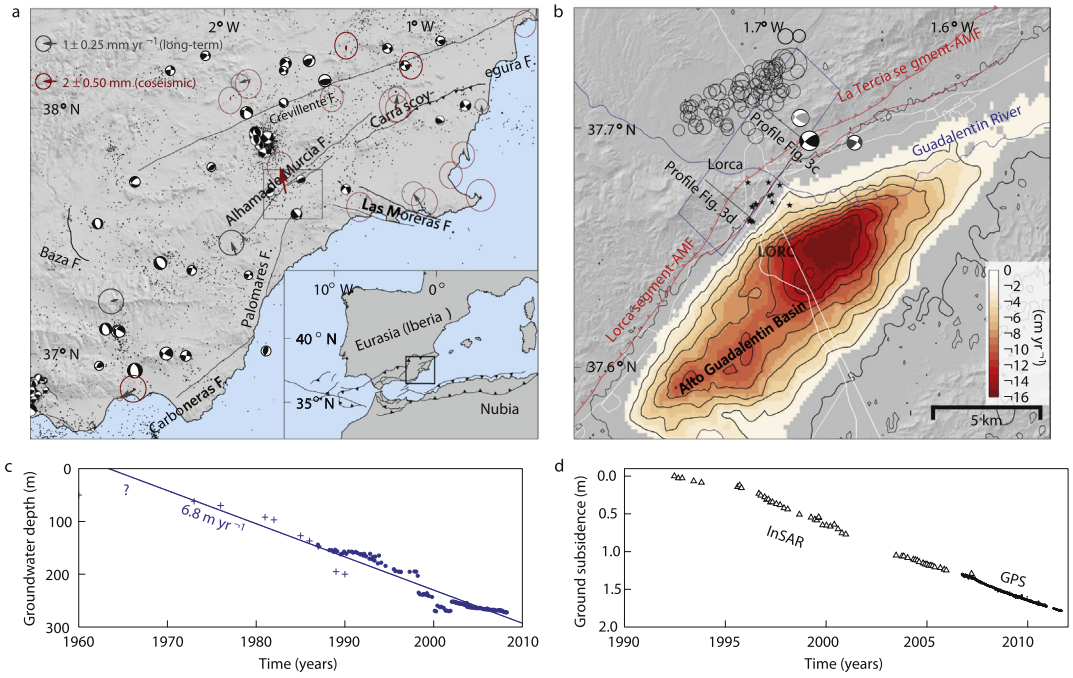


Fig. 16. Location and kinematics of the Lorca earthquake. a: southwest Spain seismicity (2000–2010), focal mechanisms (1970–2010), long-term GPS velocity (2006–2011, gray) and coseismic vectors (red). Major mapped faults are labeled. b: Lorca city and Alto Guadalentin Basin. Mainshock focal mechanisms (black), pre-shock (light gray), largest aftershock (dark gray), and relocated seismic sequence. Black stars are damage locations, red lines are faults. Contour lines indicate 2 cm/a InSAR subsidence due to groundwater pumping. Blue rectangle: fault surface projection. AMF, Alhama de Murcia Fault. c, Groundwater depth. d, InSAR (triangles) and line-of-sight (LOS)-projected GPS ground-surface subsidence at station LORC. (From González et al. (2012).)

principal stress was vertical and was relieved by a combination of volumetric closure and normal faulting, consistent with the vertical closure of galleries. Richardson and Jordan (2002) studied seismicity associated with five deep mines in the Far West Rand district using data recorded 1994–2000 on in-mine arrays. Seismic rates exceeded 1000 events/day. Some earthquakes occurred within 100 m of active mining faces. Those events were attributed to blasting, stress perturbations from the excavation, and closure of stopes. Other events were distributed throughout the mining region, had M > 3, and were similar to regional tectonic earthquakes.

3.2.2. Solution mining

Solution mining recovers minerals via boreholes drilled into the deposit. A lixiviant–a liquid used to dissolve the target mineral–is pumped into the resource via an injection borehole, circulates through the rock dissolving the mineral, and is extracted via a production well. The lixiviant may be water (e.g., to extract salt), or acid or sodium bicarbonate to extract metals (e.g., uranium, copper, gold or lithium).

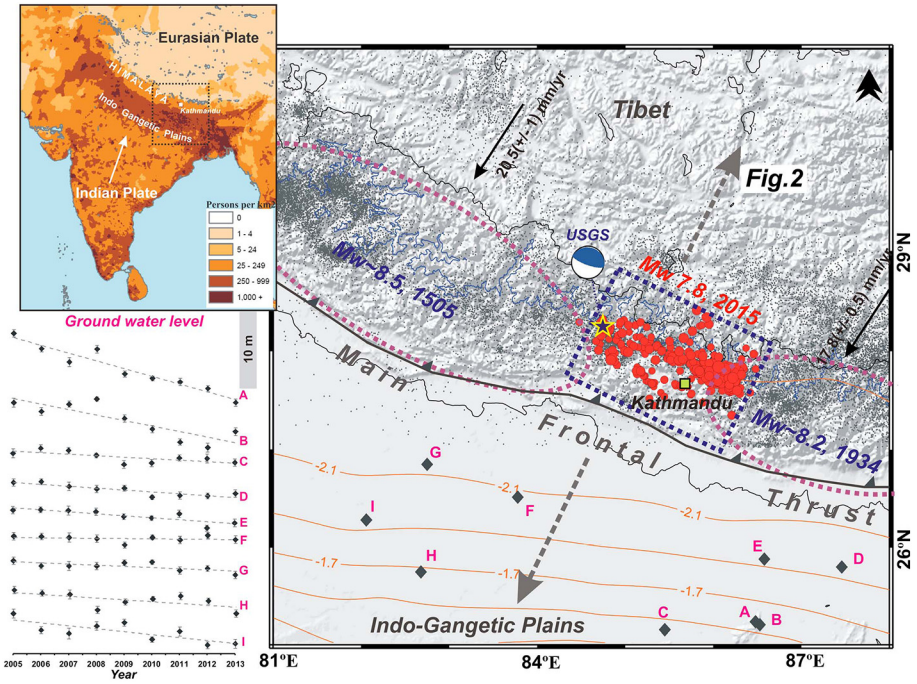


Fig. 17. Seismotectonic context of the 2015 M_W 7.8 Gorkha, Nepal earthquake. Black star: epicenter of the mainshock; red circles: aftershocks; black arrows: convergence rate; gray dots: mid-crustal seismicity 1995–2008; blue contour: 3500-m elevation; ellipses: approximate rupture locations of historic events since 1505; orange contours: anthropogenic groundwater loss in cm/a water thickness for the period 2002–2008 (multiply by 5 to get drop in water table); black diamonds: sampling sites; inset at left: site depletion trends; inset top left: population density (people/km^2).
(From Kundu et al. (2015).)

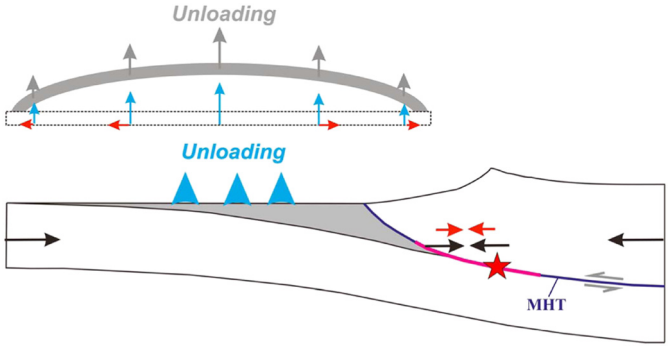


Fig. 18. Schematic diagram showing the effect of unloading by anthropogenic groundwater loss on the Main Himalayan Thrust. Dewatering induces a component of horizontal compression (red arrows) that adds to the secular interseismic contraction (black arrows) at seismogenic depths. Red star: the 2015 Gorkha, Nepal earthquake; pink line: the associated rupture.
(From Kundu et al. (2015)).

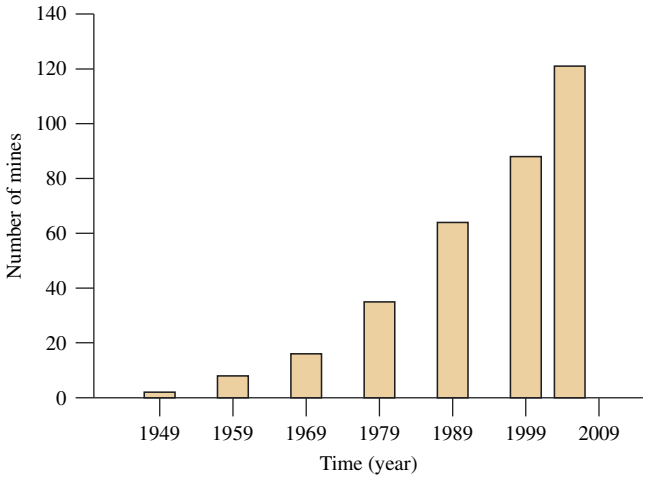


Fig. 20. Number of mines in China with rockburst hazard vs. time.
(From Li et al. (2007)).

Roughly half the world's uranium is produced by solution mining.

HiQuake contains eight cases of seismicity postulated to be associated with solution mining. At the Vauvert Field, France, brine is produced from a layer at 1900–3000 m depth comprising ~50% salt. Water is circulated through fractured zones via a well doublet. Some cavities created dissipate by salt creep but earthquakes occur where this process cannot keep up with mass removal. Seismicity also results from hydraulic fracturing used to create porosity. Over 125,000 earthquakes with M −3 to −0.5 occurred 1992–2007 have been located (Godano et al., 2010).

In the USA three cases are documented, from Attica and Dale (New York) and Cleveland (Ohio). Of three M_L ~5 events that occurred near Attica, in 1929, 1966 and 1967, two had hypocentral depths as shallow as 2–3 km (Herrmann, 1978). They are postulated to have been induced by salt solution mining (Nicholson and Wesson, 1992).

In China, a M_L 4.6 earthquake occurred in 1985 in association with solution mining of salt from depths of 800–1800 m at the Zigong salt mine, Sichuan Province (Li et al., 2007). This earthquake induced the highest intensity of ground shaking measured for any mining-induced earthquake in China. It is the largest mining-related event of any kind known from China.

At Mishraq, Iraq, earthquakes occurred in association with mining of sulfur by injecting hot (~150 °C) water at pressures of 0.6–0.8 MPa into layers up to 190 m deep (Terashima, 1981). Surface subsidence of up to several mm/day resulted in surface cracking. Felt earthquakes occurred 1973–1975 and were most numerous at times of high injection rate.

3.2.3. *Tunnel excavation*

Earthquakes accompanying excavation of tunnels and cavities have been reported in 20 cases. These include excavations for power-station housing (e.g., the underground powerhouse of the Pubugou, China hydroelectric station), water transport at hydro-electric and nuclear power stations (e.g., the Yuzixi hydro-electric station, China, and the Forsmark nuclear plant, Sweden), and road and railway transport (e.g., the Ritsem tunnel, Sweden, and the Qinling railway tunnel, China) (Tang et al., 2010).

The 57-km-long Gotthard Base Tunnel, Switzerland, part of the New Alpine Traverse through the Swiss Alps (Husen et al., 2012), was excavated for freight and passenger rail transport 2002–2006 using drilling and blasting. Three “Multi-Function Stations” (MFSs) divide the tunnel into five sections.

A series of 112 earthquakes with M_L −1.0 to 2.4 occurred

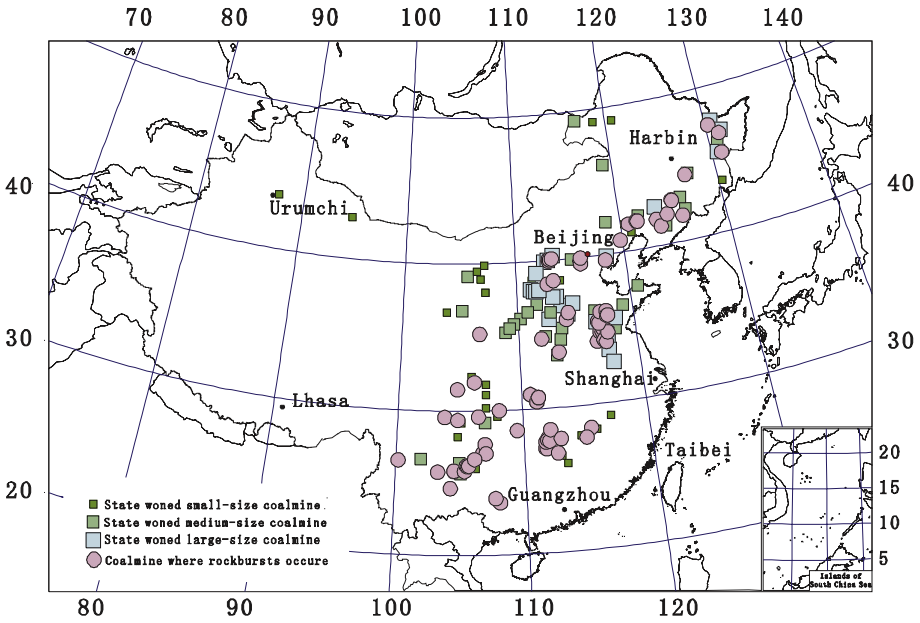


Fig. 19. Map of China. Green squares: Small, medium and large state-owned coal mines. Pink dots: Coal mines where mining-induced seismicity occurs.
(From Li et al. (2007)).

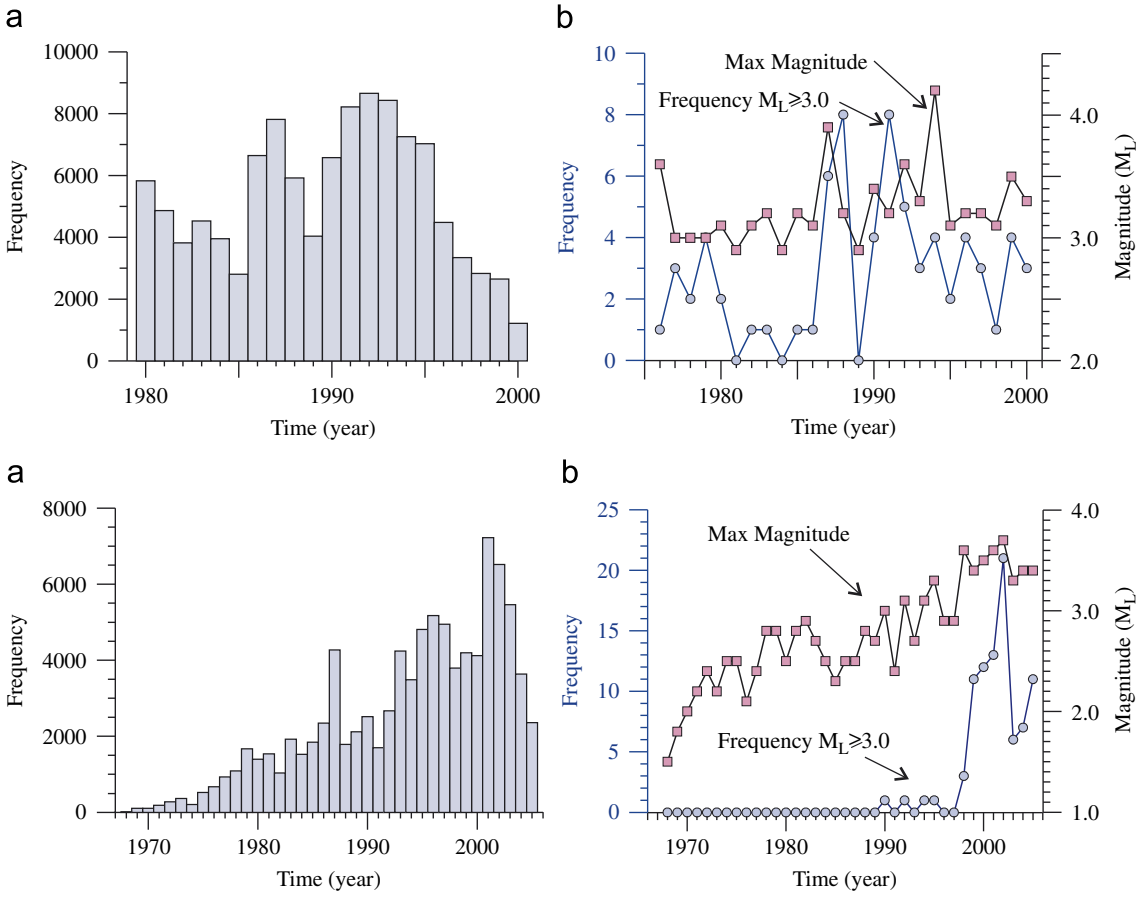


Fig. 21. Top panels: Mining-induced earthquakes at Mentougou coal mine, Beijing, (a) events M > 1.0, (b) events M > 3.0 and the maximum event magnitudes. Bottom panels: same as top panels except for the Fushun coal mine field in Liaoning Province.
(From Li et al. (2007)).

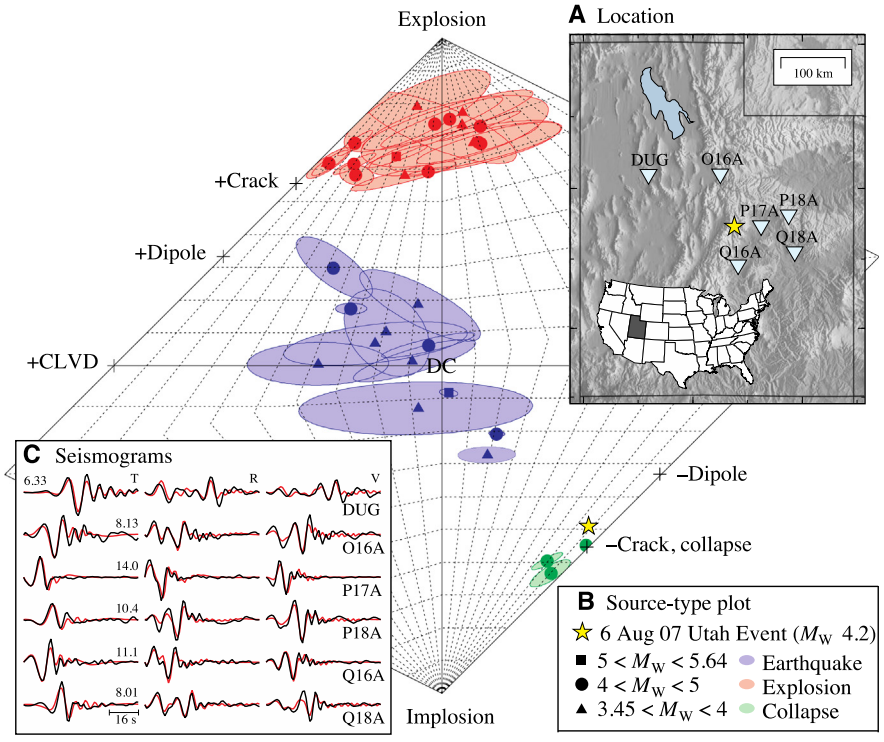


Fig. 22. (A) Locations of the 6 August 2007 Crandall mine, Utah, earthquake and six of the closest USArray and Advanced National Seismic System (ANSS) seismic stations. (B) Source-type plot showing separation of populations of earthquakes, explosions, and collapses. Yellow star shows the focal mechanism solution. (C) Observed seismograms (black) compared to synthetics (red) for the solution, which is similar to a horizontal closing crack (B). The maximum displacement (10–7 m) of each set of tangential (T), radial (R), and vertical (V) observations is given.
(From Dreger et al. (2008).)



Fig. 23. Surface imprints of Neolithic flint mining at Grimes Graves, Suffolk, England (www.english-heritage.org.uk).

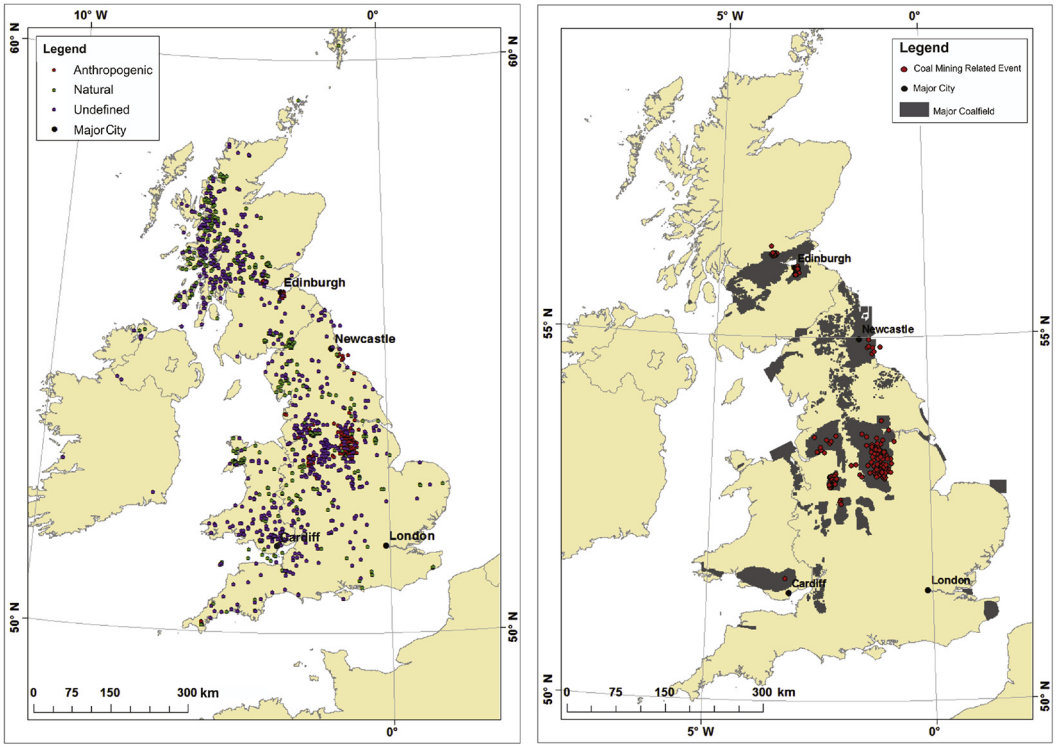


Fig. 24. For earthquakes with $M_L \geq 1.5$ for the period 1970–2012, left: map of the UK showing 1769 onshore seismic events categorized as anthropogenic (red), natural (green) and undefined (purple). Right: 369 events postulated to be induced by coal mining. These correlate spatially with major coalfields (dark gray).
(From Wilson et al. (2015).)

2005–2007 in association with excavation of the southernmost station, MFS Faido. The largest event was just 0.5–1.0 km deep and felt strongly at the surface. The station cavity was damaged including flaking of the reinforced walls and upwarping of the floor by ~0.5 m. The seismicity correlated spatially and temporally with excavation of the station (Figs. 26 and 27). Accurate locations obtained using a dense, temporary seismic network showed that the earthquakes occurred at a similar depth to the tunnel. Some correlated with rockbursts in the tunnel shortly after blasting.

The focal mechanism of the largest earthquake indicated normal faulting on a steep plane 50–170 m long belonging to the local fault system. The tunnel traverses igneous and metamorphic rocks and a complex of structures with different rheological properties, including faulted and heavily fractured sections. Modeling suggested the earthquakes resulted from an unfavorable juxtaposition of rocks with different rheologies in a fault zone. The horizontal stresses added by the excavations were relieved by shrinking of the tunnel which reactivated the fault zone.

3.3. Hydrocarbons

Suckale (2009, 2010) reviewed seismicity induced by hydrocarbon production. There are ~67,000 hydrocarbon fields worldwide (Li, 2011) including ~1500 giant and major fields, and ~1,000,000 producing oil and gas wells. Seismic response to production varies and no seismicity is reported for most fields. Reporting is, however, incomplete, and many fields are not instrumented (Section 7.1). Earthquakes account for only a small percentage of the deformation associated with reservoir compaction with the majority being taken up by ground subsidence or counteracted by fluid recharge from the sides.

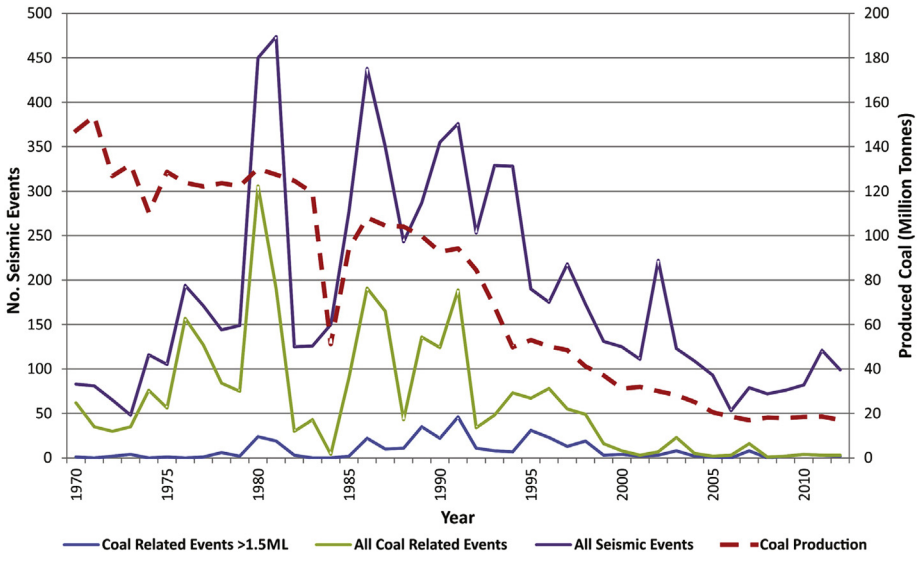


Fig. 25. UK coal production (dotted red line) vs. numbers of earthquakes postulated to be induced (blue line: $M_L \geq 1.5$, green line: all postulated coal-related events, purple line: all located earthquakes in the British Geological Survey database) for the period 1970–2012. The effect of the miners' strike of 1984 can be seen clearly in the drop in production and seismicity.
(From Wilson et al. (2015).)

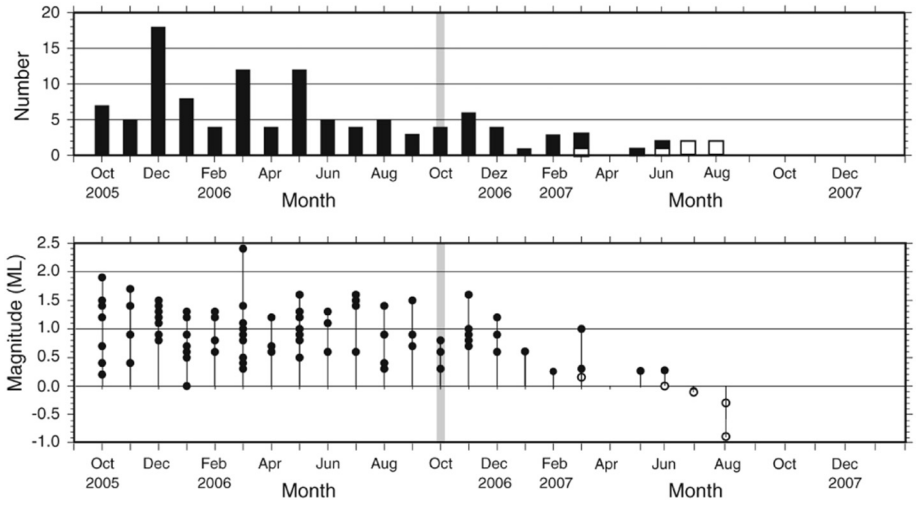


Fig. 26. Temporal evolution of the seismicity observed in the vicinity of the multi-function station Faido, Switzerland, October 2005–December 2007. Top: number of events per month. Bottom: local magnitudes. Open circles: earthquakes for which magnitude could only be computed using data from one station. Gray band marks the end of the excavation work.
(From Husen et al. (2012).)

The earthquakes reported often occur on faults that were either previously unknown or considered to be inactive.

3.3.1. Gas

There are 36 cases of seismicity postulated to have been induced by extraction of natural gas. These are from Canada (1 case), China (1 case), France (2 cases), Germany (7 cases), Italy (1 case), the Netherlands (18 cases), Oman (1 case), the USA (4 cases) and Uzbekistan (1 case).

The most extreme case is that of the Gazli reservoir, Uzbekistan. In 1976 and 1984, three M_S ~7 earthquakes occurred, seriously damaging the local town of Gazli and causing one death and ~100 injuries (Simpson and Leith, 1985). An additional M_S 5.7 event occurred in 1978. Events occurred as follows:

1956 the Gazli field was discovered;
1963 pipelines to the Urals industrial region were completed;
1966 production of ~20 × 10^9 m^3/year of gas began. Reservoir pressure was ~7 MPa;
1968–71 production peaked;
1976 pressure had declined to 3–3.5 MPa; two M_S ~7 earthquakes occurred;
1978 a M_S 5.7 earthquake occurred;
1984 a M_S ~7 earthquake occurred;
1985 pressure had declined to 1.5 MPa.

Gas was produced from a reservoir at ~2 km depth, hosted in an open anticline of tight Paleogene sandstones. This structure is cut by several blind faults and the M_S ~7 earthquakes are thought to have occurred on one of these (Fig. 28). Fault-plane solutions suggest that they occurred on a north-dipping, easterly striking thrust fault, consistent with regional tectonics. Extrapolation of this fault to shallow depth suggests that it intersects with the gas reservoir. In addition to this geometric correspondence, Simpson and Leith (1985) cite as additional evidence that these events were induced:

- previous seismic quiescence;
- an anomalous magnitude distribution which involved three M_S ~7 events rather than a mainshock-aftershock sequence;
- the large decrease in pressure in the reservoir; and
- unusual downwards rupture propagation.

That these earthquakes were induced has been challenged, e.g., by Bossu et al. (1996), on the grounds that the stress perturbation on the fault was too small to have triggered such large earthquakes. Possible analyses of this case are limited because data on operations are sparse. However, the Gazli case is important because of its implications for the maximum possible magnitude of earthquakes that could be induced by gas extraction.

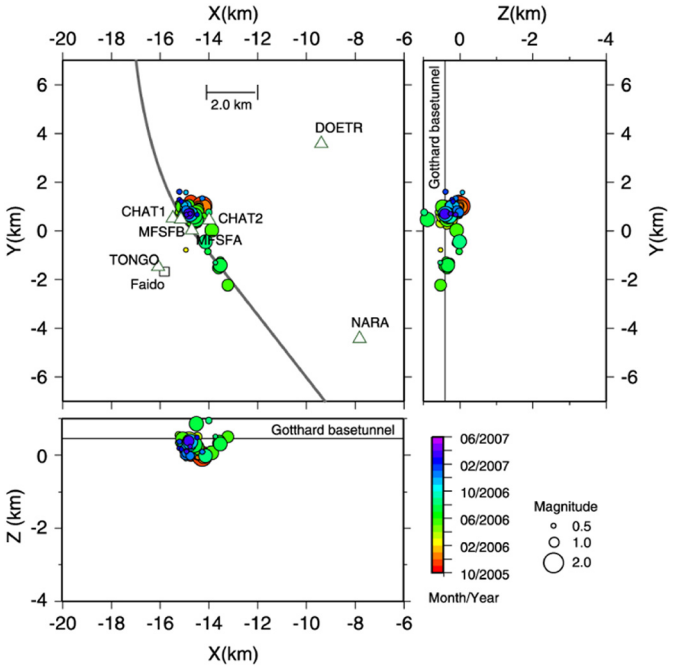


Fig. 27. Hypocenter locations of earthquakes in the vicinity of the multi-function station Faido, Switzerland, October 2005–June 2007.
(From Husen et al. (2012).)

The largest such postulated earthquake in Europe is the 1951 M 5.5 event that occurred in the previously aseismic Caviaga Gasfield, Po Valley, Italy (Caloi et al., 1956). There, large-scale extraction of methane at pressures > 10 MPa had been underway. The earthquake cannot be well studied because limited instrumentation was in place at the time. Simple analysis of paper recordings suggested that the largest, M_L 5.5 event, nucleated at ~5 km depth and had a thrust mechanism.

The case of Caviaga is the only M ≥ 5 gas-extraction-induced earthquake reported for Europe. Several other European gas-extraction projects are associated with M ≥ 4 seismicity. The Lacq Gasfield, France, has generated earthquakes up to M_L 4.2 and > 2000 were located there from 1974 to 1997 (Bardainne et al., 2008).

Production at Lacq started in 1957 with extraction of gas from a depth of 3.2–5 km, beneath a 600-m-deep oilfield. The reservoir occupies a 20-km-long fractured anticline in Mesozoic limestones sealed by Cretaceous marl. Reservoir pressure decreased from 66 MPa to 2.3 MPa 1957–2008 and the surface subsided ~6 cm.

The first earthquake noticed, the 1969 M 3–4 event, occurred after the gas pressure had declined to 36 MPa. This, and the subsequent seismicity, are unlikely to have been natural because of their location in the gas field and because Lacq is 30 km north of the nearest seismically active structure, the Pyrenean Frontal Thrust. About 70% of the earthquakes located above the gas reservoir, many on faults optimally-oriented with respect to the stress perturbation caused by gas removal. Poorly oriented faults tended to be aseismic. There is poor correlation between the surface subsidence and the seismicity. Seismicity migrated from the center to the periphery of the reservoir (Fig. 29). Comparison of the distribution of hypocenters with deformation models favored the model of Odonne et al. (1999) rather than that of Segall (1989) (Fig. 30).

In The Netherlands, ~300 gas fields are produced. Of these, just a few percent are seismically active but globally this is a high rate of reported seismogenesis. The induction mechanism is thought to be differential compaction (Gee et al., 2016).

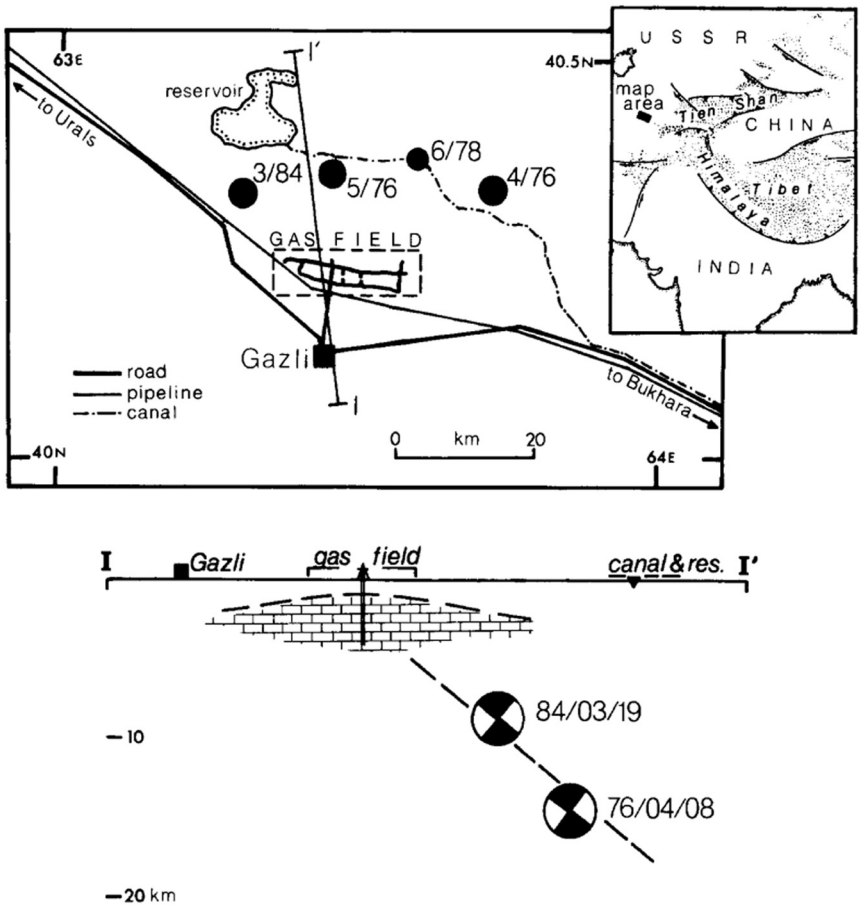


Fig. 28. Top: Map of the Gazli, Uzbekistan, area showing epicenters of the three M ~7 earthquakes in 1976 and 1984, and the M 5.7 earthquake in 1978. Bottom: Cross-section with hypocenters projected at their distance from the town of Gazli, with focal mechanisms of the M_S 7.0 events of 8 April 1976 and 19 March 1984. The fault plane (dashed line) is deduced from geodetic data. (From Simpson and Leith (1985).)

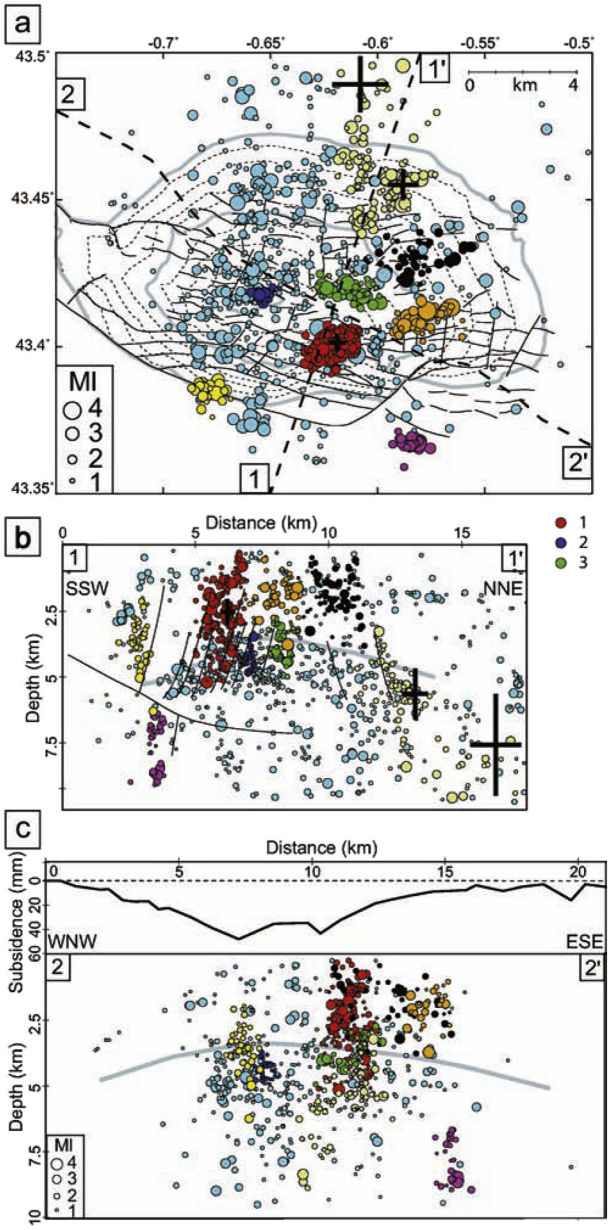


Fig. 29. Seismicity in the Lacq Gasfield, France. (a) Map view and location of cross-sections. Inset shows location in the region. (b) SSW-NNE cross-section and (c) WNW-ESE cross section. Colors: different earthquake clusters; dashed and solid gray lines: isobaths of the gas field; black lines: faults; crosses: location uncertainties for three swarms. (From Bardainne et al. (2008).)

One of the largest earthquakes attributed to induction in The Netherlands is the 2012 Groningen M_L 3.6 event. In addition to this a further 8 events with M > 3.0 have occurred in that field (Fig. 31). Seismicity was first recorded in December 1991 when the reservoir reached ~28% depletion, some 28 years after the start of gas extraction in 1962 (Fig. 32).

The Netherlands has a low rate of historic seismicity compared with neighboring countries where much higher rates are associated with the Upper Rhine Graben (Figs. 33 and 34) (van Eck et al., 2006). Currently, the majority of earthquakes in the northern Netherlands is associated with gas extraction. Several hundred have been recorded in the Groningen Field. This reservoir, the largest natural gas field in Europe and the tenth-largest in the world, originally contained ~3×10^9 m^3 of gas in a porous sandstone formation up to 300 m thick and 45 × 25 km in area. Both the seismic rate and the magnitudes of the largest

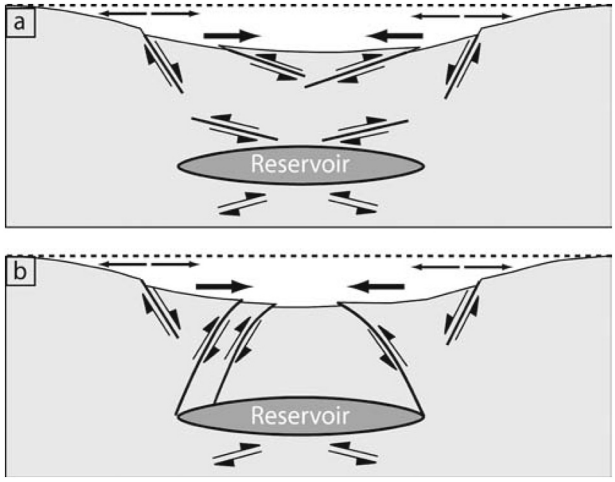


Fig. 30. Deformation models of (a) Segall (1989), and (b) Odonne et al. (1999) for a depleting subsurface reservoir. Both models predict extensional deformation on the flanks and compressional deformation centrally in the field. (From Bardainne et al. (2008).)

earthquakes have increased with time (Fig. 32). An apparent increase in the slope of the Gutenberg-Richter distribution (the "*b*-value") with time is consistent, however, with a progressive reduction in the proportion of large to small earthquakes (van Eck et al., 2006; Van Wees et al., 2014). Reservoir compaction is greatest in two northwesterly trending zones of the reservoir and the earthquakes correlate with the southernmost of these (Fig. 35).

A renowned case in the USA is the Fashing Gasfield, Texas (Fig. 36) (Pennington et al., 1986). Production there started in 1958 from 3.2 km depth. By 1983 the pressure had decreased by ~7 MPa and a M 3.4 earthquake occurred (Fig. 37). The depleting reservoir was replenished by reinjecting produced water. In 1992 a M 4.3 earthquake occurred and in 2011 a M_W 4.8 event. This case is usually considered jointly with the nearby Imogene Oilfield (Section 3.3.2).

3.3.2. Oil

In many oilfields multiple processes are underway simultaneously including oil and gas extraction, waste-water disposal, water injection to aid oil recovery and hydrofracturing or thermal fracturing. It may thus be difficult to attribute unambiguously any seismicity to oil extraction alone (Section 1.7). Nevertheless, we have identified eight cases where earthquakes have been postulated to be associated with oil extraction. These are from the USA, Iran, Russia and Norway. This is very few compared with the ~1,000,000 producing oilfields worldwide (Section 3.3).

One of the earliest reports of earthquakes accompanying oil production is from Goose Creek, Texas, where small earthquakes occurred in the 1920s (Fig. 38). Following the extraction of several million barrels of oil an area ~10 km^2 in size subsided by up to 1 m over an ~8-year period (Nicholson and Wesson, 1992; Pratt and Johnson, 1926). Goose Creek is a coastal region and a substantial area sank below sea level requiring industrial infrastructure to be adapted to the flooded conditions.

The largest earthquake attributed to oil extraction in *HiQuake* is the M_W 6.2 1983 Coalinga, California, event. This event, along with the 1985 M_W 6.1 Kettleman North Dome earthquake and the 1987 M_L 5.9 Montebello Fields (Whittier Narrows) earthquake, both in California, were attributed to the removal of oil from fields in uplifting anticlines (McGarr, 1991). The Coalinga and Whittier Narrows events were widely felt and caused multiple deaths and injuries (Fig. 39).

All three events nucleated at ~10 km depth. McGarr (1991) suggested that net extraction of oil and water reduced the average density of the upper crust, and that the seismic deformation approximately

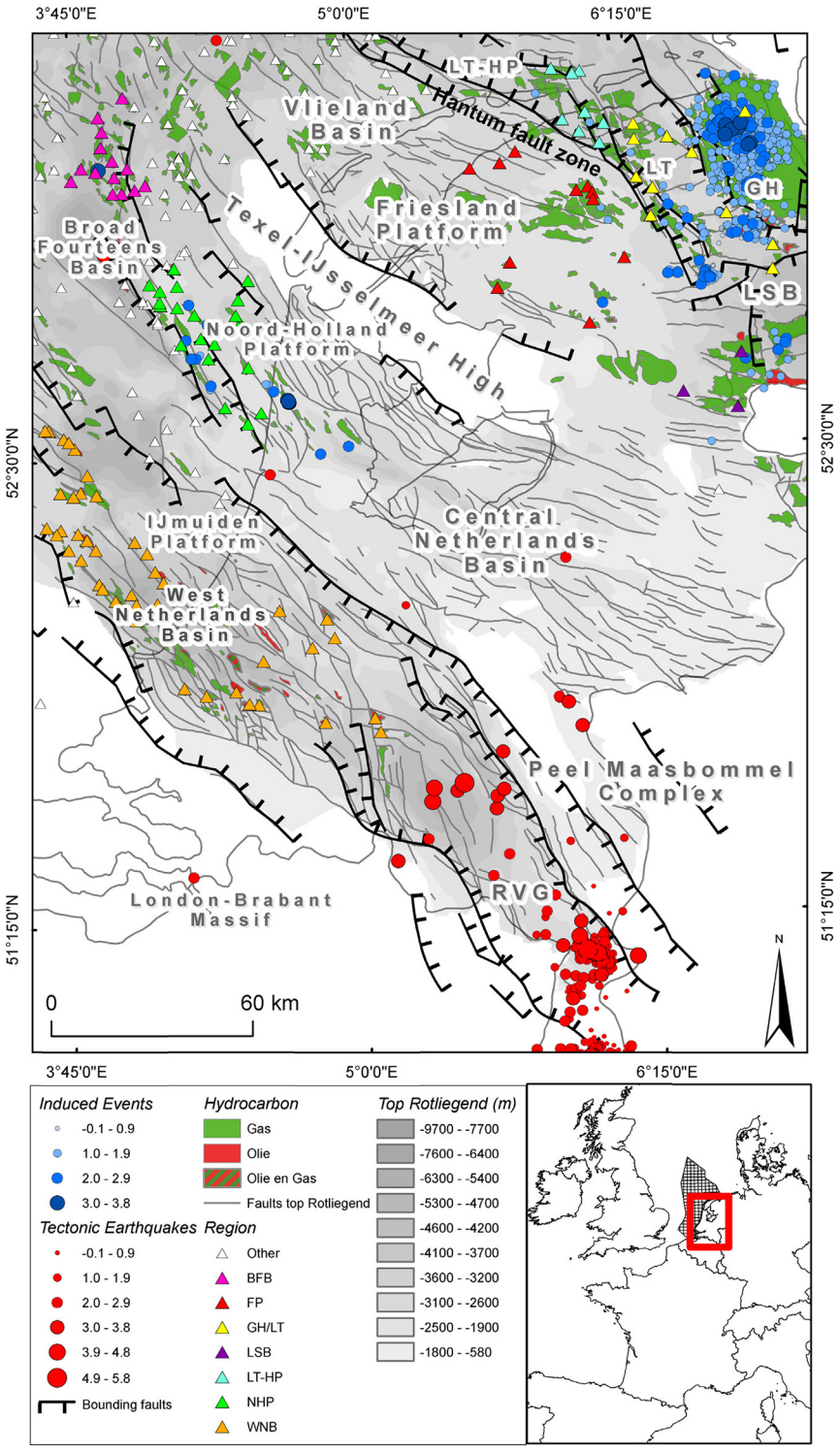


Fig. 31. Tectonic map, seismicity, and hydrocarbon reservoirs in the Netherlands. Regional location of the main map is shown in the lower right panel. Red circles: natural seismicity; blue circles: induced seismicity; green: gas reservoirs; red: oil reservoirs; solid lines: major fault zones; triangles: where leak-off tests have been performed. BFB = Broad Fourteen Basin, FP = Friesland Platform, GH/LT = Groningen High/Lauwerszee Trough, LSB = Lower Saxony Basin, LT-HP = Lauwerszee trough-Hantum Platform, NHP = Noord Holland Platform, WNB = West Netherlands Basin, RVG = Roer Valley Graben, PB = Peelrand Block, EL = Ems Low. (From Van Wees et al. (2014).)

restored isostatic equilibrium (Fig. 40). This was challenged by Segall (1989) who concluded that depletion of the reservoir would have only loaded the nucleation region by ~0.01–0.03 MPa. Nicholson and Wesson (1992) suggested that the earthquake might have occurred in response to larger stresses imposed by fluids migrating into the mid-to-lower crust. They suggested changes in pressure resulting from withdrawal of oil induced fluid migration and brought the fault closer to failure. The Coalinga earthquake has also been attributed to extraction of groundwater for irrigation from the nearby San Joaquin valley (Section 3.1) (Amos et al., 2014). The Coalinga earthquake contributed to stress released six years later in the 1989 M_W 6.9 Loma Prieta earthquake. This event ruptured a section of the San Andreas fault system 96 km south of San Francisco causing 63 deaths, 3757 injuries and $5.6–6 billion of damage (Reasenberg and Simpson, 1992). The 1933 M_L 6.3 Long Beach, California, earthquake which killed > 100 people and did $40 million of damage may have resulted from oil production in the nearby Wilmington and Huntington Beach Oilfields (Section 4.1.3) (Nicholson and Wesson, 1992).

There is little dispute that earthquakes were induced primarily by oil extraction from the Imogene Oilfield, Texas (Pennington et al.,

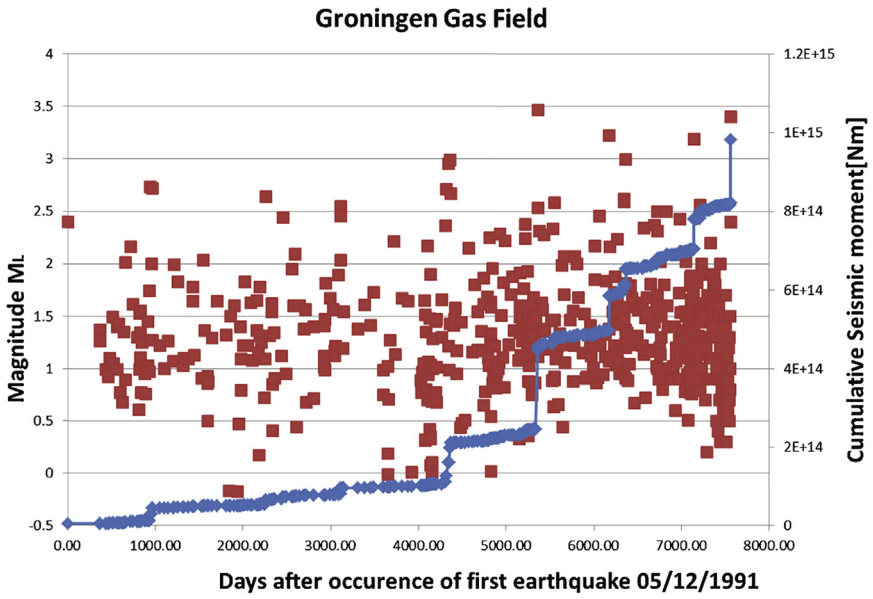


Fig. 32. Magnitude of induced events in the Groningen Gasfield, Netherlands, 5 December 1991–16 August 2012, and cumulative seismic moment in N m.
(From Van Wees et al. (2014).)

1986). This field lies ~25 km from the seismogenic Fashing Gasfield (Section 3.3.1; Fig. 36). In 1984 a M_L 3.9 earthquake occurred in the Imogene Oilfield, followed by aftershocks 2–3 km deep near the reservoir bounding fault.

The Imogene Oilfield occupies Cretaceous limestone bounded by high-angle faults that splay at shallow depth. Production began in 1944 from a 33-m-thick horizon at 2.4 km depth. By 1973 reservoir pressure had dropped from 25 MPa to ~10 MPa. It was flooded 1972–1978 with 55,000 m^3 of water via injection wells to mitigate this pressure reduction. This is, however, much less than the ~1 million m^3 of oil and gas produced, and flooding ceased several years before the 1984 earthquake. As a consequence, the seismicity has been attributed to depressurization of the field as a result of oil depletion.

The most spectacular example of subsidence and induced earthquakes associated with a producing oilfield is that of the Wilmington Field, California (Figs. 41 and 38). Oil production began in 1936 and over the following 30 years up to 9 m of subsidence and 3.6 m of horizontal contraction occurred. Strain rates were >1000 times greater than along locked sections of the San Andreas fault (Kovach, 1974; Segall, 1989).

Earthquakes began to occur above and below the reservoir when reduction in pressure reached ~10 MPa. Eight earthquakes with M_L 2.4–5.1 occurred on shallow, low-angle bedding planes. The largest, which occurred in 1949, sheared off hundreds of production wells causing >$9 million of damage. An area of ~5.7 km^2 was affected and up to 20 cm of ground deformation occurred (Nicholson and Wesson, 1992; Segall, 1989). Seven of the earthquakes occurred during the oil production period and one after significant water flooding began in 1958 to mitigate the subsidence. No further earthquakes occurred after 1961 and subsidence had been arrested by 1966. In this case seismicity may have been stopped, rather than induced, by the introduction of fluids.

Despite large quantities of oil being produced in the Middle East there are only two accounts of earthquakes postulated to have been induced by extraction there. One reports hundreds of earthquakes up to M_L 4.24 in the Uthmaniyah-Hawaiyah and Haradh divisions of the Ghawar oil/gas field, Saudi Arabia. These earthquakes occurred underneath producing horizons and are attributed to fluid extraction. Focal mechanisms suggest the active elements are crust-penetrative basement faults (Mogren and Mukhopadhyay, 2013).

The other example is from Kuwait, where 465 M 0.3–4.3 earthquakes occurred 1997–2007. A large percentage occurred in the oilfields, including the Sabiriyah, Raudhatain, Bahra, Minagish, Umm Gudair, Wafra, Abduliyah and Dharif Fields (Fig. 42). Some of this activity is likely associated with oil extraction (Al-Enezi et al., 2008). The largest proposed induced event related to Middle Eastern oilfields is the 1993 M 4.7 event in Kuwait. It may have been induced by the 1990 gushing and burning of oil wells by Iraqi armed forces leading to rapid pore pressure reduction and changes in subsurface stress (Bou-Rabee and Nur, 2002).

3.4. Geothermal production (heat/fluids)

Small, natural earthquakes are common in wet, high-temperature geothermal areas, and were known in Iceland as “hverakippur” (trans: “hot-spring bump”) before they were studied scientifically. They are likely caused by a combination of active tectonics in plate-boundary zones and volcanoes, and natural geothermal heat loss. The latter causes cooling and contraction of the geothermal heat source and stress is relieved by rock fracturing with a component of tensile failure. Both the opening and closing of voids have been identified seismically (Foulger, 1988a, 1988b; Foulger and Long, 1984; Foulger et al., 1989; Miller et al., 1998a; Miller et al., 1998b; Ross et al., 1999). Production from geothermal fields by extraction of hot fluids will enhance natural fluid- and heat-loss and may increase seismic rates.

As for hydrocarbon reservoirs, it may be difficult to attribute confidently earthquakes in exploited geothermal areas where multiple processes are underway. They may also be induced by natural recharge, either shallow, cold groundwater or deep hot water. *HiQuake* contains only six cases where earthquakes are postulated to have been induced by geothermal production. These cases are the Cerro Prieto Field, Mexico (Glowacka and Nava, 1996), the Reykjanes and Svartsengi Fields, Iceland (Keiding et al., 2010), Larderello, Italy (Batini et al., 1985), The Geysers, USA (Eberhart-Phillips and Oppenheimer, 1984) and Olkaria, Kenya (Simiyu and Keller, 2000).

The largest were strike-slip events in the Imperial Valley (1979, M_L 6.6), Victoria (~30 km southeast of the Cerro Prieto field; 1980, M 6.1), and at Cerro Prieto (1987, M 5.4) (Fig. 43). Glowacka and Nava (1996) base this proposal on qualitative correlations between increased fluid extraction and seismic moment release, with delays of ~1 year (Fig. 44).

Electrical power production at Cerro Prieto began in 1973. Steam and water at 250–350 °C is produced from 1500 to 3000 m depth. Over 1 km^3 of fluid was extracted 1973–1996. The region is part of the plate

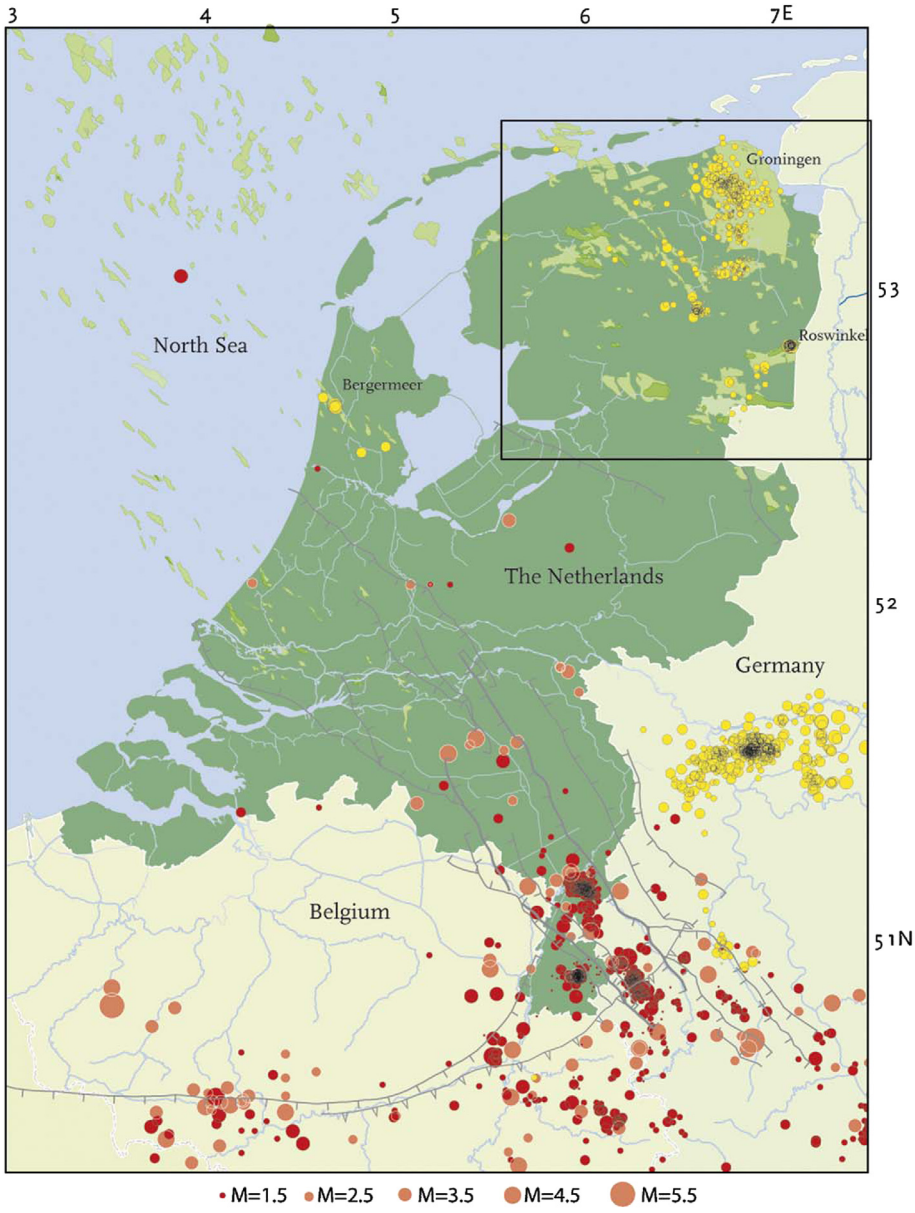


Fig. 33. Seismicity in the Netherlands and surrounding region since 1900. Red circles: natural tectonic earthquakes; yellow circles: suspected induced earthquakes (usually mining or gas exploitation); gray solid lines: mapped faults in the upper-North-Sea formation; light green: gas fields. Detail of boxed region shown in Fig. 34. (From van Eck et al. (2006).)

boundary between the Pacific and North America and tectonics are dominated by the strike-slip Imperial fault which has a history of M > 6 earthquakes. Glowacka and Nava (1996) found the numerical data insufficient to support statistically a correlation between production and large earthquakes but argue that pore pressure decreases of a few MPa in the geothermal field were sufficient to have triggered them. Majer and McEvilly (1981, 1982) suggested, on the basis of data from local, temporary seismic networks, that earlier increases in production correlated with increases in small earthquakes.

Correlation between geothermal production and earthquakes has been proposed at the Reykjanes and Svartsengi geothermal areas, Iceland (Keiding et al., 2010). In some areas, deformation associated with extension along the plate boundary and ~5 cm/a of subsidence resulting from geothermal fluid extraction were detected 1992–2009 using Interferometric Synthetic Aperture Radar (InSAR) and GPS data. Swarms of earthquakes up to M_L 4.1 occurred on the flanks of the rifts containing the geothermal areas. The events were postulated to have been induced by stress changes from geothermal fluid extraction (Fig. 45) but it is not possible to rule out a tectonic origin.

The Geysers geothermal field, California, is a vapor-dominated field that has been exploited for over 150 years, lately generating electricity. It is intensely seismically active (Fig. 46) and earthquakes occurred even before large-scale fluid injections began (Fig. 47). The pre-injection seismicity, and some current seismicity, is likely production-related (Eberhart-Phillips and Oppenheimer, 1984). It is difficult to distinguish production- from injection-related seismicity because both processes are underway simultaneously. Over the last 50 years or so, the seismic rate has, however, correlated grossly with injection (Section 4.1.5).

3.5. *Extraction from the subsurface: summary*

Mining is the commonest cause of extraction-related earthquakes and contributes 267 cases to *HiQuake*. Five cases relate to groundwater and six to geothermal resources. The largest earthquakes postulated to be induced by subsurface extraction are the M_W 7.8 Gorkha, Nepal, earthquake, the M_L 6.1 Bachatsky, Russia, earthquake, the M_S 7.3 Gazli, Uzbekistan earthquake and the M_L 6.6 Cerro Prieto, Imperial Valley, Mexico, earthquake.

In the case of groundwater-withdrawal cases, stress changes as small as 0.001 MPa have been postulated to induce events (e.g., for the 2015

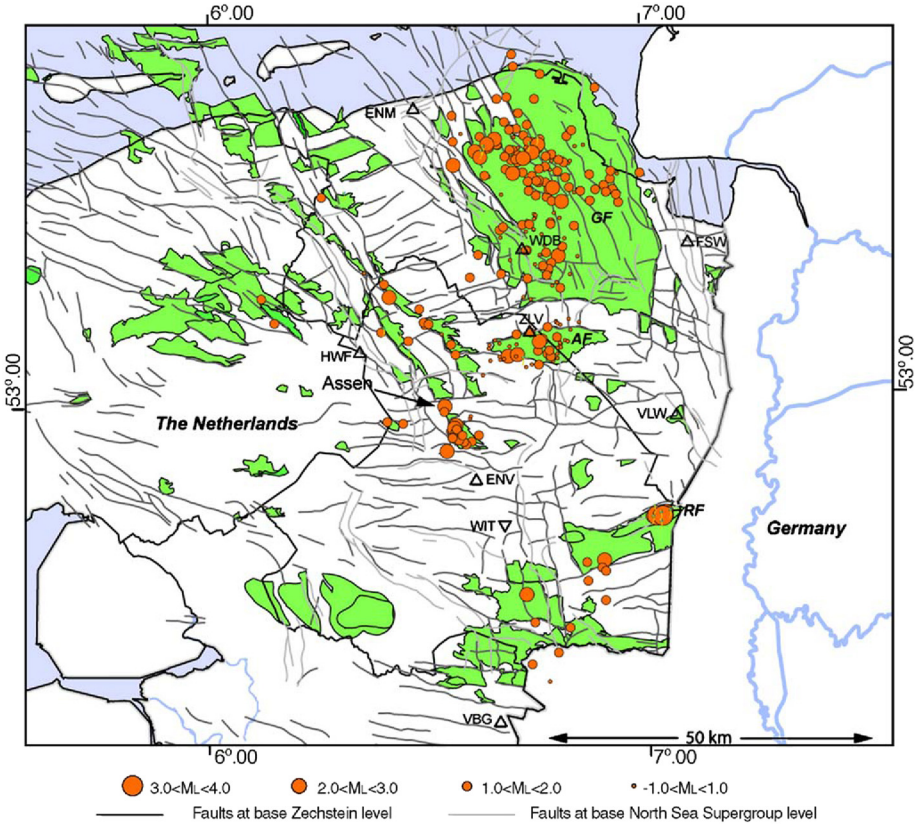


Fig. 34. Map showing produced gas fields (green), major fault structures and seismicity (orange dots) in the northeast Netherlands (boxed region of Fig. 33). RF: Roswinkel Field; GF: Groningen Field; EF: Eleveld Field; AF: Annerveen Field.
(From van Eck et al. (2006).)

M_W 7.8 Gorkha, Nepal, earthquake; Kundu et al., 2015). This is small even compared with Earth tides (Section 7.3). The ability of such small stresses to induce earthquakes is theoretically in keeping with the self-similar, critical earthquake nucleation process. However, such small effects may be comparable to many other natural and anthropogenic processes such as weather and the expansion of cities.

The sizes of postulated gas-extraction induced earthquakes are shown in Fig. 48 for the 35 cases where this parameter is reported. There is a continuous spectrum of sizes with the exception of the M_S 7.3 Gazli, Uzbekistan, event, which is 1.8 magnitude units larger than the second largest.

Although oil extraction removes large masses from the crust, few earthquakes have been attributed to this process. Possible reasons are:

- the process is only weakly seismogenic, perhaps because natural aquifer influx (peripheral or bottom water) partially replaces mass extracted;
- under-reporting; and
- ambiguity of induction process, since fluid injection often accompanies production.

4. Injection into the subsurface

The burgeoning issue of injection-related earthquakes was highlighted by Ellsworth (2013) who pointed out the recent dramatic increase in earthquake rate for M ≥ 3 events in the central and eastern USA. More than 100 such earthquakes occurred annually, on average, 2010–2012 compared with just 21 events/year on average 1967–2000. Despite incomplete reporting, *HiQuake* shows that increasing incidence of injection-related earthquakes is not confined to the USA.

Fluids are injected into the ground for diverse reasons including (Table 2):

- solution mining (Section 3.2.2);
- disposal of by-products;
- enhancing oil recovery;
- fracturing rock (i.e. the very process that causes earthquakes);
- research into the earthquake nucleation process;
- disposing of hot waste water;
- underground storage of natural gas, hydrogen and compressed air; and
- CO_2 geostorage to reduce emissions.

In addition, passive groundwater inflow may occur when reservoirs are produced, or pumping to suppress groundwater levels is terminated in abandoned mines.

HiQuake contains 180 cases where injections have been postulated to induce seismicity. Whereas in general, the removal of mass from the crust is expected to reduce the normal stress that prevents slip on faults, the introduction of fluids into faulted rock is expected to increase the pore pressure that encourages failure. Both these changes thus, capriciously, are expected to induce earthquakes. In the case of injections, in addition to the direct hazard from earthquakes, there is the added risk that if the target formation or its caprock are ruptured the injected fluid might escape. This could add to hazard, e.g., where the injectate is polluted water, natural gas or CO_2.

4.1. Liquid

4.1.1. Military waste

HiQuake contains only one case where seismicity was, to a high degree of confidence, induced by the injection of military waste. This is the legendary case of the so-called Denver earthquakes. It raised widespread awareness among seismologists and the general public that human activity can induce earthquakes.

The incident began in 1961 when the Army Corps of Engineers drilled a 3.7-km deep well into highly fractured crystalline Precambrian basement at the Rocky Mountain Arsenal, northeast of Denver,

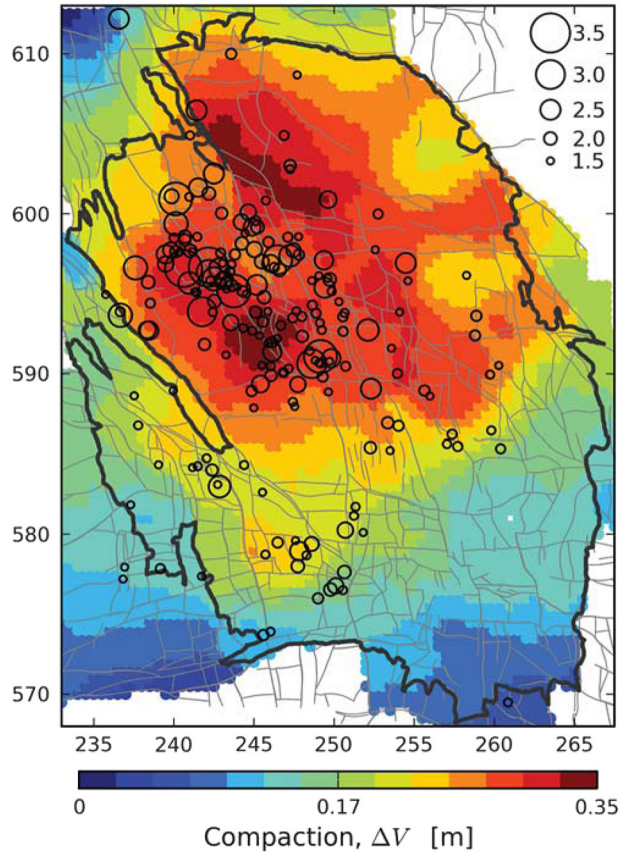


Fig. 35. The Groningen Gasfield. Earthquake epicenters for events with M ≥ 1.5 for the period 1995–2012, superimposed on a model of reservoir compaction for 1960–2012. Black line: perimeter of the Groningen Gasfield; thin gray lines: faults close to the reservoir level. Map coordinates are kilometers in the Dutch national triangulation coordinate system (Rijksdriehoek).
(From Bourne et al. (2015).)

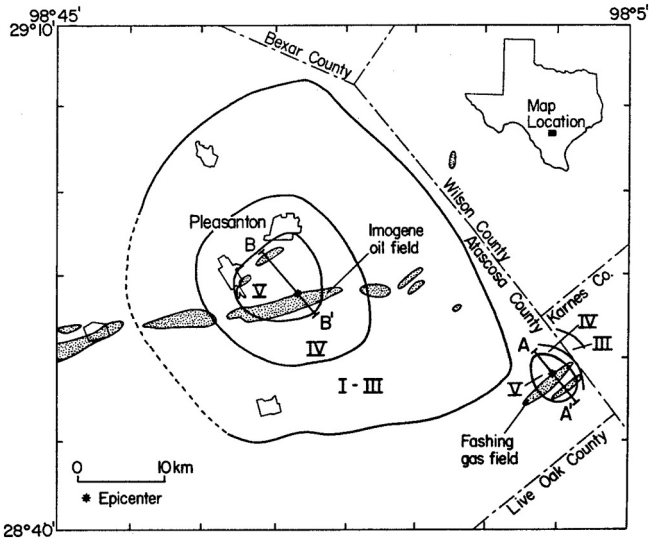


Fig. 36. Oilfields and gas fields in the Imogene/Fashing area, south Texas, where earthquakes are postulated to have been induced. Shaded regions are more prominent fields. Isoseismals for the largest events on the Modified Mercalli intensity scale are shown.
(From Pennington et al. (1986).)

Colorado (Evans, 1966; Hsieh and Bredehoeft, 1981). The purpose of the well has been reported to have been disposal of contaminated wastewater which was done by injection into the bottom, unlined,

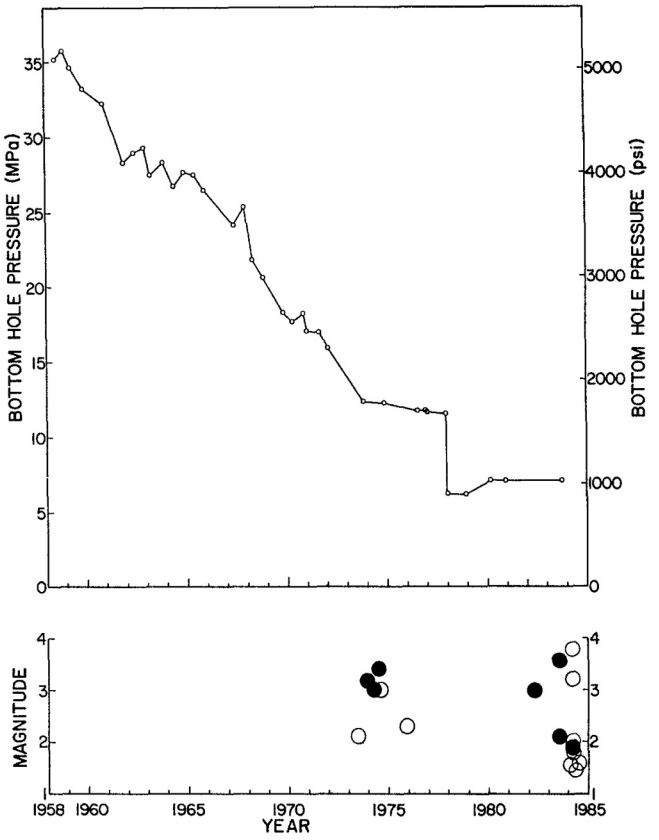


Fig. 37. Pressure history of a well near the fault in the Fashing Gasfield along with known earthquakes in the Fashing-Pleasanton area. Black dots: earthquakes from the Fashing area; open circles: earthquakes from the Pleasanton (Imogene) area.
(From Pennington et al. (1986).)

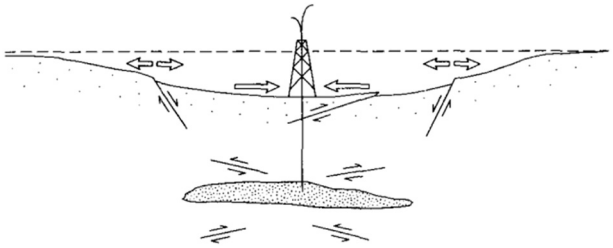


Fig. 38. Schematic cross section summarizing surface deformation and faulting associated with fluid withdrawal. Normal faults develop on the flanks of the field, as observed at the Goose Creek, Texas, Oilfield. Reverse faults develop above reservoirs as observed at Wilmington, Buena Vista Hills, the Pau Basin and beneath the Strachan Field.
(From Segall (1989).)

21 m. Disposal began in March 1962 at pressures ranging from atmospheric to ~7.2 MPa above formation pressure. In the four-year period up to 1966 625,000 m^3 of fluid were injected.

Minor earthquakes started to occur in the Denver area shortly after injection began and by 1967 over 1500 earthquakes, some of which were M 3–4, had been recorded (Fig. 49). The correlation between volume injected and frequency of earthquakes, along with epicenters located < 8 km from the well, led Evans (1966) to suggest they had been induced.

Although waste disposal ceased in 1966, earthquake activity continued and in 1967 three earthquakes with $M_L > 5$ occurred, damaging infrastructure in Denver. Seismicity then declined and by the early 1980s had essentially ceased. Ironically, the large earthquakes that occurred after the end of injection weakened the temporal correlation between earthquakes and injection and thus the case argued for

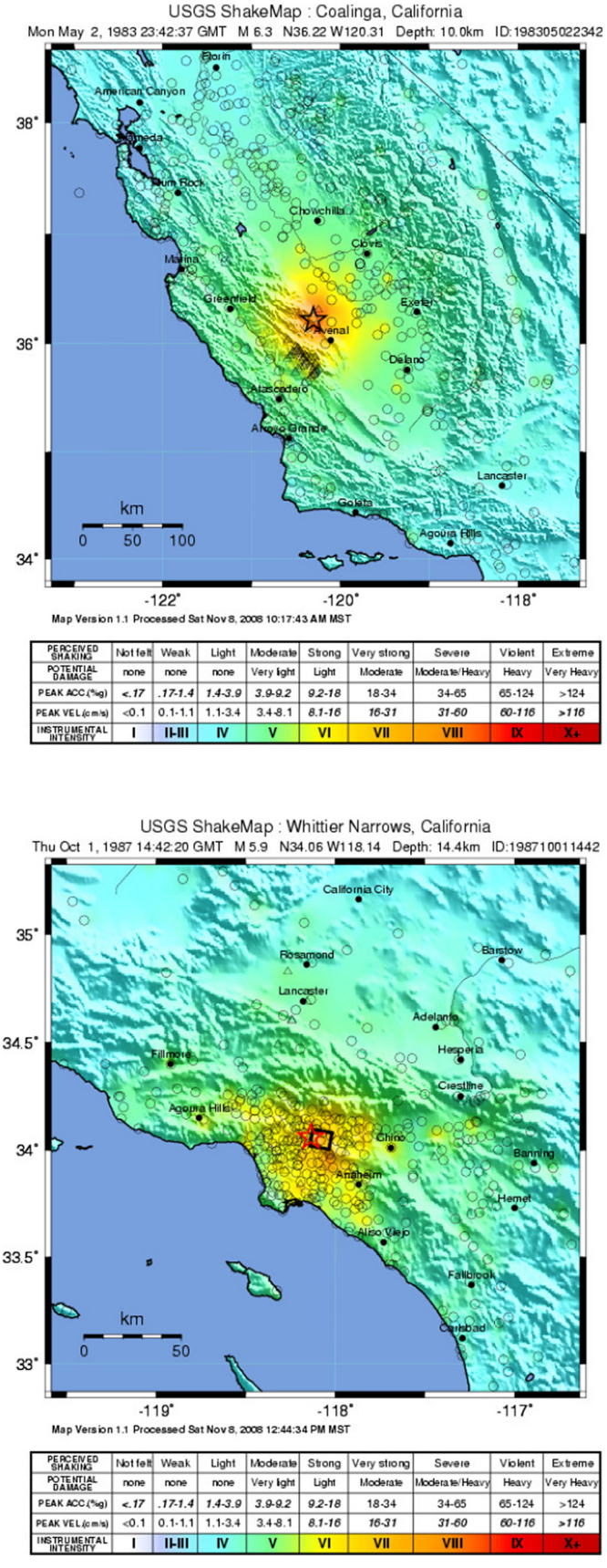


Fig. 39. U.S. Geological Survey shake maps (http://earthquake.usgs.gov/earthquakes/shakemap/). Top: 1983 M_W 6.2 Coalinga, California earthquake, which injured 94 people and was felt throughout half the state. Bottom: 1987 M_L 5.9 Whittier Narrows, California earthquake, which killed six people. Ground shaking was felt throughout the regions shown in the maps and ranged from Light (cool colours) to Severe (warm colours). See the U.S. Geological Survey webpage for more details.

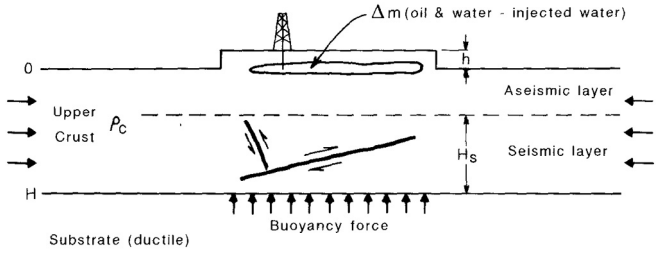


Fig. 40. Schematic cross section showing proposed crustal response mechanism to oil production. Mass removal results in a vertical force imbalance causing seismic deformation in the seismogenic layer. This deformation, together with aseismic deformation in the shallow crust, restores isostatic balance.
(From McGarr (1991).)

induction. Diffusion of the fluid would have continued after injection stopped, however, and could account for the ongoing seismicity (Healy et al., 1968).

4.1.2. Wastewater disposal

Large quantities of connate brine, sometimes mixed with water, are typically co-produced with oil, especially as fields age. Water-to-oil ratios may exceed 20 (Gluyas and Peters, 2010). It is commonly re-injected into depleted oilfields for disposal, to maintain reservoir pressure, and to promote sweep thus aiding oil recovery. Injected cold water commonly leads to thermal fracturing, especially in low-permeability reservoirs. Thermal fracturing is a desirable outcome as it facilitates lower injection pressures (and thus lower pump power requirements and costs) to be used. In California alone there are currently ~2300 wastewater injection wells.

HiQuake contains 33 cases of induced seismicity attributed to waste fluid injection. Of these, three are in Canada, two in China, one in Italy and 27 in the USA. An interesting case is that of Paradox Valley, Colorado, so-named because the Dolores River runs transversely across the valley. This case is noteworthy because of the apparently large distances from the injecting well of some of the postulated induced earthquakes (Ake et al., 2005; Block et al., 2015; King et al., 2014; Yeck et al., 2015).

At Paradox Valley, brine is injected into a sub-horizontal layer of Mississippian-age limestone at the bottom of a 4800-m-deep well. The objective is to reduce the salinity of Dolores River water and, as a consequence, the Colorado River into which it flows. Salt enters the Dolores River by inflow of groundwater ~8 times more saline than sea water. To manage this, shallow brine is extracted from the ground from nine production wells and re-injected at greater depth via a single disposal well at surface pressures up to 35 MPa (Yeck et al., 2015). Continuous injection has been underway since 1996. In the following two decades > 5700 earthquakes surmised to have been induced were located, including a M 4.3 event in 2000 (Fig. 50). Some epicenters lie > 10 km from the disposal well and a few are up to ~25 km distant.

The 1986 M_W 4.9 Painesville, Ohio, earthquake was possibly induced and occurred close to critical infrastructure (Ahmad and Smith, 1988; McGarr, 2014; Nicholson et al., 1988). This event, which was felt in 11 states and parts of Canada, occurred in Precambrian basement. It was within 17 km of the Perry Nuclear Power Plant on the edge of Lake Erie, and ground acceleration reached 0.23 g. The injection of 1.2×10^6 m^3 of liquid agricultural waste into three wells ~12 km away was implicated. These injections began in 1976. The mainshock and associated M < 2.5 aftershocks thus occurred a decade after injections began by which time pressure had increased by 11.8 MPa at the injection location.

Whether this earthquake sequence was induced is controversial. Prior to instrumentation, similar earthquakes occurred in 1906, 1928, 1943 and 1958 (i.e. about every ~20 years) in the area. The 1986 earthquakes thus may have been natural. The long delay of seismicity after the start of injection also erodes confidence that the two processes

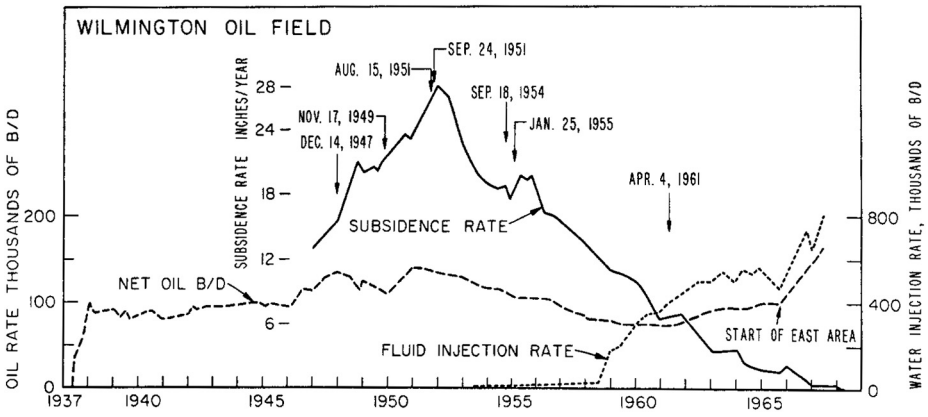


Fig. 41. For the Wilmington Oilfield, California, subsidence rate in the center of the field, oil production and water injection rates. Arrows show dates of major damaging earthquakes.
(From Kovach (1974).)

were linked (Hitzman, 2013). However, the many cases of postulated delayed earthquake induction that have occurred subsequently render it more plausible that the 1986 Painesville earthquakes were induced.

A European case is that of the 2012 M_L 5.9 Emilia-Romagna, Italy, earthquake sequence which resulted in 27 fatalities (Cartlidge, 2014). It was postulated that hydrocarbon exploitation at the Mirandola Field and geothermal exploitation at Casaglia contributed to stress changes that induced this sequence.

Because of serious impact to people and infrastructure a commission was established to investigate whether it was induced (Styles et al., 2014). The commission found statistical correlations with production parameters in the weeks before the earthquakes but concluded stress changes resulting from reservoir depletion had not contributed. It concluded that, while an anthropogenic effect could not be ruled out, it was "highly unlikely" that the sequence had been induced.

A link between injection pressure and induced earthquakes is reported for the Huangjiachang Gasfield, Sichuan Basin, China (Lei et al., 2013). Few earthquakes occurred there until injection wellhead pressure exceeded 2 MPa. After that, > 5000 M > 1.0 earthquakes occurred close to reservoir depth, the largest with M_L 4.4.

The Sichuan Basin is relatively tectonically stable with sparse historic seismicity. Gas occupies shallow, high-porosity Paleozoic and Mesozoic limestone/dolomite anticlines. Faults cross both reservoirs and basement. The Huangjiachang Gasfield is small and hosted in fractured, jointed, karstified Permian limestone at 2500 m depth. Wastewater injection began there in 2007. For the first two years, water was introduced under atmospheric pressure and seismic rates were low. In 2009 injection pressures were increased, ultimately reaching

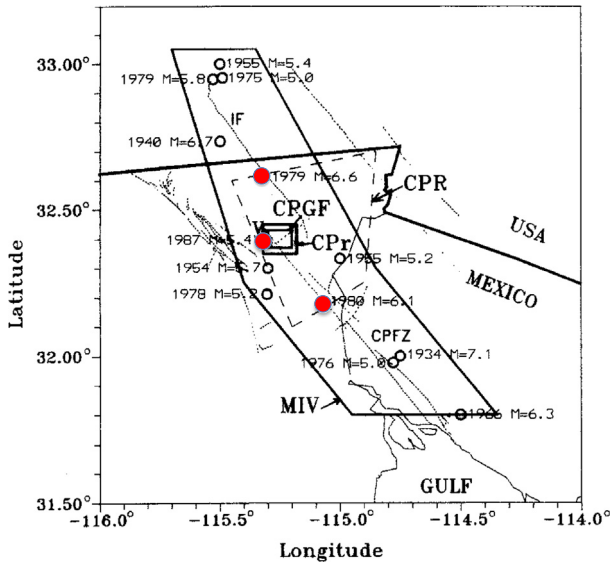


Fig. 43. The Cerro Prieto geothermal field. Circles: earthquakes with M ≥ 5; red dots: earthquakes proposed to have been induced (the 1979 M_L 6.6 Imperial Valley earthquake, the 1980 M_L 6.1 Victoria earthquake, and the 1987 M_L 5.4 Cerro Prieto earthquake); dotted lines: faults; IF: the Imperial fault; CPFZ: Cerro Prieto fault zone; V: the Cerro Prieto volcano.
(From Glowacka and Nava (1996).)

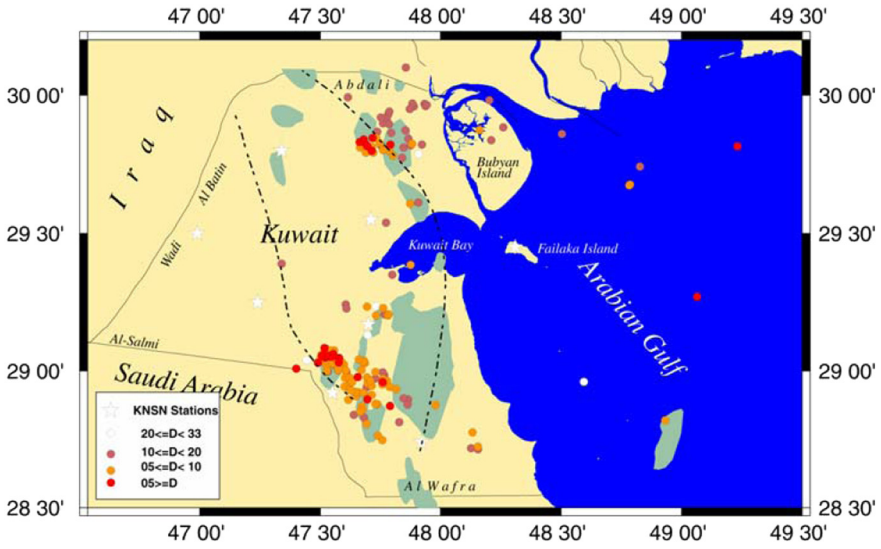


Fig. 42. Seismicity of Kuwait for the period March 1997–October 2007.
(From Al-Enezi et al. (2008).)

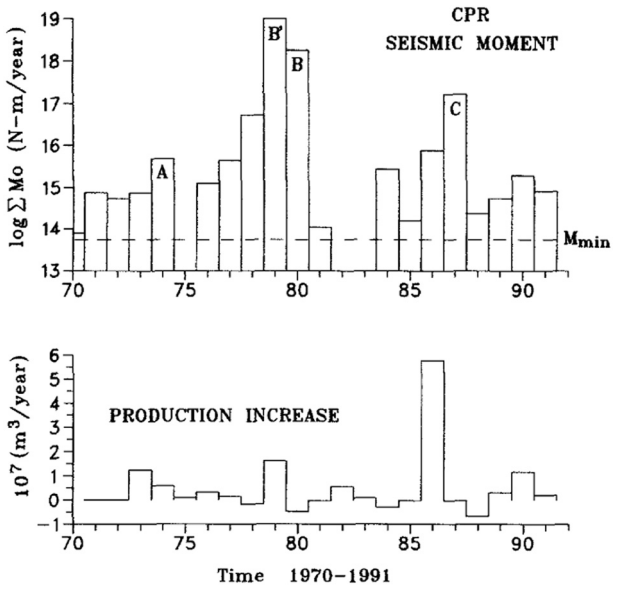


Fig. 44. For the Cerro Prieto geothermal field, Mexico, top: annual seismic moment release; bottom: production rate.
(From Glowacka and Nava (1996).)

2.1–2.9 MPa, and earthquakes began to occur.

Particularly vigorous seismicity was reportedly induced by wastewater disposal in the Rongchang Field, also in the Sichuan Basin (Lei et al., 2008). Starting in 1989, two months after water injection began > 32,000 earthquakes up to M_L 5.2 were recorded. The largest event reactivated a thrust fault in the basement and earthquake locations suggested that failure occurred in both reservoir and basement.

An unprecedented surge in seismic rate occurred in Oklahoma in 2009 (Fig. 51) (Ellsworth, 2013). During 2008–2013 Oklahoma was the most seismically active state in the USA for M > 3 earthquakes, exceeding even California, which hosts the San Andreas fault zone, and the New Madrid Seismic Zone, formerly considered to be the most hazardous intraplate seismic zone in the USA. The largest event since 1950 in the New Madrid Seismic Zone has been M 4.9. In Oklahoma the M_W 5.8 Pawnee earthquake occurred in 2016.

Faults in Oklahoma are widespread but only one is known to have been active historically. This is the Meers fault, which is thought to have generated M 6.5–7 earthquakes over the last 3500 years (McNamara et al., 2015). The injection of water for enhanced oil recovery has been practiced in Oklahoma since the 1930s and the 1952 M ~5.6 event (the El Reno earthquake) may have been related to oil and gas extraction (Nicholson and Wesson, 1992). Hough and Page (2015) investigated whether the population of Oklahoma has been sufficiently stable historically for comparable earthquake activity to have been noted. The population has been large and well-distributed since the early 20th century, suggesting that that knowledge of M ≥ 4 earthquakes is nearly complete (Fig. 52). The occurrence of industrially induced earthquakes in Oklahoma currently are essentially beyond doubt.

As elsewhere, multiple industrial processes are underway simultaneously in the hydrocarbon fields of Oklahoma so it is difficult to be certain which induced any particular earthquake. In addition to production there are ~7000 injection wells that are used for:

- disposal of produced brine (the dominant use);
- enhanced oil recovery;
- hydrofracturing to increase permeability in shale; and
- disposal of hydrofracture fluid.

Most of the fluid is injected into the Arbuckle Group, a sequence of carbonates and sandstones overlying Precambrian crystalline basement (Fig. 53).

The largest and most damaging earthquake to have occurred in Oklahoma is the 2016 M_W 5.8 Pawnee earthquake. This exceeded the well-studied 2011 M_W 5.7 Prague earthquake which is confidently associated with wastewater disposal into a depleted oilfield (e.g., Keranen et al., 2013). The Prague earthquake was felt in 17 states and in Chicago, 1000 km away. It caused considerable damage, destroying 14 houses and injuring two people. This and the Pawnee earthquake are the largest in the world associated with waste-water disposal and have led to re-assessment of the potential size of injection-induced earthquakes and the delay time following the onset of operations.

Earthquake activity in the Prague area began in February 2010 with a M_W 4.1 earthquake in the Wilzetta Oilfield. This lies within the ~200-km-long Pennsylvanian Wilzetta fault zone (Fig. 54). In 2011 the activity culminated in the Prague sequence that included three earthquakes with M_W 5.0, 5.7, and 5.0 in November, and prolific aftershocks. Hypocentral locations and focal mechanisms from 1183 aftershocks clarified the geometry of the hypocentral zone (Fig. 55) (Keranen et al., 2013). Strike-slip motion occurred on steeply dipping planes that intersect sedimentary layers and basement. The tip of the initial rupture plane lay within ~200 m of active injection wells at ~1 km depth.

In the Wilzetta zone, oil is contained in fault-bounded structural traps that are barriers to fluid migration through the porous limestone host formation. Where the Prague sequence occurred, production has been ongoing since the 1950s but has now declined. Three waste-disposal injection wells which came online in 1993 are nearby (Fig. 55). They inject water into sealed rock compartments at ~1.3–2.1 km depth.

Over the 17-year period 1993–2011 injection pressure increased from atmospheric, reaching 3.6 MPa by 2006. Seismicity may have started when the injected volume exceeded that extracted from the fault-bounded compartment. Once the compartment had been refilled ongoing injection may have reduced confining stress on the reservoir-

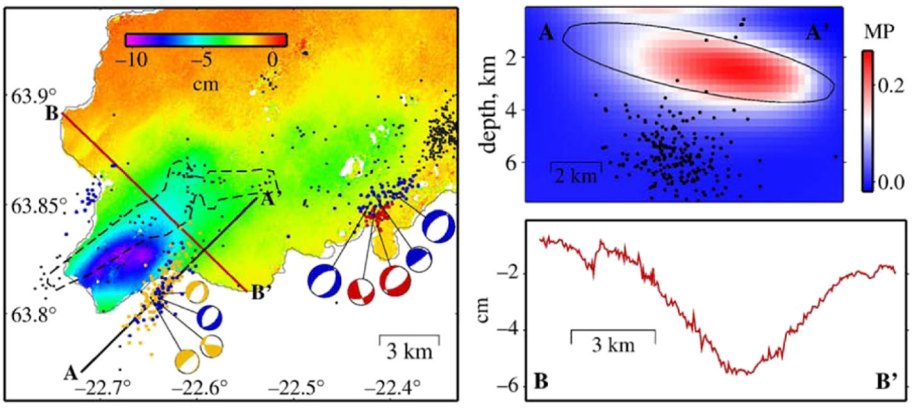


Fig. 45. For the Reykjanes and Svartsengi geothermal fields, southwest Iceland, left: the near-vertical radar displacement field June 2005–May 2008, earthquake locations and focal mechanisms. Black dots: background events. Distinct swarm events are shown for 2006 (orange), 2007 (red) and 2008 (blue). Stippled outline: location of the 1972 swarm activity from Klein et al. (1977). Top right: profile AA′ shows the predicted change in Coulomb failure stress for normal slip on NE-SW-trending fault planes, computed using an elastic half-space ellipsoidal source model for subsidence around the Reykjanes geothermal field. Bottom right: profile BB′ shows the observed near-vertical radar displacement across the Reykjanes subsidence bowl.
(From Keiding et al. (2010).)

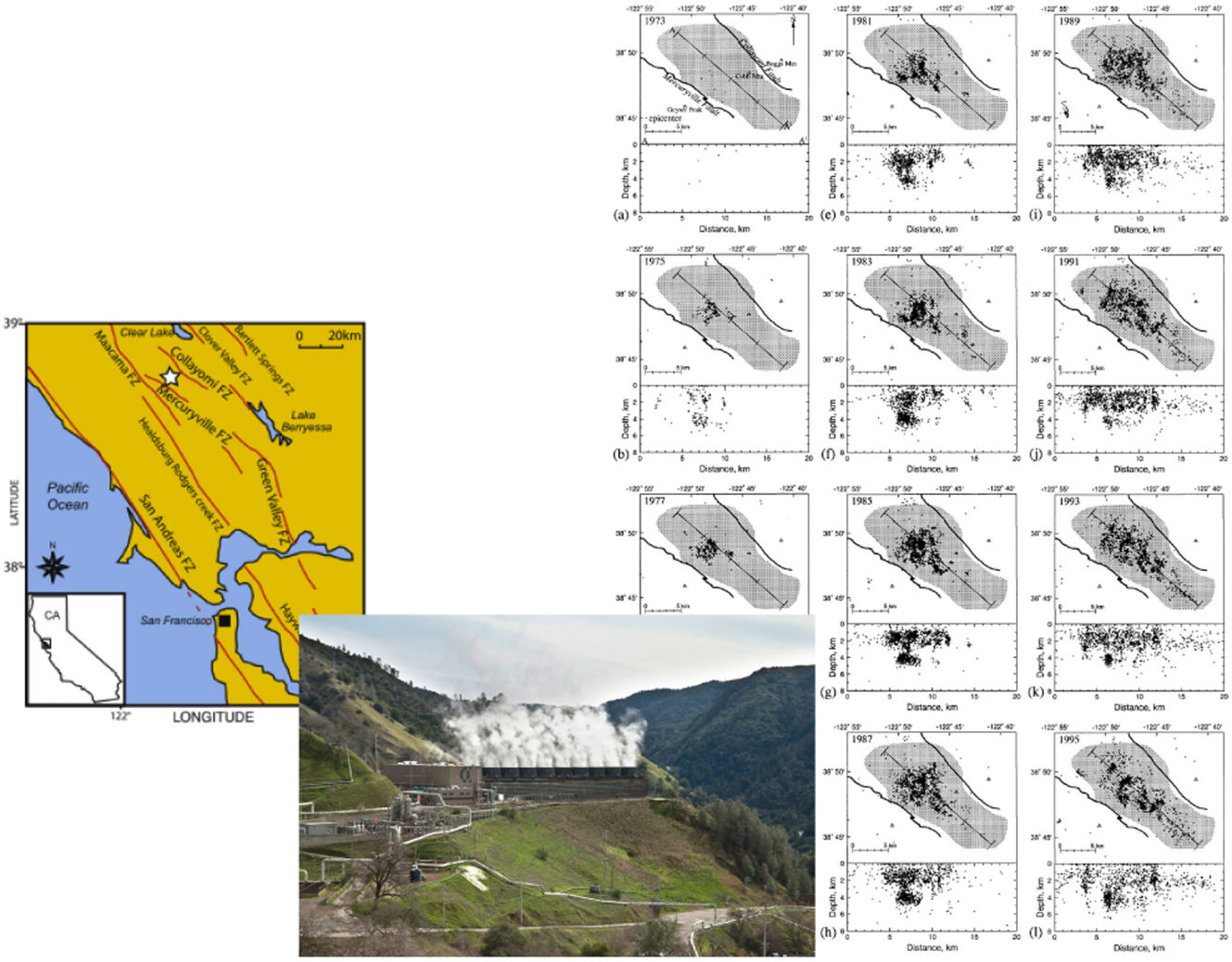


Fig. 46. The Geysers geothermal field, California. Left: regional map showing location of the field. Middle: McCabe Units 5 and 6 at The Geysers (http://www.energy.ca.gov/tour/geysers/). Right: maps of seismicity at The Geysers at biannual intervals from 1973 to 1995. Locations are from the Northern California Seismic Network catalog for earthquakes with M > 1.2. Gray area: steam field. Line shows line-of-section for depth sections below each map.
(From Ross et al. (1999).)

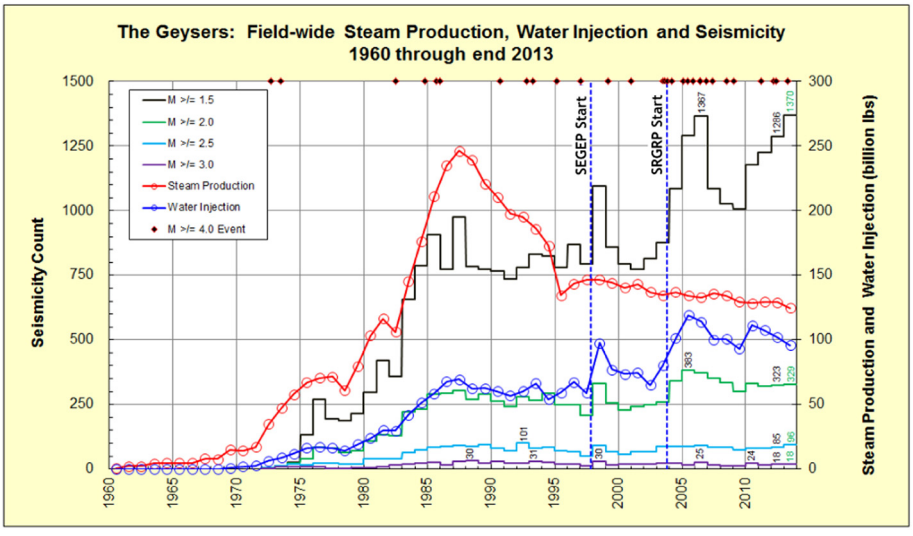


Fig. 47. Yearly field-wide steam production, water injection and seismicity 1960–2013. Earthquakes with M ≥ 4 are indicated as red diamonds along the top boundary of the graph.
(From Hartline (2014).)

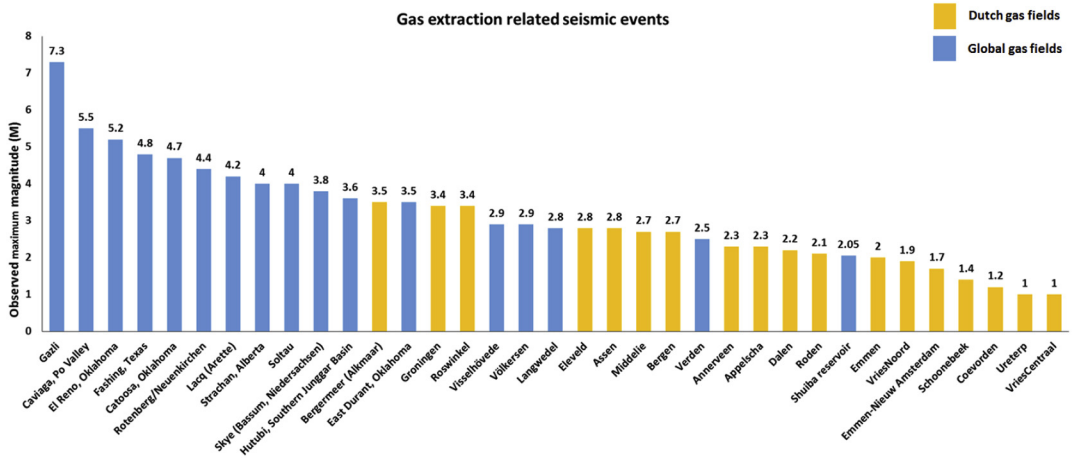


Fig. 48. M_{MAX} for seismic sequences postulated to be induced by the extraction of natural gas at the 35 fields where this parameter is reported. The Hutubi, northwest China case is associated with both extraction and storage (Tang et al., 2015).

Table 2
Classification categories of underground injection wells in The Code of Federal Regulations of the USA (40 CFR 144.6-Classification of wells).[a]

Class of well	Purpose
Class I	Industrial and municipal waste disposal wells
Class II	Oil and gas related injection wells
Class III	Injection wells for solution mining
Class IV	Shallow hazardous and radioactive injection wells
Class V	Wells for injection of non-hazardous fluids into or above underground sources of drinking water
Class VI	Wells used for geologic sequestration of CO_2

[a] https://www.epa.gov/uic/general-information-about-injection-wells#regulates.

bounding faults which failed as a consequence. More stress was released than corresponds to the total volume injected, so tectonic stress was probably also released. Both injection and M > 3 earthquakes continue in the Wilzetta Field.

Fig. 56 shows seismicity and oil production in Oklahoma over the last century. Between 2009 and 2014, 26 M ≥ 4 events occurred in the state with over 100 M ≥ 3.5 events in 2014 alone. Monthly statewide wastewater injectate volume has doubled since 1997 (Walsh and Zoback, 2015). Correlations between earthquakes and injection or production are rare, and Fig. 57 shows earthquakes and fluid injections for the entire state and for individual study areas. Earthquakes do not correlate with faults and most earthquakes occur in the least faulted part of Oklahoma.

Faults that fail in Oklahoma are probably those favorably oriented relative to the regional stress direction. Most events occur at 5–6 km depth in the basement on faults kilometers or tens of kilometers in length. Such faults can maximally sustain M 5–6 earthquakes. Some earthquakes occur on well-known faults that have larger seismic potentials. The length of segments activated can be determined from aftershock distributions.

Oklahoma earthquake activity exhibits both similarities and differences to other induced seismicity. No short-term monthly correlation with injection is apparent and seismicity surged long after the start of injections, 17 years in the case of the Prague sequence. In this it resembles the Wilmington Oilfield, California, where induced seismicity began years after water injection started for enhanced oil recovery (Section 4.1.3). However, it is unlike the "Denver earthquakes" sequence (Section 4.1.1) where seismicity began almost immediately after injections. Induced earthquake sequences do not necessarily start with the largest event, and stress from earlier events may trigger larger ones.

In addition to induction by hydrocarbon-related operations, earthquakes in Oklahoma are also triggered by distant large earthquakes ("remote triggering"). Van der Elst et al. (2013) noted that a M_W 4.1 event near Prague occurred following the 27 February 2010 M_W 8.8 Maule, Chile, earthquake (Fig. 58). Stress changes resulting from distant earthquakes can be calculated and can reveal the failure susceptibilities of faults.

4.1.3. Water injected for enhanced oil recovery

Oil recovery is enhanced by injecting low-salinity water, water-alternating-gas and water viscosifiers, and by thermal and chemical methods to modify either the viscosity of the fluids or the surface properties of the host reservoir. Distinguishing earthquakes induced by these processes from events induced by oil extraction is not straightforward if both are underway simultaneously. Temporal associations are persuasive, e.g., if seismicity surges shortly after water injection commences in producing oilfields that were previously aseismic.

HiQuake contains 38 cases of seismicity proposed to have been induced by enhanced oil recovery. Of these, 24 are from the USA and the rest from Canada, China, Denmark, France, Kuwait, Norway, Romania, Russia and Turkmenistan.

The classic example is that of the Rangely Oilfield, Colorado, where induced earthquakes could be controlled (Section 4.1.8) (Raleigh et al., 1976). Water was injected in wells up to 2 km deep where formation pressure was ~17 MPa. The seismic rate could be increased or decreased by varying the pore pressure around 26 MPa. This case raised hopes that earthquakes might be controlled, including damaging events on the San Andreas fault system. However, it was quickly realized that the fractal nature of earthquakes is such that the stress released by a few moderate earthquakes cannot substitute for a single large earthquake. Thus, hopes that damaging earthquakes might be averted by using engineering means were not realized.

The largest earthquakes postulated to have been induced by enhanced oil recovery are the M 6.2 1983 Coalinga event, the 1985 M_W 6.1 Kettleman North Dome event, and the 1987 M_L 5.9 Montebello Fields (Whittier Narrows) event, all in California. The primary cause for these earthquakes was, however, most likely oil extraction (Section 3.3.2) (McGarr, 1991).

More clear-cut examples come from the Newport-Inglewood fault zone, Los Angeles Basin, California. Of the 3 billion barrels (~ 490,000,000 m^3) of original reserves in the giant Wilmington Oilfield, 2.7 billion (~440,000,000 m^3) have been removed. Early production may have contributed to the damaging 1933 M_L 6.3 Long Beach, California, earthquake, and the events of 1947, 1949, 1951, 1954, 1955 and 1961 (Section 3.3.2) (Kovach, 1974).

Water flooding for enhanced oil recovery and to counteract massive subsidence started in the Wilmington Oilfield in 1954. Earthquakes up

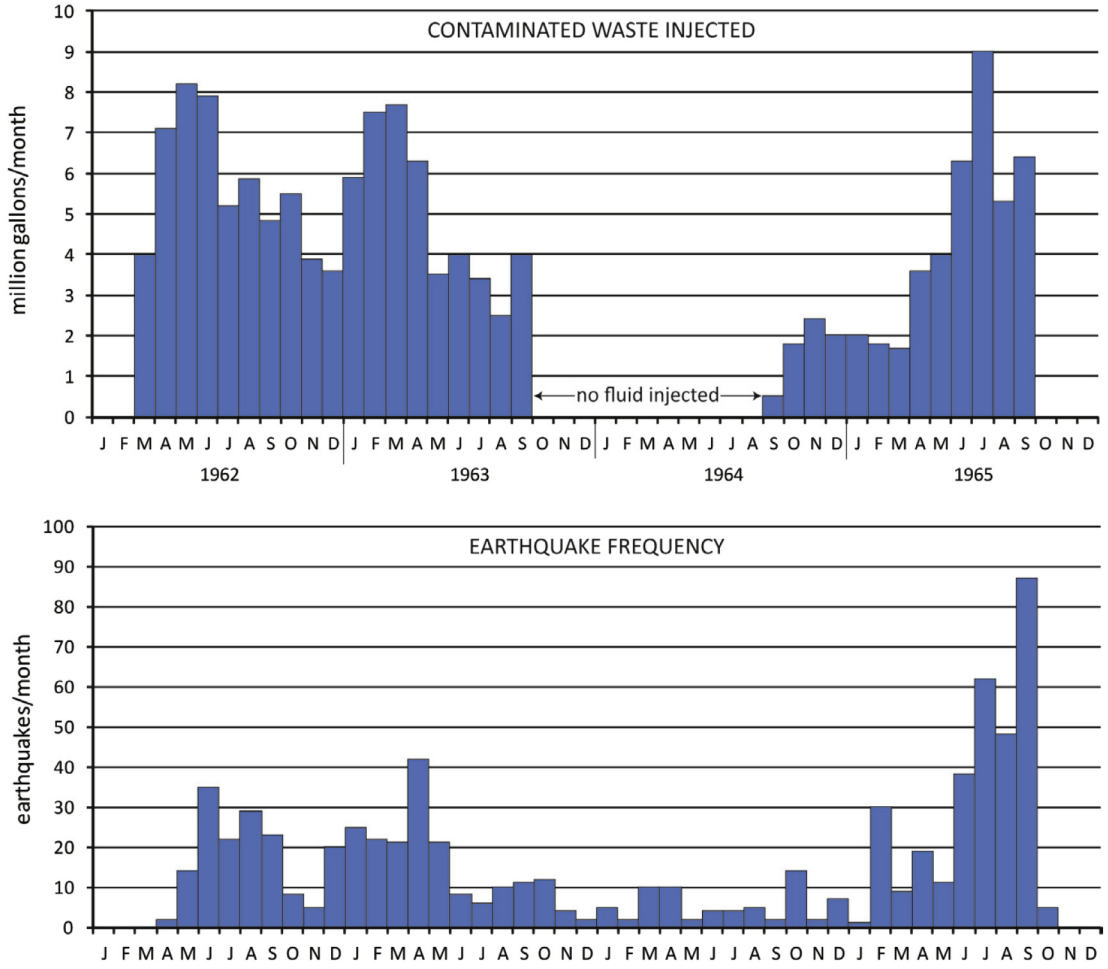


Fig. 49. Volume of waste injected into the Rocky Mountain Arsenal borehole and earthquake frequency. (Redrawn by Hitzman (2013) from Healy et al., 1968).

to M 3.0 that are thought to have correlated with injection volumes occurred in 1971. Injection was continued at approximately the same volumetric rate as production and seismicity did not continue (Nicholson and Wesson, 1992).

A more persuasive case of water-flooding-induced seismicity which caused significant damage and loss of life is that of the Inglewood Field, ~20 km further north along the Newport-Inglewood fault zone. In 1963 an earth dam containing the nearby Baldwin Hills Reservoir failed,

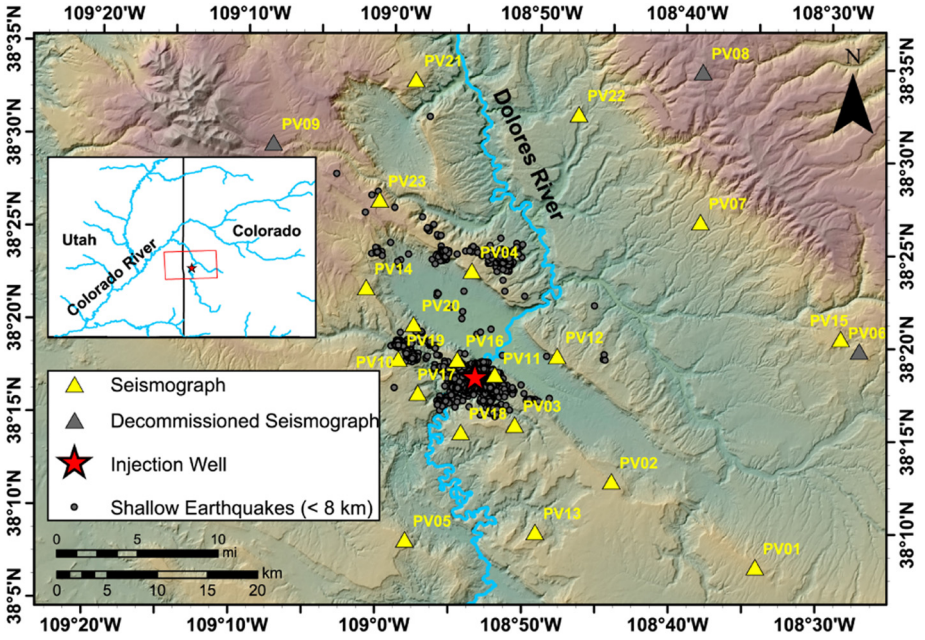


Fig. 50. The region around Paradox Valley, Colorado (the northwest-oriented depression). Yellow triangles: seismic stations; gray circles: earthquakes thought to be induced by brine injections.
(From Yeck et al. (2015).)

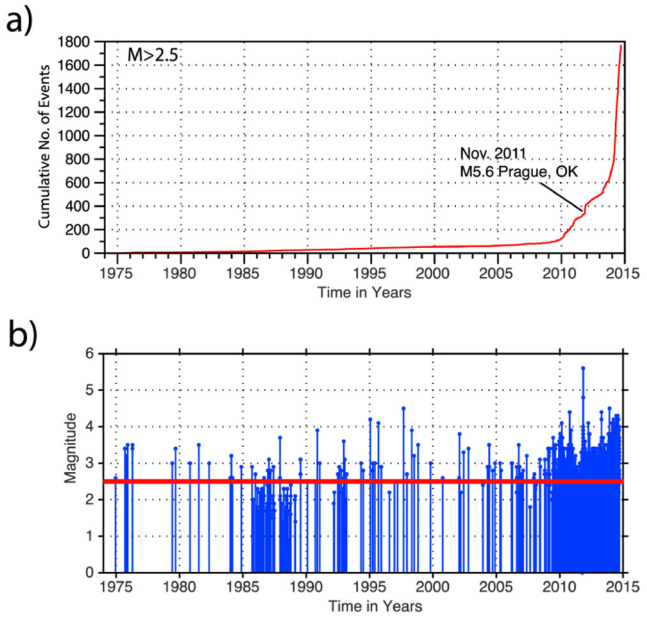


Fig. 51. Earthquakes recorded on the National Earthquake Information Center (NEIC) (http://earthquake.usgs.gov/contactus/golden/neic.php) system for the period 1975 through 2014. a) Cumulative seismicity in Oklahoma with M > 2.5. b) Earthquake magnitudes.
(From McNamara et al. (2015).)

releasing 11 × 10^6 m^3 of water into a residential area. This flood damaged over 1000 homes, killed five people and caused $12 million of damage. Failure of the dam was attributed to cumulative fault displacements that resulted from water flooding of the Inglewood Oilfield for enhanced oil recovery (Castle and Yerkes, 1976; Hamilton and Meehan, 1971).

Discovered in 1924, the Inglewood Oilfield occupies an anticline within a zone of faults and folds. Reserves were initially 430 million barrels but the field is now ~93% depleted. For the first three decades production occurred under only exsolution-gas- (pressure depletion) and peripheral-water drive. Some 83 × 10^6 m^3 of oil, water and sand were extracted. Pressures declined from 3.9 to 0.34 MPa by the 1950s. A well-defined subsidence bowl centered on the oilfield developed. Subsidence was up to 1.75 m during 1911–1963. Horizontal displacements were up to 0.68 m 1934–1961 with radially oriented extension. The Baldwin Hills reservoir lay on the edge of this subsidence bowl.

In 1954 a water-flood program for enhanced oil recovery began. Deformation accelerated immediately. A sharp reduction in subsidence occurred in the eastern part of the field. Horizontal displacements and strain were consistent with the operations and a tectonic origin for the deformation could be rejected to a high degree of certainty.

Shallow seismicity increased in 1962 and the following year the Baldwin Hills dam ruptured. It was deduced that movement on one of the faults allowed water to flow into the soil under the dam, resulting in failure. This case, and that of the Wilmington Oilfield, highlights the risk of major hydrocarbon operations near to dense populations, particularly where prior tectonic activity is known.

4.1.4. Enhanced Geothermal Systems (EGS)

Extraction of geothermal heat from rock with insufficient natural water was pioneered in the 1970s by the "hot dry rock" projects of Fenton Hill, New Mexico, and Cornwall, UK. These did not lead to economic development and were abandoned. The technology was resurrected early in the 21st century as "Enhanced Geothermal Systems" (EGS). An important milestone in this was the report "*The Future of Geothermal Energy*", prepared by the Massachusetts Institute of Technology for the U.S. Department of Energy (Tester et al., 2006).[6]

The fundamental concept of EGS is to pump high-pressure fluid into a well to hydrofracture and thermofracture hot rock, enhancing permeability and creating an underground heat exchanger. Later, cold water is pumped down an injection well, it circulates through the hot rock, and hot water and steam are extracted via production wells drilled into the fractured rock.

The objective of injection is to produce a network of fractures in the otherwise low-permeability target formation. As for shale-gas hydrofracturing, earthquakes are an inevitable consequence of a successful EGS project. Dense seismometer networks are installed prior to hydrofracturing to enable the best possible earthquake locations, magnitudes and source mechanisms. Such state-of-the-art projects are advancing basic seismology.

Notable EGS projects have been conducted at:

- Fenton Hill, New Mexico (e.g., Ferrazzini et al., 1990);
- Cornwall, UK (e.g., Turbitt et al., 1984);
- Soultz-sous-Forêts, France (e.g., Baisch et al., 2010; Calo et al., 2014);
- Basel, Switzerland (e.g., Zang et al., 2014a);
- Newberry volcano, Oregon (Cladouhos et al., 2013);
- the Coso geothermal area, California (Section 4.1.5) (Julian et al., 2010);
- Desert Peak, Nevada (Chabora et al., 2012); and
- Cooper Basin, Australia (e.g., Asanuma et al., 2005).

The Fenton Hill, New Mexico, hot dry rock project was the first of its kind. It was completed in 1977 in rock at ~2.6 km depth 185 °C. Work continued into the 1990s, achieving production of ~10 MW thermal, but was terminated because of lack of funding.

An early modern EGS project commenced at Soultz-sous-Forêts, in the central Upper Rhine Graben, France in 1987 (Fig. 59) (Baisch et al., 2010; Calo et al., 2014). The site lies in highly fractured granite overlain by ~1400 m of sediments. It contains three ~5000 m deep injection wells and several shallower wells. Massive hydraulic stimulations were performed at depths > 4000 m. In 2000, well GPK2 was stimulated with ~23,000 m^3 of water at flow rates of 30–50 l/s and overpressures of up to 13 MPa. Well GPK3 was stimulated in 2003 with ~37,000 m^3 of water at similar flow rates and overpressures. Well GPK4 was stimulated twice with a total of ~22,000 m^3 of fluid. In 2010 the project began to deliver 1.5 MW to the grid.

The injections were monitored using a sparse seismic network of multi-component, down-hole sensors at 1500–3500 m depths. More than 114,000 earthquakes were detected at rates of up to 8000 events/day (Fig. 60). Activity migrated away from the injection wells with time and the largest events occurred after injection stopped. Such behavior causes problems for "traffic light" systems for adjusting injection strategies to avoid large earthquakes on the basis of ongoing seismicity. Earthquake magnitudes eventually reached M_L 2.9 and caused public concern. After the largest event in 2003 the flow rates and injected volumes were reduced. The project demonstrated that better understanding of induced seismicity is needed if it is not to jeopardize commercial implementation of EGS technology.

The most infamous example of nuisance seismicity induced by EGS operations is from Basel, Switzerland. The city of Basel lies where the Upper Rhine Graben intersects the Jura Mountains fold/thrust belt (Fig. 1). Basel has a history of large earthquakes, including the largest historical event in NW Europe, the M ~6.5 earthquake of 1356 which destroyed the city. There may have been additional M ~7 events post-Pleistocene.

A summary of this project is provided by Häring et al. (2008) and a 2014 Special Issue of Geothermics (Zang et al., 2014a). The project was

[6] http://geothermal.inel.gov and http://www1.eere.energy.gov/geothermal/egs_technology.html.

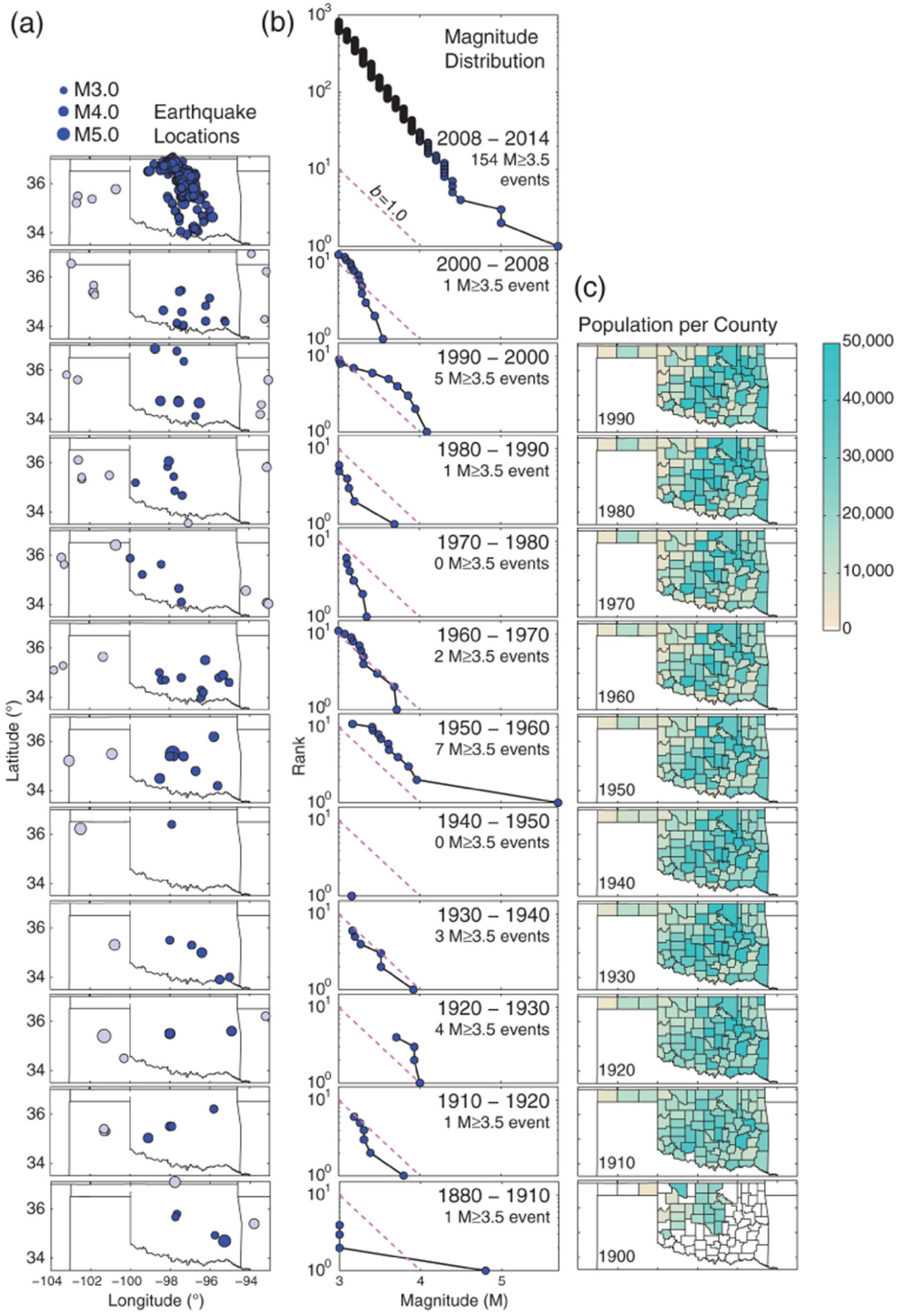


Fig. 52. Oklahoma seismicity. Left panels: Earthquake locations: blue–Oklahoma, gray–neighboring states. Center panels: magnitudes plotted cumulatively 1880–2014. Right panels: human population by county.
(From Hough and Page (2015).)

designed to provide power to Basel. A seismic network was installed in 2006 and the Basel-1 well drilled to 5 km depth. The wellbore intersects 2.4 km of sedimentary rocks and 2.6 km of granitic basement.

The granite in the open hole below 4629 m was hydraulically stimulated by injecting 11,570 m^3 of fluid. It was planned to inject for 21 days. However, seismicity became intense during the first 6 days, with events up to M_L 2.6 occurring at ~4.6–5.0 km depth. These events precipitated cessation of injection in response to a pre-approved procedure. Five hours later an earthquake with M_L 3.4 occurred and a further three M > 3 events followed over the next 56 days (Fig. 61).

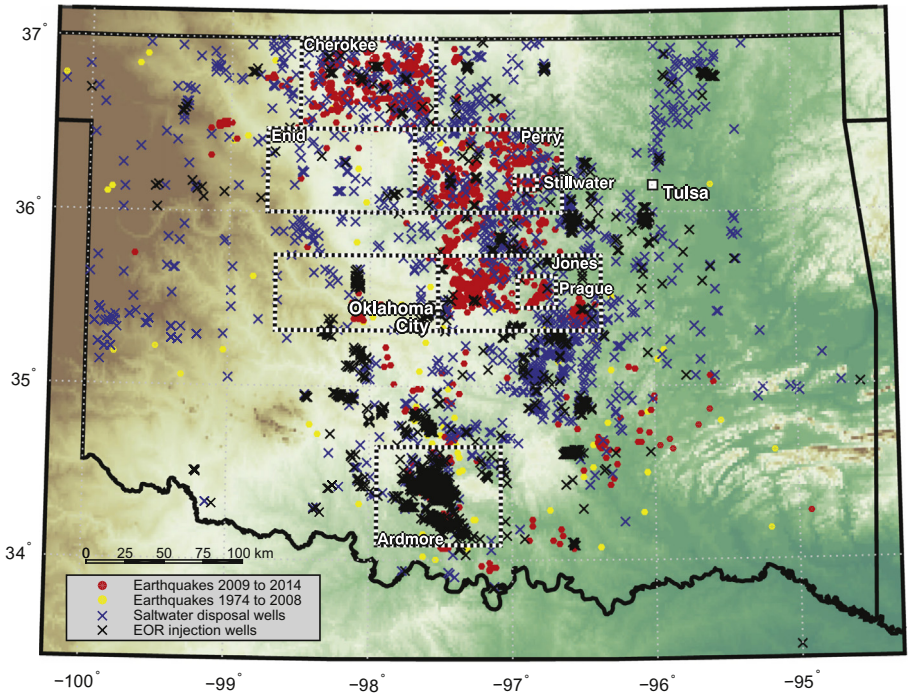


Fig. 53. Earthquakes and injection wells in Oklahoma. Red dots: locations of earthquakes 2009–2014; yellow dots: historical earthquakes 1974–2008; black crosses: enhanced oil recovery wells; blue crosses: salt water disposal wells that injected > 30,000 barrels (~4800 m^3) in any month in the most recent three years of data; boxes: areas of detailed study.
(From Walsh and Zoback (2015).)

There was considerable citizen anxiety and the project is now abandoned.

EGS has been extensively conducted in Cooper Basin, Australia, where the largest earthquake induced to date was M_W 3.7. Cooper Basin is ideal for EGS. It lies in the interior of Australia, remote from population centers. Significant oil and gas resources were explored and exploited since the 1960s and industrial infrastructure was left in place that was used from 2002 when geothermal exploration started. The target heat source is granitic rocks with temperatures up to 240 °C at 3.5 km depth. These are the hottest known granitic rocks in the world at economic drilling depths that are not near active volcanoes.

Six wells were drilled into the granite to 3629–4852 m depths. Four are in the Habanero Field and the other two are 9 and 18 km away in the Jolokia and Savina Fields. EGS fluid injections were conducted 2003–2012 (e.g., Asanuma et al., 2005; Baisch et al., 2009; Baisch et al., 2006; Baisch et al., 2015; Kaieda et al., 2010). These induced up to 20,000 earthquakes well-recorded by dense, modern seismic networks.

Although all the stimulations were conducted in the same granite formation, they induced variable seismic responses (Fig. 62). These are exemplified by two carried out in 2010 and 2012 (Baisch et al., 2015). The 2010 stimulation injected fluid into the Jolokia well at > 4000 m depth. It induced only minor seismic activity, even at extremely high fluid pressures (~120 MPa), and the injection rate achieved was only ~1.0 l/s, one to two orders of magnitude less than typical. Only 73 earthquakes with M_L −1.4 to 1.0 were recorded over an eight-day stimulation period and an additional 139 over the next six months. The largest was M 1.6 which occurred 127 days after injection ceased–another case where the largest event occurred after injection finished. Hypocenters clustered around the injection well a few tens or hundreds of meters away, suggesting that they occurred on fractures poorly oriented for slip in the regional stress field.

The 2012 stimulation in well Habanero 4 injected 34,000 m^3 of water at 4100–4400 m depths with flow rates > 60 l/s, and wellhead pressures of ~50 MPa. This induced > 29,000 earthquakes with M_L

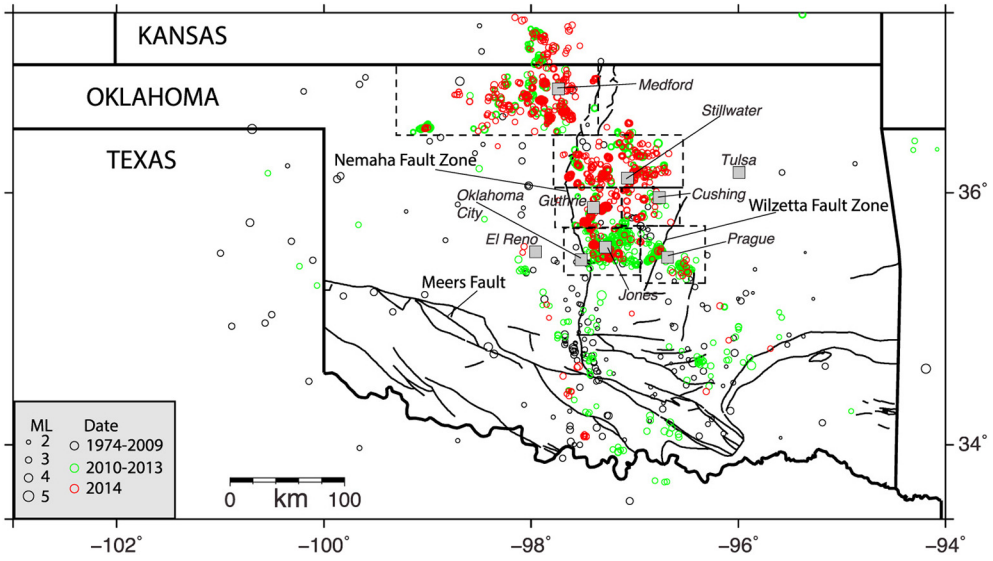


Fig. 54. For Oklahoma, U.S. Geological Survey earthquake epicenters from the National Earthquake Information Center (NEIC) database (http://earthquake.usgs.gov/contactus/golden/neic.php), 1974–2014. Black lines: subsurface and surface faults; dashed black lines: detailed study regions; Meers fault: the only known active fault in Oklahoma prior to the recent increase in seismicity.
(From McNamara et al. (2015).)

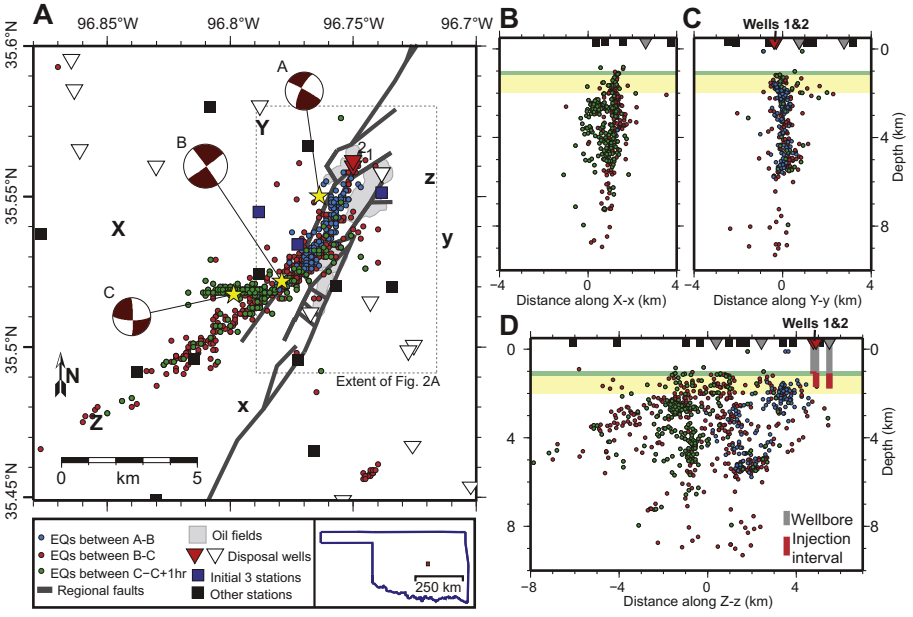


Fig. 55. Seismicity, focal mechanisms, seismic stations, active disposal wells, and oilfields in the neighborhood of the 2011 Prague, Oklahoma, seismic sequence. Stars: major earthquakes in the sequence. B–D: Cross sections showing seismicity projected from up to 4 km out of plane. Vertical lines: wellbores, red where perforated or open; green bands: the Hunton and Simpson Groups; yellow bands: Arbuckle Group which overlies basement. Inset: Oklahoma and location of map area.
(From Keranen et al. (2013).)

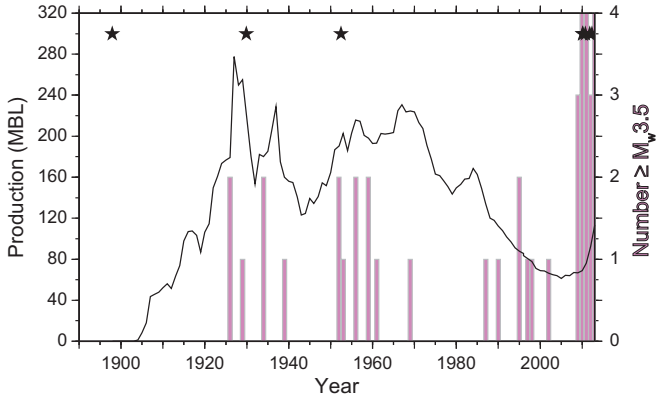


Fig. 56. Oklahoma seismicity rates compared with oil production in millions of barrels (multiply by 0.159 to convert to m^3). Bars: number of earthquakes with M ≥ 3.5 in a given year; black stars: M ≥ 4 events.
(From Hough and Page (2015).)

−1.6 to 3.0 recorded on a local 24-station network. From these data, 21,720 locations and 525 focal mechanisms were derived. This may be the most prolific EGS-induced earthquake dataset ever collected. In contrast to the well-hugging, sub-vertical fracture activated by stimulation of well Jolokia 1, the Habanero 4 stimulation activated a single, sub-horizontal fault zone only a few meters thick, extending > 1.5 km from the well. Failure was consistent with the regional stress field.

These remarkably different seismic responses characterized injections in different wells penetrating the same granite formation. This exemplifies the challenge of predicting the behavior of formations under stimulation, even when excellent geological knowledge is available. Despite the major technological advances achieved in the Cooper Basin project, due to low oil prices and changing government priorities, the project was decommissioned in 2016.

Despite the challenges that currently face development of EGS, much has been learned recently that will underpin the future of the industry. Because it is known beforehand that projects induce seismicity, exemplary seismic monitoring and public outreach practices have been developed. These include installing custom-designed networks of three-component borehole instruments well in advance of operations to obtain a pre-operational baseline for seismic activity. Data are streamed to public websites and outreach includes town-hall meetings, seismometers in public buildings in nearby communities, distributing information to the public by talks, printed materials and the internet, and involving local communities in the commercial activity.

4.1.5. Geothermal reinjection

Water is re-injected into exploited geothermal fields to maintain pressure. Although classified technically as renewable resources geothermal fields are, in reality, not so. If large quantities of hot fluid are removed at high rates for many years, exceeding natural recharge, the resource becomes depleted and progressive reduction in reservoir pressure leads to reduced production. To maintain pressure water is re-injected while avoiding cooling production wells.

The most remarkable case of seismicity attributed to geothermal reinjection is The Geysers field, California (Fig. 46). The Geysers is a rare vapor-dominated reservoir that lies in the strike-slip regime of the San Andreas fault system, California. Exploitation began in the 1860s. Steam was first used to generate electricity in 1922 when 1 kW was produced. Production peaked in 1987 at about 3.5×10^3 kg s^{-1} of steam from which 1800 MW of electricity was generated (Fig. 47).

Power production decreased thereafter because the modest amount of reinjection done could not maintain declining steam pressure. Condensate was the main re-injectate and less was available than the amount of water produced. Reservoir pressure is sub-hydrostatic and thus the water could be reintroduced at atmospheric pressure, i.e. it was poured into boreholes and drained back into the reservoir under gravity.

The US Geological Survey routinely locates > 10,000 earthquakes/year at The Geysers. The annual seismic rate is currently 200–300 M 2 earthquakes and 1–2 M 4 earthquakes. The Geysers earthquake dataset is without doubt the richest set of induced earthquake data available in the world with > 250,000 located events in the catalog of the Northern California Earthquake Data Center.[7]

For many years it was not acknowledged that the industrial activity induced the earthquakes. However, as data accumulated the link could not be denied. It was initially assumed that the earthquakes resulted from the contracting reservoir collapsing in on itself. Surface subsidence rates are up to 5 cm/year (Lofgren, 1978; Mossop and Segall, 1999; Vasco et al., 2013).

It is now clear that seismicity correlates better with reinjection than

[7] http://www.ncedc.org.

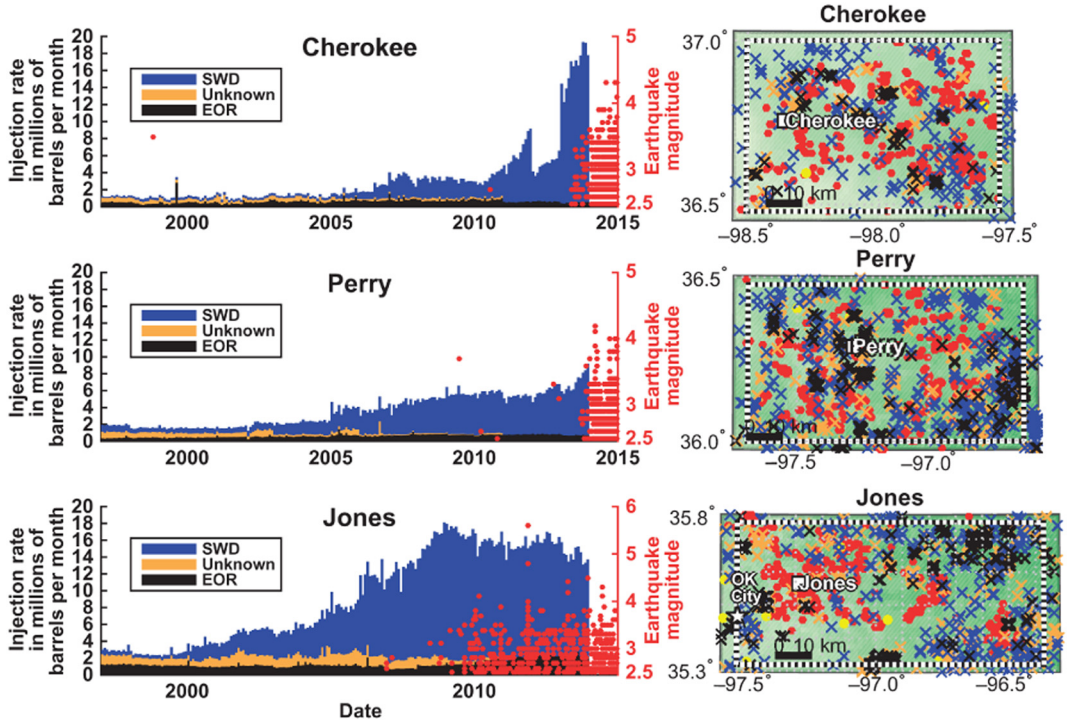


Fig. 57. Injection from enhanced oil recovery, brine disposal, and unknown wells, and earthquakes in the Cherokee, Perry, and Jones study areas (boxes in Fig. 53). Symbols are the same as in Fig. 53. Each study area is 5000 km^2 in size.
(From Walsh and Zoback (2015).)

production (e.g., Majer and Peterson, 2007; Stark, 1990). It has been possible to make this link since 1998 when the first of two major water-acquisition and reinjection projects began. The South East Geysers Effluent Project (SEGEP) began to re-inject water via a 46-km-long pipeline from Lake County that delivers up to 22 × 10^6 l/day of gray water. In 2003 the second project came online, the Santa Rosa Geysers Recharge Project (SGRP), which delivers up to 41 × 10^6 l/day via a 64-km-long pipeline from Santa Rosa (Fig. 47) (Majer and Peterson, 2007). Surges in earthquake rate correlate with the increases in water injection with those projects. Surges of earthquakes also correlate with individual

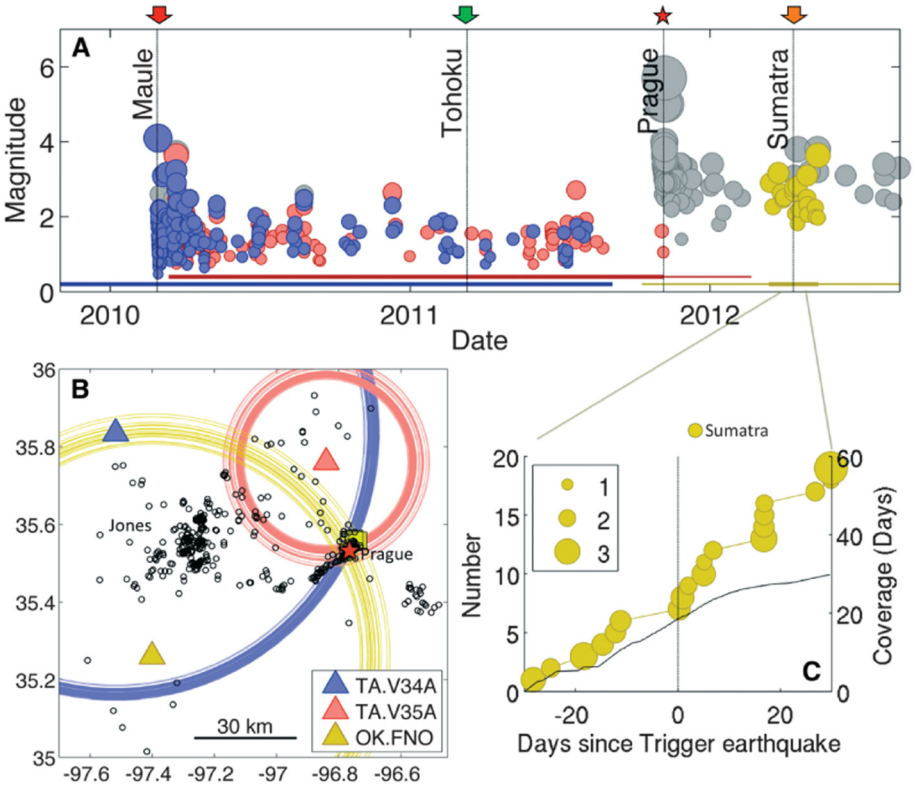


Fig. 58. Earthquakes in the Prague, Oklahoma, area. (A) Detected events, showing triggering by the 2010 Maule, Chile earthquake. Red star: the 6 November 2011 M_W 5.7 Prague earthquake. (B) Distances to detected events. (C) Cumulative number of events in the time period surrounding the 11 April 2012 M_W 8.6 and 8.2 Sumatra earthquakes.
(From van der Elst et al. (2013).)

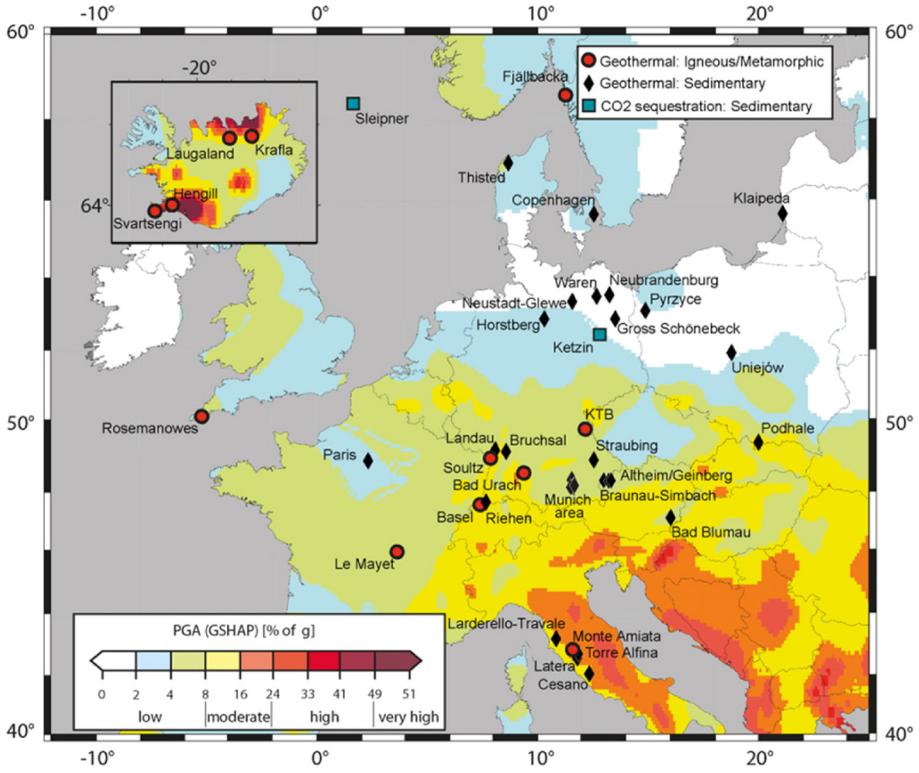


Fig. 59. Location of geothermal and CO_2 injection sites in Europe, superimposed on a seismic hazard map from the Global Seismic Hazard Assessment Program (GSHAP (http://www.seismo.ethz.ch/static/GSHAP)). Color scale denotes GSHAP index of local seismic hazard from natural earthquakes defined as peak ground acceleration in percent of the acceleration due to gravity (g) on stiff soil that has a 10% probability of being exceeded in 50 years (equivalent to a recurrence period of 475 years).
(From Evans et al. (2012).)

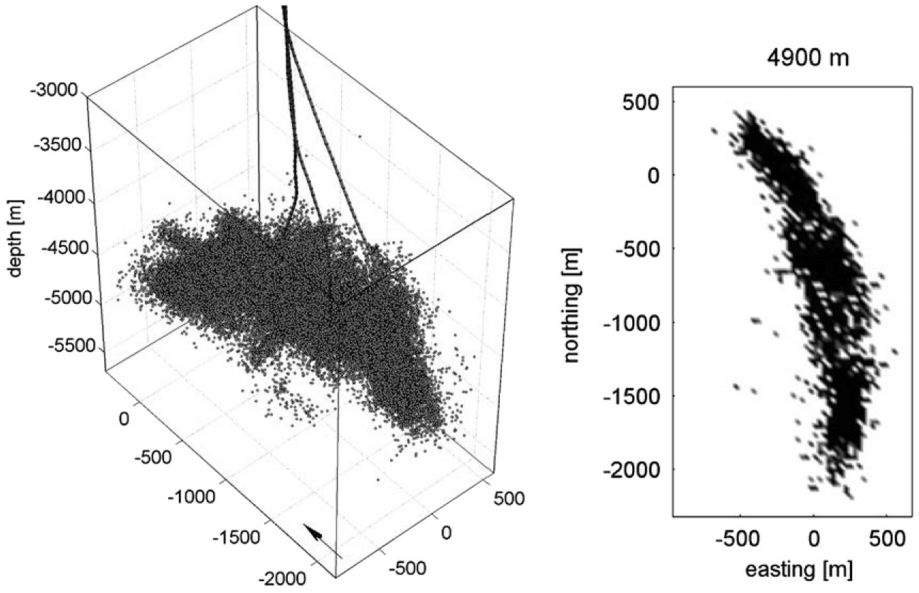


Fig. 60. Top left: Distribution of earthquake hypocenters at the Soultz-sous-Forêts EGS project in perspective view. Solid lines: wells GPK2, GPK3 and GPK4. Top right: Depth slice of the hypocenter density distribution at 4900 m depth. Dark shading: regions of high density.
(From Baisch et al. (2010).)

injections and injection wells (Majer and Peterson, 2007; Stark, 1990), e.g., in the high-temperature northwest Geysers in 2004 (Fig. 63).

Ground shaking from earthquakes with Modified Mercalli intensities of II–VI are felt daily in settlements near The Geysers. The largest earthquake that has occurred is the 2014 M_W 4.5 event. On the basis of historical seismicity, the absence of long faults in the reservoir, and the lack of epicentral alignments, Majer et al. (2007) estimated that the largest earthquake that could occur was M ~5.0. An extensive review of The Geysers seismicity is provided by Majer and Peterson (2007). They conclude that the seismicity results from a diverse set of processes that may work independently or together and either enhance or possibly reduce seismicity. To the processes listed in Section 1.3, thermal contraction from cooling the rock matrix can be added.

A second example of particularly rich geothermal-induced seismicity is from the Coso geothermal field. This field lies in the southwestern corner of the Basin and Range province in eastern California, at a right releasing step-over in the southern Owens Valley fault zone (Monastero et al., 2005). It lies on a US Navy weapons test site, and is thus uninhabited and not generally accessible to the public. Electricity has been generated since the 1980s, producing about 250 MW. Because there is a shortage of local water, only about half the volume produced is replaced by reinjection and the local water table has lowered greatly.

Tectonic seismicity is intense in the region, but even in this context the geothermal field is anomalously seismogenic. Several thousand locatable earthquakes per year occur within the ~5 × 5 km production field, the majority of which must be induced. These earthquakes have

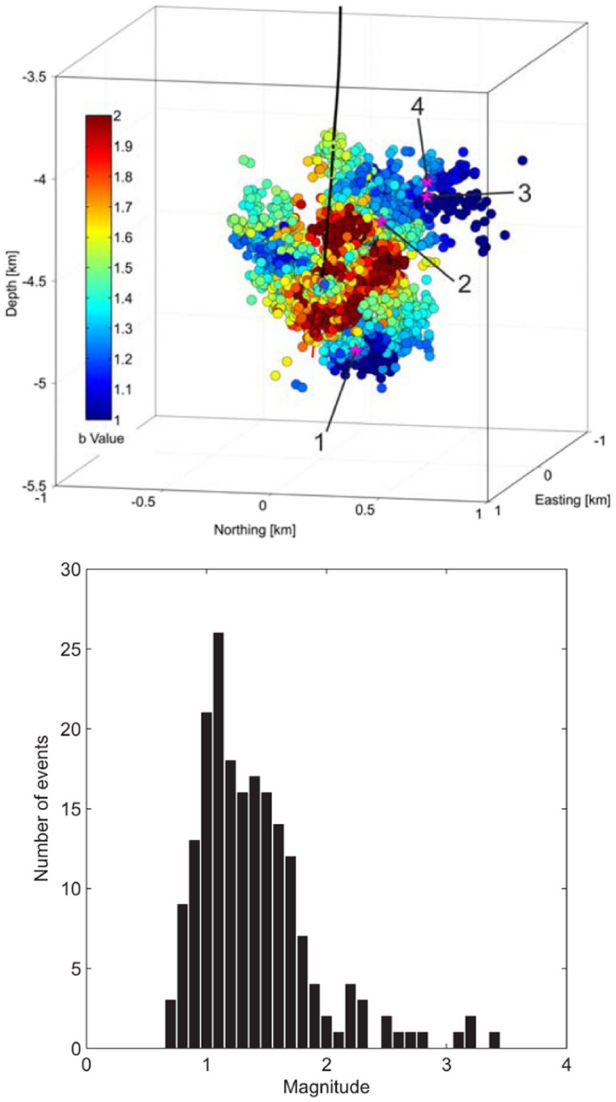


Fig. 61. Top: Earthquakes induced by hydraulic stimulation of the Basel, Switzerland, EGS injection well in 2006 and 2007. Hypocenters are color coded according to *b*-values calculated for the volume in which they occurred. Stars: large earthquakes (from Zang et al., 2014b). Bottom: Magnitude histogram of the induced seismicity recorded by the Swiss Seismological Service 3 December 2006–30 November 2007 (from Deichmann and Ernst, 2009).

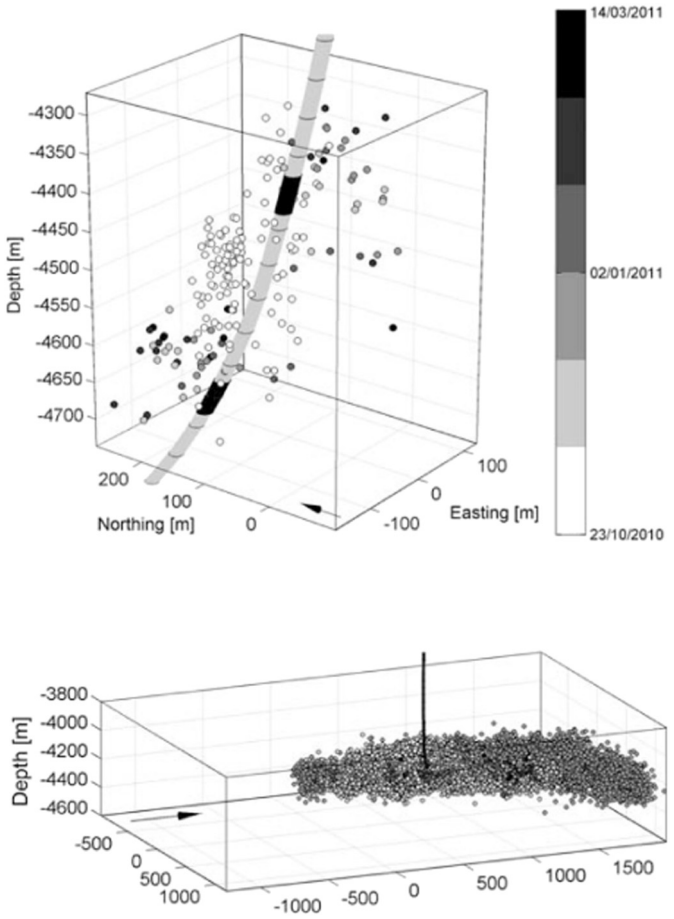


Fig. 62. EGS-induced earthquakes at Cooper Basin, Australia. Top: the Jolokia Field–hypocenters of earthquakes induced by hydraulic stimulation of well 1 in in 2010. Known fracture intersections with the wellbore are shown in black. Bottom: the Habanero field–hypocenters of earthquakes induced by stimulation of well 4 (vertical line) in 2012. (From Baisch et al. (2015).)

been used for detailed research (e.g., Julian et al., 2004; Julian et al., 2007; Kaven et al., 2014; Monastero et al., 2005). Most production and reinjection data are proprietary, so published correlations between operations and seismicity are rare.

One of these rare cases is described by Julian et al. (2007). In 2005 an existing well was used for an EGS experiment. Fluid was injected at rates of up to 20 l/s into well 34-9RD2 in order to increase permeability and enhance production in nearby producing wells. 34-9RD2 was reworked prior to the injection to deepen it and replace the existing slotted liner with an un-slotted one.

Major unexpected circulation-loss zones were encountered resulting in a total loss of up to 20 l/s of drilling mud at 2672 m depth. The planned EGS project thus instantly metamorphosed into an unplanned reinjection operation. A vigorous earthquake swarm began immediately. High-resolution locations, relative locations, and full moment tensors were determined using an exceptionally high-quality dataset acquired on 36 digital, three-component seismic stations of the permanent network operated by the Geothermal Program Office of the US Navy augmented by temporary stations.

The swarm opened, in tensile mode, several hundred meters of a preexisting fault immediately adjacent to the well. The existence of this structure, deduced from the seismic evidence, was confirmed by surface geological mapping and a borehole televiewer log. This was an early demonstration of the potential of earthquake techniques to study the detailed subsurface fracture network in a geothermal reservoir.

In Europe, three geothermal projects have been associated with M > 3 induced earthquakes, all in Italy:

- the Larderello-Travale area (M_{MAX} 3.2);
- the Monte Amiata geothermal field (M_{MAX} 3.5); and
- the Torre Alfina Field (M_{MAX} 3.0).

Of these, the most notable case is Larderello-Travale, Tuscany, which, like The Geysers, is a rare vapor-dominated system. Tuscany is tectonically active with transcurrent-transtensional-strike-slip deformation, high thermal gradients and temperatures up to 400 °C. There are several geothermal fields of economic interest. The shallower Larderello-Travale reservoirs occupy Triassic carbonate and evaporite rocks and the deeper ones fractured metamorphic basement.

Larderello-Travale has generated electricity almost continuously since 1904, and is thought to have a long history of seismicity. In the early 1970s, injection of cold condensate from the power plants started to recharge the upper reservoir and a seismic network was installed (Batini et al., 1985; Batini et al., 1980).

Seismicity is variable in rate and *b*-values. The events are mostly < 8 km deep, with 75% 3.0–5.5 km deep. The largest event reported

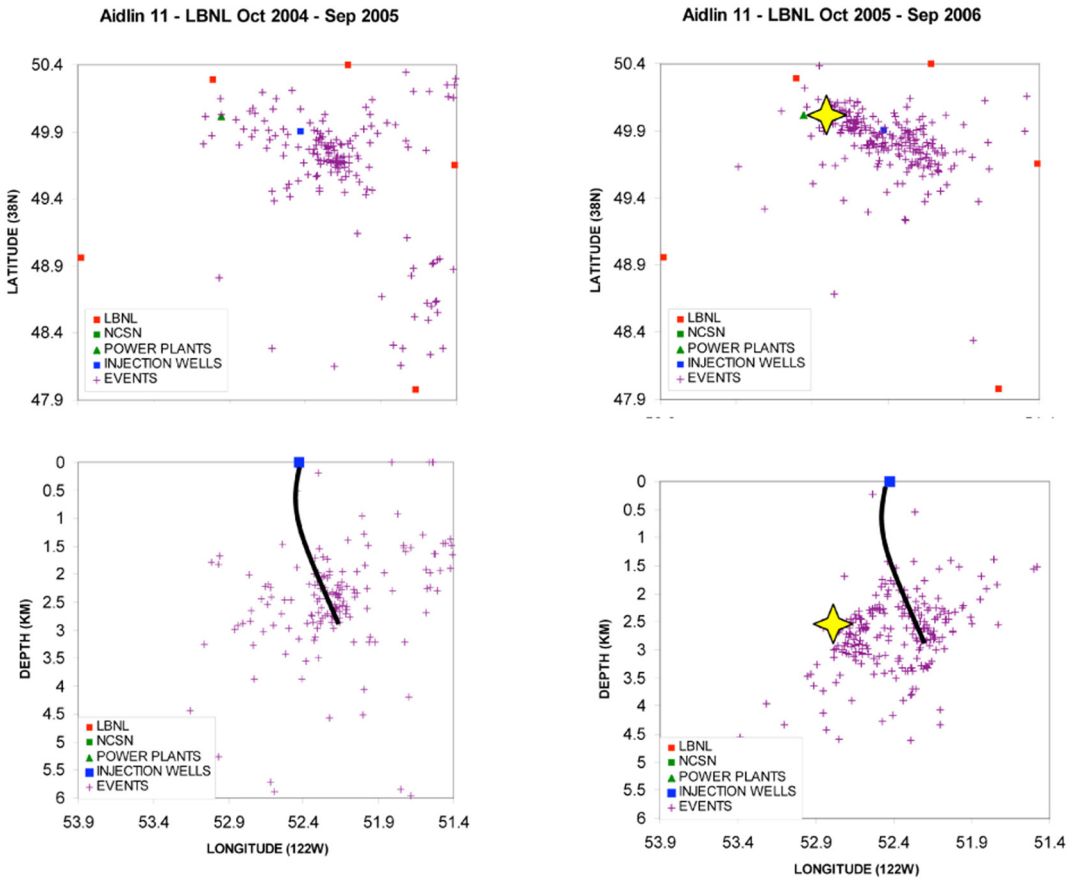


Fig. 63. Earthquakes surmised to be injection-related at the northwest Geysers geothermal area. Maps and east-west cross sections show earthquakes in the Aidlin area. Blue square and black line: injection well; yellow star: a M 4 event that occurred October 2005.
(From Majer and Peterson (2007).)



Fig. 64. States of the USA where shale-gas hydrofracturing is currently ongoing.

was M 3.2 and occurred in 1977. Events have significant non-shear focal mechanism components, indicating tensile failure (Kravania et al., 2000). Because of the long history of seismic activity it has been suggested that many events are natural. However, there is a clear correlation between injected volume and seismic rate (Batini et al., 1985; Evans et al., 2012).

4.1.6. Shale-gas hydrofracturing

Gas-bearing shale formations are hydrofractured ("fracked") to increase permeability and release the contained gas. It is typically done by drilling shallow horizontal wells into the target formation. Fluids are injected containing chemicals and solids designed to propagate fractures and prop them open. It is extensively applied in the USA where it has brought about a major reduction in the cost of natural gas (Fig. 64). As a result of this success there is widespread interest in the technology in other countries. However, in regions where population density is high there may be public concern about potential environmental effects, including ground-water pollution, industrialization and induced earthquakes.

Although over 2.5 million shale-gas hydrofracturing jobs have been completed worldwide, maximum earthquake magnitudes for only 21 cases have been reported. Of these cases, eight are from the USA, 12 from Canada, and one from the UK (Baisch and Vörös, 2011; de Pater and Baisch, 2011). This is only 0.001% of all shale-gas hydrofracturing jobs (Section 7.1). Of those cases, moderately large earthquakes are reported from British Columbia (M 4.4, 4.4 and 3.8 events) and Alberta (M_L 4.4), both in Canada (Kao et al., 2015; Schultz et al., 2015). In the USA the largest shale-gas hydrofracturing-related earthquakes reported have been four M > 3 events in Oklahoma and Ohio (Darold et al., 2014; Skoumal et al., 2015).

These statistics are misleading because the fundamental purpose of hydrofracturing in gas-bearing shale is to crack the rock. Thus, all successful hydrofracturing jobs induce earthquakes but an aim is that they do not cause nuisance. Meeting this objective is helped in the USA and Canada by operating in regions of low population density. Seismic monitoring is often done because the earthquake locations indicate the location and volume of the fracture network created. However, if nuisance seismicity is not induced there is little reason to report it publically. Seismic analyses focus on investigating the spatial distribution and mode of fracturing, the results are not of public interest, and they are likely to remain proprietary.

A remarkable case was associated with injection operations in 2013 near Crooked Lake, Alberta. There, the largest shale-gas hydrofracturing-related earthquakes on record were induced. The target formation was Devonian Duvemay organic-rich shale. Operations involved multi-stage, high-pressure injections of proppant with weight-in-well ~60 MPa and volumes of a few thousand cubic meters. Of ~3000 hydrofracturing operations in Alberta in 2013, only three (0.1%) are reported to have been accompanied by noteworthy seismicity, with 160 events up to M_L 4.4 being observed over a ~2-year period (Schultz et al., 2015).

The quality of information about the sequences is limited because there were no local seismic stations. Data from distant stations were subject to sophisticated processing and suggested close spatial and temporal correlation with the shale-gas hydrofracturing (Fig. 65). Correlation also occurred between injection stages, a "screen-out" (i.e. interruption in slurry flow causing shutdown of injection) and seismicity. Associations between screen-outs and seismicity are reported from elsewhere (Clarke et al., 2014; Skoumal et al., 2015). The seismicity may have hampered operations at Crooked Lake.

The Horn River Basin, British Columbia, is a major shale gas production area. Hydrofracturing commenced in 2006 and gas production peaked in 2010 and 2011 (Farahbod et al., 2015). Prior to the hydrofracturing, seismic rates were low. Only 24 earthquakes with M 1.8–2.9 were located locally in a ~2-year period. When hydrofracturing started the seismic rate increased to > 100 earthquakes/year and correlated with hydrofracturing (Fig. 66). A logarithmic correlation between seismic moment, maximum magnitude and volume injected was observed (Fig. 67).

For the entire Horn River Basin, injected volume was more closely related to seismicity than injection pressure. Increases in volume increased earthquake frequency but not magnitude. Large earthquakes ($> 10^{14}$ N m, i.e., $M_W \sim 3.5$) occurred only when ~150,000 m^3 of fluid were injected per month. Time lags between injections and seismicity ranged from days to months.

The embryonic UK shale-gas industry began with the unfortunate case of the 2011 Preese Hall, Lancashire, earthquake sequence. There, the first UK dedicated multi-stage shale-gas hydrofracturing operation was conducted in a 1000-m section of the Carboniferous gas-bearing Bowland Shale. Following the injection of 2245 m^3 of fluid and 117 t of proppant, a nearby M_L 2.3 earthquake was reported by the British Geological Survey. The earthquake was felt, and was unusual in that location. The nearest monitoring station was 80 km away. Additional

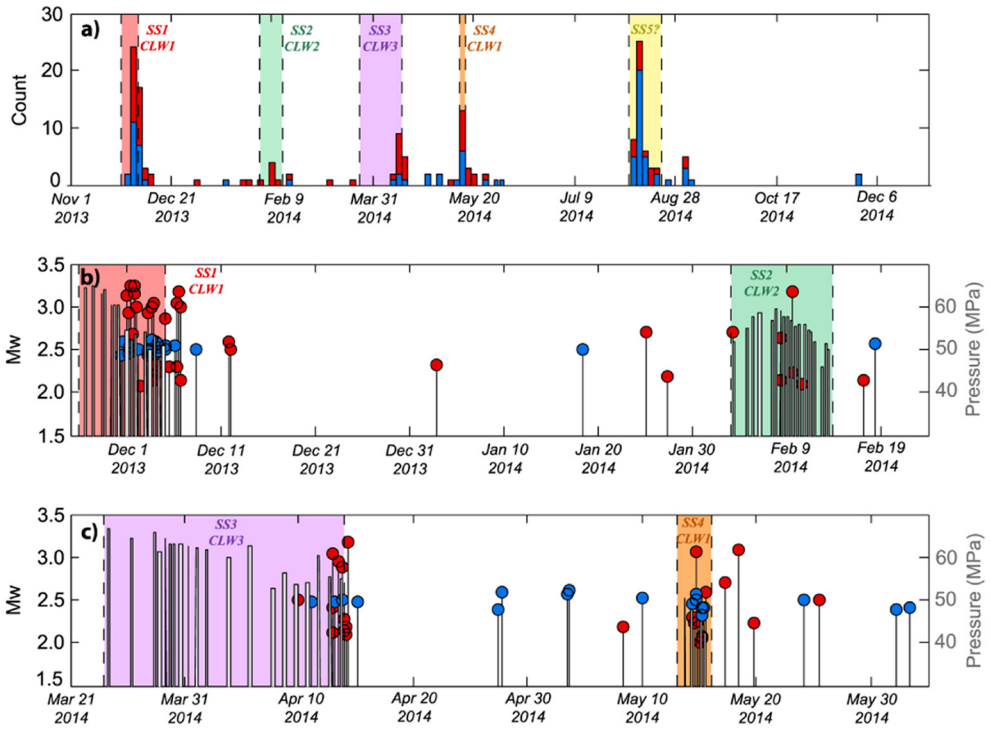


Fig. 65. Comparison of earthquakes and hydraulic fracturing completions at Crooked Lake, Alberta, Canada. (a) Histogram of located seismicity (red bars), with number of earthquakes increased using waveform cross correlation (blue bars). Hydrofracture schedules are bounded by colored boxes and labeled with respective subsequence and borehole. (b) Magnitudes of located (red circles), detected (blue circles) earthquakes and average injection pressure during hydrofracture stages (gray bars). (c) Same as (b) for later borehole completions.
(From Schultz et al. (2015).)

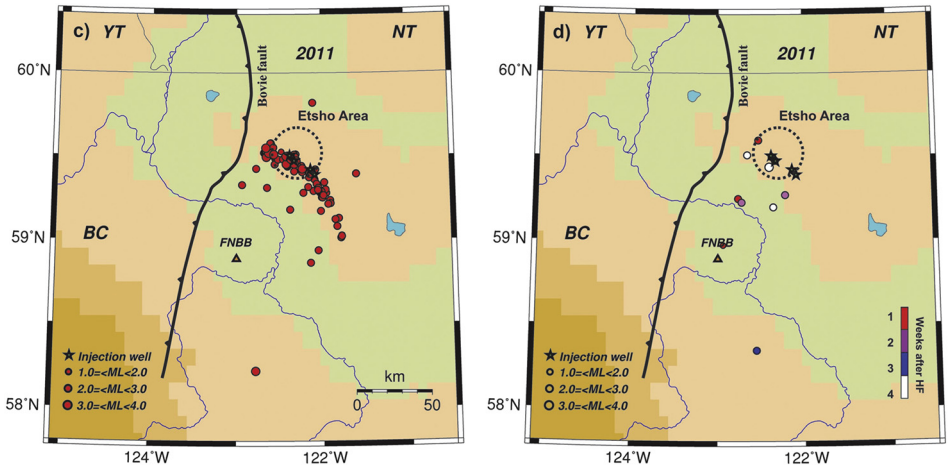


Fig. 66. Map of the Horn River Basin, British Columbia, Canada. Left: seismicity on days when hydrofracturing took place. Right: days when it did not occur.
(From Farahbod et al. (2015).)

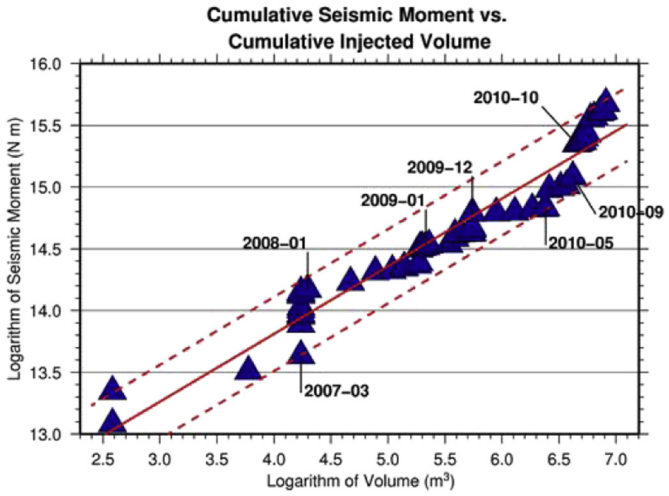


Fig. 67. Logarithm of seismic moment vs. logarithm of volume injected in shale gas hydrofracturing operations in the Etsho area, Horn River Basin, British Columbia, Canada. (From Kao et al. (2015).)

seismic stations were deployed rapidly but no aftershocks recorded. UK shale-gas hydrofracturing thus started with a rare phenomenon–the suspected induction of a nuisance earthquake.

Operations continued, but about six weeks later a second felt event of M_L 1.5 occurred ~1.0 km from the well. Citizen disquiet followed and operations were suspended. A total of 52 earthquakes in the magnitude range M_L −2.0 to 2.3 were detected with similar waveforms to the two largest events. A government enquiry and 18-month suspension of operations ensued while the problem was investigated. The close relationship between hydrofracturing and seismicity left little doubt that the earthquakes had been induced (Fig. 68).

The UK Department of Energy and Climate Change (DECC) commissioned a review and recommendations for mitigation of seismic risk associated with future shale-gas hydrofracturing operations in the UK. Recommendations included monitoring test injections prior to the main injections, monitoring fracture growth during injections, near-real-time seismic monitoring, and halting or changing injection strategy at the occurrence of seismicity with a threshold magnitude of M_L 0.5 (Green et al., 2012).

Detailed studies of the locations and fault mechanisms of the poorly recorded seismicity, combined with seismic reflection data, showed that the earthquakes probably occurred a few hundred meters below the well perforations on a fault that was not previously known (Clarke et al., 2014; Green et al., 2012). The fault does not intersect the borehole but was close enough that hydrofracture fluid may have leaked into it. The structure is an ancient transpressional fault that formed at the end of a Carboniferous basin inversion which had been inactive for 260 Ma. This case illustrates that even long-inactive faults, which are common in most continental crust, are close to failure and may be induced to slip by nearby injections.

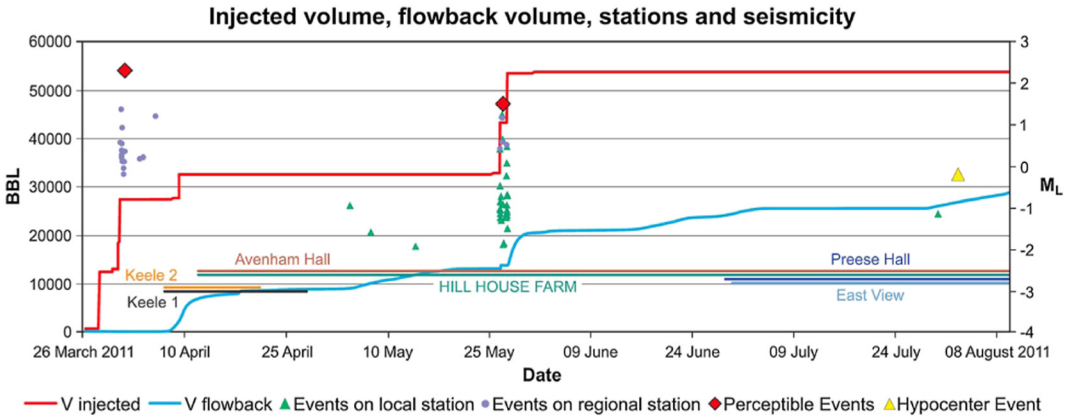


Fig. 68. Injection activity and seismicity associated with shale-gas hydrofracturing at Preese Hall, Lancashire, UK. Red line: injected volume; blue line: flow-back volume from the wellhead in US barrels (0.159 m^3); violet dots: earthquakes detected on seismic stations at distances of > 80 km; green triangles: earthquakes detected on two local stations; yellow triangle: event for which source mechanism and reliable hypocenter were obtained.
(From Clarke et al. (2014).)



Fig. 69. Site of the former Cacoosing Valley, Pennsylvania, quarry. Red oval: approximate boundary of the old quarry. Satellite image from Google Maps.

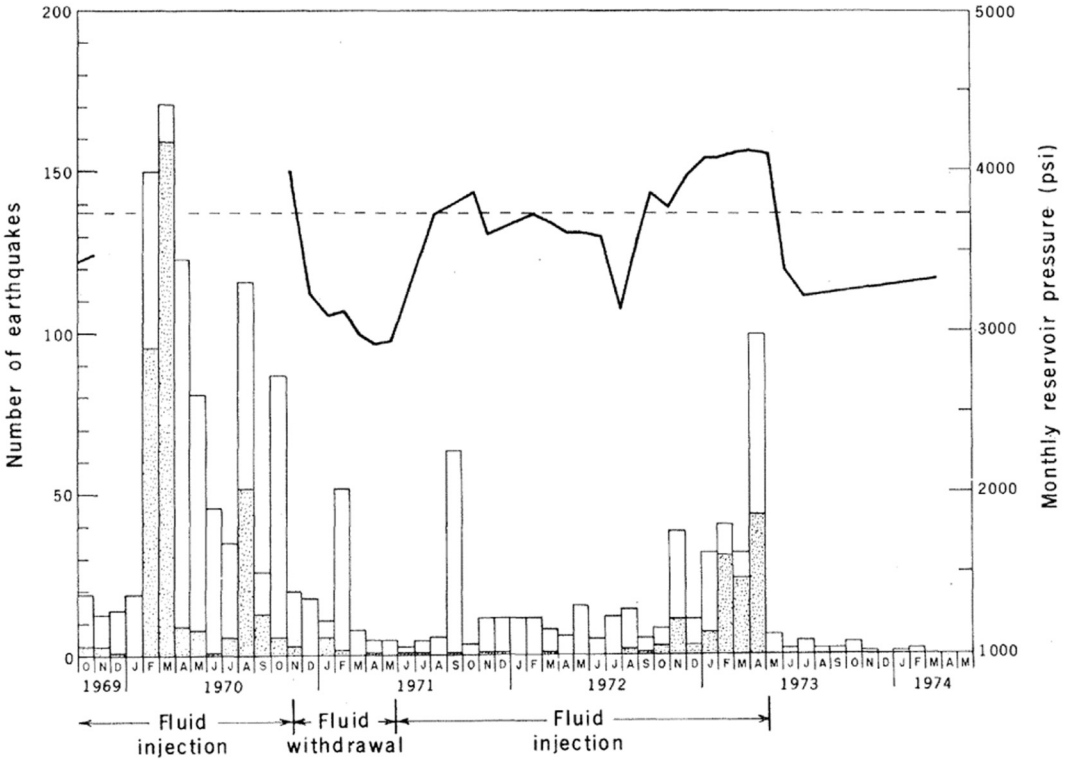


Fig. 70. Frequency of earthquakes at the Rangely Oilfield, Colorado, and reservoir pressures during fluid injection and fluid withdrawal. Stippled bars: earthquakes within 1 km of injection wells; black line: pressure history in injection well Fee 69; dashed line: predicted critical reservoir pressure.
(From Raleigh et al. (1976).)

4.1.7. Allowing mines to flood

Removal of rock from mines lowers confining stress on nearby faults and brings them closer to failure. The simultaneous pumping out of water during mining lowers pore pressure, increasing the strength of faults and counteracting the effect of rock removal. These processes roughly balance until a mine is abandoned and pumping stopped. After this, natural groundwater recharge may encourage seismicity.

A classic case is that of the 1994 Cacoosing Valley, Pennsylvania, earthquake sequence (Fig. 69) (Seeber et al., 1998). Groundwater recharge is implicated in a M_L 4.4 earthquake that occurred beneath an 800-m-wide carbonate quarry from which ~4×10^6 m^3 had been removed. The earthquake caused ~$2 million of damage to nearby homes. The quarry had been excavated to an average depth of 50 m over the 58-year time period 1934–1992. Groundwater pumping done during the mining period stopped after mining ceased and the water table rose by ~10 m in a few months. The rock is permeable karstic carbonate and depletion of groundwater, along with subsequent recharge, likely extended over a wider area than the footprint of the quarry.

Earthquake activity commenced approximately five months after

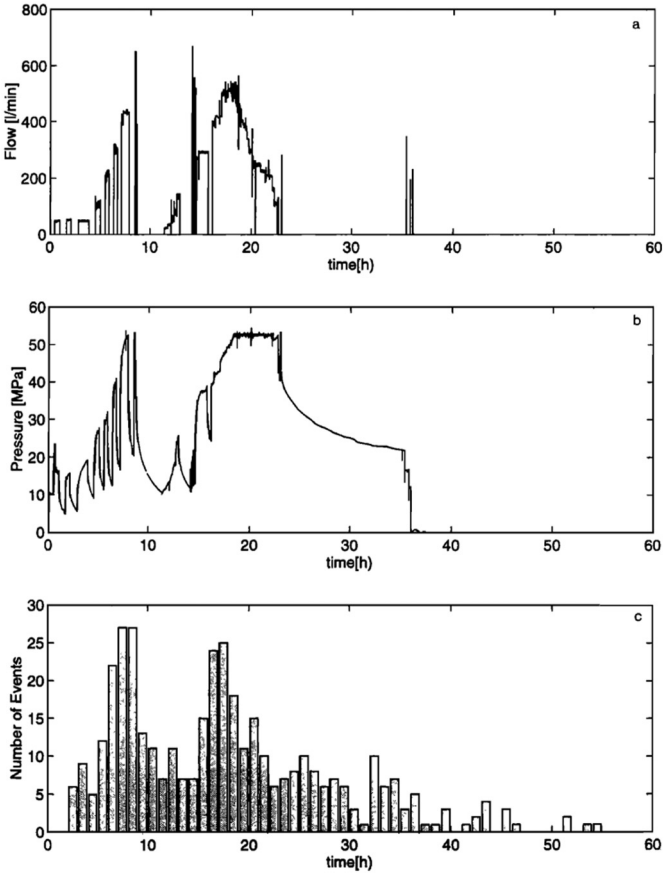


Fig. 71. Flow rates, pressure and number of earthquakes induced by brine injection into the Kontinentales Tiefbohrprogramm der Bundesrepublik Deutschland (KTB–the German Continental Deep Drilling Program) borehole during a 60-hour period. (From Zoback and Harjes (1997).)

pumping ceased. A rapidly deployed temporary seismometer recorded 67 aftershocks. They occurred in the upper 2.5 km in a planar pattern interpreted as the fault plane that slipped. Focal mechanisms suggested the mainshock had a thrust mechanism. The earthquakes occurred in the hanging-wall block such that unloading by rock removal would have encouraged slip. Surprisingly, the seismicity did not activate any of the plentiful, known, large-displacement faults in the region. Instead, stress was released on a set of small, unmapped faults which probably had a more suitable orientation. The mining had reduced confining stress by ~0.13 MPa, while the M_L 4.4 mainshock had a stress drop of 1–4 MPa.

The Cacoosing Valley event may have been similar to one that occurred two decades earlier beneath a large quarry at Wappingers Falls, New York (Pomeroy et al., 1976). A m_b 3.3 earthquake occurred there in 1974. Again, the mainshock and aftershocks nucleated at exceptionally shallow depth with some as shallow as 0.5 km. Slip occurred on a reverse fault immediately below the quarry and had a source mechanism consistent with the regional stress field. Over the preceding ~75 years ~30×10^6 m^3 of rock had been removed by open-casting down to a depth of ~50 m. This changed the stress by ~1.5 MPa at the surface and reduced the normal stress on faults below.

4.1.8. Research projects

In the wake of the Denver, Colorado earthquakes (Section 4.1.1) there was speculation that earthquakes might be controllable. Partly as a result, a series of earthquake-induction experiments have been conducted for research purposes. These have investigated the physical properties of natural fault zones and the processes that accompany earthquake occurrence. *HiQuake* contains 13 cases of earthquakes induced by research projects.

The first such project was conducted in 1969 at the Rangely Oilfield, Colorado (Raleigh et al., 1976). This oilfield occupies Mesozoic and Paleozoic sedimentary rocks at ~1700 m depth and is underlain by crystalline basement at ~3000 m. There is little local faulting, but earthquake activity had occurred with water flooding for enhanced recovery (Section 4.1.3). A seismograph array and prior earthquake record were therefore available. Fluid pressure in wells near the

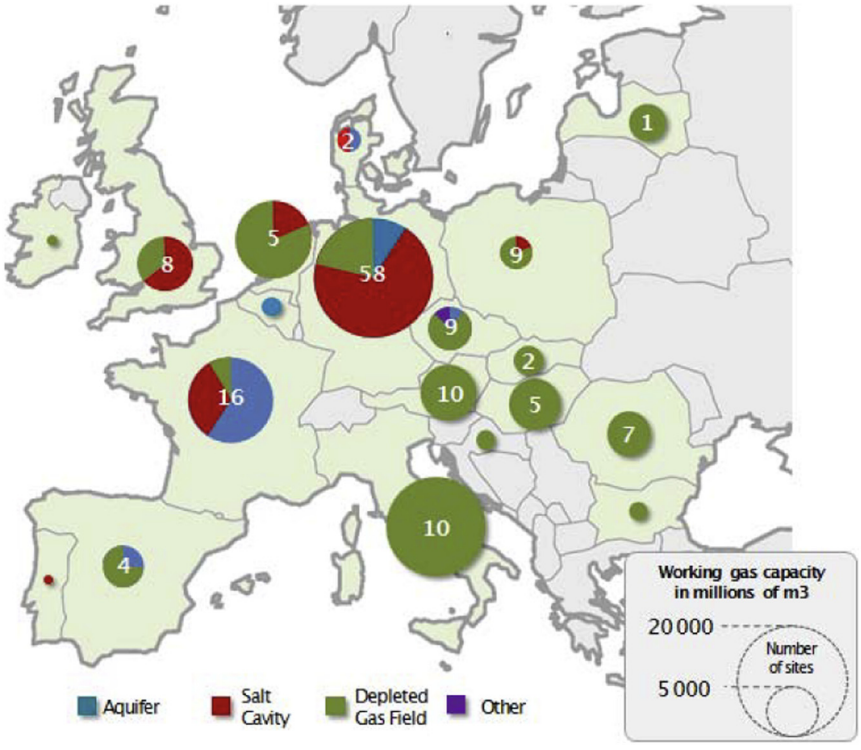


Fig. 72. Working gas capacities of underground storage sites in Europe (http://www.gasinfocus.com/en/; http://www.gie.eu/index.php/maps-data/gse-storage-map).

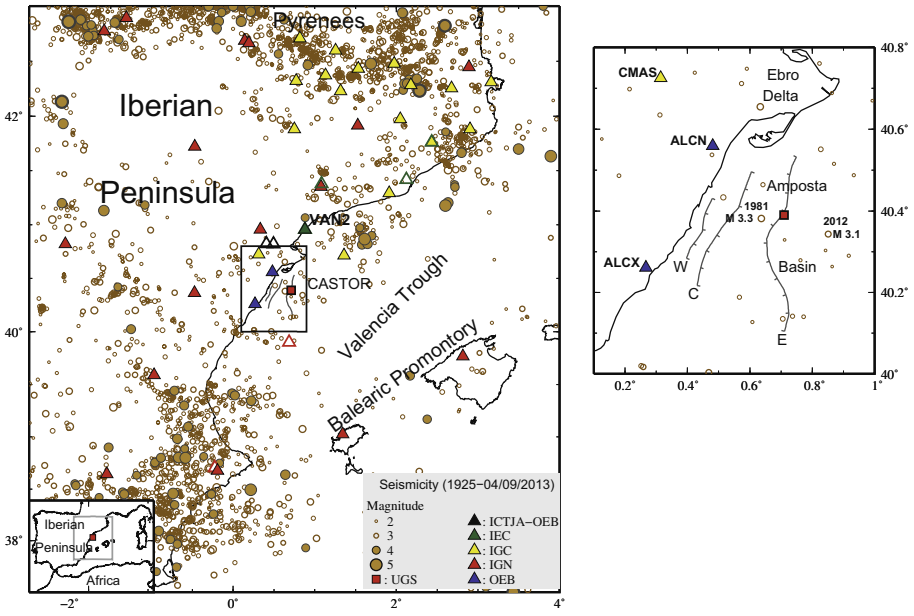


Fig. 73. Seismicity of the eastern Iberian Peninsula, Spain. Triangles: seismic stations; red square: location of the Castor underground gas storage reservoir. W, C and E denote the Western, Central and Eastern Amposta faults. (From Gaite et al. (2016).)

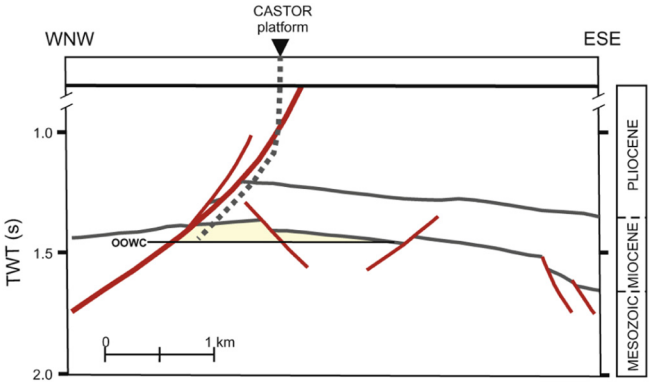


Fig. 74. Schematic diagram of the old Amposta Oilfield, Spain, in WNW-ESE section. TWT: two-way travel time; dashed line: approximate location of the Castor injection well: OOWC: original oil-water contact at 1940 m depth; yellow area: approximate location of the gas reservoir.
(From Gaite et al. (2016).)

earthquakes was experimentally cycled to investigate the effect on the seismicity. There was close correlation between seismicity and high pore pressure and events up to M_L 3.1 were induced (Fig. 70).

In 1970 another experiment was conducted at Matsushiro, Japan. A volume of 2883 m^3 of water at wellhead pressures of 1.4–5.0 MPa was pumped into an 1800-m-deep well to test whether earthquakes were induced by increasing pore pressure in a fault zone. After several days of injection earthquake activity started within a few kilometers of the well (Ohtake, 1974).

After a hiatus in experimenting of 16 years, in 1990, perhaps the best known research experiment to study fluid-induced seismicity was begun–the Kontinentales Tiefbohrprogramm der Bundesrepublik Deutschland (KTB)–the German Continental Deep Drilling Program. Extensive literature documents this project including a 1997 special section of Journal of Geophysical Research (No. 102) (e.g., Baisch and Harjes, 2003; Baisch et al., 2002; Bohnhoff et al., 2004; Erzinger and Stober, 2005; Fielitz and Wegler, 2015; Grasle et al., 2006; Jahr et al., 2005; Jahr et al., 2007; Jahr et al., 2008; Jost et al., 1998; Shapiro et al., 2006; Zoback and Harjes, 1997).

The main borehole was drilled 1990–1994 to a depth of 9.1 km. The first hydraulic stimulation was conducted in 1994 at depths and pressures close to the brittle-ductile transition. About 400 earthquakes up to M_L 1.2 were induced at about 8.8 km depth (Fig. 71). Focal mechanisms were consistent with stress measured in the borehole. Seismicity began within a few hours of pumping and a few tens of meters from the borehole. Modeling suggested that the earthquakes occurred in response to pressure perturbations of < 1 MPa, i.e. $< 1\%$ of the ambient, hydrostatic pore pressure at the nucleation depth.

An important conclusion of this experiment was that differential stress in the crust is limited by the frictional strength of well-oriented, pre-existing faults ("Byerlee's Law") and the crust is in brittle failure equilibrium even at great depth in stable intraplate areas. Hydraulic experiments at the site have continued up to recent years (e.g., Jahr et al., 2008).

A 1997 project in the Philippines injected 36,000 m^3 of water into a well intersecting a creeping portion of the Philippine Fault at the Tongonan geothermal field. The water entered the formation at 1308–2177 m below the surface (Prioul et al., 2000). Several hundred earthquakes occurred but all were away from the fault in the geothermal reservoir. Prioul et al. (2000) concluded that tectonic stress on the fault is relieved aseismically and as a consequence there was no differential shear stress to be released by the water injection.

In the same year, a water-injection experiment was conducted in the Nojima fault zone, Japan, shortly after it ruptured in the 1995 M 6.9 Kobe earthquake (Tadokoro et al., 2000). This experiment gathered information on the physical properties of a fault plane in the immediate post-rupture period. Over periods of a few days, 258 m^3 of water were injected into an 1800-m-deep borehole at a pressure of ~ 4 MPa at the surface, entering the fault zone at 1480–1670 m depth. An increase in M -2 to 1 seismicity occurred a few days after each injection. It was concluded that the fault zone was highly permeable and could slip with pore-fluid pressure increases of $< 10\%$.

Two additional experiments have been conducted in recent years, the first in 2013 as part of the Wenchuan Earthquake Fault Science Drilling (WFSD) project (Ma et al., 2015). This project studied the fault healing process. Over a four-month period 47,520 m^3 of water at 10–15 MPa was injected at rates of up to 1.7 l/s into a 552-m-deep well that intersected a fault zone at 430 m depth. The fault was activated and over 20,000 earthquakes up to M ~ 1 were detected by downhole observations. The hypocentral zone suggested failure in the same sense as the regional stress.

A similar phenomenon was reported by Guglielmi et al. (2015) in an experiment that stimulated an inactive fault in a carbonate formation. The experiment injected 0.95 m^3 of water into a 518-m-deep

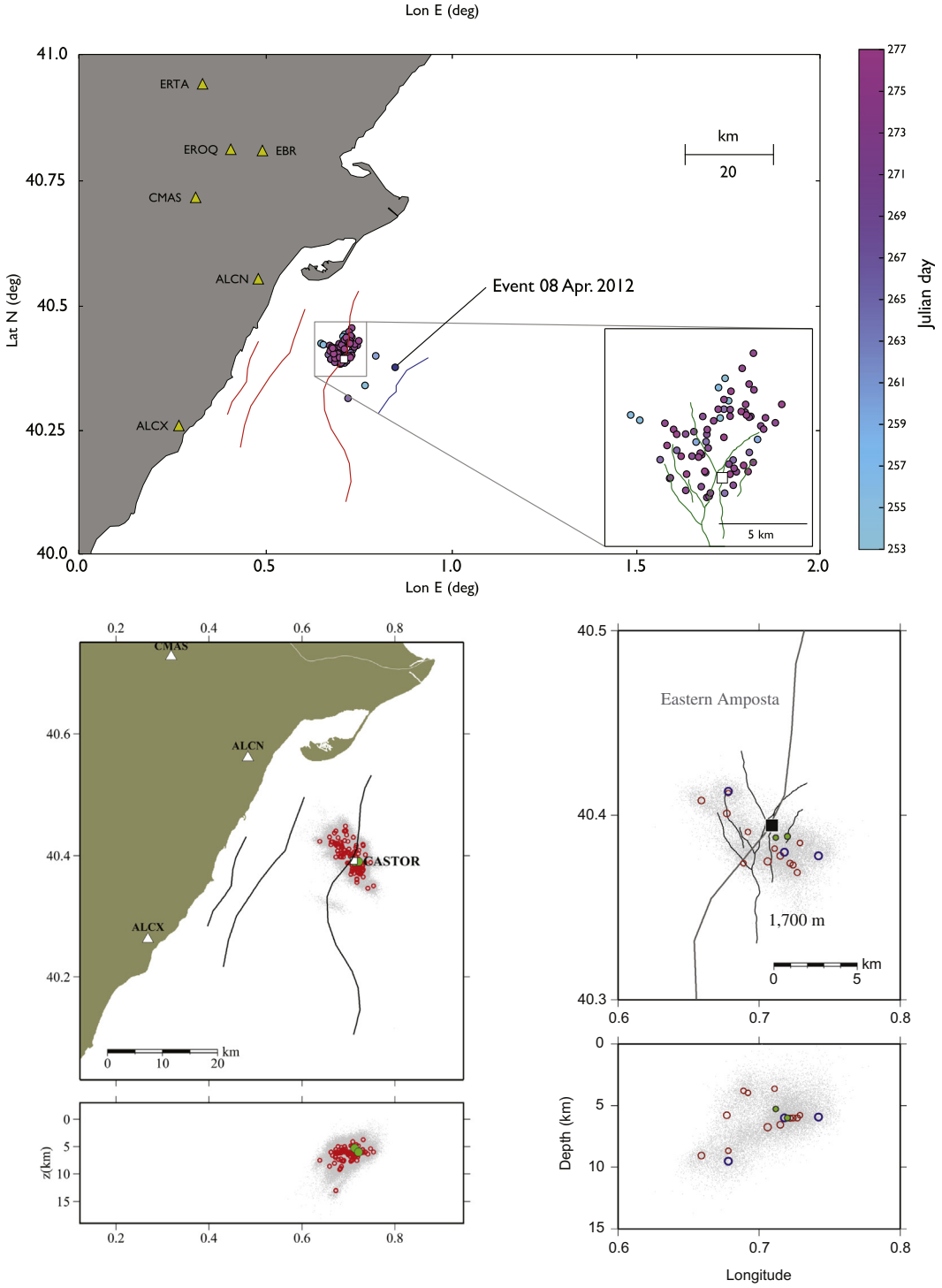


Fig. 75. Top: Faults and epicenters for the largest events in the 2013 earthquake sequence in the old Amposta Field. White square: Castor platform; colored lines: faults near the injection site; red lines: the Amposta faults; blue and green lines: additional faults (from Cesca et al., 2014). Centre left and bottom left: map and cross-section showing 116 earthquakes associated as a multiplet; triangles: seismic stations; white square: injection well; green dots: two events with M 3.0 and 3.2. Centre right and bottom right: map and cross-section of earthquakes with M > 3; black square: injection well (from Gaite et al., 2016).

underground experimental facility in southeastern France where a vertical well intersected a fault at 282 m depth. Aseismic shear slip started at a pressure of ~1.5 MPa, and ~80 earthquakes occurred a few meters from the injection point. These accounted for only a small fraction of the slip on the fault, however. The accumulated moment at the end of the experiment was $M_o = 65 \times 10^9$ N m (equivalent to an earthquake with M_W 1.17). This was far larger than the moment released by the seismicity, which totaled $M_o < 2$ N m. Aseismic slip dominated deformation in the fault zone and the earthquakes occurred in rock mass outside the pressurized zone. Other experiments have been performed in a salt solution mine at Cerville-Buissoncourt in Lorraine, France (Kinscher et al., 2015; Mercerat et al., 2010) and the Wairakei geothermal field, New Zealand (Allis et al., 1985; Davis and Frohlich, 1993).

This multi-decade, multi-national research endeavor has answered some critical questions, not always those originally posed and not

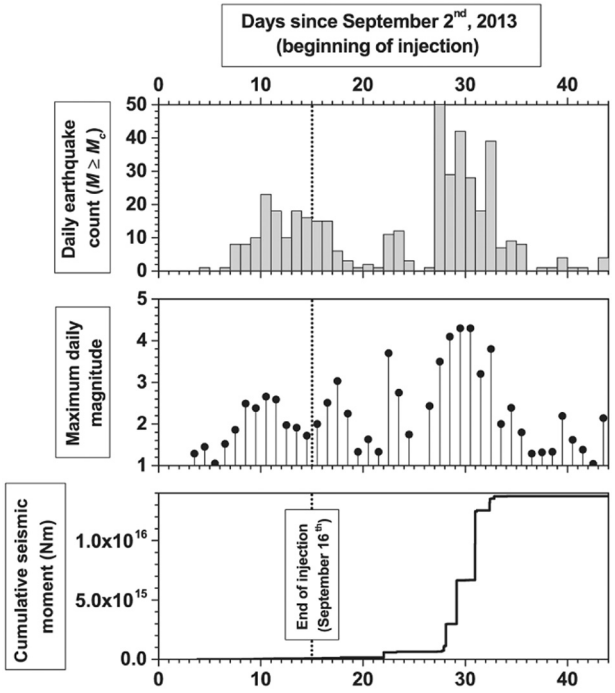


Fig. 76. Temporal evolution of seismicity with M > 2 associated with the Castor project, Spain, for 44 days from the beginning of gas injection, 2 September 2013. Top: daily number of events. Center: maximum daily magnitude. Bottom: cumulative seismic moment.
(From Cesca et al. (2014).)

always with the preferred answer. Relieving in a controlled way the stress naturally released in large earthquakes is scientifically challenging. The continental crust is near to failure, even to great depths and where large faults are not known. Earthquakes can be induced by relatively small stress perturbations, but in some cases stress on a targeted fault is relieved aseismically. In these cases, motion on that fault may induce secondary earthquakes in the surrounding rock mass. Fluid injection may thus induce primarily aseismic slip, and seismicity may be a secondary effect, with imperfect spatial correlation with the injection activities. In many cases of induced seismicity more stress is released than is loaded on faults artificially, since pre-existing tectonic stress is also released. However, the southeastern France experiment illustrates that the reverse sometimes occurs–some of the anthropogenically loaded stress may be released aseismically.

4.2. Gas

4.2.1. Natural gas storage

To stabilize supply and increase energy security nations store natural gas reserves, often underground. In May 2015, 268 underground gas storage facilities existed or were planned in Europe (Fig. 72) and over 400 in the USA.

Depleted hydrocarbon reservoirs, aquifers, and salt cavern formations are obvious repositories because they are usually well understood geologically and engineering infrastructure including wells and pipelines may already be in place. They may also be conveniently close to consumption centers.

HiQuake contains seven cases of induced seismicity reported to have been associated with underground gas storage:

- Gazli, Uzbekistan (Simpson and Leith, 1985);
- the Castor project (in the old Amposta Field), Spain (Cesca et al., 2014; Gaite et al., 2016);
- Bergermeer, Norg and Grijpskerk, Netherlands (Anonymous, 2014);
- Háje, Czech Republic (Benetatos et al., 2013; Zedník et al., 2001);

and

- Hutubi, China (Tang et al., 2015).

At the Bergermeer Gasfield, a few earthquakes up to M 0.7 occurred in 2013 in association with the injection of cushion gas. Up to 15 earthquakes per month up to M 1.5, several of which were felt, were reported for the Háje storage facility. Larger earthquakes occurred in association with gas storage at Hutubi, with over 700 earthquakes up to M 3.6 in the period 2009–2015.

The Gazli Gasfield, Uzbekistan, is primarily renowned for the three damaging M_S ~7 earthquakes that caused death and destruction in the local town of Gazli in 1976 and 1984 (Section 3.3.1). When this field had been largely depleted, it was used for storage. Gas was cycled in and out as required. Plotnikova et al. (1996) report seismicity up to M 5 induced by this process that correlates with the amount of gas stored.

The best-documented case history is that of the 2013 Castor project, Spain. This project aimed to use a depleted oilfield in the Gulf of Valencia, the old Amposta Field, ~20 km from the coast of north-eastern Spain (Fig. 73). It was planned to store 1.3×10^9 m^3 of natural gas there, sufficient to meet 25% of Spain's storage requirements. Earthquakes began shortly after the commencement of gas injection, however, the largest of which was M_W 4.3. Public reaction to the earthquakes was negative, not least because the population was sensitized after the 2011 M_W 5.1 Lorca earthquake only two years before, 250 km to the south along the coast (Section 3.1). We understand that as a result of the earthquakes the project has been discontinued.

The old Amposta oil reservoir occupies fractured and brecciated Lower Cretaceous dolomitic limestone and is one of several in the region (Fig. 74). It produced 56 million barrels (~9×10^6 m^3) of an estimated total in-place volume of 140 million barrels of oil (22×10^6 m^3) 1973–1989. Secondary injection for enhanced recovery was not needed because of strong natural water drive. After 1989 the depleted field lay dormant.

Installation of the necessary infrastructure for conversion of the reservoir into a gas storage facility commenced in 2009 and included a platform and gas pipeline. Injection of an initial ~10^8 m^3 (at 25 °C and 0.1 MPa pressure) of cushion gas (i.e. gas intended as permanent inventory in the reservoir) was conducted in 2013 at 1.75 km below sea level.

Three days after injection began, seismicity with events up to M 2.6 occurred (Figs. 75 and 76). Injection was stopped after 12 days but earthquakes continued to occur. The largest, a M_W 4.3 event, occurred two weeks after injection stopped. In total, over 1000 earthquakes were detected, > 420 with M ≥ 2 (Fig. 76). Seismicity was still ongoing in 2016 (Gaite et al., 2016).

Accurate hypocentral locations were difficult to calculate because the project, being offshore, was monitored by a seismic network with limited coverage. The closest station was 26 km from the Castor platform and, since most of the stations were on land, there was restricted azimuthal coverage (Gaite et al., 2016). As a result, different studies of the hypocentral locations yield different results and even the orientation of the hypocentral distribution as a whole (which might reveal the activated fault structure) and the hypocentral depths (which might show proximity to the injection site) vary significantly between studies. Both NW and NE orientations for the hypocentral zone are reported, along with depths that vary from close to the gas injection depth to several kilometers deeper (Fig. 75) (e.g., Cesca et al., 2014; Gaite et al., 2016).

The epicentral area forms part of the dominantly ENE-WSW Catalan-Valencian normal-faulting extensional region (Perea et al., 2012) and focal mechanism studies of the mainshock show motion compatible with slip in this sense (Cesca et al., 2014). The most significant potentially seismogenic feature near the old Amposta Field is the 51-km-long, NE-SW oriented, Fosa de Amposta fault system (Gaite et al., 2016). If such a major fault zone were to rupture in its entirety a M 5–7 earthquake could occur (Fig. 77). Combined interpretation of the

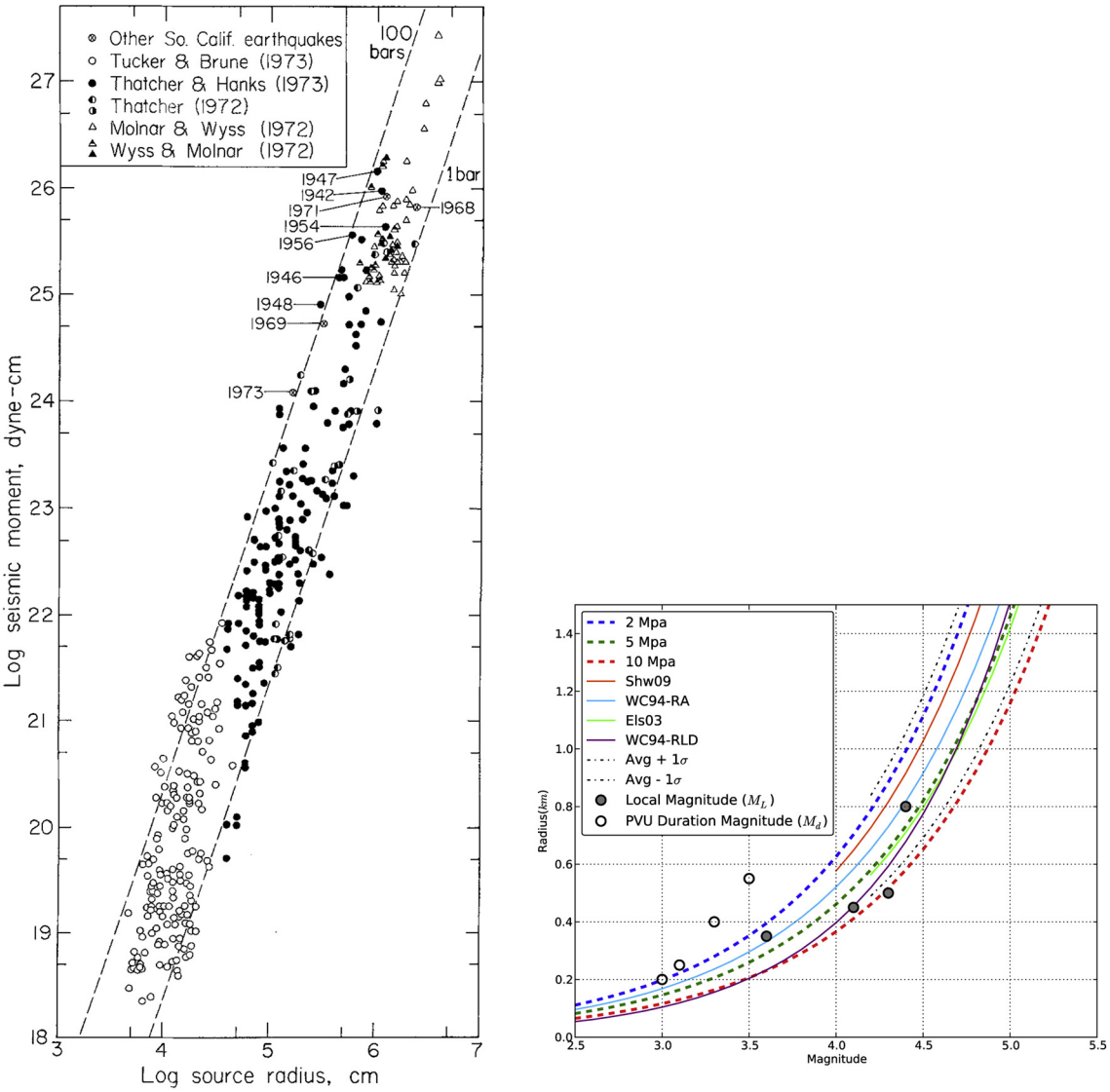


Fig. 77. Left: Set of data for small earthquakes showing the relationship between seismic moment and source radius. Dashed lines are of constant stress drop (Hanks, 1977). Right: Rupture radius vs. duration earthquake magnitude for several models. Black dotted lines: average of these relationships ± 1σ; blue, green and red dashed lines: relationships derived from the moment-magnitude relation of Hanks and Kanamori (1979) for stress drops of 2, 5 and 10 MPa respectively, and estimated fault radius using half the rupture-length-at-depth parameter; gray and white circles: values for individual earthquakes induced at Paradox Valley, Colorado.
(From Yeck et al. (2015).)

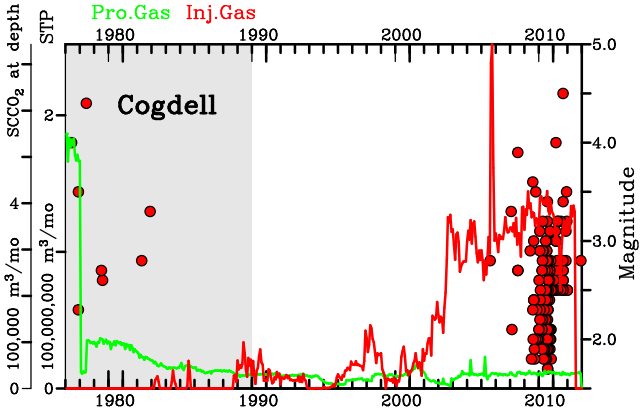


Fig. 78. Operations and seismicity at the Cogdell Oilfield, Texas. Green: monthly volumes of natural gas produced; red: gas injected; red dots: earthquakes detected 1977–2012. There was a clear increase in seismic activity from 2006, five years after the start of CO_2 injection.
(From Gan and Frohlich (2013).)

locations and source mechanisms suggests that this fault was not activated, however.

The seismicity was unusual for the area in both magnitude and seismic rate compared with the preceding two decades (Fig. 73). Although earthquake activity occurs along the coast of Spain to the north and south, the Pyrenees mountain chain in Portugal, and the coast of North Africa, no significant historical seismicity was known on the fault system local to the Castor project prior to the gas injection. For this reason, and because of the close spatial and temporal correlation with gas injection, there is little doubt that the earthquakes were induced.

4.2.2. CO_2 for oil recovery

There are approximately 100 enhanced oil recovery injection sites where CO_2 is used, mostly in Texas. *HiQuake* contains two cases where seismicity is postulated to be induced by this process. These are at the Cogdell Field, Texas (Gan and Frohlich, 2013) and Weyburn Oilfield, Saskatchewan (Maxwell and Fabriol, 2004; Verdon et al., 2013). The latter is a hybrid project and also classified as a Carbon Capture and Storage (CCS) project (Section 4.2.3).

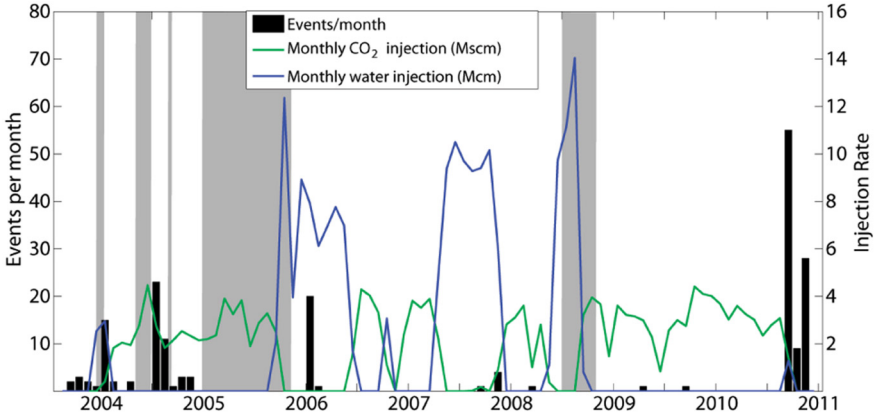


Fig. 79. CO_2, water injection, and associated earthquakes at the Weyburn Oilfield, Saskatchewan, Canada. Shaded periods: monitoring array was inoperative.
(From Verdon et al. (2013).)

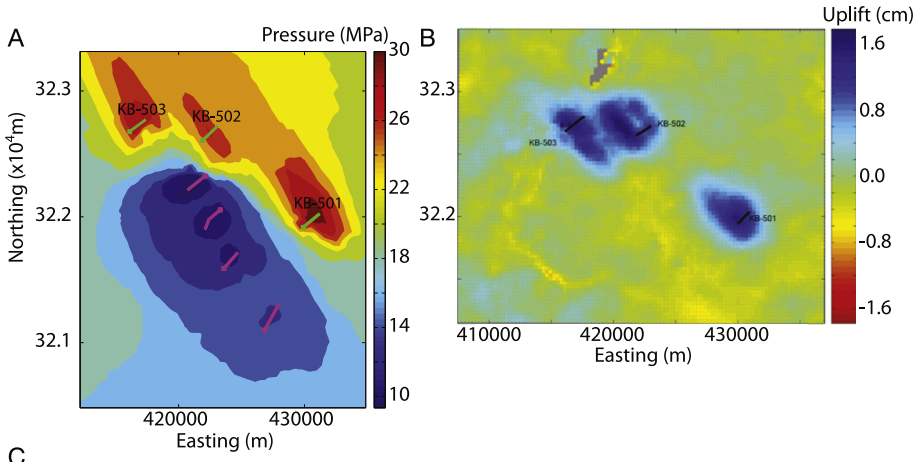


Fig. 80. Modelled pore pressure and geo-mechanical deformation at In Salah, Algeria. A: Map of pore pressure after three years of injection. B: Surface uplift measured by InSAR. C: Modelled pressure at the three injection wells and in the producing part of the reservoir.
(From Verdon et al. (2013).)

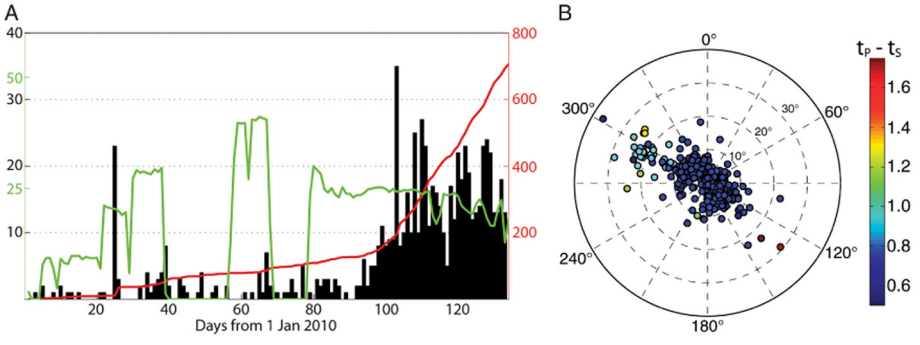


Fig. 81. Microseismicity at In Salah, Algeria. A: Black: daily seismicity rate; red: cumulative number of events January–April 2010; green: CO_2 injection rate in millions of standard cubic feet per day (1 million standard cubic feet of gas per day at 15 °C = 28,250 m^3/day). B. Event arrival angles in polar projection, colored by differential *S*- and *P*-wave arrival times.
(From Verdon et al. (2013).)

Early on in its history, the Cogdell Oilfield generated earthquakes surmised to have been induced by water injection (Gan and Frohlich, 2013). Lately, CO_2 has been injected and is associated with earthquakes up to M_W 4.4 (Fig. 78).

The Cogdell Oilfield is a large subsurface limestone reef mound, not a fault-bounded oil trap, and there are no mapped faults nearby. Production began in 1949 and 1957–1983 oil recovery was enhanced by brine injection. This was associated with earthquakes, including a M_L 5.3 event in 1978. This earthquake was only poorly located as a result of the rudimentary nature of seismic monitoring in Texas at the



Fig. 82. Aerial photograph of the Nevada test site, USA. View of Yucca Flat looking south-southeast. Center of ring road is at 37°N 9.57′, 116°W 4.63′, elevation 4400 m (https://en.wikipedia.org/wiki/Nevada_Test_Site).

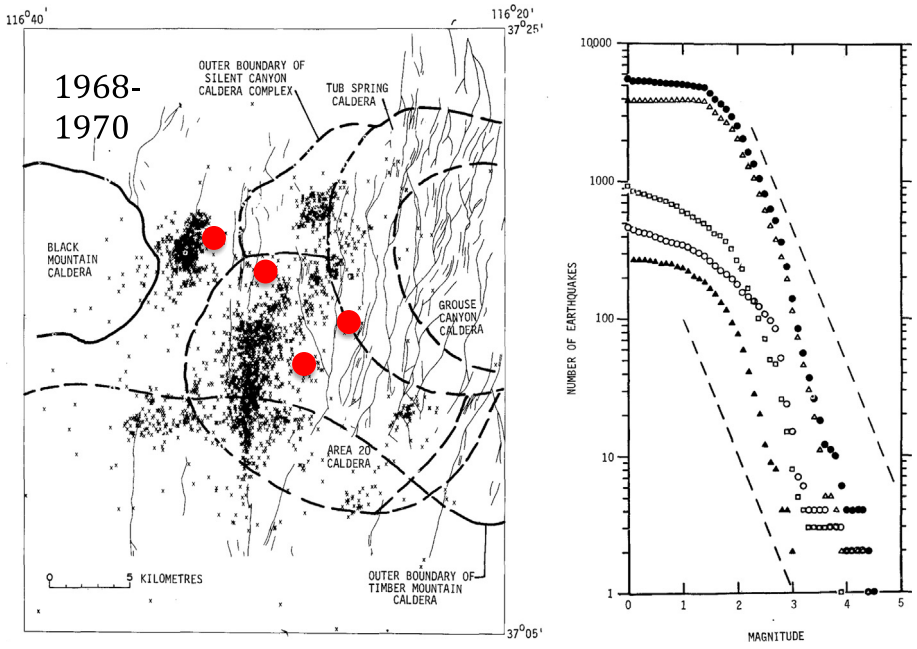


Fig. 83. Left: Epicenters of aftershocks of the Benham (1968), Jorum (1969), Purse (1969), and Handley (1970) nuclear explosions at the Nevada Test Site. Heavy lines: caldera boundaries; light lines: basin-range faults; red dots: locations of nuclear explosions. Right: Frequency-magnitude distribution for aftershocks in Pahute Mesa (from Hamilton et al., 1972). Dots: entire recording period; open triangles: the period Benham to Purse; solid triangles: Purse to Jorum; circles: Jorum to Handley; squares: Handley to the end. Dashed lines have a slope of −1; the data above M 2 define *b*-values of about −1.4 (from McKeown, 1975).

time. Davis and Pennington (1989) suggested that the earthquakes correlated with injection volume and high reservoir pressure gradients.

Gas injection began in 2001 and grew to a constant, high level of ~40 × 10^6 m^3/month from 2004. It was introduced at ~2.1 km depth, 20 MPa pressure and 75 °C, under which conditions CO_2 is supercritical. In 2006, after 23 years of seismic quiescence and following a significant increase in gas injection rate, earthquakes began again. Over the following five years 18 events with M > 3 occurred and in 2011 one of M_W 4.4.

A 21-month period March 2009–December 2010 could be studied in detail because at this time USArray, a rolling program to cover the entire country with temporary seismic stations,[8] swept across Texas. During this period the network recorded 93 locatable events, many within 2 km of wells actively injecting gas. Locations and focal mechanisms showed that the events occurred on previously unknown faults. Although the neighboring Kelly-Snyder and Salt Creek Fields have similar operational histories, seismicity is not induced in them.

4.2.3. Carbon Capture and Storage (CCS)

In the case of Carbon Capture and Storage (CCS), in addition to causing a nuisance, induced earthquakes could rupture the impermeable containment caprock that contains the CO_2 in the storage reservoir, and release it back into the environment. Carbon geostorage is in its infancy, but 20–30 tests are already underway globally, including eight operational commercial-scale plants.[9] Of these, three are seismogenic. An illustrative range of seismic responses is provided by the Sleipner Field, the Weyburn Field (Saskatchewan, Canada) and In Salah

[8] http://www.usarray.org.

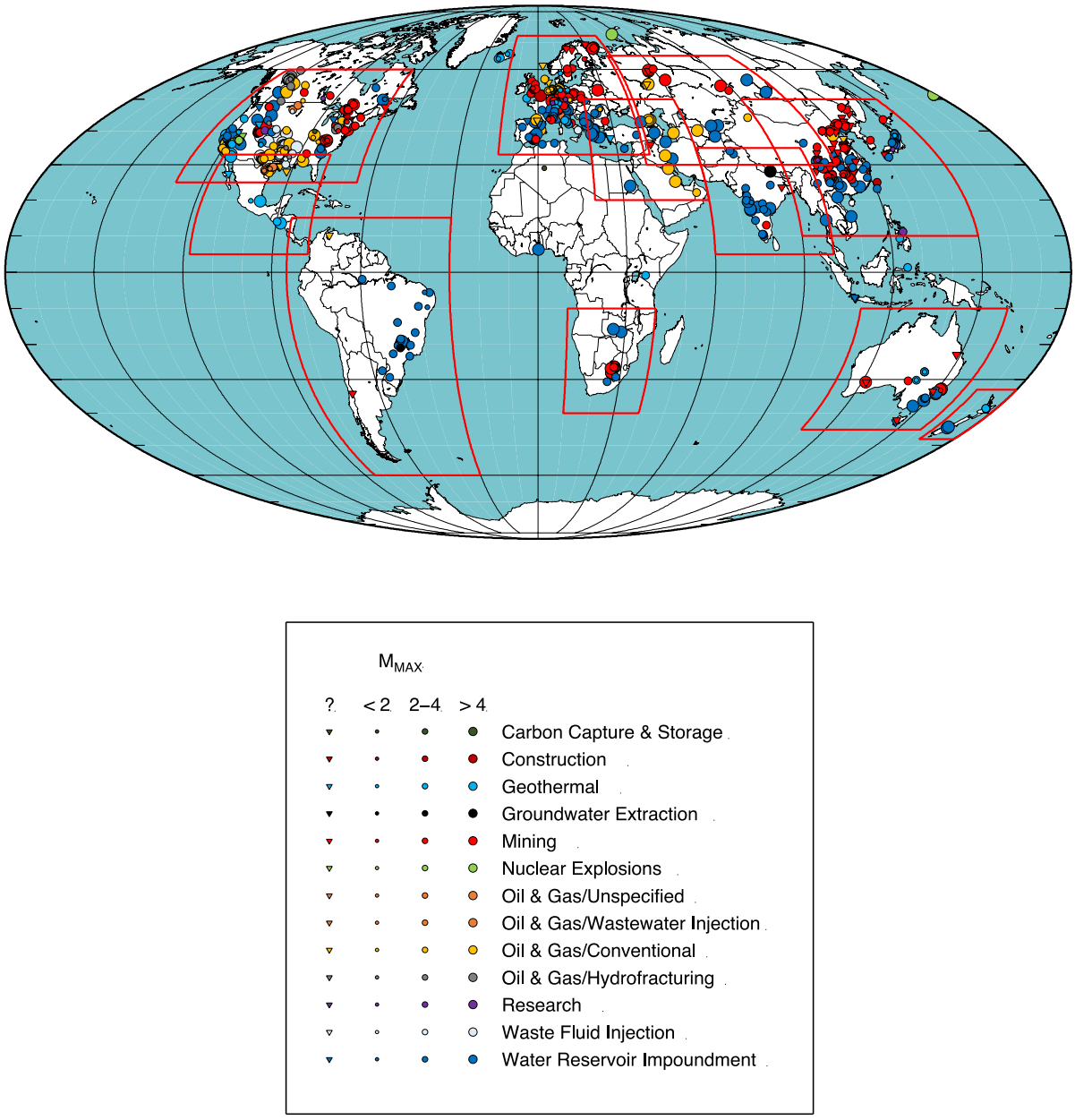


Fig. 84. Cases of human-induced seismicity world-wide, in Mollweide projection, centered on the Greenwich meridian. Colors of symbols indicate different categories of seismogenic activity. Circle sizes indicate the magnitudes of the largest reported induced earthquakes in each category, and inverted triangles indicate cases for which this magnitude was not reported. Red boxes show the locations of the regional maps.

(Algeria) (Verdon et al., 2013).

Since 1996 $\sim 10^6$ t/year of CO_2 has been removed from the natural gas produced from the Sleipner Field (Norwegian North Sea) and re-injected into a shallow saline aquifer (the Utsira Formation). This aquifer is large and comprises well-connected, little-faulted sandstone with high porosity and permeability at ~1 km depth beneath North Sea mean sea level. By 2011 the total volume of CO_2 injected amounted to only ~0.003% of the available pore space. No pore-pressure increase, mechanical deformation or seismicity has been detected for the entire > 20 years of injection. The Sleipner Field is, however, not seismically monitored locally so small earthquakes would go undetected. The nearest earthquakes to the Sleipner Field listed in the British Geological Survey catalog are a M_L 3.5 event at 1 km distance and a M 2.5 earthquake at 6 km distance. The uncertainties in these locations are large.

The Weyburn Oilfield, Saskatchewan, Canada, has been exploited for 45 years and is somewhat seismogenic. CO_2 injections started in 2000 both for enhanced oil production and CO_2 sequestration and now $\sim 3 \times 10^6$ t/year are injected annually. This is accompanied by minor, low-magnitude earthquake activity (Fig. 79). Some earthquakes clustered near injection wells, but no clear temporal correlations are apparent.

In contrast, vigorous earthquake activity accompanied CO_2 sequestration at the producing In Salah Gasfield, Algeria. There, CO_2 was injected into a low-permeability, 13–20% porosity, ~20-m-thick fractured sandstone in a non-producing, water-dominated part of field at 1850–1950 m depth. Hundreds of earthquakes accompanied surface uplift.

CO_2 injection at In Salah 2004–2013 amounted to a total of $\sim 3.85 \times 10^6$ t of CO_2 which was produced from nearby gas wells and

[9] http://www.ccsassociation.org/faqs/ccs-globally/.

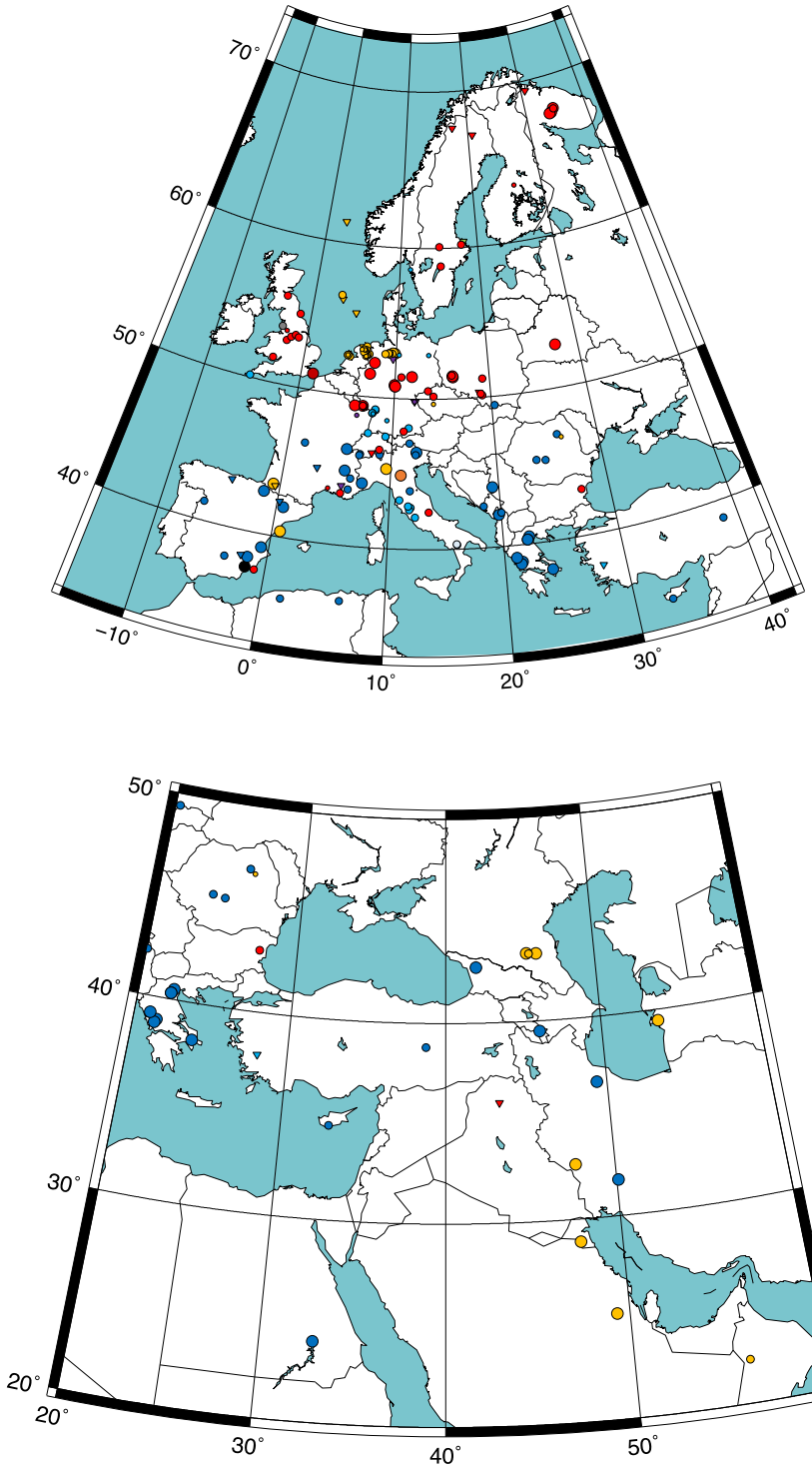


Fig. 85. Same as Fig. 84 except for (top) Europe, and (bottom) Middle East.

re-injected via horizontal boreholes. There was little pressure communication with the producing part of the field. Pore pressures increased from initial conditions of ~18 MPa at the injection points to ~30 MPa while reducing in the production parts of the reservoir (Fig. 80). Deformation monitoring detected surface-blistering type uplift of up to ~1 cm/year locally around the injection wells.

A nearby borehole seismometer detected over 1000 events in 2010. The data were consistent with locations in the receiving formation beneath the injection well though there was no correlation with CO_2 injection (Fig. 81). The project was subsequently terminated because of seal integrity concerns.

Verdon et al. (2013) conclude that at Sleipner, where the target aquifer is large and pressure increases during injection minimal, little deformation, either seismic or aseismic, results. At Weyburn, deformation and seismicity may be partly mitigated by ongoing oil extraction which serves to offset pressure increase resulting from the CO_2 injections. At In Salah, however, the formation into which CO_2 is injected had poor pressure communication with the producing parts of the reservoir and natural gas extraction did not compensate for the injections. Pore pressures increased as a consequence leading to both seismic and aseismic deformation.

Another seismogenic CCS demonstration site is at Decatur, Illinois

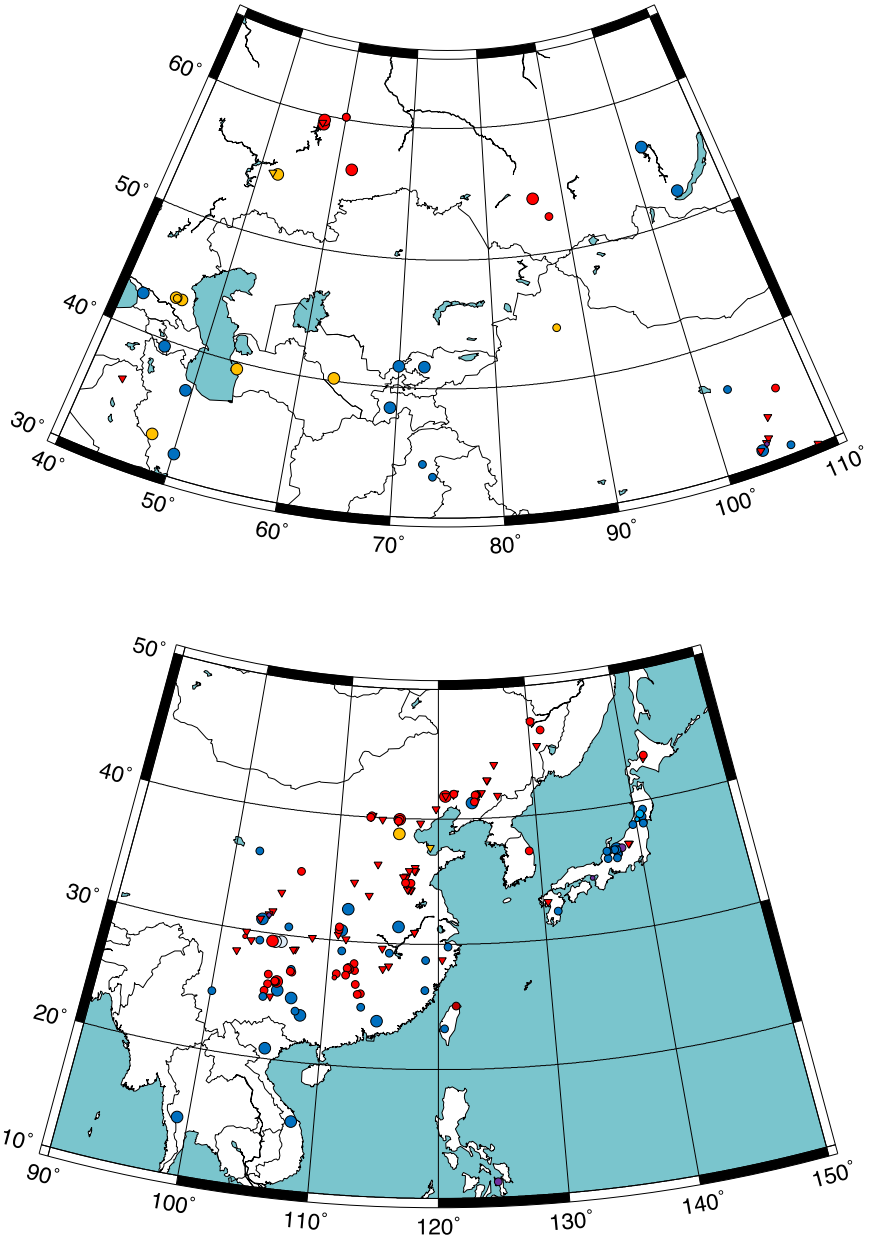


Fig. 86. Same as Fig. 84 except for (top) central Asia, and (bottom) east Asia.

(Kaven et al., 2015). There, ~10^6 t of supercritical CO_2 were injected over a period of three years at a depth of 2.1 km into a regionally extensive, 460-m-thick high porosity/permeability sandstone. The CO_2 used is a by-product of local ethanol production. Approximately 180 earthquakes up to M_W 1.26 occurred over about two years within a few kilometers of the injection well and at the approximate depth of injection. Kaven et al. (2015) concluded that earthquakes nucleated on preexisting faults in the basement well oriented with respect to the regional stress field. Little seismic hazard is posed to the host formation because the earthquakes are remote and small.

All other CCS projects have been shorter in duration and with total volumes no more than 10s or 100s of thousands of tonnes. CCS projects have developed recently in China where eleven projects are reported (Huaman and Jun, 2014). Limited information is available on these projects and none regarding seismicity induced.

4.2.4. Injection into the subsurface: summary

Diverse fluids are injected into the ground for various reasons and related seismogenic behavior is variable. For most projects no earthquakes are reported. For others, small earthquakes occur that are of insufficient general interest to publish details. For a small minority induced seismicity is sufficiently troublesome to hinder operations or result in project abandonment.

Correlations between seismic and operational parameters vary. Earthquakes thought to be induced may be co-located with injections to 10 s or 100 s of meters or they may occur tens of kilometers away. Earthquakes may begin as soon as operations start or be delayed for decades. Small operations may induce large earthquakes and large operations may be aseismic.

Why is Oklahoma highly seismogenic while large-scale injection projects are conducted in many states of the USA without nuisance earthquakes occurring? We are not aware of any current theories as to why this is.

5. Explosions

Since the first test of a nuclear device, the Trinity explosion of July 16, 1945, approximately 2000 such tests have been conducted by eight

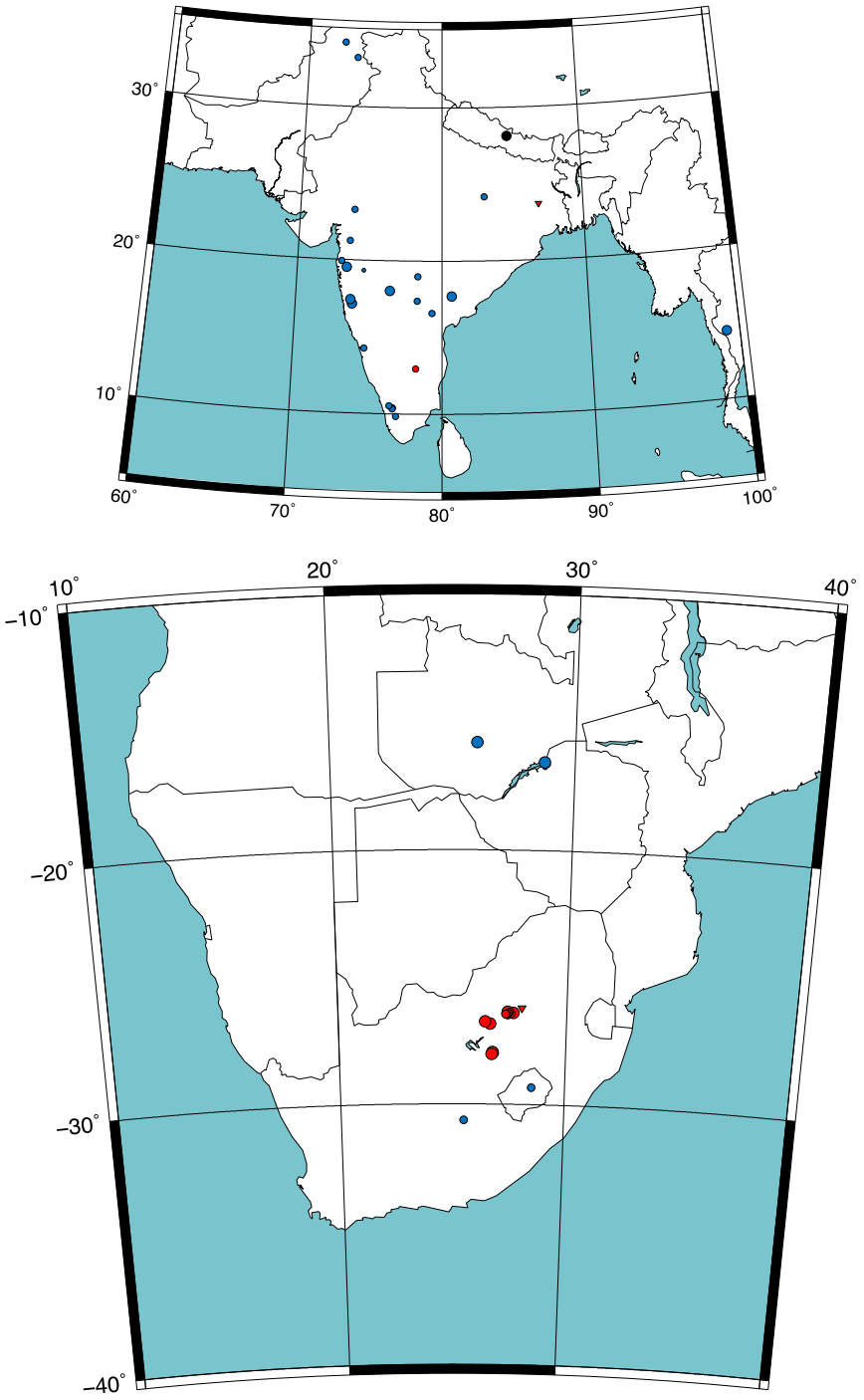


Fig. 87. Same as Fig. 84 except for (top) India and vicinity, and (bottom) southern Africa.

nations, 1352 of them underground. Seismicity was reported to be associated with 22 of these, 21 in the USA and one in Russia (Boucher et al., 1969; Engdahl, 1972; Hamilton et al., 1972; McKeown, 1975; McKeown and Dickey, 1969).

American nuclear tests were conducted at the Nevada Test Site for the 48-year-period 1945–1992 (Fig. 82). Boucher et al. (1969) investigated the possibility of induced seismicity associated with 16 nuclear tests by searching the University of Nevada database of earthquake locations. They reported induced earthquakes after all of the 10 tests where the explosion itself registered $m_b \geq 5.0$. The explosions themselves are not included in the *HiQuake* database. The largest earthquake induced was at least one magnitude unit smaller than the inducting explosion. Earthquakes may have been induced by many, if not all of the tests, but been too small to be clearly recorded.

A test ironically named Faultless (19/1/1968) induced clearly visible surface slip on faults up to 40 km away, even though the test was only one megaton in yield. Ground deformation associated with this, and other nuclear tests, has been captured on film (McKeown and Dickey, 1969).[10]

Detailed studies of the seismicity induced by large nuclear tests were done for the Benham (19/12/1968), Purse (07/05/1969), Jorum (16/09/1969) and Handley (26/03/1970) tests (Fig. 83) (Hamilton et al., 1972; McKeown, 1975). Earthquakes occurred immediately after the tests and clustered on Pahute Mesa where a 4-km-thick sequence of volcanic rocks contains both caldera- and basin-range-type normal

[10] See, for example, https://www.youtube.com/watch?v=6ETHnsKnKiA.

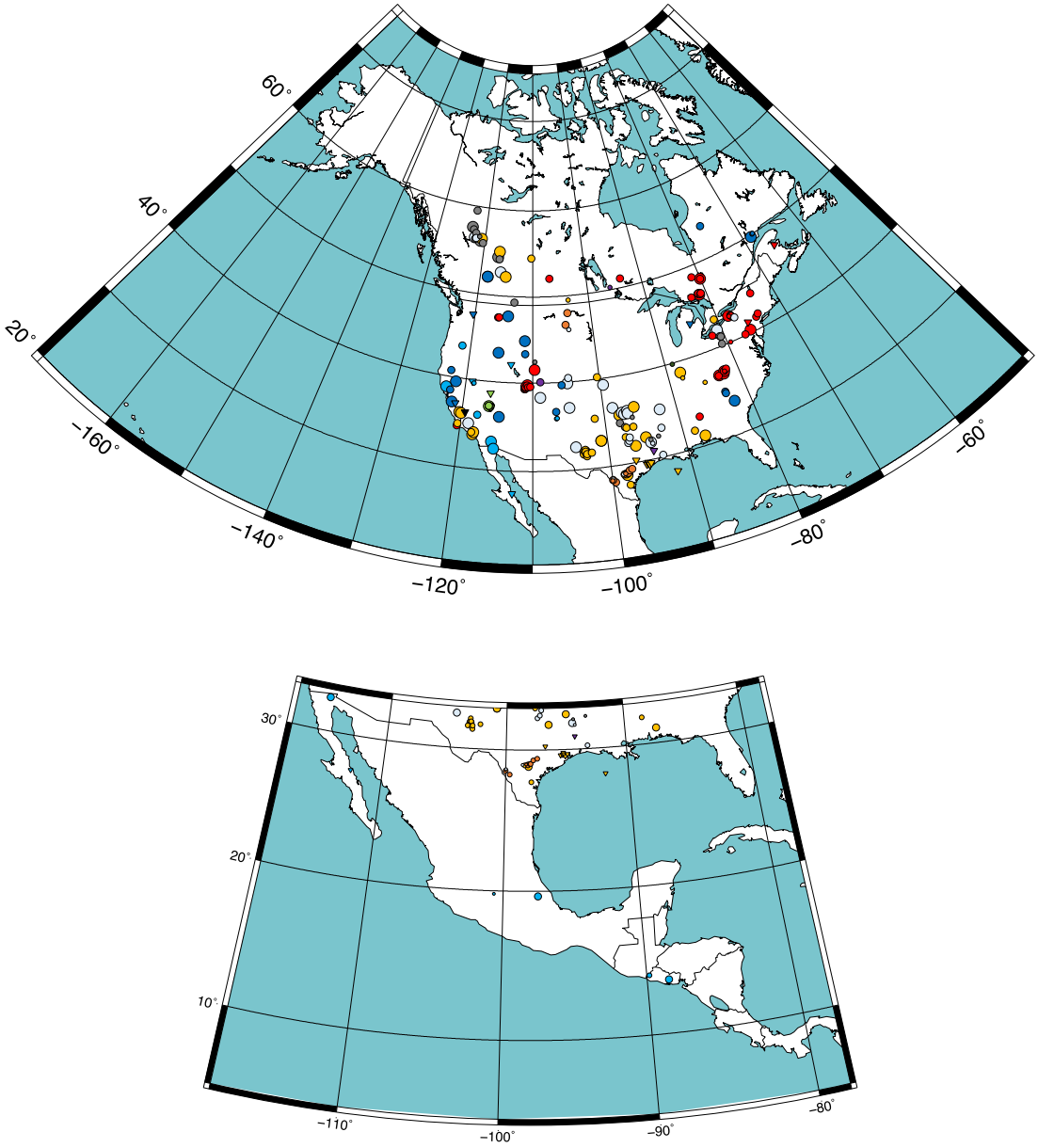


Fig. 88. Same as Fig. 84 except for (top) North America, and (bottom) central America.

faults. Most of the earthquakes induced occurred 10–70 days after the tests, at < 5 km depths and closer than ~15 km to ground zero. The locations of the earthquakes were mostly controlled by local geological structure and lay on faults in the caldera ring-fracture zones (Fig. 83) (McKeown and Dickey, 1969).

Underground nuclear tests in Amchitka, Alaska, resulted in permanent displacement on faults up to 1 m in the vertical and 15 cm in the horizontal for faults up to 8 km long (McKeown and Dickey, 1969). Both the Milrow (1969) and Cannikin (1971) tests generated several hundred small earthquakes with M < 4, thought to be related to deterioration of the explosion cavity. The sequences concluded with large, complex events and simultaneous subsidence of the surface resulting from final collapse of the explosion cavity. In the case of the Cannikin test, small events continued up to 13 km from ground zero for several weeks. The earthquakes are thought to have released ambient tectonic stresses. The more modest post-test seismic response from tests in Amchitka compared with those conducted in Nevada may result from the lower level of tectonic stress (Engdahl, 1972). Tectonic stress is also released simultaneously with the explosions themselves, as shown by blast focal mechanisms involving both shear and explosive components (Fig. 22) (Toksöz and Kehrer, 1972; Wallace et al., 1983). The largest earthquake induced by a nuclear test had a magnitude of m_b 4.9 and was associated with collapse of the cavity of the Cannikin, Amchitka test.

Most large chemical explosions are associated with rocket launching, military research and operations, and accidents in the military, space-program and industrial sectors. Such explosions may be equivalent of several kilotonnes (kt) of TNT. They occur at the surface on land or on ships and are thus poorly coupled to the ground. Tsunamis, but not earthquakes, have been reported in association with some of these.

It has been suggested that deep penetrating bombs may modulate earthquake activity. Balassanian (2005) examined earthquake activity over ~2-year periods spanning bombing incidents at Kosovo, Yugoslavia (1999), Baghdad, Iraq (1991), Tora Bora, Afghanistan (2001) and Kirkuk, Iraq (2003). It was suggested that the incidence of M ≥ 5 earthquakes increased within 1000 km and one year of the bombings at Kosovo and Tora Bora but not after those at Baghdad and Kirkuk.

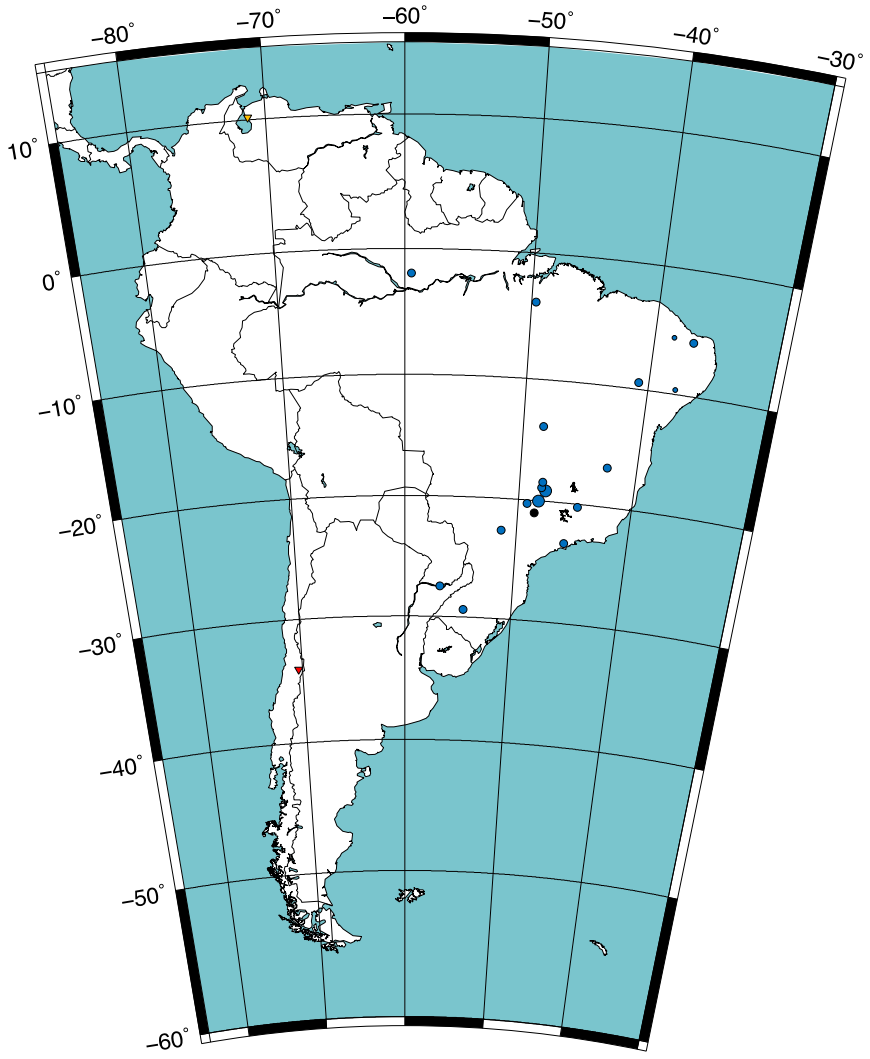


Fig. 89. Same as Fig. 84 except for South America.

Arkhipova et al. (2012) suggested that the 23 October 2011 M 7.8 Van earthquake, eastern Turkey, was encouraged by mass bombing associated with the Libyan conflict, 1300–1500 km away.

Deep penetrating bombs explode at depths of a few meters in the ground, improving the coupling by factors of several tens of percent compared with equivalent surface explosions. Nevertheless, deep penetrating bombs are generally not larger than the equivalent of ~1 kt of TNT, much smaller than the megatonne- or multi-megatonne scale typical of nuclear devices reported to have induced earthquakes. In the case of the nuclear tests, earthquakes have been induced out to a maximum of ~40 km away and activity has decayed away over periods of a few days or weeks (Boucher et al., 1969). Given the relatively small subsurface effects of chemical explosions and the great distances and relatively long time delays of earthquakes postulated to have been induced by them, these suggestions must be considered speculative.

6. Summary

Human-induced earthquakes are reported from every continent except Antarctica (Fig. 84). Figs. 85–90 show regional maps for Europe, the Middle East, central- and east Asia, India and vicinity, southern Africa, North-, central- and South America, Australia and New Zealand. Induced seismicity correlates with industrial activity and not with tectonic plate boundaries.

The magnitudes of the largest earthquakes (M_{MAX}) associated with projects of different types vary widely. The largest have been reported for water reservoirs, conventional oil and gas exploitation, and geothermal operations. Median magnitudes also vary between project types but the most commonly reported are $3 \leq M < 4$ which apply to water reservoirs, construction, conventional oil and gas, hydrofracturing, mining, and research projects. For some types of project the number of cases reported is small. For all project types it is essentially certain that large numbers of smaller induced earthquake sequences have not been reported.

Relationships between seismic and operational parameters have been suggested for a number of projects. For example, seismic moment released and volume injected correlate in shale gas hydrofracturing operations at the Etsho area, Horn River Basin, British Columbia (Fig. 67) (Farahbod et al., 2015). Of interest for future projects is what correlations might exist for all projects of the same kind.

From the point of view of nuisance, the magnitudes of the largest earthquakes induced are the most important. Seismic rate and total number of earthquakes are of secondary importance because the fractal nature of earthquakes means that most are small. Because a large and systematic part of the true dataset is missing (i.e. the unreported cases) correlations with operational parameters cannot convey any information on average M_{MAX}. Of interest is whether *the largest* M_{MAX} for projects of a particular kind correlates with operational parameters.

Fig. 91 shows a plot of M_{MAX} vs. water reservoir volume for 126 cases. The magnitude of *the largest* M_{MAX} (i.e., the apparent M_{MAX} ceiling) increases with reservoir volume. However, there is no correlation between M_{MAX} and reservoir volume for the dataset as a whole. If

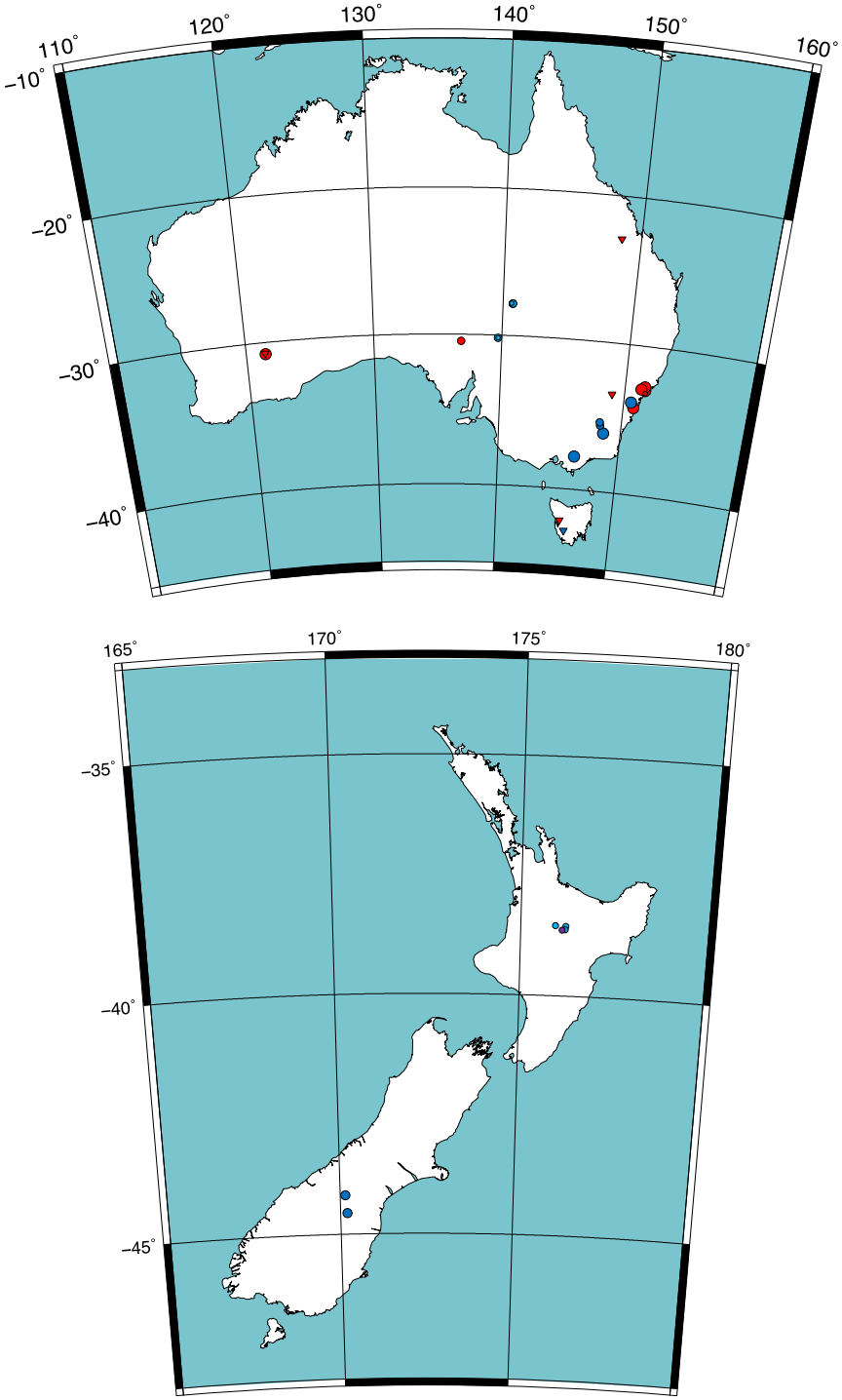


Fig. 90. Same as Fig. 84 except for (top) Australia, and (bottom) New Zealand.

reporting were complete, the region of the plot beneath the observed M_{MAX} upper bound would probably be entirely populated with points. Because the reported data are biased in this way we have not calculated correlation coefficients between all values of M_{MAX} and other parameters.

Relationships observed include:

- *Water reservoir volume* (Fig. 91): Volumes plotted range from 0.004 km^3 to 164 km^3. There is a nearly linear boundary to the upper left of the cloud of points which suggests a relationship between reservoir volume and largest observed M_{MAX}. The 2008 M_W ~8 Wenchuan, China, event, which is disputed because of its seemingly disproportionately large size, also plots on this alignment.
- *Water reservoir mass per unit area* (Fig. 92): The largest M_{MAX} (i.e. the upper bound of M_{MAX}) increases with reservoir water mass per unit area.
- *Volume added or removed in surface operations* (Fig. 93): The largest M_{MAX} increases with this parameter.
- *Volume of material removed from the subsurface* (Fig. 94): We combined conventional oil and gas, geothermal, and mining-produced volumes. The largest reported M_{MAX} increases with volume removed. The relationship for M_{MAX} for injection volumes proposed by McGarr (2014) on the basis of theoretical considerations fits these data well (Fig. 95).

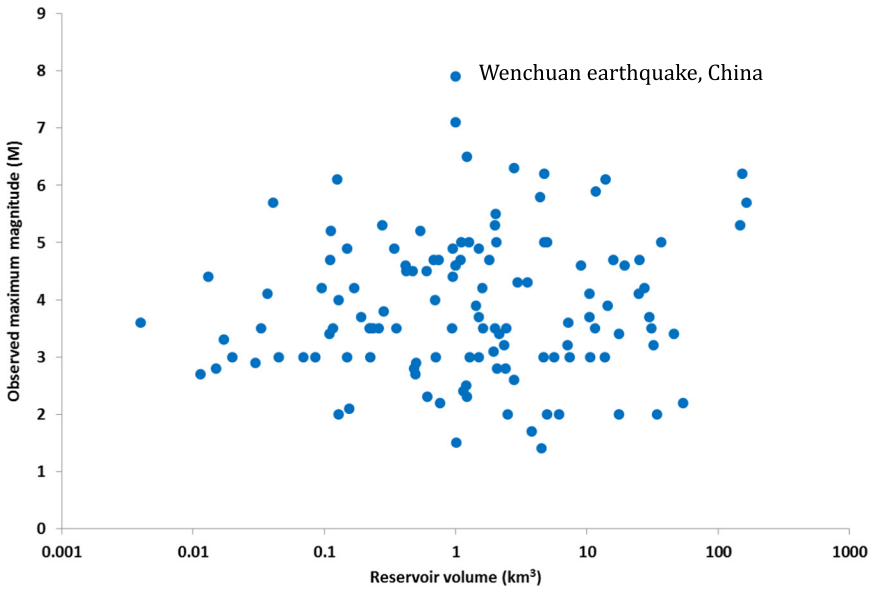


Fig. 91. Plot of M_{MAX} vs. water reservoir volume for the 126 cases for which data are available.

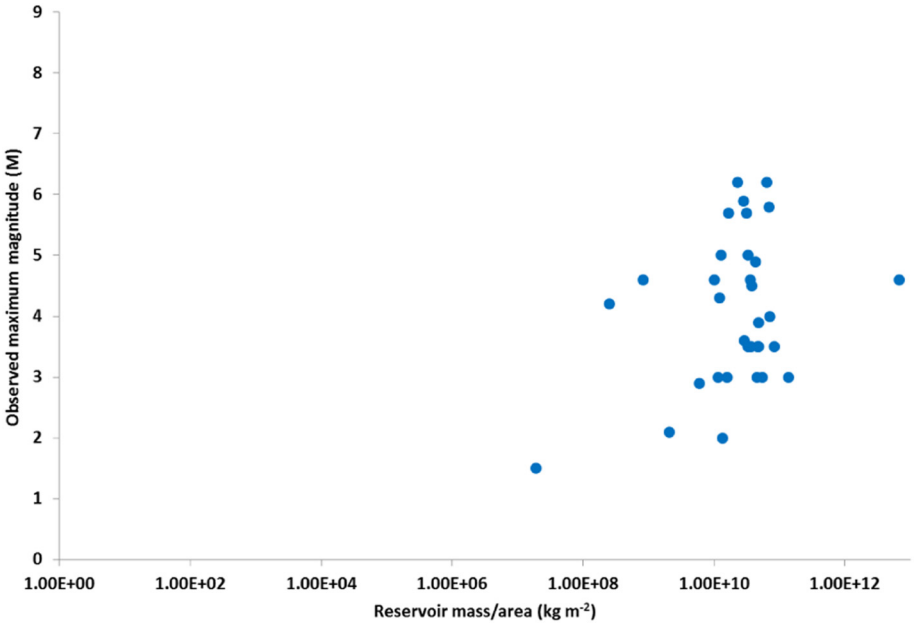


Fig. 92. Plot of M_{MAX} vs. water reservoir mass per unit area for the 33 cases for which data are available.

- *Shale-gas hydrofracturing – injection pressure, rate and volume* (Fig. 96): The largest M_{MAX} increases with all these parameters, in agreement with the relationship proposed by McGarr (2014).
- *Injected volume for all projects* (Fig. 97): Data from 69 cases are available to study this parameter. The largest earthquake plotted is the 2011 M_W 5.7 Prague, Oklahoma, event. This and a small number of additional earthquakes, mostly postulated to be induced by waste fluid injection, slightly exceed the upper-bound magnitude limit proposed by McGarr (2014).
- *Injection pressure* (Fig. 98): Data are available for 79 cases. Pressures range from atmospheric to 89 MPa. There is a tendency for the largest M_{MAX} to reduce with maximum injection pressure.
- *Volume or proxy volume removed from or added to the subsurface* (Fig. 99): We calculated volume or proxy volume (mass converted to volume using an appropriate density) for 218 cases. There is a clear upper bound to M_{MAX}. The relationship proposed by McGarr (2014) for injection volumes fits this wider dataset well with a few exceptions.
- *Mass removed from or added to the subsurface* (Fig. 100): As for volume, there is a clear linear observed upper bound to M_{MAX}.
- *Yield of nuclear devices* (Fig. 101): M_{MAX} for induced earthquakes correlates with explosion size for the seven cases for which data are available. This finding is in agreement with the correlation between the activated-fault length and explosive yield at Pahute Mesa, Nevada Test Site (McKeown and Dickey, 1969).
- *Project scale* (Fig. 102): We updated the plot of McGarr et al. (2002) with 20 additional cases. The data generally confirm the earlier observations. Two cases exceed the empirical upper bound of McGarr et al. (2002)–the 1979 M_L 6.6 Imperial Valley, California, earthquake (linked to the Cerro Prieto geothermal field; Section 3.4) and the 2008 $M_W \sim 8$ Wenchuan, China, earthquake (Section 2.1.1).
- *Project type* (Fig. 103): The largest earthquakes postulated to have been induced, in order of decreasing magnitude, are associated with water reservoirs, groundwater extraction and conventional oil and gas operations. These have all been linked to earthquakes with $M > 7$. Only relatively small earthquakes have been postulated to be associated with CCS, research experiments, construction and hydrofracturing. The number of projects in each category varies.

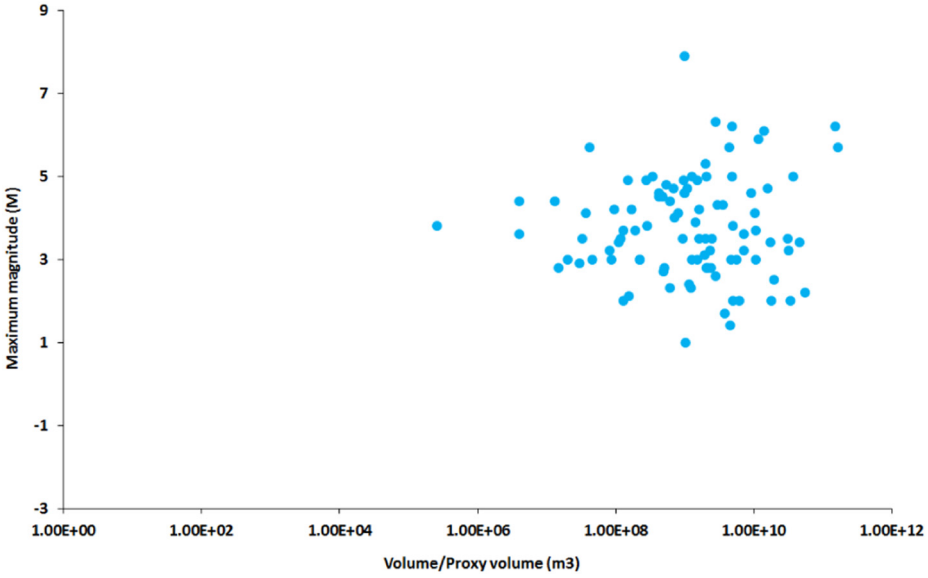


Fig. 93. Plot of M_{MAX} vs. volume added or removed by surface operations.

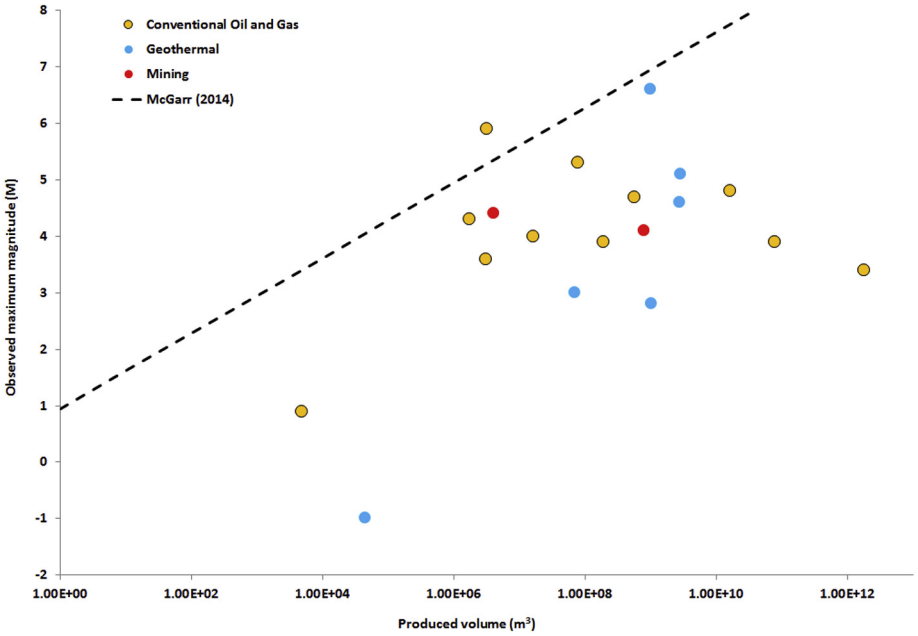


Fig. 94. M_{MAX} vs. produced volume (m^3) for 23 projects that involved extraction of mass from the subsurface. Some of these projects also involved injection, so their association with extraction is not certain. The upper limit to M_{MAX} proposed by McGarr (2014) on the basis of theoretical considerations is also plotted.

- *Distance of epicenter from the inducing project* (Fig. 104): There is a slight tendency for the largest reported M_{MAX} to decrease with distance from the project.

A relationship is not observed for:

- *Dam height* (Fig. 105): Data are available for 159 cases, many from Brazil, China, and the USA.
- *Water reservoir area* (Fig. 106): Areas of seismogenic reservoirs range from 1.6 km^2 to 53,600 km^2. The result that there is no significant tendency for the largest M_{MAX} to increase with reservoir area is perhaps unsurprising because large parts of reservoirs may be shallow.
- *Pressure change in subsurface reservoirs* (Fig. 107): No correlation was found for the 55 cases where data are available.
- *Injection rate for all projects* (Fig. 108): Although some individual projects report correlations there is no clear correlation for projects as a whole.

Fig. 109 shows the distribution of induced earthquakes by tectonic regime. The most numerous cases are from intraplate areas (79% of all cases) with the next largest category (13%) located in convergent plate-boundary zones. Most large industrial projects are conducted on land and most land is in the interior of plates with plate boundaries comprising relatively (though not absolutely) narrow zones. Most spreading plate boundaries are in the oceans and currently beyond reach of industrial development. Because induced earthquakes are mostly in intraplate regions they affect regions not traditionally associated with seismicity nor accustomed to it.

The lack of a relationship between M_{MAX} and operational parameters such as injection rate, coupled with the difficulty of predicting which projects will be seismogenetic and which not, suggests that non-operational parameters are important. The pre-existing stress state is the most obvious such parameter. Several lines of research indicate that most faults in the crust are nearly critically stressed, though they may not be optimally oriented to slip under ambient conditions. The local geology, in particular pre-existing faults and fractures, must be important for understanding the extreme variations in seismogenesis

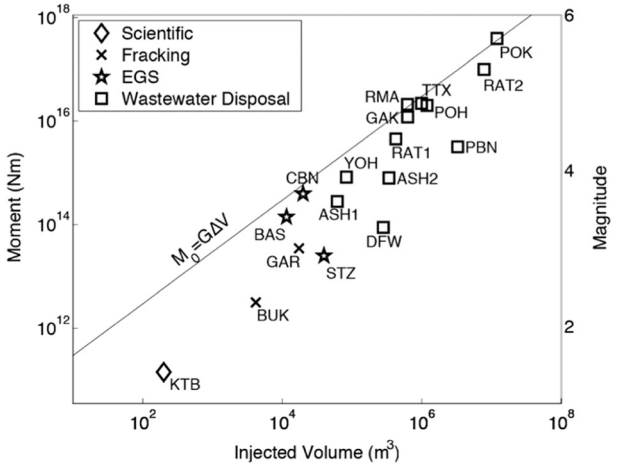


Fig. 95. Maximum seismic moment and magnitude vs. total volume of injected fluid from the start of injection until the time of the largest induced earthquake. The line relates the theoretical upper bound seismic moment to the product of the modulus of rigidity and the total volume of injected fluid, and fits the data well.
(From McGarr (2014).)

between apparently similar projects in different locations. In order for large earthquakes to occur, long faults that are suitably orientated and stressed must pre-exist.

The empirical results of this study have implications for individual projects. For example, at The Geysers geothermal field, California, net production (i.e. total production minus re-injection) since 1960 has been $\sim 1.7 \times 10^9$ m^3. The relationship of McGarr (2014), which links fluid-injection volume to the largest M_{MAX} (Fig. 97) fits well data from all volumetric projects. This relationship predicts that the upper bound to induced earthquakes associated with The Geysers volume change is M 7.0. This geothermal field has a maximum NW-SE long dimension of ~21 km. The largest induced earthquake reported from projects of this scale is ~M 6.6 (Fig. 102). Fig. 110 shows a histogram of numbers of seismogenic geothermal power-producing fields ranked by size (data from Bertani, 2010). The larger the geothermal operation the more likely it is that induced earthquakes are reported.

The largest earthquake that has occurred to date at The Geysers is the 2014 M_W 4.5 event. There is no evidence that a fault long enough to sustain a M 6.6 or 7.0 earthquake exists in the reservoir. However, The Geysers lies between the regional Mercuryville fault to the southwest and the Collayomi fault zone to the northeast, within the active Pacific/North America transform plate boundary zone. There is no evidence that the Mercuryville fault zone is active but the Collayomi fault zone contains at least one active fault (Lofgren, 1981).

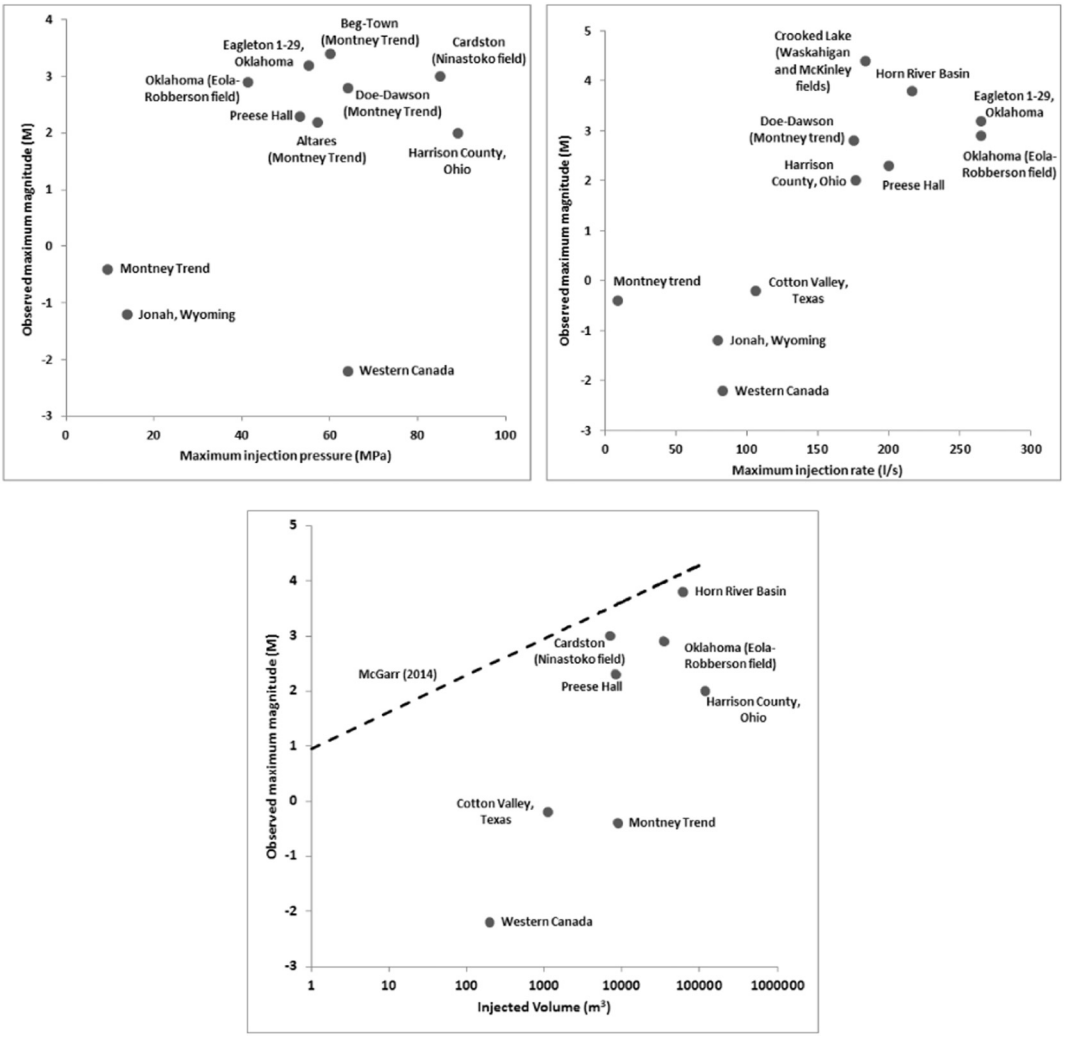


Fig. 96. For all cases of shale-gas hydrofracturing-induced earthquakes in our database where data are available, top left: M_{MAX} vs. maximum injection pressure, top right: M_{MAX} vs. maximum injection rate, and bottom: M_{MAX} vs. injected volume.

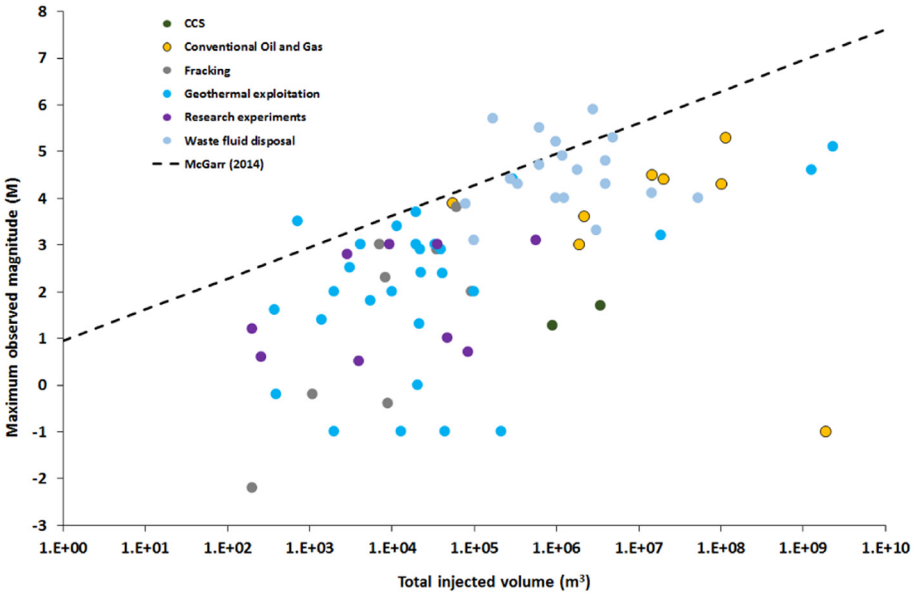


Fig. 97. M_{MAX} vs. total injected volume for the 69 cases of induced seismicity for which data are available. The upper-bound magnitude limit proposed by McGarr (2014) on the basis of theoretical considerations is also plotted.

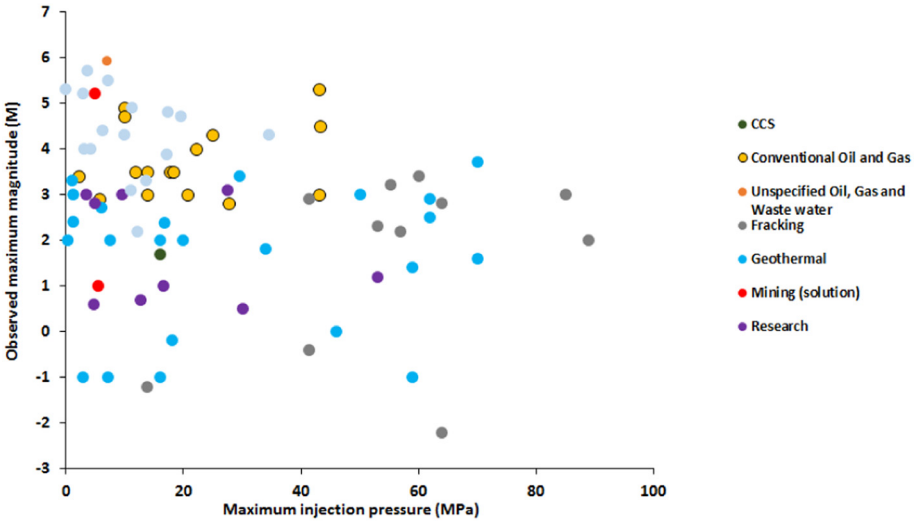


Fig. 98. M_{MAX} vs. maximum wellhead injection pressure for the 79 cases where data are reported.

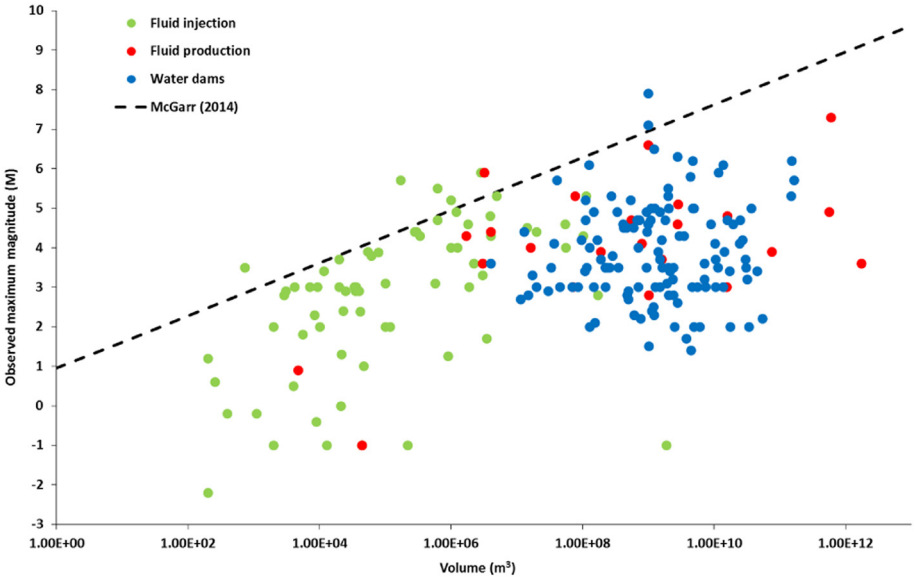


Fig. 99. M_{MAX} vs. volume or proxy volume of material removed or added for the 218 cases for which data are available, along with the relationship proposed by McGarr (2014) on the basis of theoretical considerations. Volumes and proxy volumes were estimated as follows: Water dams–the volume of the impounded reservoir; fluid injection or extraction–fluid volume injected into or extracted from the subsurface; mining–mass of material excavated, converted to volume using an appropriate density; construction–relevant mass converted to volume using an appropriate density for the building materials; CCS–mass of injected CO_2 converted to volume using a density of liquid CO_2 of 1100 kg/m^3.

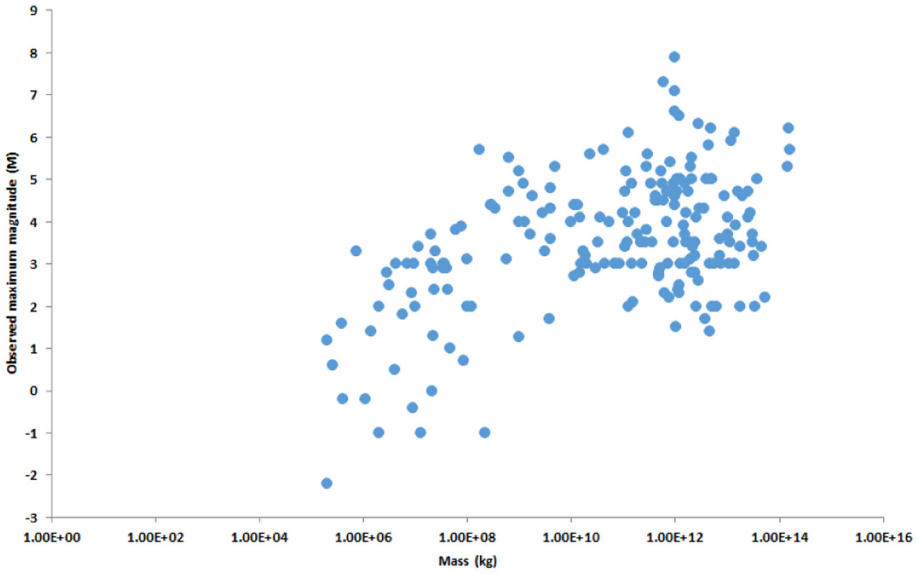


Fig. 100. M_{MAX} vs. mass of material removed or added for the 203 cases where data are available. Water volumes were converted to mass using a density 1000 kg/m^3. Oil and gas are not included in this plot except where quantity was reported in units of mass. Project types plotted include CCS, construction, conventional oil and gas, shale-gas hydrofracturing, geothermal, mining, research experiments, waste fluid injection and water reservoirs.

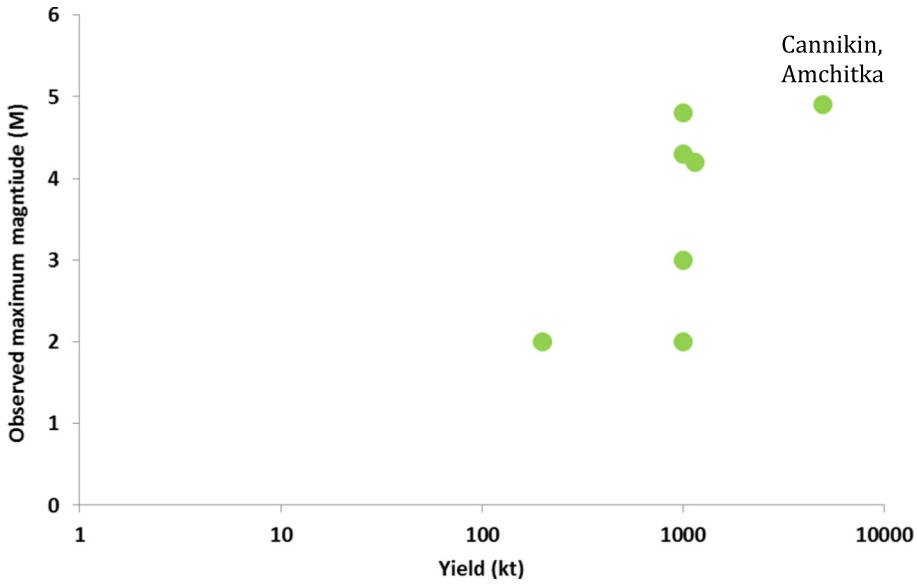


Fig. 101. M_{MAX} vs. yield in kilotonnes for nuclear tests that activated faults for the seven cases reported. Only one of these (Benham) is in common with the dataset of McKeown and Dickey (1969).

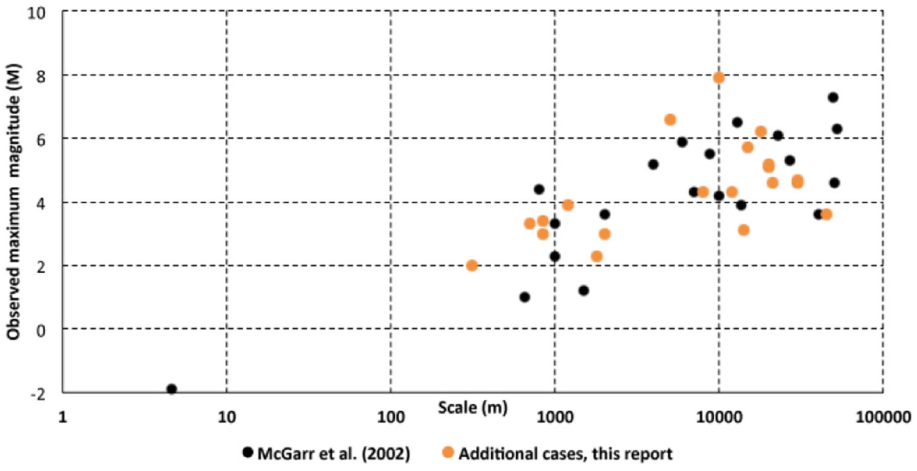


Fig. 102. M_{MAX} vs. project scale in meters. Black dots: cases studied by McGarr et al. (2002); orange dots: 20 additional cases from our database. Project scale was estimated using the longest dimension of the project, e.g., the length of a water reservoir.

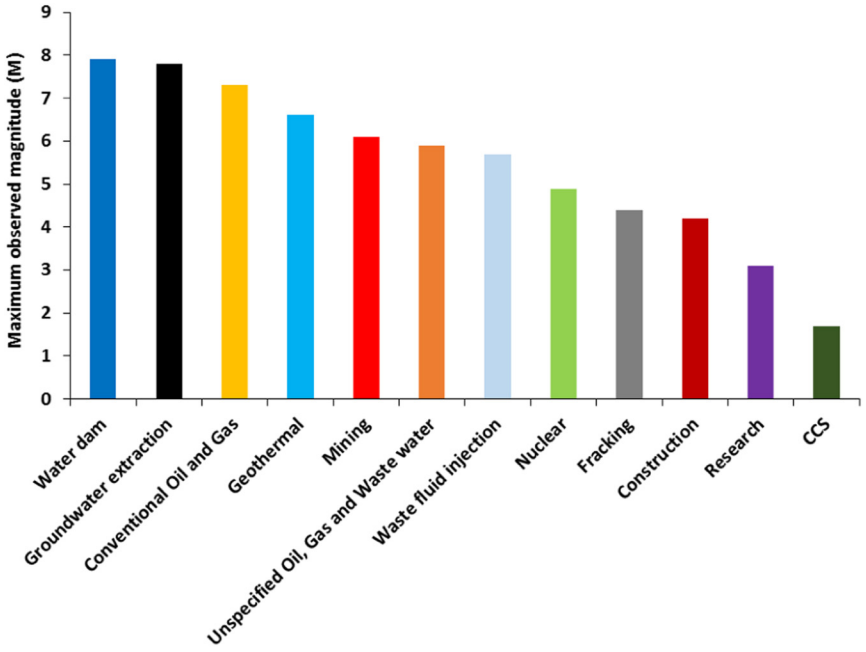


Fig. 103. Histogram of M_{MAX} for different categories of project.

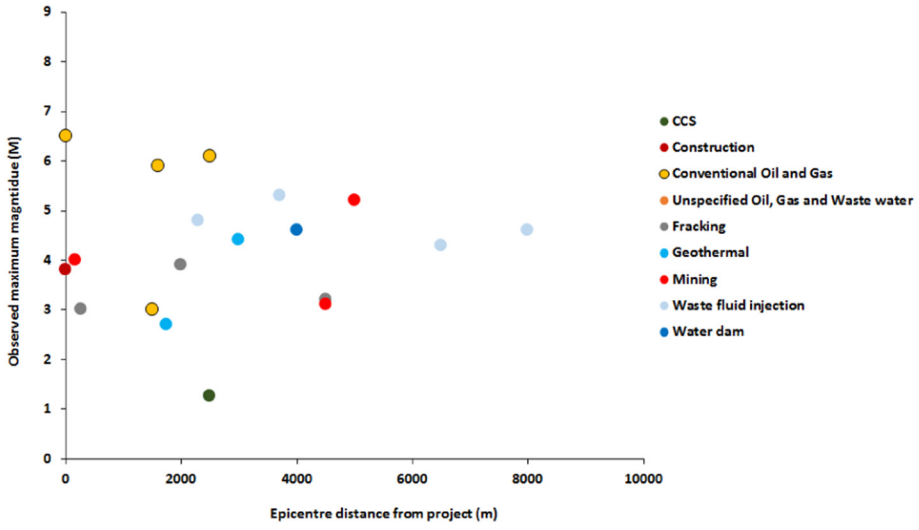


Fig. 104. M_{MAX} vs. distance from project for postulated induced earthquakes up to 10 km away for the 19 cases where data are available.

7. Discussion and conclusions

7.1. How common are induced earthquakes?

The total number of industrial projects in various categories, along with the number reported to be seismogenic are given in Table 3. Without doubt under-reporting is severe. Seismicity at projects remote from settlements is likely to escape notice. Known cases may not be publicized unless they are large and of nuisance or unusual interest. For example, ~2.5 million shale-gas hydrofracture jobs have now been completed world-wide. All successful hydrofracturing projects induce small earthquakes but only 21 cases have been reported (Table 3; Section 4.1.6). The absence of reports of seismicity does not correspond to an absence of seismicity. Statements such as "no seismicity is reported" does not equate to "no induced earthquakes occurred" or "no earthquakes were observed". Some earthquakes may also have been reported by national seismic networks without their induced nature being recognized.

M_{MAX} for the 562 seismogenic projects where this parameter is reported is shown as a plot of cumulative number of cases vs. M_{MAX} in Fig. 111. The linearity of the distribution at the high-magnitude end suggests that reporting is complete for M_{MAX} 5 and above, and that underreporting becomes progressively greater for projects smaller than M_{MAX} 4. Downward extrapolation of the linear, M_{MAX} 5–7 part of the plot suggests that ~30% of M ~4 induced earthquakes have gone unrecognized or unreported, 60% of M ~3 events and ~90% of those with M ~2 (Table 4).

The hydrocarbon fields around Britain provide a regional example of this problem. Comparison of the UK earthquake database of the British Geological Survey with maps of hydrocarbon fields in the North Sea suggests correlations between fields and earthquake locations (Fig. 112). Expanded maps of several fields are shown in Fig. 113. Epicenters cluster near the Beatrice Oilfield (Moray Firth), the Britannia Gasfield, the Southern North Sea Gas Province and the Leman Gasfield.

Most of the recorded earthquakes in the southern North Sea occur in or near fields developed in Permian Rotliegend reservoirs. There, gas is produced using simple pressure depletion from the original hydrostatic pressure. Water is not injected to support production. Many of the poorer-quality wells used to explore and appraise this gas province were prop-fracked to obtain initial gas flow and a few fields (e.g.,

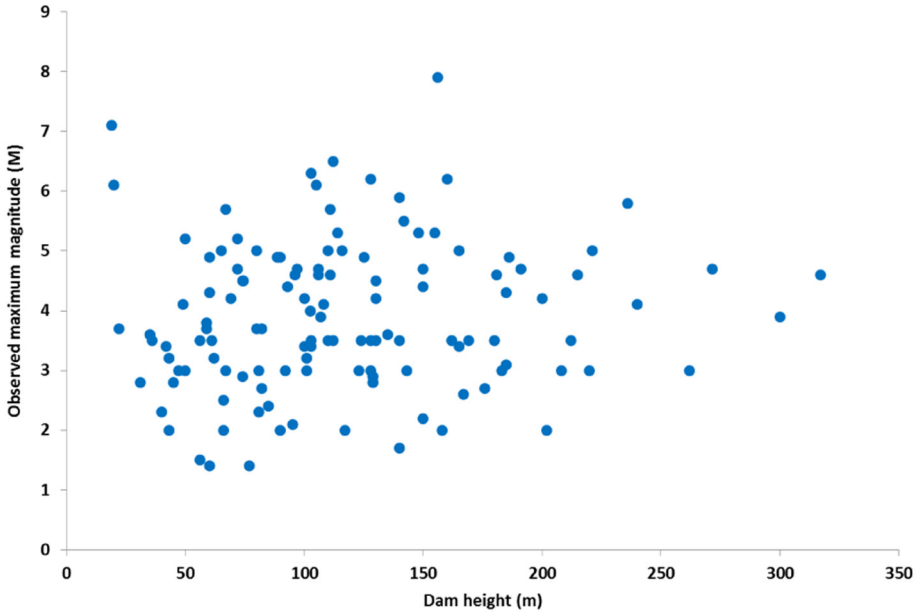


Fig. 105. M_{MAX} vs. dam height for the 159 cases of seismogenic water reservoirs for which data are available.

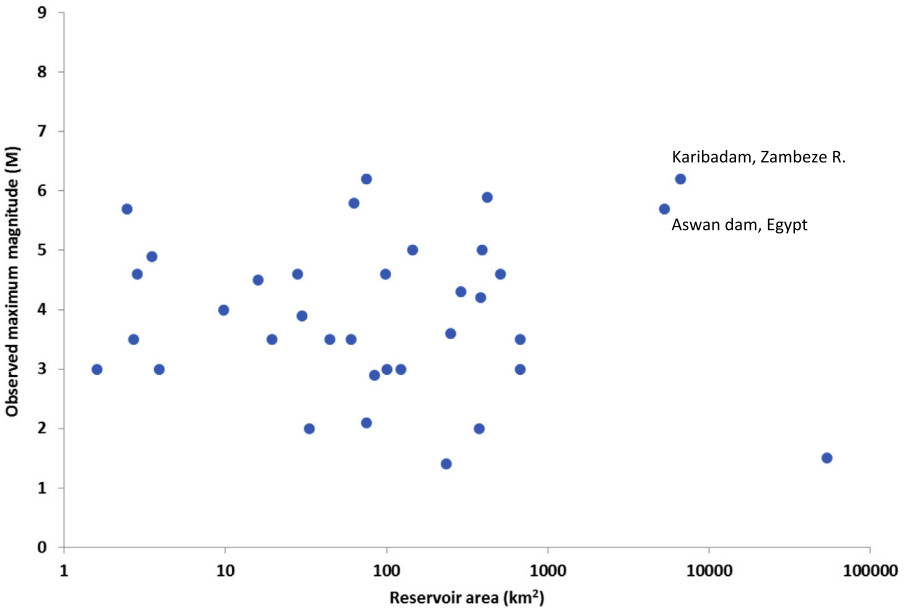


Fig. 106. M_{MAX} vs. water reservoir area for the 35 cases for which data are available.

Clipper South, Gluyas and Swarbrick, in press, 2017; Purvis et al., 2010) used hydrofracturing in development wells. The Viking Graben contains mostly oilfields that were developed by allowing natural pressure decline to deliver the first oil and then injecting water to support continued production. The water used is seawater at typical North Sea temperatures of ~4 °C, while the reservoirs are at 90–140 °C. The central North Sea and Moray Firth contain a heterogeneous mix of oil and gas fields produced by a combination of pressure depletion and water injection. When discovered some fields were naturally at high pressure and close to the fracture gradient.

Many of these activities are potentially seismogenic. Nevertheless, there are no reports of induced seismicity from these fields. Comparison of seismicity with hydrocarbon production information available from DECC for 1975–2008 shows no temporal correlations and, because the North Sea was seismogenic before hydrocarbon production started, it cannot be ruled out that the seismicity is natural. Detailed work on individual events and their possible connection to operations in individual oil and gas fields is required to resolve this ambiguity (Wilson et al., 2015).

7.2. Hydraulics

Groundwater influences earthquake occurrence. Overwhelming, observational data show that pore pressure in fault zones strongly influences seismicity (Section 1.3). The suggestions that large-scale extraction of groundwater influences seismicity imply an unfortunate association between earthquakes and human need to manage water for utilization and flood control.

The five cases we found of earthquakes suggested to be linked to groundwater extraction raise the question of whether other earthquakes that were both shallow and where major water table changes have occurred were induced. An example is the 2011 M 7.1 Christchurch, New Zealand, earthquake (Fig. 114). The city of Christchurch is built on what was once an extensive swamp fed by the rivers Avon and Heathcote and numerous smaller streams. Major engineering works have changed the hydrology there over the last century.

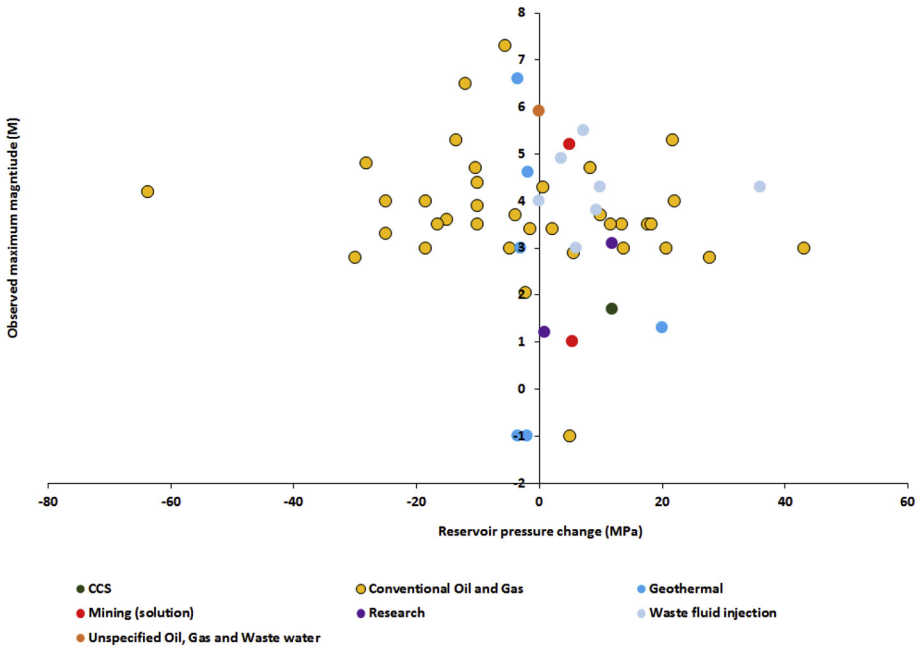


Fig. 107. M_{MAX} vs. change in reservoir fluid pressure resulting from production/injection for the 55 cases where data are available. We include 9 cases of conventional oil and gas where the pressure change results from both injection and production.

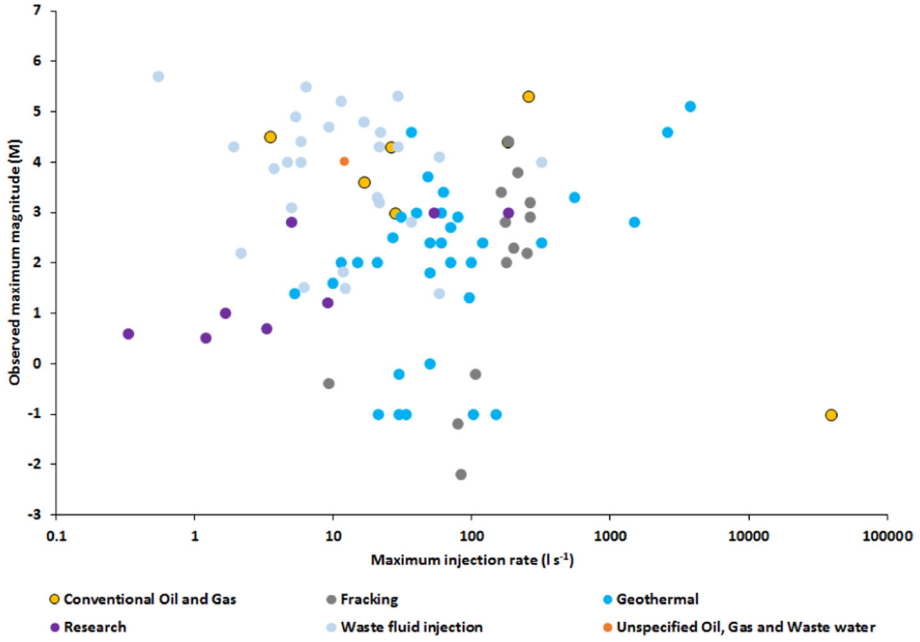


Fig. 108. M_{MAX} vs. maximum injection rate for the 88 cases for which data are reported. Rates of injection varied from 0.33 to ~40,000 l/s. At rates greater than ~1000 l/s, values apply to entire fields rather than individual wells.

The 1811–1812 New Madrid earthquakes occurred in the central Mississippi river valley. This renowned sequence included three M ~7 earthquakes and about seven with M > ~6.5. These earthquakes are remarkable for having been felt at distances of up to 1700 km as a result of efficient transmission of seismic waves through the eastern USA lithosphere. They are also remarkable in occurring in an intraplate area. They are a paradox in any paradigm that expects large earthquakes to occur in plate boundary zones.

The New Madrid earthquakes occurred at and just south of the confluence of the 6000 m^3/s Middle Mississippi and the 8000 m^3/s Ohio rivers which forms the Lower Mississippi River. The possibility that the earthquake activity is linked to local hydraulics has been suggested previously but not seriously entertained. In view of the growing evidence that hydraulic changes can modulate the seismic behavior of faults it may be timely to revisit this possibility with investigation into pre-earthquake hydraulic activity and numerical modeling.

Hydraulic effects may explain why both mass addition and removal can induce earthquakes. This is illustrated by the fact that the commonest earthquake-induction process is mining (i.e. mass removal–38% of cases; Fig. 115) and the second most common is water reservoir impoundment (i.e. mass addition–24%). Hydraulic changes induced by mass redistribution may result in migration of fluid into fault zones, increasing pore pressure. This process may explain the possible induction of earthquakes by erecting the Taipei 101 building (Section 2.1.2). It may also explain earthquake induction by hydrocarbon extraction in the absence of fluid injections, since natural groundwater recharge may occur.

Global earthquake databases show that moderate earthquakes are fairly common near large lakes and reservoirs, e.g., in east Africa, even though induction has not been proposed. Intraplate earthquakes in the UK are not currently understood. At least 21% of UK earthquakes in the

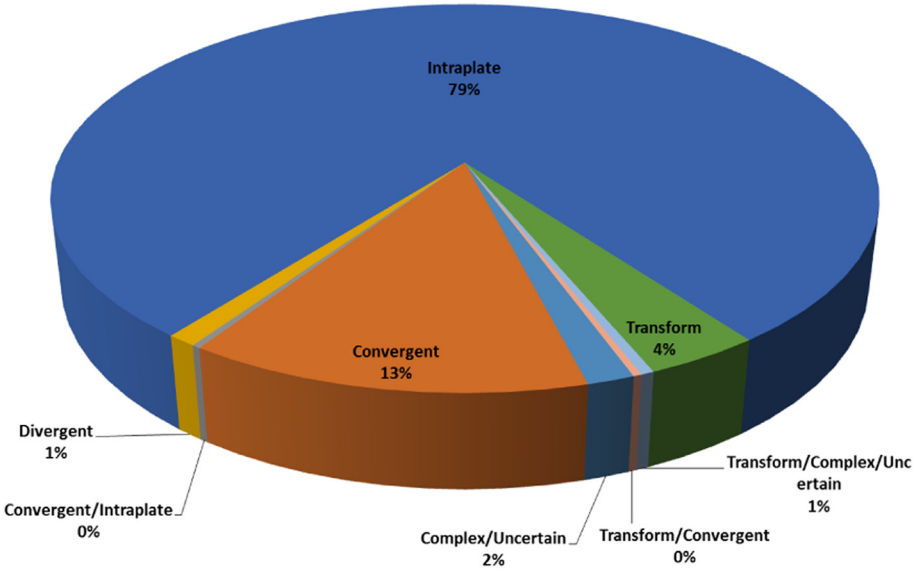


Fig. 109. Tectonic settings of human-induced earthquake activity.

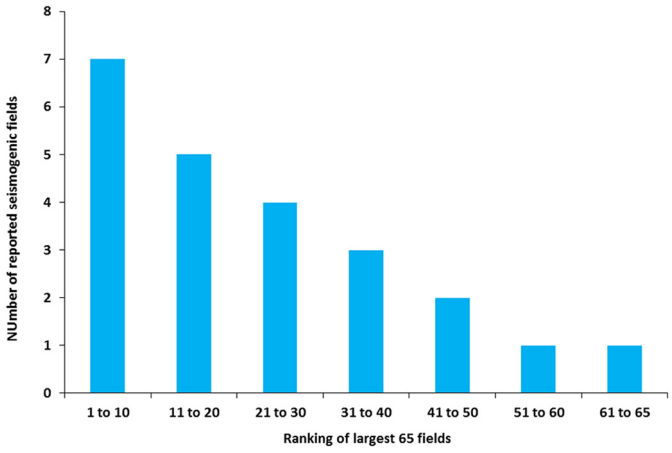


Fig. 110. Number of reports of induced seismicity vs. size of field for the 65 largest global power-producing geothermal fields in groups of 10.

British Geological Survey catalog are thought to be related to mines, but many others are probably natural. The seismic rate in the UK is ~one M_L 3.6 event/year (Wilson et al., 2015). A possible link with hydraulics is under investigation (Graham et al., 2017).

7.3. How much stress loading is required to induce earthquakes?

Earthquakes occur naturally, without any human intervention at all. The minimum amount of added anthropogenic stress needed for an earthquake to start is thus zero.

Many natural processes contribute to stress build-up on faults. These include tectonic deformation, volcanism, natural heat loss, isostatic uplift following deglaciation or oceanic unloading, Earth tides, intraplate deformation resulting from distant plate boundary events, remote large earthquakes, erosion, dissolution, the natural migration of groundwater and weather. To these are added industrial activities. It is an ill-posed question to ask the origin of the final stress increment that "broke the camel's back" and precipitated an earthquake. In the case of large earthquakes this question may be akin to asking whether one particular skier of many was responsible for an avalanche.

Instead of viewing industrial activity as inducing earthquakes, it could instead be viewed as modulating the timescale on which inevitable earthquakes occur. Unfortunately it cannot be known what events would have occurred had the industrial activity not been done because history cannot be re-run with a change of circumstance. Furthermore, had an equivalent earthquake occurred at a different time, it cannot be known if it would have affected people and infrastructure to the same extent. Nevertheless, in the cases of many industrial projects, the association between earthquakes and the project is

Table 3
Induced seismicity statistics for the total numbers of projects of different types, the number that are seismogenic, and related data.

Project type	# projects	# cases in the database	% projects that are seismogenic	Observed maximum magnitude (M_{MAX})	# seismogenic projects reported by Hitzman (2013)	Source for # projects
CCS	75	2	2.67	1.7	–	Huaman and Jun (2014)
Construction	Unknown	2	–	4.2	–	
Conventional oil and gas	67,000 fields	116	0.17	7.3	65	Li (2011)
Fracking	2,500,000 wells	21	0.00	4.4	2	King (2012)
Geothermal	Unknown	56	–	6.6	26	Bertani (2010)
Groundwater extraction	Unknown	5	–	7.8	–	
Mining	13,262 currently active mines	267	2.01	6.1	8 ("other")	http://mrdata.usgs.gov/
Nuclear (Underground)	1352 tests	22	1.63	4.9	–	Pavlovski (1998)
Research	Unknown	13	–	3.1	–	
Waste fluid injection wells (Class II wells)	151,000 wells (USA only)	33	0.02	5.7	11	Hitzman (2013)
Water dam	6862 reservoirs (> 0.1 km^3)	168	2.45	7.9	44	Lehner et al. (2011)
Total		705			156	

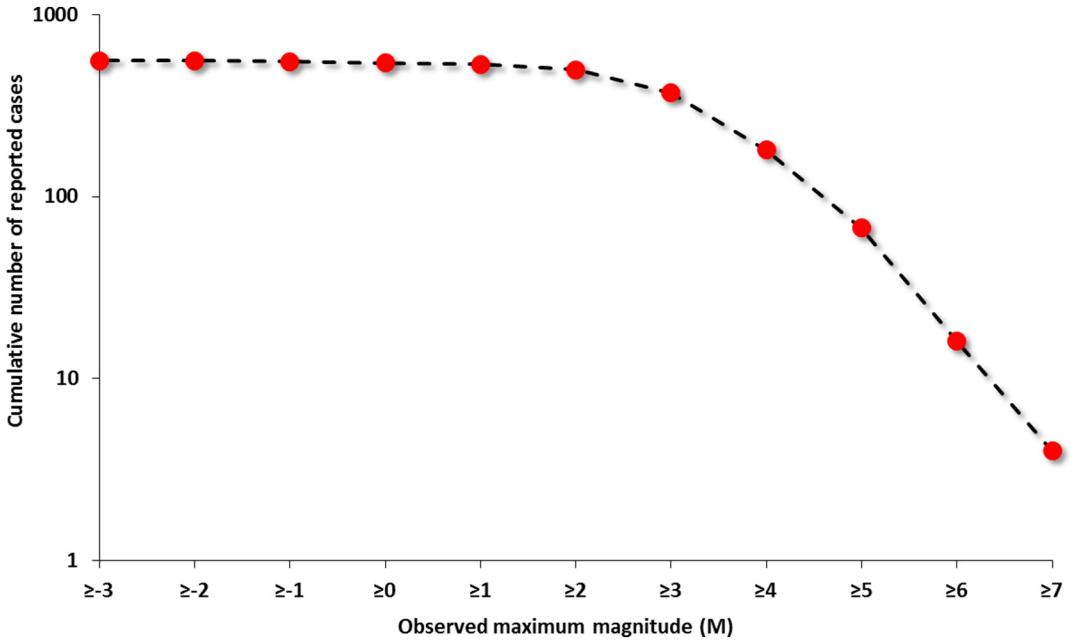


Fig. 111. Cumulative number of reported cases of induced seismicity vs. M_{MAX} for the 562 cases for which data are available.

Table 4
Number of reported M_{MAX} values and number predicted from downward extrapolation of the linear trend of earthquakes with M_{MAX} 5–7 shown in Fig. 111.

M_{MAX}	# reported earthquakes	# predicted earthquakes
7	4	4
6	17	16
5	68	67
4	181	~250
3	371	~1000
2	497	~4000

undeniable. The clear induction of some earthquakes by very small incremental stresses means that objections to induced status on the grounds that the stress perturbation was too small may be weak.

Anthropogenic stress changes proposed to have induced earthquakes range from a fraction of a MPa (e.g., Keranen et al., 2014), the equivalent of about a meter of rock overburden, to several tens of MPa (Table 5) (Fig. 116). For example, both the 2007 M_L 4.2 Folkestone, UK, earthquake and the 2008 $M_W \sim 8$ Wenchuan, China, earthquake have been attributed to anthropogenic stress changes of only a few kPa.

The question "How much stress change is needed to induce earthquakes?" may be unanswerable. However, it may be possible to address the question "What is the smallest stress change observed to induce earthquakes?" This can be attempted using natural stress changes known to correlate with earthquakes, as follows (Table 6).

7.3.1. Earth tides

The spatial non-uniformity of the gravitational fields of the Sun and Moon (and to a much smaller extent, other celestial bodies) produces differential stresses in the solid body of Earth approaching 0.005 MPa. Loading of the solid Earth by ocean tides produces additional stresses that can be about an order of magnitude larger but depend strongly on geographic location. The stress drops of most earthquakes are 1–10 MPa so tides might sometimes have a detectable effect on earthquake occurrence.

Most early studies of earthquakes and tides failed to find any significant correlation. The main cause of this failure was probably oversimplification of the problem. Both stresses and earthquake mechanisms are tensors, but many studies looked, for example, for correlations between seismicity and tidal amplitude ranges, effectively treating both stress and earthquake mechanism as scalars. Another difficulty with such analyses was the difficulty of computing ocean tides from the complicated shapes of ocean basins.

There were, however, two exceptions to this failure. First, deep moonquakes, detected by seismometers placed by Apollo astronauts, correlate strongly with tides (Latham et al., 1973). Second, earthquakes at volcanic and geothermal areas show a tidal effect that is easily detected (e.g., McNutt and Beavan, 1981). Recently, studies that account for earthquake focal mechanisms and compute ocean loading accurately have found that shallow thrust-faulting earthquakes correlate significantly with tidal stresses (Cochran et al., 2004).

7.3.2. Static stress changes resulting from large earthquakes

The 1989 M_W 6.9 Loma Prieta, California, earthquake modulated seismicity from around the epicenter out to distances where the coseismic stress changes were ≥ 0.01 MPa (equivalent to ~0.4 m of overburden) (Reasenberg and Simpson, 1992). The 1992 M_W 7.3 Landers, California, earthquake also modulated nearby seismicity. Aftershocks were abundant up to about two source dimensions from the mainshock (a few tens of km), where the Coulomb stress on optimally orientated faults was increased by > 0.05 MPa. They were sparse where stress was reduced by this amount (Fig. 117). The 1992 M_W 6.5 Big Bear aftershock occurred in a region where stress was increased by 0.3 MPa (King et al., 1994). The effect of static stress changes on neighboring faults has also been expressed in terms of the number of years by which the next large earthquake has been advanced in time (e.g., King et al., 1994; Reasenberg and Simpson, 1992).

7.3.3. Remote triggering

The 1992 M_W 7.3 Landers, California, earthquake is remarkable because it precipitated earthquake activity up to 17 source dimensions distant from the mainshock (1250 km). Most of this activity occurred at volcanic or geothermal areas such as Yellowstone. Static stress changes are vanishingly small at such distances. These remote earthquakes are thought to have been triggered by dynamic stress changes of a few tenths of a MPa in the propagating shear- and surface elastic waves interacting with fluids in hydrothermal and magmatic systems (Hill et al., 1993). This phenomenon of "remote triggering" has subsequently been observed elsewhere. When first unambiguously recognized following the Landers earthquake, it was thought only volcanic and

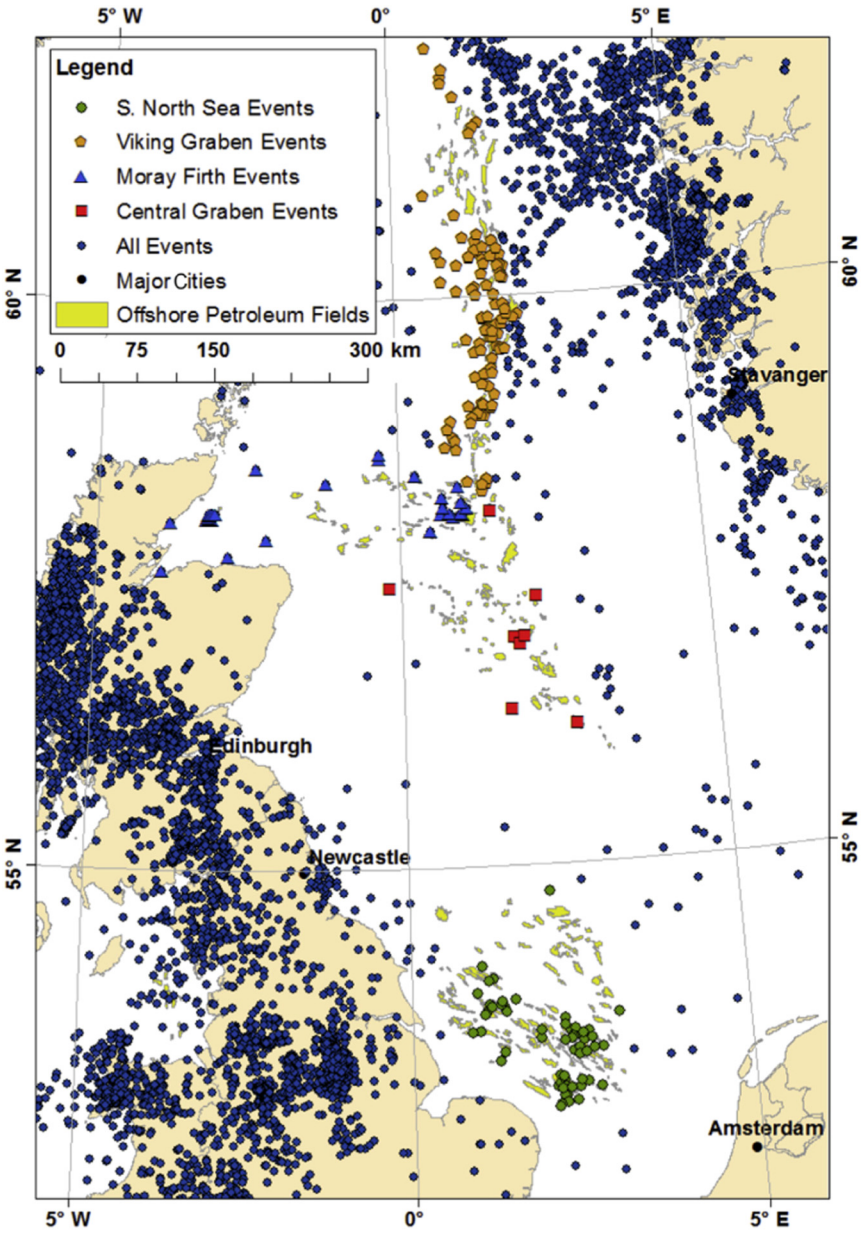


Fig. 112. Epicenters from the UK earthquake catalog of the British Geological Survey. Orange circles: Viking Graben events; blue triangles: Moray Firth events; red squares: Central Graben events; green circles Southern North Sea Gas Province events; yellow shading: offshore hydrocarbon fields.
(From Wilson et al. (2015).)

geothermal areas were affected and the process might reveal the locations of geothermal areas previously unknown. However, remote triggering has now been reported in other environments, e.g., the hydrocarbon region of Oklahoma (Fig. 58) (van der Elst et al., 2013).

7.3.4. Weather

A number of studies have postulated that earthquakes were induced by heavy rainfall (e.g., Husen et al., 2007; Roth et al., 1992). Correlations have also been suggested between "slow earthquakes" (accelerated creep on faults) and atmospheric pressure changes accompanying typhoons in Taiwan (Liu et al., 2009). Such pressure changes alter stress on land areas but not beneath the ocean because seawater flow maintains pressure equilibrium offshore. The effect contributes a stress change of ~0.003 MPa that encourages slip on coast-parallel thrust faults.

7.4. How large are induced earthquakes?

Stress changes postulated induce earthquakes do not correlate with stress drops brought about by the earthquakes or magnitudes. Counter-intuitively, M_{MAX} reported for induced sequences *decreases* with increasing calculated stress perturbation (Fig. 116). The final size of an earthquake is determined by how much of a fault was sufficiently stressed to move once activation began. If slip on a fault reduces to zero before the next event on the same fault starts, a series of discrete events is recognized. If slip does not stop, the event may grow and all the strain release is considered to have occurred in a single event. Great earthquakes that rupture much of the lithosphere typically comprise a cascading chain of M ~7 sub-events, each triggered by the stress changes resulting from the previous ones. Although likely very rare, it cannot be ruled out that industrial activity could contribute to the onset of an initial sub-event. It is also not uncommon for foreshocks to occur immediately preceding the onset of a mainshock several magnitude units higher. An initial M_W 5 earthquake in Oklahoma may have triggered successive earthquakes, including the M_W 5.7 event the following day (Keranen et al., 2013). In the case of the great 2008 M_W ~8 Wenchuan earthquake (Section 2.1.1), once the first sub-event began slip on the fault did not stop until several large fault segments had failed.

This view is consistent with the findings of McGarr (2014). He derived a relationship that related volume injected to the size of injection-

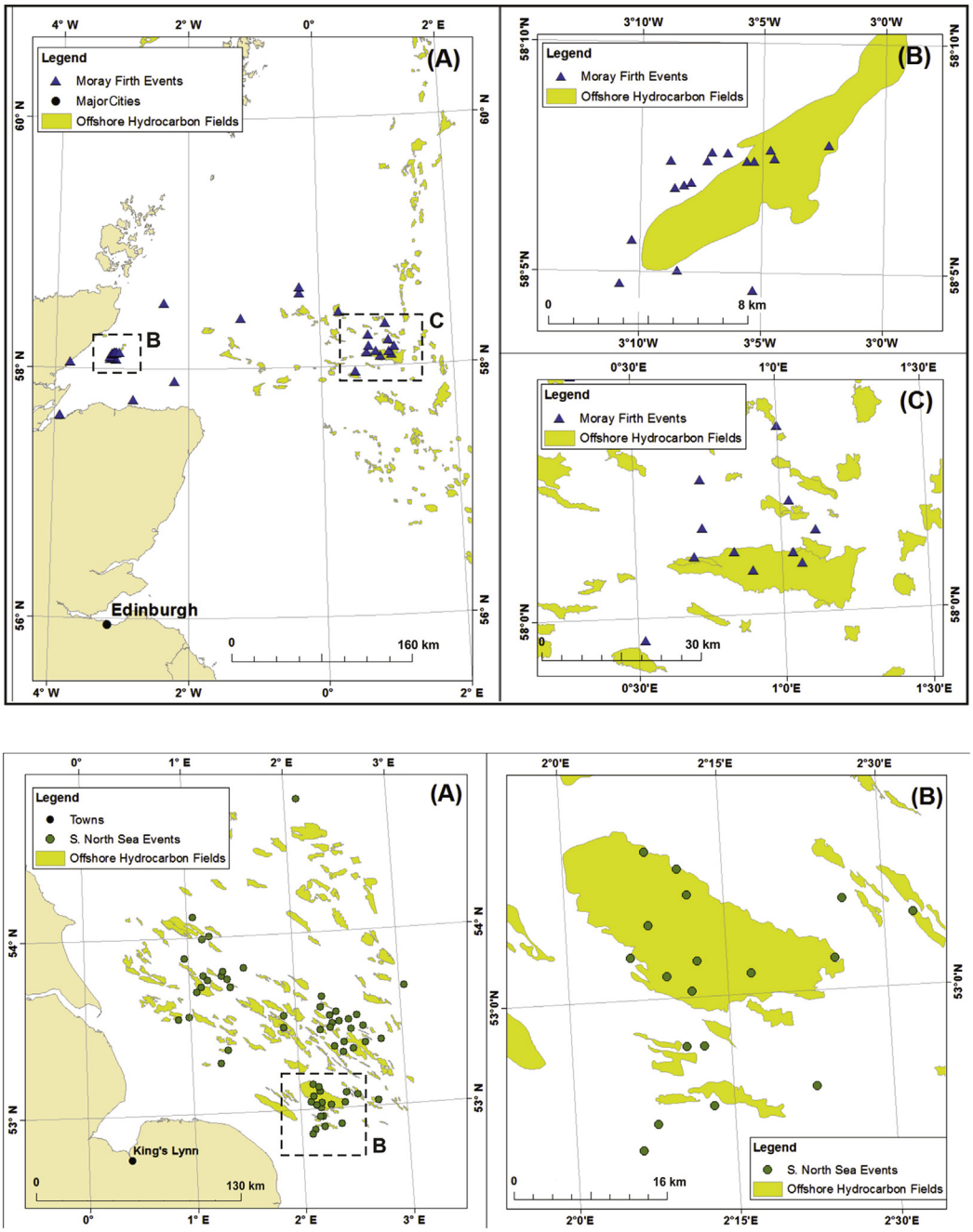


Fig. 113. Expanded view of some parts of Fig. 112. Top row: A–the Moray Firth. Yellow: hydrocarbon fields; blue triangles: earthquakes. B–the Beatrice Oilfield. C–the Britannia Gasfield. Bottom row: A–the Southern North Sea Gas Province. Green dots: earthquakes. Bottom row: B–the Leman Gasfield.
(From Wilson et al. (2015).)

induced earthquakes and showed that it fit well observations of 18 of the largest-magnitude earthquakes (Fig. 95). However, he also pointed out that this upper bound only applies to induced earthquakes whose source regions were confined to the volumes directly affected by the injection, and that if fault slip propagated outside of this volume then larger earthquakes could occur.

7.5. Natural or induced?

The strength of evidence for earthquake induction varies greatly between cases. For some examples the association with an industrial activity is beyond reasonable doubt. For example, over 250,000 earthquakes have been located in a tight cluster in The Geysers geothermal area, California, by the U.S. Geological Survey during the last half century. At the other end of the spectrum, induction has been suggested for cases where only one earthquake occurred and the calculated stress changes were smaller than those induced by Earth tides, e.g., for the 2007 M_L 4.2 Folkestone, UK, earthquake (Klose, 2007b). For those cases, mere coincidence cannot be ruled out (Sections 2.1.3 and 7.3). The suggestion that earthquakes were induced over 1000 km away and over a year later by bombing of cities with non-nuclear weapons is not persuasive strongly supported (Section 5).

The number of postulated induced cases is increasing rapidly and with it the urgency for management strategies. It is desirable, not only to know *a posteriori* whether an earthquake was natural or induced, but also to forecast which projects may be seismogenic in future and how great the hazard is likely to be. In the past, schemes have been proposed to address the question whether earthquakes are natural or induced. For



Fig. 114. Damage done to the cathedral in Canterbury, New Zealand, by the 2010 M 7.1 earthquake (http://www.npr.org/sections/parallels/2015/04/05/397093510/will-new-zealand-rebuild-the-cathedral-my-forefather-erected).

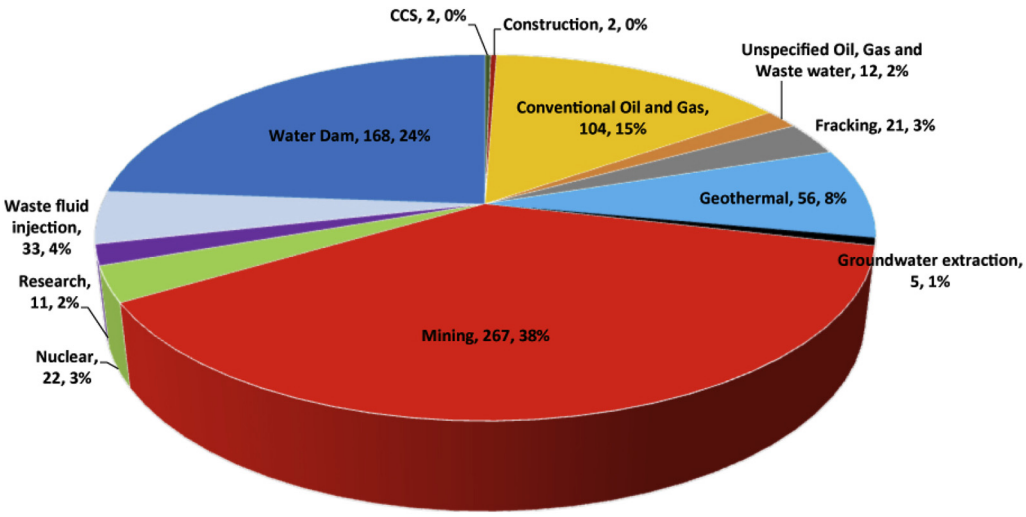


Fig. 115. Percentage of total cases for each project category in the database.

Table 5
Conversions for commonly used units of pressure.

1 bar = 0.1 MPa, equivalent to ~4 m of rock overburden
1 atm = 0.1 MPa
1 kg/cm^2 = 0.1 MPa
1 lb/in.^{2} (psi) = 6.9 × 10^{-3} MPa
1 acre-foot of water/football field[a] = 29 × 10^{-6} MPa
Hydrostatic gradient = 10 MPa/km
Lithostatic gradient = ~25 MPa/km

[a] American football, including end zones.

example, Davis and Frohlich (1993) list seven questions to profile a seismic sequence and judge whether it was induced or not (Table 7). In the light of the large number of case histories now available, some of these parameters can be re-examined:

1. *Whether the region had a previous history of seismicity*. Induced earthquakes have now been postulated to occur in both historically seismic and aseismic areas. Evidence from research in boreholes suggests that faults everywhere are close to failure, regardless of the known history of seismicity.
2. *Close temporal association with the induction activity*. Reported delays in the onset of postulated inducted seismicity vary from essentially zero to several decades.
3. *In the case of injection-related earthquakes, proximity of a few kilometers*. Distances of up to 25 km have now been reported (Fig. 104; Section 4.1.2).
4. *Known geological structures that can channel flow*. Many earthquakes postulated to be induced have been attributed to previously unknown faults.
5. *Substantial stress changes*. Stress changes as small as a few kPa have been postulated to induce earthquakes (Section 2.1.3).

Simple criteria for deciding whether an earthquake is induced or not are elusive. There is extreme diversity in the circumstances of cases. Postulated induction activities may take place over time periods from a few minutes to decades. The volumes of material added or removed vary over many orders of magnitude and the maximum magnitude of events postulated to be induced vary from M < 0 to M ~ 8.

Several unusual characteristics are commonly reported for earthquakes suspected of having been induced. These include:

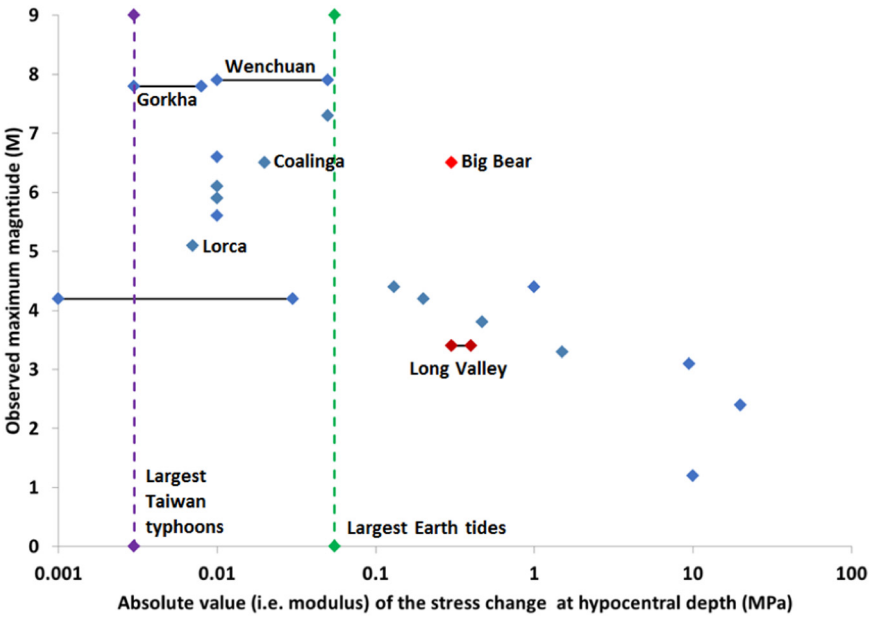


Fig. 116. M_{MAX} vs. absolute value of stress changes calculated by various authors to have occurred at the hypocentral depths of possibly induced earthquakes. Vertical dashed green line: largest Earth tides; vertical dashed purple line: largest Taiwan typhoons. Blue diamonds: earthquakes proposed to have been human-induced, diamonds connected by solid black lines: ranges of stress changes calculated. Some example earthquakes are labeled. Red diamonds: natural earthquakes that followed the 28th June 1992 M_W 7.3 Landers, California, earthquake (data from Hill et al., 1993). The Big Bear earthquake is proposed to have been induced by static stress changes, and the Long Valley earthquakes by the dynamic stresses from the surface waves.

Table 6
Stress changes associated with some natural processes postulated to induce earthquakes.

Effect	Stress change (MPa)
Earth tides	0.05
Seismic static stress changes	0.03
Remote triggering	~0.5
Typhoons	0.003

1. Unusually shallow nucleation depths (e.g., the 2011 M_W 5.1 Lorca, Spain, earthquake, Section 3.1);
2. Occurrence on previously unknown faults ("blind faults"; e.g., in the Cogdell oilfield, Texas, Section 4.2.2);
3. Release of stress in the same sense as the regional on suitably orientated structures (e.g., in Oklahoma, Section 4.1.2);
4. The largest earthquake in a sequence occurring after the induction activity has ceased, suggesting that fluid diffusion is important (e.g., the 1962–1968 Denver earthquakes, Section 4.1.1);
5. Faults in the basement beneath water and hydrocarbon reservoirs being reactivated, sometimes transecting the sedimentary formations above (e.g., the Coalinga, California, earthquake; Section 3.3.2).

These observations raise a number of questions. For example, if induced seismicity commonly occurs on previously unknown faults, could hazard be reduced by extensive subsurface mapping prior to operations? Since the crust is thought to be pervasively faulted and near to failure essentially everywhere, it is not clear this would be the case–perhaps everywhere should be considered potentially seismogenic. Also, if large earthquakes occur after operations have stopped, for how long should seismic hazard mitigation measures be continued after the end of a project?

More reliable, but less universally applicable ways of discriminating include:

1. Simple spatial and temporal associations, e.g., earthquakes beginning to occur as soon as injection starts and close to the injection point;
2. Earthquakes occurring in previously aseismic regions;
3. Visual observation, e.g., gallery collapses in mines or ground rupture when a nuclear test is conducted;
4. Earthquake focal mechanisms, e.g., discriminating between natural, shear-faulting earthquakes and volumetric mining collapses, as was done by McGarr (1992a, 1992b) for well-recorded earthquakes in South African gold mines and Dreger et al. (2008) for a mine collapse in Utah.

Work is currently ongoing to develop additional ways of discriminating induced from natural earthquakes. These include using statistical features of background earthquakes and clustered sub-populations. For example, Zaliapin and Ben-Zion (2016) have suggested several statistical features that may distinguish induced seismicity from natural tectonic activity including a higher rate of background events and more rapid aftershock decay.

7.6. Why are earthquakes induced by some industrial projects and not others?

In addition to needing an explanation for why earthquakes occur at particular projects, any theory for induced earthquakes must also explain why they do not occur at most projects. This endeavor is hampered by under-reporting (Section 7.1; Table 3). A necessary pre-requisite to explaining induced seismicity as a whole or in different categories is to know its true extent.

For industrial activity as a whole, reports of induced earthquakes are extraordinarily rare (Table 3). Induced nuisance earthquakes are even rarer. Only ~2% of mines, water reservoirs, and CCS projects are reported to be seismogenic. All other categories of project for which we found data were < 2% seismogenic.

Individual cases are diverse and site-specific and the lack of similarities is perhaps a stronger feature than common factors. With the exception of large geothermal projects and hydrofracturing (where almost all are probably seismogenic but only 0.001% are reported to be so) it is seemingly unpredictable which projects will report induced earthquakes. Many if not most induced earthquakes, except at hydrofracturing projects, were unexpected. On the other hand, a research experiment that specifically aimed to induce seismicity, by injecting water into an active fault zone, failed to do so (Section 4.1.8) (Prioul et al., 2000).

A majority of induced earthquakes occur in intraplate areas (Fig. 109). This is not surprising in view of the fact that rocks are close to failure everywhere so the potential for inducing earthquakes in intraplate and plate-boundary regions may be similar (Section 1.1). This,

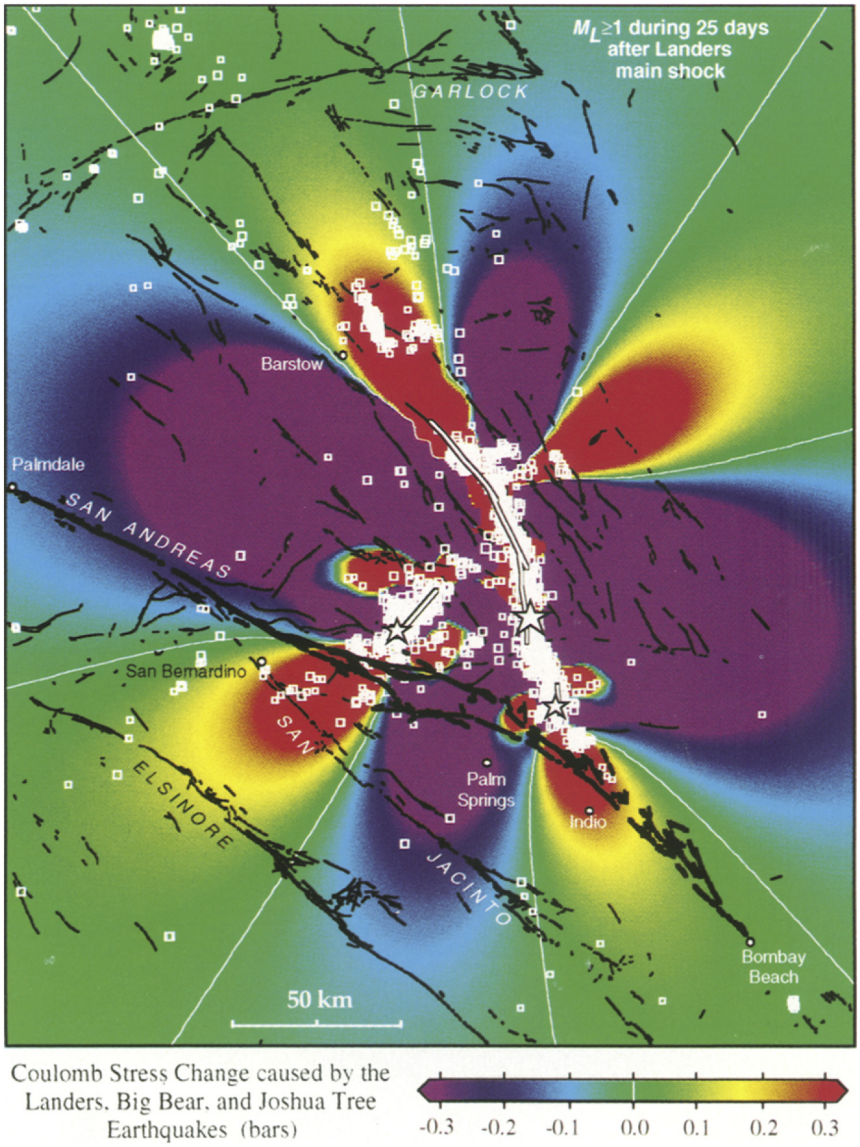


Fig. 117. Coulomb stress changes at a depth of 6.25 km caused by the M_W 7.3 Landers, California, earthquake and large aftershocks. (From King et al. (1994).)

Table 7
Seven questions proposed by Davis and Frohlich (1993) to diagnose earthquakes induced by fluid injection. (From Davis and Frohlich (1993).)

	Question	Earthquakes clearly not induced	Earthquakes clearly induced	I Denver, Colorado	II Painesville, Ohio
	Background seismicity				
1	Are these events the first known earthquakes of this character in the region?	NO	YES	YES	NO
	Temporal correlation				
2	Is there a clear correlation between injection and seismicity	NO	YES	YES	NO
	Spatial correlation				
3a	Are epicenters near wells (within 5 km)?	NO	YES	YES	YES?
3b	Do some earthquakes occur at or near injection depths?	NO	YES	YES	YES?
3c	If not, are there known geologic structures that may channel flow to sites of earthquakes?	NO	YES	NO?	NO?
	Injection practices				
4a	Are changes in fluid pressure at well bottoms sufficient to encourage seismicity?	NO	YES	YES	YES
4b	Are changes in fluid pressure at hypocentral locations sufficient to encourage seismicity?	NO	YES	YES	NO?
	Total “YES” answers	0	7	6	3

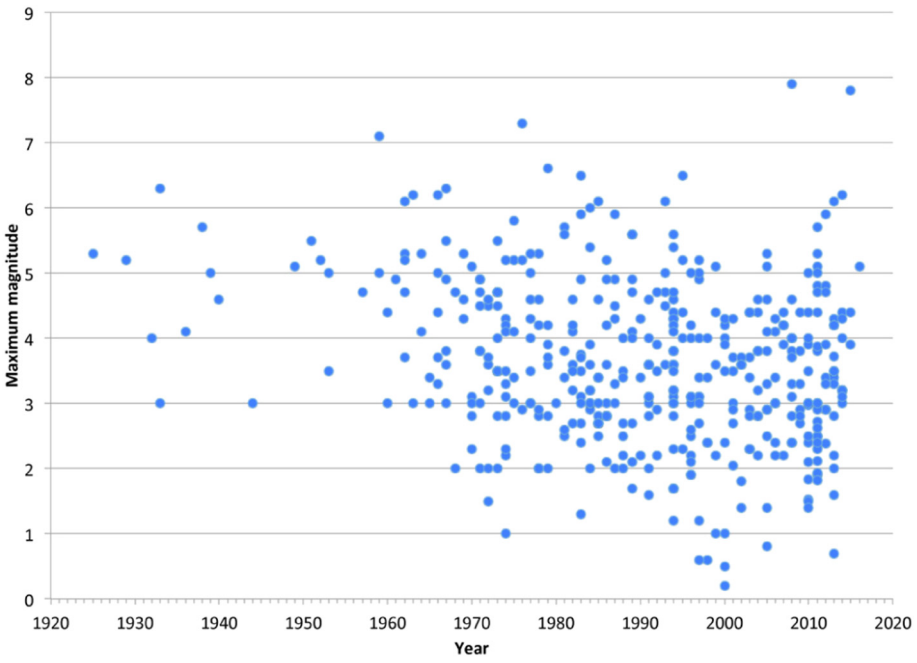


Fig. 118. M_{MAX} vs. year for the 419 cases where data are available.

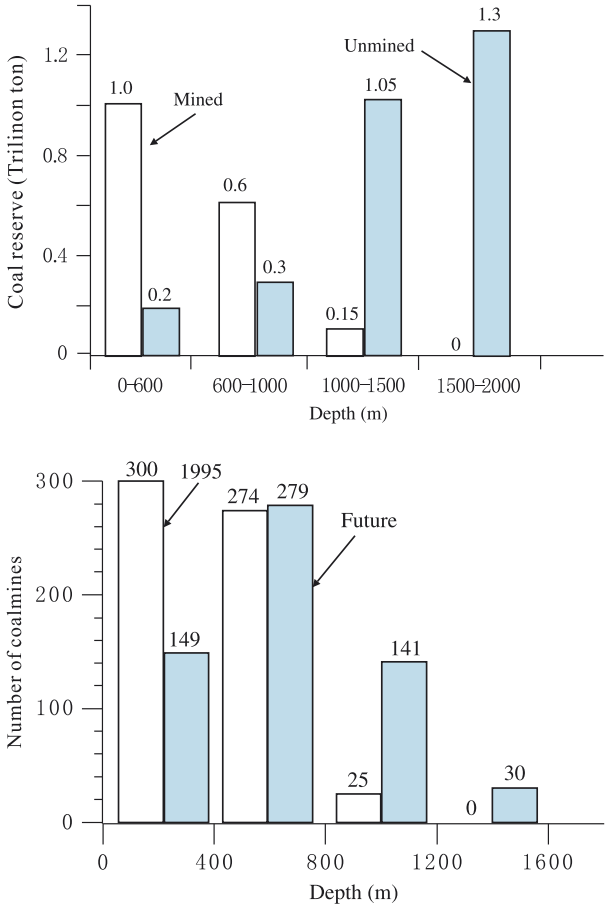


Fig. 119. Top: Depth distribution of Chinese coal reserves (1995 statistics). Bottom: Depth distribution of 599 state-owned Chinese coal mines.
(From Li et al. (2007).)

coupled with many earthquake sequences being unexpected and in areas previously aseismic, means that populations may be unprepared. To add to this, pre-industrial seismic risk assessments may be difficult if there is no history of seismicity or seismic monitoring. Wilson et al. (2015) recently tried to rectify this problem for the UK in advance of possible expansion of the shale-gas industry by estimating a baseline for UK seismicity.

For most non-research purposes the parameter of importance is not whether seismicity is induced but whether nuisance seismicity is induced (Section 1.2). M_{MAX} is thus critical. Section 6 describes an initial examination of *HiQuake* for correlations. The currently observed upper limit to M_{MAX} correlates with water reservoir volume and mass per unit area, volume added or removed at the surface, volume extracted or added to the subsurface, injection pressure (negative correlation), rate and volume, the yield of nuclear tests and scale of project. Most of these are basically measures of project size. Factors such as reservoir pressure change and injection/extraction rate do not correlate with the observed M_{MAX} ceiling.

Suggestions for what operational parameters might be adjusted to mitigate induced seismicity include injecting into formations that are sealed from the basement, and avoiding known faults. There has, however, yet to be a demonstration of an approach that works in general for projects of a particular type. It is also not clear how we would we recognize success since there can be no evidence for the earthquake that did not occur.

7.7. Future trends

7.7.1. Earthquake prediction

There is presently no reliable method to predict earthquakes. Current approaches to reducing hazard comprise long-term forecasting based on the history of past earthquakes including instrumental data, historical information, and paleoseismology using methods such as trenching (e.g., Obermeier, 1996). This approach assumes that patterns of seismicity persist in local areas. It cannot make predictions, even in plate boundary zones (Lindh, 2005), and may work even more poorly in intraplate areas (Section 1.1) (Brooks et al., n.d.; Stein et al., 2015). In regions with little history of seismicity it may not be possible to implement.

Nicol et al. (2011) reviewed this issue from the point of view of CCS. Focus tends to be on reservoir-scale pressure increases and the effect of crustal loading on local faults is not routinely considered. Modeling crustal loading or unloading, along with the likely effects on groundwater, might be fruitful avenues of approach. Another useful approach

could be to study jointly surface deformation and seismicity. The technology to measure surface deformation is well developed. Both satellite and ground-based methods are available but rarely have integrated studies with ground truthing been reported. InSAR and GPS were applied to the depleted Alkmaar Gas Field in the Netherlands (Gee et al., 2016), and Intermittent SBAS satellite data were used to confirm the deformation from earlier GPS work. These results could potentially be integrated with legacy earthquake data.

The two types of data have been jointly interpreted in the case of several projects (e.g., Goertz-Allmann et al., 2014; Keiding et al., 2010). However, systematic relationships have not been explored for induced earthquakes as a whole.

7.7.2. Monitoring recommendations

Good industrial practice first and foremost requires high-quality information. Projects that have the potential to induce earthquakes should be monitored seismically and geodetically. Joint interpretation of these two types of data is more powerful than either in isolation. In addition to the nuisance of seismic deformations (i.e. earthquakes), aseismic deformations can alter the surface and cause nuisance such as infrastructure damage, flooding, and other changes to groundwater circulation.

Geophysical monitoring need not necessarily be elaborate and can be tailored to the circumstances. Unless there is evidence or compelling expectations for earthquakes or surface deformation, minimal instrumentation will suffice. Data should be publically available to all stakeholders.

The current paper contributes a full review of what type of projects have been claimed to induce earthquakes in the past. This is currently the best guide identifying what projects will induce earthquakes in future.

7.7.3. Earthquake management

The largest reported induced earthquake has increased with time from M 6.3 in 1933 to ~M 8 in 2008 (Fig. 118). The number of reported cases has also increased greatly, probably because of the increasing number of large-scale industrial projects. The lower magnitude threshold of reporting is reducing, probably partly because of improved monitoring. These statements, and others made in this paper, should be viewed in the context that they are underpinned by a database of all earthquakes postulated to be induced, with no selection for credibility.

There is a growing need to manage the problem of industrially induced earthquakes and this is well-illustrated by coal mining in China (Section 3.2.1). The expanding Chinese economy is founded on coal as an energy source but at the same time shallow resources are being rapidly depleted (Fig. 119). The future trend is thus to go deeper (Li et al., 2007). In the two decades from 1980 to 2000 the average mining depth increased from 288 m to 500 m. Now, over 75% of the coal has been removed from the top 1000 m and the recent increase in mine seismicity there results largely from increases in mining depth and the size of galleries. Super-deep mines (> 1200 m in depth), such as have induced seismicity in South Africa for decades, are planned in China for the future. Fluid injection for waste disposal, enhanced oil recovery, hydrofracturing and geothermal energy, are also expanding rapidly and have resulted in some of the most significant increases in induced seismicity in recent years (Ellsworth, 2013). Other industries such as building dams and CCS may expand over the coming years.

Management of the problem is moving forward rapidly as additional stakeholders become involved (e.g., Wang et al., 2016). For example, the issue of induced earthquakes is now of concern to the US Army Corps of Engineers because of the threat to critical federal infrastructure, e.g., levees and dams. No societal benefit comes without price–there is no such thing as a free lunch. However, public policy, engineering, preparation, and outreach can enable economically and societally beneficial projects to go ahead under appropriate health-and-safety conditions and in contexts that are understood and acceptable to stakeholders.

Acknowledgments

This work benefitted from discussions with and assistance from Julian Bommer, Kosuke Heki, Tianhui Ma, Steve Spottiswoode, Michelle Grobbelaar, Deborah Weiser, Irene Beardsley and Dan Bloomberg. Ang Li assisted with locating Chinese cases. The authors thank Art McGarr and two anonymous reviewers for helpful reviews, and Giuliano Panza, Editor, for handling the manuscript. The project was funded by the Nederlandse Aardolie Maatschappij BV (NAM), Schepersmaat 2, 9405 TA Assen, The Netherlands. This paper is based on a report submitted to Jan van Elk and Dirk Doornhof (NAM).

Appendix A. Supplementary data

Supplementary data to this article can be found online at http://dx.doi.org/10.1016/j.earscirev.2017.07.008.

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Gas injection may have triggered earthquakes in the Cogdell oil field, Texas

Wei Gan[a,b] and Cliff Frohlich[b,1]

[a]School of Earth Sciences and Resources, China University of Geosciences, Beijing 10083, China; and [b]Institute for Geophysics, Jackson School of Geosciences, University of Texas at Austin, Austin, TX 78758-4445

Edited by Donald W. Forsyth, Brown University, Providence, RI, and approved October 4, 2013 (received for review June 13, 2013)

Between 1957 and 1982, water flooding was conducted to improve petroleum production in the Cogdell oil field north of Snyder, TX, and a contemporary analysis concluded this induced earthquakes that occurred between 1975 and 1982. The National Earthquake Information Center detected no further activity between 1983 and 2005, but between 2006 and 2011 reported 18 earthquakes having magnitudes 3 and greater. To investigate these earthquakes, we analyzed data recorded by six temporary seismograph stations deployed by the USArray program, and identified 93 well-recorded earthquakes occurring between March 2009 and December 2010. Relocation with a double-difference method shows that most earthquakes occurred within several northeast–southwest-trending linear clusters, with trends corresponding to nodal planes of regional focal mechanisms, possibly indicating the presence of previously unidentified faults. We have evaluated data concerning injection and extraction of oil, water, and gas in the Cogdell field. Water injection cannot explain the 2006–2011 earthquakes, especially as net volumes (injection minus extraction) are significantly less than in the 1957–1982 period. However, since 2004 significant volumes of gases including supercritical CO_2 have been injected into the Cogdell field. The timing of gas injection suggests it may have contributed to triggering the recent seismic activity. If so, this represents an instance where gas injection has triggered earthquakes having magnitudes 3 and larger. Further modeling studies may help evaluate recent assertions suggesting significant risks accompany large-scale carbon capture and storage as a strategy for managing climate change.

triggered seismicity | fluid injection | carbon sequestration

Induced seismicity related to underground injection of liquids has been widely reported (1–10) but there are very few reports of gas injection triggering earthquakes large enough to be felt or cause damage at the surface. Thus, the injection-induced earthquakes of concern are not the tiny events accompanying hydrofracturing that have magnitudes of 1.5 or smaller; rather, they are the larger-magnitude earthquakes sometimes caused by injection for water flooding, enhanced production, or waste disposal.

For liquid injection, it is plausible that triggered earthquakes occur when fluids reach suitably oriented preexisting faults, reducing the normal stress and hence the friction, and releasing regional tectonic shear stresses. The same mechanism should allow gas injection to trigger earthquakes. Recently Zoback and Gorelick (11) argued that there is a "high probability that earthquakes will be triggered" by the large-scale injection of CO_2 as a strategy to reduce greenhouse gases; however, they offered no examples of CO_2-injection-triggered earthquakes. Also, we are unaware of any reports of gas-injection-triggered earthquakes having magnitudes exceeding 3 (M3).

The present investigation concerns seismic activity and injection in petroleum fields in Scurry and Kent Counties, Texas (Figs. 1 and 2). The northern field straddling the Scurry–Kent county line is the Cogdell field. The larger field in Scurry County west of Snyder is called the Kelly–Snyder field, or sometimes the Scurry Area Canyon Reef Operators Committee unit. These fields produce from the Horseshoe Atoll, which accumulated in the Late Paleozoic and is one of the largest subsurface limestone reef mounds in the world (12, 13).

The Cogdell field underwent water flooding for secondary recovery between 1956 and 1982 and the earliest earthquakes detected there occurred in November 1974; the largest was an M4.6 on June 16, 1978 (14). Davis and Pennington (1) found that Cogdell seismic activity was correlated with the net liquid injection rate, with the first earthquakes occurring almost 20 y after injection commenced (Fig. S1). They modeled fluid pressures in the field and concluded that the earthquakes occurred at the boundaries of relatively low-pressure areas surrounded by higher-pressure regions. Although they suggested the earthquakes occurred on preexisting faults, there are no faults on regional tectonic maps and available locations of aftershocks did not occur along lineations or elongated clusters (Fig. 3).

There is a history of gas injection as well as water injection in the Kelly–Snyder and Cogdell fields. Northern sections of the Kelly–Snyder field have been undergoing CO_2 injection to enhance recovery since 1971 (17). In 2008 some Kelly–Snyder wells were used for a monitoring and modeling case study to learn about carbon capture use and geologic storage applications (18). Finally, in the Cogdell field, injection of CO_2 to enhance recovery began in 2001 and has been ongoing with nearly constant injection volumes since 2004.

For gas injection at wells in the Cogdell and Kelly–Snyder fields, the database available for this study reports monthly gas volumes at surface pressures and temperatures (STP 1 bar and 15 °C), and does not specify whether the gas injected is CO_2 or methane. At the depth of injection in Cogdell (~2.1 km) the pressure and temperature are ~200 bars and ~75 °C; under these conditions CO_2 is a supercritical fluid ($SCCO_2$) with a volume

Significance

Between 2006 and 2011 a series of earthquakes occurred in the Cogdell oil field near Snyder, TX. A previous series of earthquakes occurring 1975–1982 was attributed to the injection of water into wells to enhance oil production. We evaluated injection and extraction of oil, water, and gas in the Cogdell field. Water injection cannot explain the 2006–2011 earthquakes. However, since 2004 significant volumes of gas including CO_2 have been injected into Cogdell wells. If this triggered the 2006–2011 seismicity, this represents an instance where gas injection has triggered earthquakes having magnitudes 3 and larger. Understanding when gas injection triggers earthquakes will help evaluate risks associated with large-scale carbon capture and storage as a strategy for managing climate change.

Author contributions: C.F. designed research; W.G. evaluated seismic records; W.G. and C.F. analyzed results; and W.G. and C.F. wrote the paper.

The authors declare no conflict of interest.

This article is a PNAS Direct Submission.

[1]To whom correspondence should be addressed. E-mail: cliff@ig.utexas.edu.

This article contains supporting information online at www.pnas.org/lookup/suppl/doi:10.1073/pnas.1311316110/-/DCSupplemental.

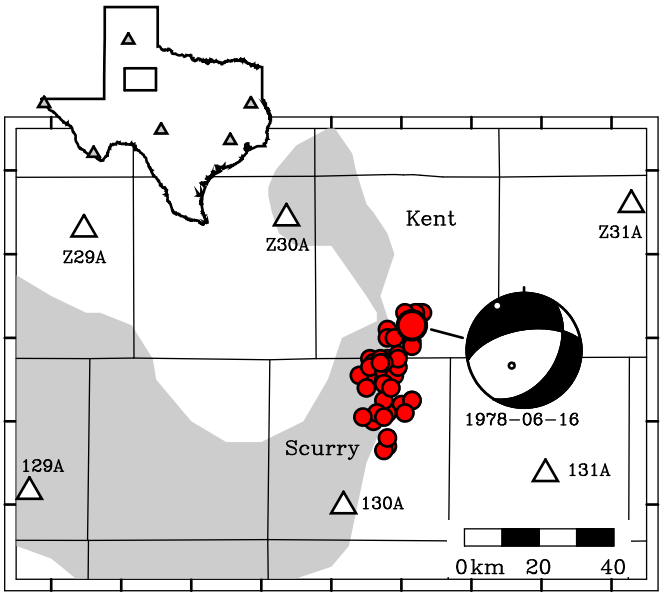


Fig. 1. Map showing location of study area, with earthquakes (red circles) reported by the NEIC 1977–2012, and USArray Transportable Array stations (white triangles) operating March 2009–December 2010 (Table S1). Gray shaded area indicates extent of Horseshoe Atoll. (*Inset*) Rectangle in Texas shows map boundaries; gray triangles in inset are seismograph stations operating in 2005 before passage of USArray. Light lines are county boundaries; labels indicate Scurry and Kent Counties.

~1/339th of that at STP; for methane the volume is ~1/180th of that at STP.

In the Cogdell, since 2004 monthly gas injection volumes have exceeded 85 million m^3/mo at STP (Fig. 4). Thus, at the depth of injection this corresponds to 250,000 m^3/mo for CO_2 and 475,000 m^3/mo for methane. In Cogdell and elsewhere, injected $SCCO_2$ and/or methane are often mixed with water, and the mixtures may undergo phase changes as they move away from the site of injection, so the volumes calculated at depth (e.g., left axis on Fig. 4) are only approximate.

The National Earthquake Information Center (NEIC) reports no Cogdell earthquakes between 1983 and 2005, but since 2006 they list 38 events that appear to be from a different population than earlier seismic activity (Fig. S3). The 2006–2011 epicenters include 18 with magnitudes M3 and greater and one on September 11, 2011, with moment magnitude (M_W) 4.4; if similar events had occurred between 1983 and 2005 most would have been detected and reported by the NEIC (19). Between 2009 and 2011 the EarthScope USArray temporary seismic stations were deployed in Texas; during this period we found 105 epicenters in the Cogdell area in the catalogs from the NEIC, the International Seismological Center (ISC), and the Array Network Facility (ANF), the organization that manages USArray data. Of these, 97 occurred between March 2009 and December 2010 when the six USArray stations surrounding Cogdell were all operational.

The focus of the present investigation is to analyze the characteristics of the recent Cogdell seismicity and to evaluate its relationship with water and gas injection. Although some of the recent earthquakes occurred at distances as great as ~5 km from active injection wells (Fig. 3), induced earthquakes at greater distances have been observed elsewhere (2, 3), especially where injection has been ongoing for many years. The fortuitous presence of the USArray stations between 2009 and 2011 makes it possible to identify much smaller earthquakes and determine their epicenters more accurately than during prior or subsequent times (Fig. 1).

Results

Earthquake Locations and Focal Mechanisms. The relocated epicenters (red circles, Fig. 3) cluster into several discrete groups. Overall they form a much less diffuse pattern than the epicenters reported in the ANF catalog (Fig. S4).

Certain linear features in the groups are approximately consistent with focal mechanism nodal planes. In the north a group of five events (labeled "A" in Fig. 3) forms a lineation trending just north of east, approximately the same as the trend (80° east of north) as the most steeply dipping nodal plane of the June 16, 1978, earthquake (Table S2). About 4 km to the southwest there are two more groups; one with 14 events (group B) forms a tight cluster, whereas the other group of 30 events (group C) lies along a distinct line trending ~45° east of north. Still further south are several more clusters; groups D, E, F, and G all lie along a line trending about 25° east of north. This is nearly identical to the 23° east of north trend of a nodal plane for the August 8, 2010, earthquake which is a member of group F. Finally, two small outlier clusters (H and J) of three and two events, respectively, lie ~2–3 km to the west of the other events.

The linear features in the relocated epicenters, including some approximately coincident with nodal planes, suggest that the seismic activity may occur along preexisting faults. As noted in previous studies (1, 13), the absence of mapped faults is unsurprising considering that the Cogdell and Kelly–Snyder reservoirs are reef buildups rather than fault-bounded traps.

No accurate location is available for the largest historical Cogdell earthquake (June 16, 1978; M4.6) because of near-absence of contemporary nearby regional seismographs. However, the

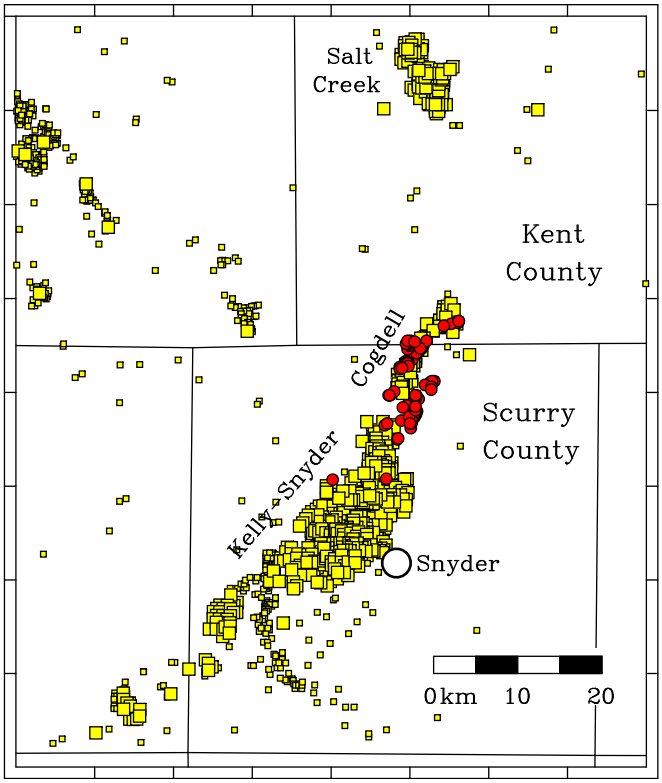


Fig. 2. Map of study area, showing 2009–2011 earthquakes (red circles) located in this study, and wells injecting water (yellow squares). Large squares, wells where monthly injection volumes exceeded 16,000 m^3/mo for one or more months during 2004–2011 period. White circle indicates town of Snyder, TX. Labels "Cogdell," "Kelly–Snyder," and "Salt Creek" are petroleum fields discussed in the text.

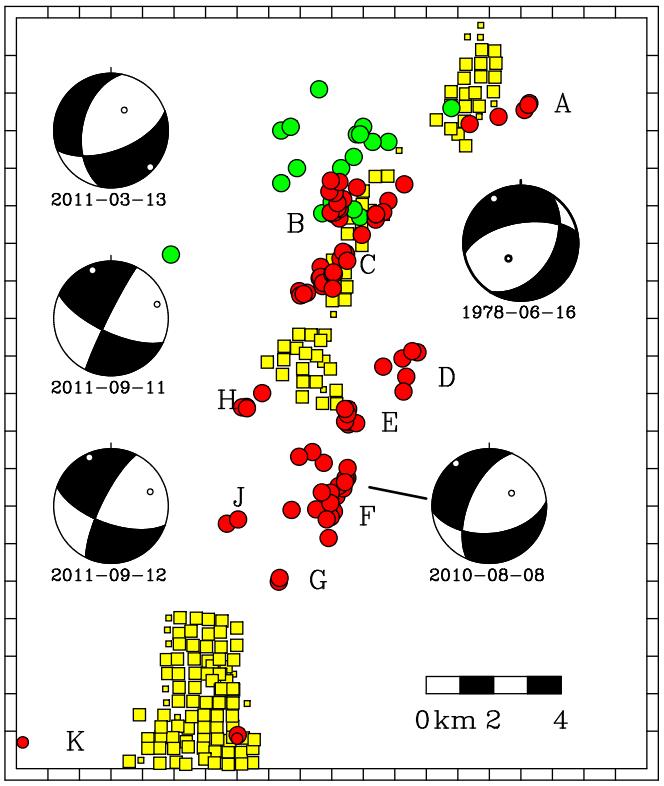


Fig. 3. Map showing 2009–2011 earthquakes relocated in this study (red circles), earthquakes occurring 1979–1980 (green circles) reported by Harding (15), gas injection wells active since 2004 (yellow squares), and focal mechanisms for regional events. Focal mechanisms are from the St. Louis group (16); labels indicate the date of occurrence (Table S2). Only the August 8, 2010, mechanism is for an earthquake relocated in this study. Larger red circles are epicenters occurring between March 2009 and December 2010 relocated using the double-difference method; two smaller red circles at southernmost boundary of plot are single-event locations of outlier events. Labels "A" through "K" indicate clusters discussed in *Results*. The 1979–1980 epicenters were determined from data collected by a temporary local network. For gas injection wells, larger symbols indicate wells where maximum monthly injection rate exceeds 2.8 million m^3/mo at standard conditions (8360 m^3/mo at depth for $SCCO_2$).

epicenters of aftershocks determined by a temporary local network in 1979–80 (green circles in Fig. 3) are mostly within a few kilometers of group B of 2009–2011 epicenters, suggesting that the 1978 epicenter may have been nearby, and that the present seismicity is a renewal of the earlier activity.

Seismicity and Injection/Extraction of Liquids and Gas. For wells in the Cogdell field, the available digital database has continuous monthly reports of oil produced, water extracted, water injected, gas produced, and gas injected extending back to 1990 (Figs. 4 and 5). Before that, and especially before 1982, the data are incomplete; Davis and Pennington (1) retrieved some of this information from records stored on microfiche and reported that the net volume of fluid extracted before 1982 exceeded 300,000,000 m^3 (Fig. S1).

Since 1990, however, volumes of water/oil injection and production have been roughly comparable, generally in the range of 400,000–800,000 m^3/mo (Fig. 5). A brief spike of higher injection volumes did take place in July and August of 2006 and this coincides with the renaissance of earthquake activity (the M2.8 August 8, 2006 event). However, there are no sustained changes in injection or extraction rates occurring before the 2006–2011 seismic activity, and no obvious overall changes in volumes of liquid extraction, injection, or the net during or before the 2006–2011 period when the field again became seismically active.

In contrast, a significant increase in gas injection (Fig. 4) in the Cogdell field took place before the 2006–2011 earthquake activity. $SCCO_2$ injection began in 2001, but rates were negligible until 2002, when sustained injection at rates of ~40 million m^3/mo at standard conditions (125,000 m^3/mo at depth for $SCCO_2$) began in the cluster of wells near label A in Fig. 3. In 2003 sustained injection at rates of ~25–50 million m^3/mo (80,000–160,000 m^3/mo at depth for $SCCO_2$) began in the cluster of wells near H in Fig. 3; the rates in August and September of 2006 were anomalous and exceeded 85 million m^3/mo (250,000 m^3/mo at depth for $SCCO_2$). Also in 2006, injection at rates averaging ~25 million m^3/mo (80,000 m^3/mo at depth for $SCCO_2$) began in the cluster of wells near B and C in Fig. 3. In August–September 2006 this group of wells also experienced a 2-mo spike in injection where rates were 70–82 million m^3/mo (209,000–242,000 m^3/mo at depth for $SCCO_2$). For Cogdell as a whole, the combined effect is that gas injection rates were about 113 million m^3/mo (334,000 m^3/mo at depth for $SCCO_2$) between 2004 and 2012, and there was a temporary increase to more than 225 million m^3/mo (668,000 m^3/mo at depth for $SCCO_2$) in August of 2006, just as the first earthquake in the 2006–2011 sequence was detected.

Gas injection rates also increased for wells in the northern Kelly–Snyder field (wells near K label in Fig. 3), but this occurred somewhat later than in Cogdell. For Kelly–Snyder wells north of the southern boundary of Fig. 3, injected volumes first exceeded 42 million m^3/mo (125,000 m^3/mo at depth for $SCCO_2$) in July 2009, and increased to rates that averaged more than 285 million m^3/mo (840,000 m^3/mo at depth for $SCCO_2$) after July 2010.

Discussion and Summary

Earthquakes Possibly Triggered by Gas Injection. The most significant result of this investigation is that gas injection may have contributed to triggering a sequence of earthquakes occurring since 2006 in and near the Cogdell field in Texas. This sequence followed a 24-y interval when no earthquakes were detected. The post-2006 sequence followed significant increases in gas injection in the Cogdell field (Fig. 4) and many earthquake epicenters were within 2 km of actively injecting wells (groups A–C, E, and

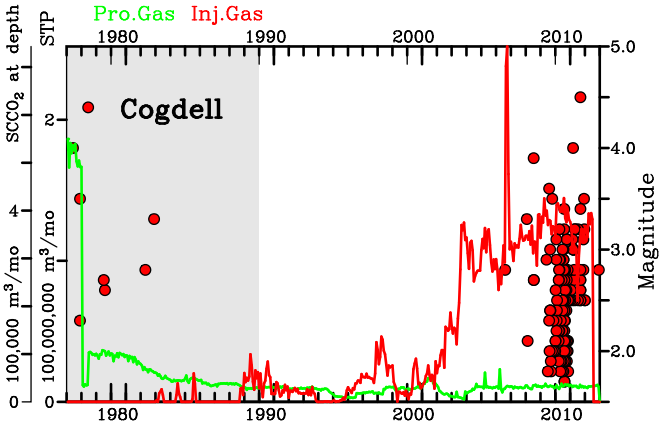


Fig. 4. For the Cogdell field, monthly volumes of natural gas produced (green line), gas injected (red line), and earthquakes detected from 1977 to 2012 (red circles). Volumes on left axes are as reported by RRC for gas at surface at STP, and for CO_2 at 200 bars and 75 °C ($SCCO_2$ at depth). Volumes at depth are highly approximate because the pressure–temperature effect differs for natural gas and CO_2, and because injected gas is often mixed with water and the physical properties of the mixture changes after injection. Gas volume data are from RRC and IHS digital database for the region labeled "Cogdell" in Fig. S2. Gas volume data before 1990 (gray area) are incomplete (see *Materials and Methods*).

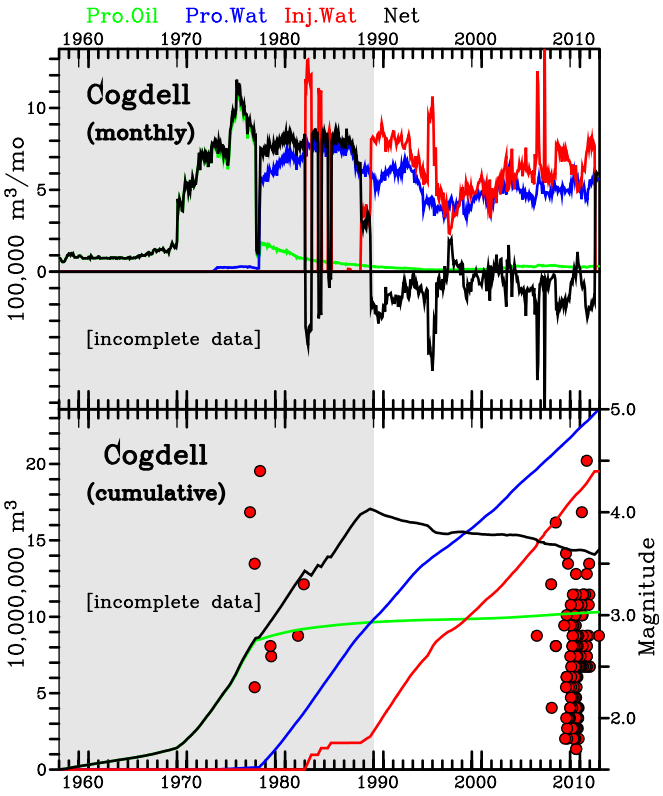


Fig. 5. For the Cogdell field, monthly (*Upper*) and cumulative (*Lower*) volumes of oil produced (green line), water produced (blue line), water injected (red line), and net volume extracted (black line: oil + water produced minus water injected). Red circles and right axis are earthquakes detected from 1977 to 2012. Volume data are from RRC and IHS digital database for the region labeled "Cogdell" in Fig. S2. Data before 1990 (gray area) are incomplete (see *Materials and Methods*).

H in Fig. 3). Between 1990 and 2006 there were no significant changes in rates of injected water except for a 1-y interval beginning in 1995 and 2 mo in 2006 (Fig. 5).

Since 1990 net cumulative volumes (liquid extracted minus injected) have been negative, i.e., the volume of material at depth has increased, and amount to about 20,000,000 m^3 (Figs. 5 and 6). When this volume is adjusted to account for the effect of extracted and injected gas, an additional ~20,000,000 m^3 since 2004 is attributable to injected gas (red line, Fig. 6). Thus, if one attributes the seismicity either to overpressuring reducing friction on faults, or to exceeding the capacity of "effectively sealed compartments," as Keranen et al. (10) recently suggested might contribute to causing a 2011 M5.7 earthquake in Oklahoma, it is plausible that injected gas played a dominant role.

This is an unusual and noteworthy instance where gas injection may have contributed to triggering earthquakes having magnitudes of 3 or larger, as the 2006–2012 sequence included 18 earthquakes with magnitudes exceeding 3, and an M_W4.4 earthquake that occurred September 11, 2011. A recent review of induced seismicity associated with CO_2 storage reported no instances where gas injection triggered seismicity (20). Microseismic monitoring has accompanied $SCCO_2$ injection projects at fields in Australia, Algeria, and Utah (21, 22), but in each case recorded seismic activity had magnitudes of zero or less, even in fields where interferometric synthetic aperture radar measurements showed that surface uplifts of several centimeters accompanied the injection. Two reportedly induced or triggered earthquakes with magnitudes of M7 occurred in 1976 and 1984 in gas fields in Gazli, Soviet Uzbekistan (23); however, these have been associated with massive gas extraction (not injection), and there is controversy about whether they are induced or natural.

Faulting in the Cogdell Region? The recent seismic activity provides strong evidence for the presence of subsurface faults in the Cogdell region. The five currently available focal mechanisms (Fig. 3) include both predominantly normal-faulting and strike slip mechanisms; all five have nearly horizontal tension axes along a north-northwest–south-southeast direction. The observed northeast–southwest-trending linear features in the relocated epicenters, some approximately parallel to the nodal planes, are consistent with the hypothesis that seismicity is releasing tectonic stress along previously existing faults. The observation that some of the 2009–2011 epicenters are near locations reported in 1979–1980 (15) suggests these may be the same faults or part of the same fault system active 1974–1982. Elsewhere in Texas, in Dallas–Fort Worth (8), earthquakes apparently triggered by the injection of water occur along similar northeast–southwest-trending linear features.

Unanswered Questions. If the recent Cogdell earthquakes are triggered, it is still puzzling why there are no earthquakes in similar nearby fields (Fig. 2) such as the Kelly–Snyder field and the Salt Creek field. Like Cogdell, both fields have experienced a combination of years of sustained injection/extraction of water/oil, followed by recent increases in gas injection (Fig. 6 and Figs. S5–S8). Since 1990, when the injection/extraction data are complete, within all three fields liquid injection and extraction rates have been approximately equal, whereas the injection of gas has increased the volume of material at depth (Fig. 6).

This observation, and the fact that no other gas injection sites have reported earthquakes with magnitudes as large as 3, suggests that despite Zoback and Gorelick's (11) concerns, it is possible that in many locations large-volume CO_2 injection may not induce earthquakes. What is different about Cogdell that allows earthquakes

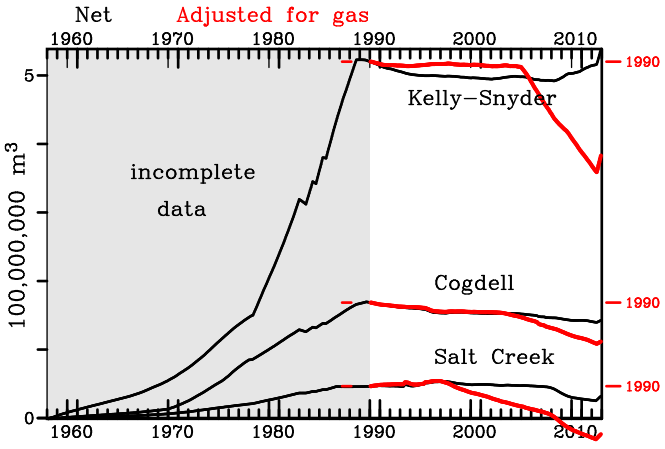


Fig. 6. Comparison of net cumulative volumes extracted for the Cogdell, Salt Creek, and Kelly–Snyder fields. Black line is oil + water produced minus water injected. Red line is volume adjusted for gas produced and injected after 1990 to approximate volume removed at production depth since 1990. Adjusted volumes are determined by assuming gas extracted is methane, and injected gas is CO_2; thus, red line is black line plus (1/180) gas produced minus (1/339) gas injected; at production depths where temperature is ~75 °C and pressure is ~200 bars, volumes of natural gas and CO_2 are ~(1/180) and ~(1/339), respectively, of volumes at surface conditions (see introduction in text). Volume data are from IHS digital database for the three regions (Fig. S2). Data before 1990 (gray area) are incomplete (see *Materials and Methods*). Ticks labeled "1990" on right axis show net volume as of 1990; note that since 1990 effect of gas injection is to decrease cumulative volume extracted, i.e., to increase the volume at depth.

to occur there? Detailed modeling investigations (21, 24) of hydrology and subsurface stress, comparing subsurface conditions in the Cogdell, Kelly–Snyder, and Salt Creek fields, might provide answers to this question. There have been preliminary monitoring and modeling of the consequences of $SCCO_2$ injection in the Kelly–Snyder (SACROC) unit (25, 26). The presence of detectable seismic activity in the Cogdell field and its absence in the apparently similar Kelly–Snyder and Salt Creek fields makes these fields attractive candidates for detailed geomechanical modeling, as has been recently applied to CO_2 injection sites near the coast of Italy (27). It would be informative to apply similar analyses to the Cogdell field, incorporating information about faulting, our reported epicentral locations, and Texas Railroad Commission (RRC) data concerning extraction/injection rates at individual wells.

Utility of USArray Data. As in our previous investigation of triggered seismicity in the Barnett Shale of northeast Texas (9), the present study is an apt example of a positive but unanticipated benefit of the USArray Temporary Array, part of the National Science Foundation-funded EarthScope program. EarthScope was conceived and funded before recent concerns about possible hazards from earthquakes triggered by water injection associated with disposal of hydrofracturing wastes (27) or by $SCCO_2$ injection for carbon sequestration (11, 28, 29). Analysis of USArray data makes it possible to determine accurate epicenters for small events and evaluate their proximity to nearby wells; it is plausible that similar analysis could provide critical information about possibly triggered earthquakes elsewhere.

For studies of this kind, the most serious limitation of USArray data is that it is difficult to assess the focal depths of triggered earthquakes with data collected at 70-km average station spacing. In the present study we arbitrarily fixed the depths at 5 km. To obtain more accurate depths from travel times one needs data from stations situated at intervals of a few kilometers or less. Alternatively, if very accurate information about crustal structure were available, reliable depths might be determined using currently available data by comparing recorded waveforms with synthetics.

Materials and Methods

Information concerning volumes of gas, oil, and water injected and extracted at individual wells is publicly available from the Texas RRC. The RRC regulates activity related to petroleum production and issues permits for drilling wells; by law, petroleum producers must provide the RRC with information concerning well locations, depths, and monthly volumes of injection/extraction of oil, water, and gas. Originally this information was filed as paper records and archived on microfiche. Nowadays most of these data are stored digitally. There has been some effort to convert older data; because this required keypunching there are occasional errors. This study mostly used RRC data as compiled by the company IHS Inc. Generally, before about 1990 the digital information is only partially complete. We wrote computer programs to sum data from individual wells and construct volume/time histories for specific fields and geographic areas. The RRC reports volumes of liquids in units of barrels. Because the volumes of oil and other fluids depend on pressure and on amounts of dissolved gas, subsurface volumes may differ slightly from volumes measured at the surface; however, in this study we use the conversion factor 1 m^3 = 6.29 barrels. The RRC reports volumes of gases in thousands of cubic feet at STP; the conversion factor is 1,000 ft^3 = 35.3 m^3.

This investigation analyzed earthquakes recorded by the six USArray stations surrounding the study area (Fig. 1 and Table S1). These were simultaneously operational from March 2009 to December 2010. During this period, the combined NEIC-ISC-ANF catalogs report 97 earthquakes located in northern Scurry and southern Kent Counties. We downloaded three-component seismograms from the USArray stations for these events from the Incorporated Research Institutions for Seismology Data Management Center.

To obtain more accurate locations for these events, we manually picked primary (P) and secondary (S) phases at all six stations. Then, to ensure we were picking the same feature for each phase and thus improve relative location accuracy, we plotted phases for multiple events together (Fig. S9) and adjusted the time picks. P and S arrival time were thus picked with a precision of 20 ms or better for most phases.

We determined preliminary epicenters for 93 of these events using a standard iterated least-squares program, fixing the focal depths at 5 km because USArray station spacing (~70 km) is too large to allow determining meaningful depths. We then jointly relocated the events to determine station corrections and more accurate trial locations. Finally, we relocated using the double-difference program HYPODD (30), obtaining relative locations for 90 events (Fig. 3 and Table S3). The rms residuals for the resulting locations were all 0.12 s or less, and most were smaller than 0.05 s. For relocations we used the CHELSEA (southwest Oklahoma) crustal model used by the Oklahoma Geological Survey for routine network locations (31).

ACKNOWLEDGMENTS. We thank Sue Hovorka, J. P. Nicot, Tip Meckel, Eric Potter, and one anonymous reviewer for helpful comments that improved this manuscript. We especially thank reviewers Wayne Pennington and Bill Ellsworth, who provided helpful comments on two preliminary versions of this work. We also thank Felix Waldhauser for helping us use his double-difference algorithm to locate earthquakes having fixed focal depths. This research was partially supported by National Natural Science Foundation of China Grant 41174076 and by the US Geological Survey (USGS) Department of the Interior, under USGS Award G13AP00023.

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Garcia Freites, S., & Jones, C. (2021). *A Review of the Role of Fossil Fuel-Based Carbon Capture and Storage in the Energy System*. Tyndall Centre.

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A Review of the Role of Fossil Fuel-Based Carbon Capture and Storage in the Energy System

Client:	Friends of the Earth Scotland
Document Reference:	CCS_REV
Version:	FINAL v2
Date:	**December 2020**
Prepared by:	Dr Samira Garcia Freites & Dr Christopher Jones

NB: All views contained with this report are attributable solely to the named authors and do not necessarily reflect those of researchers within the wider Tyndall Centre for Climate Change Research.

A Review of the Role of Fossil Fuel-Based Carbon Capture and Storage in the Energy System

1. Introduction

Carbon capture and storage (CCS) is a climate change mitigation system with potential applications for decarbonising industrial processes, electricity generation, hydrogen production and providing carbon dioxide removals (CDR[1]). The focus of this report is the role of CCS in the energy sector, particularly in relation to 2030 climate change targets.

While CCS for CDR[2] features in the majority of GHG emissions pathways compatible with the 1.5°C goal of the UN Paris Agreement on Climate Change [1, 2], and it is expected to have a significant role in mitigating emissions from heavy industries, its role in low carbon energy is less clear. Expectations for the role of CCS in electricity generation in international, European and UK energy pathways have decreased – which is likely due to slow deployment of coal and gas CCS, coupled with faster progress in renewables, energy storage and demand-side technologies [4]. Most (81% of global capacity) CCS deployment to date has been for enhanced oil recovery (EOR)[6]. Notionally, its use in EOR should provide expertise and bring down costs as the technology transfers into carbon mitigation, but progress on this has been slow over the past decade [4]. If CCS is to have a meaningful role in mitigation, deployment would need to accelerate markedly. Emphasis on CCS has notably shifted to industrial applications and fossil fuel-based hydrogen production.

Overall, the role fossil fuel-based CCS can and should have in energy system decarbonisation is unclear. Global carbon budgets are increasingly constrained with substantial progress in energy sector decarbonisation required by 2030 [1, 8, 9], while significant levels of CCS are not expected until 2030 at the earliest. It is still unclear what the preferred option for decarbonising heating, long-distance transport (including aviation and shipping) and feedstock hydrogen in industrial processes will be, and CCS related products are still considered as options. However, the extent to which fossil fuel-based CCS can be a part of low carbon energy systems will also depend on the level of residual emissions from hydrogen and electricity production and fuel supply [10, 11] allowable in future carbon budgets. Delays in CCS roll out also

[1] Carbon Dioxide Removal (CDR) approaches are also referred to as greenhouse gas removal (GGR) and as negative emissions technologies (NETs).
[2] For example, through bioenergy CCS (BECCS) and direct air capture (DAC) systems.

mean that developments elsewhere are salient. CCS applications for transport, power and heating services may depend upon how it performs relative to other low carbon generators (renewables and nuclear), demand management and the electrification of transport and heating. Consequently, policy makers would be expected to have low, or zero, fossil fuel CCS energy scenarios for climate change targets to reflect these uncertainties.

This report provides an overview of CCS development to date and its expected role in future decarbonisation, considering the global context but with a focus on the UK. The focus of this report is primarily on the near-term deployment of CCS in energy systems. Section 2 of the report reviews the expectations for CCS in current energy and climate scenarios. In Section 3 the progress to date is assessed, and in Section 4 key issues for future deployment of CCS are considered.

2. The Role of CCS in Scenarios and Policy

CCS features prominently in many energy and climate change scenarios and strategies for meeting climate change mitigation targets. This includes the Intergovernmental Panel on Climate Change (IPPC), European Commission, International Energy Agency (IEA) and the UK Committee on Climate Change (CCC). It is, however, apparent that the current trend of CCS deployment worldwide has yet to reach the pace of development necessary for these scenarios to be realised.

The mitigation potential of CCS for fossil fuel power generation in the energy sector features in many IPCC emissions pathways and future IEA energy scenarios. In the case of the IPCC, there are also 1.5°C pathways with no fossil fuel CCS or BECCS, which rely instead on social, business and technological innovations that lead to lower energy demand (LED - low energy demand scenarios). Under the LED scenarios, afforestation is the only CDR alternative, and nuclear is also considered [13].

For those emissions pathways with high reliance on CCS in the energy sector, however, there is inconsistency between the CCS projects currently in the pipeline and interim and these long-term expectations. Furthermore, existing CCS facilities for fossil fuel power generation are dominated by coal, despite projections for natural gas to replace coal-fired power generation in many archetypal pathways even with CCS. This section reviews the expectations for CCS in key energy and climate change scenarios and strategies. In the next section, this is then contrasted with the current status of CCS development.

IPCC - Special Report on Global Warming of 1.5°C

The ***Intergovernmental Panel on Climate Change*** (IPCC) in its special report on global warming of 1.5°C published in 2018 [14] shows that reliance on CCS to meet climate targets varies depending on the emissions pathways. Three out of four archetypal

model pathways feature fossil fuel CCS. Within the CCS featured pathways there is a range between a limited role scenario (cumulative 348 $GtCO_2$ stored by 2100, of which BECCS is 151 $GtCO_2$) to a more extensive role scenario (cumulative 1,218 $GtCO_2$ stored by 2100, of which BECCS is 1,191 $GtCO_2$). Under these emissions pathways, CCS reduces CO_2 emissions from natural gas-based and, to a lesser extent, from coal-based power generation. The role of CCS combined with bioenergy production (BECCS) plays an even bigger part in most of the 1.5 °C emissions pathways with its potential to remove CO_2 from the atmosphere and thus delivering net negative emissions [1]. There are IPCC 1.5°C pathways (the LED scenarios) that do not include CCS or BECCS at all, which involve radically and immediately reducing energy demand, with CDR achieved through afforestation.

The IPCC illustrative pathways also show that the share of renewables for electricity generation in 2050 increases at different levels (63%-81%) across all the pathways. Inversely, for three out of the four IPCC model scenarios, the shares of coal, oil and gas as primary energy sources are expected to decline by 2050 relative to 2010 for all the model pathways. In relation to this, while the deployment of CCS on natural gas and coal power stations varies widely across IPCC pathways, in most cases the deployment of natural gas CCS is greater than coal CCS.

International Energy Agency Scenarios

The IEA Sustainable Development Scenario (SDS) lays out a major transformation of the global energy system it considers consistent with supporting the achievement of the Sustainable Development Goals (SDGs); affordable and clean energy access (SDG7), climate action (SDG13) and air quality (SDG3). The IEA SDS analysis includes a pathway without any CDR technology (global mean temperature rise below 1.8°C at a 66% probability), and one with CDR (consistent with a global mean temperature rise of 1.5 °C with a 50% chance - requiring around 300 Gt of CDR, which is less than the median level of CDR in the IPCC 1.5 °C scenarios) [15]. The contribution of CCS to energy-related CO_2 emissions reductions in the SDS is 9%, compared to 37% from efficiency improvements and 32% from renewables.

In the *SDS,* the role of CCS in the power sector is more limited compared to previous IEA scenarios (i.e. the *450 Scenario*[3]). The current SDS relies more on renewable energy in the power sector with 8,100 TWh of electricity generation from wind and solar PV compared to 3,900 TWh from nuclear and CCS; in contrast, the former IEA *450 Scenario* projected 3,600 TWh of electricity from wind and solar PV and 7,100 TWh from nuclear and CCUS. This reflects a change in expectations on the deployment of fossil fuel CCS power generation relative to renewables for delivering decarbonisation in IEA analysis.

[3] The 450 Scenario refers to the CO_2 concentration of 450 ppm consistent with a 50% chance of limiting global temperature rise below 2°C

In the IEA SDS, the power sector is expected to reach a decarbonisation rate of 90% by 2050. Under this scenario, CCS (and nuclear energy) supplement the role of renewable energy, increasing the share of low-carbon electricity generation to 84% by 2040. CCS combined with coal and gas power contributes to 5% of the electricity generation mix by 2040 in contrast to a 67% share from renewable sources and 11% from nuclear. In terms of energy generation, 1,909 TWh of electricity are produced from coal- (994 TWh) and natural gas- (915 TWh) based power CCS in contrast to 26,065 TWh of electricity generation from renewables in the latest IEA pathways.

European Commission: The European Green Deal

In response to the European Green Deal and the targets of the Paris Agreement, the European Union has committed to achieving climate-neutrality by 2050 and reducing emissions by 55%[4] from a 1990 baseline by 2030. The proposed transition to climate neutrality includes investments and directives on CCS, smart infrastructure and innovative technology, smart grids, hydrogen networks and energy storage. Regarding CCS, the 2009 EU CCS Directive provides a framework on the geological storage of carbon dioxide regulates mainly the CO_2 storage phase. It also includes some provisions related to the CO_2 capture and transport phases with the intention to facilitate the integration of the CCS supply.

The European Commission [16] has stated a key role of CCS deployment to meet the EU's long-term GHG emissions reduction target by 2050. The Commission expects CCS to become one of the few technology options to cut direct emissions at scale from industrial processes and serve as a low-carbon technology when combined with fossil fuel-based generation to provide flexibility to energy systems, with increasing variable renewable sources [16]. However, it also indicates that the role of CCS has diminished with the faster deployment of renewable energy and other technologies to reduce emissions from industrial processes [16]. Despite this, CCS is still considered necessary to capture and store the CO_2 from carbon-intensive industries; in the transition of fossil fuel-derived hydrogen production and for the deployment of bioenergy with CCS at scale to achieve negative emissions. The European Commission's Hydrogen Strategy as a whole however emphasises electrolysis derived hydrogen (targeting 40 GW of electrolysis capacity by 2030) [17].

The European Union via the EU Innovation Fund (circa 10 billion euros), and using revenues from around 450 allowances of the EU Emissions Trading Scheme, is financing innovation projects including renewable energies, CCS, energy storage and industrial low-carbon processes [18]

UK - Committee on Climate Change

[4] Recently voted on by the European Parliament and may increase to 60% by 2030 against 1990 baseline

The Committee on Climate Change (CCC) has advised the UK Government to reduce GHG emissions reduction to 'net-zero' by 2050 under the UK's obligations to the Paris Agreement. The CCC in their Net Zero report [19] introduced new scenarios to illustrate options on how to reduce emissions from current levels. The CCC indicates that current UK policies are insufficient to meet even the previous 80% of emissions by 2050 target and that efforts in climate policy need to ramp-up [20].

In statements made to date, the CCC considers CCS systems essential to deliver net-zero GHG emissions by contributing to the projected increase supply of low-carbon electricity, hydrogen production, and the requirement of GHG removal through BECCS systems [21]. The CCC has *Core*, *Further Ambition* and *Speculative* scenarios. The Core scenario represents findings on low-cost low-regret options, the *Further Ambition* scenario involves more challenging and costly options than those in the *Core* scenario, and the *Speculative* scenario includes options considered to be at low-level of technology readiness, higher cost and with barriers to public acceptability. The extent to which CCS contributes to the net-zero target, however, varies within the scenarios and involves an aggregate annual capture and storage between 75-175 $MtCO_2$ in 2050 and a major CO_2 transport and storage infrastructure servicing at least five clusters [19].

Under the *Further Ambition* Scenario, CCS has a larger role across industry, greenhouse gas removals (i.e. BECCS), hydrogen production and power generation, with up to 175 $MtCO_2$ captured and stored in 2050. In the power sector, CCS integration with gas-fired or biomass power plants would be required to supply some flexible electricity generation and complement the remaining 5% share needed to fully decarbonize the electricity supply in 2050. Under this scenario, 57 $MtCO_2$ /year and 46 $MtCO_2$/year would respectively be captured and stored from fossil-based electricity generation with CCS and fossil fuel-derived hydrogen production with CCS. This scenario also assumes higher CO_2 capture rates of 95% [19] than the conventional 90% capture rate usually assumed in the literature for power-CCS plants. Technology options and economic challenges of higher CO_2 capture rates are further discussed later in this report.

The CCC also finds that CCS progress has stalled in the UK due to slow movement on UK policy for CCS deployment. Although CCS has recently begun to be discussed as a priority again slow progress leaves the UK with currently no CCS facilities in operation or construction at this time [20]. In these scenarios, a minimum of two CCS clusters are expected to operate by 2030 capturing at least 10 $MtCO_2$ per year. This is on the basis of the government leading infrastructure deployment, with long-term contracts for carbon capture and encouraging investment. These scenarios also include the development of hydrogen, mainly through natural gas reforming, assumed to operate at scale by 2030 in industrial CCS clusters, as well as policy frameworks across energy generation, industry, and greenhouse gas removals. The CCC highlights in particular that the UK should take advantage of the significant potential in regional CCS storage capacity, estimated in 78 Gt and equivalent to over 150 $MtCO_2$ stored per year [19].

In an illustrative generation mix of the power system in 2050, the share of electricity generation through natural gas power stations with CCS could reach up to 23% in the mix, although this could be partially replaced by nuclear power and alternative renewable technologies. The main supply of electricity would derive from variable renewables with a minimum 59% share. Additionally, electricity from BECCS (6%), nuclear (11%) and others sources (i.e. existing bioenergy and hydropower, and hydrogen or ammonia to provide back-up) would complement the generation mix [20].

The UK Government and the Department for Business, Energy & Industrial Strategy (BEIS):

As part of the UK Government, the Department for Business and Industrial Strategy (BEIS) considers that CCS technology has a significant role to play in meeting the net-zero target. CCS is expected to contribute to the decarbonisation of the power and industry sectors, produce fossil-based hydrogen and achieve large-scale commercial greenhouse gas removal [22]. Specifically, in the power sector, CCS is expected to capture and store the 45 $MtCO_2$ emissions per year from existing natural gas CCGT[5] based electricity generation, assuming a 95% CO_2 capture rate. Emissions from these systems are currently equivalent to 12% of UK emissions [22]. In the production of fossil fuel based-hydrogen via natural gas reforming or biomass gasification CCS would capture CO_2 as a by-product.

The UK Government considers CCS infrastructure likely to be delivered for the net-zero target with a substantial CO_2 storage capacity (78 billion tonnes of CO_2) using reservoirs deep underground off the UK coastline [22]. To this end, research investment competitions for greenhouse gas removals and development plans for six industrial CCS have been supported. The Government has also invested over £130 million in R&D and innovation with the aim of reducing CCS costs. They are supporting innovative technologies such as those developed by C-Capture (i.e. pilot testing of non-amine capture technology at Drax power station); Carbon Clean Solutions on novel carbon capture solvent and the Allam cycle technology, used by NET Power, capable of 100% capture rate at costs similar to an unabated CCGT [23].

Since the Clean Growth Strategy [23], the government committed to deploy CCS at scale during the 2030s subject to costs coming down sufficiently and to invest up to £800 million in developing CCS infrastructure to support the decarbonisation of our power and industrial sectors [21].[6] Recently enhanced ambition to begin construction of two CCS hubs in the mid-2020s and a further two created by 2030 has been announced [24]. The role of CCS is, however, considered essential by BEIS to reduce the costs of meeting the 2050 target contributing to lower emissions across industry, power, heating and transport sector [23].

[5] Combined Cycle Gas Turbine
[6] See BEIS (2020) https://www.gov.uk/government/news/beis-in-the-budget

In scenarios with a significant role for CCS, deployment is required through the 2020s, with the delivery of major projects by 2030 at the latest (particularly in UK scenarios). In the case of the IEA projections for the role of CCS in the energy sector have been downgraded. In the UK changing expectations in the role of CCS in energy are manifest in the National Grid Future Energy Scenarios, wherein in 2015 CCS coal and natural gas power generation is significant in scenarios [25] but absent in the 2020 scenarios [26]. The role of CCS in National Grid scenarios 2020 is exclusively in combination with bioenergy and for hydrogen production for heat and transport [26]. This reflects a shift in the expectations for fossil fuel CCS from the power sector to hydrogen and a greater emphasis on CCS for CDR and industry. In the next section, the current status of CCS worldwide is reviewed. The delays in CCS deployment discussed may in part explain this shift. Table 1 provides a review of the role of CCS in key scenarios reviewed.

Table 1:Summary of the role of CCS on energy and climate change scenarios and strategies for the IPCC, IEA and UK Committee on Climate Change

Report	Emissions reduction by 2050	Characteristic of CCS contribution/participation
IPCC 1.5°C Global Warming report	91%-97% CO_2 emissions reduction by 2050 (relative to 2010) across the four illustrative 1.5°C model pathways. 78%-89% reduction in Kyoto GHG emissions by 2050 (relative to 2010) across the four illustrative model pathways	CCS (including BECCS) contribution to CO_2 emissions reduction leads to cumulative CO_2 stored until 2100 spanning (four illustrative model pathways) between: The lowest share**, zero GtCO2 for low-energy demand-LED scenarios** to **348 $GtCO_2$ stored in a sustainability-focused scenario** of which BECCS 151 $GtCO_2$, to **686 GtCO2 stored in a middle-of-the-road scenario** of which BECCS 414 $GtCO_2$, to the highest share **1218 $GtCO_2$** for the **resource and energy-intensive scenario** of which BECCS 1191 $GtCO_2$.
IEA - World Energy Outlook 2019	In the Sustainable Development Scenarios (SDS): The emissions trajectory of SDS decline by 730 Mt on average each year compared with a 400 Mt annual decline in the 450 Scenario.	**2776 Mt of CO_2, from the energy-related GHG emissions, are captured and stored through CCS by 2050.** CCUS contributes 9% of the energy-related CO_2 emissions reductions. Across all sectors, around 0.7 Gt of CO2 emissions are captured each year by 2030; this rises to almost 2.8 Gt in 2050 where CCS is equally split between power and industry. **Under the SDS in the power sector**, CCUS is applied to over 320 GW of coal- and gas-fired power generation capacity by 2040, with 20 GW per year from late 2020's to 2040. **1323 $MtCO_2$ are captured and stored through CCS in the power sector**
CCC – UK Net Zero Report (2019a, 2019b)	In the Further Ambition Scenario (required to get to net-zero GHG emissions): 96% reduction in all GHG emissions by 2050 compared to 1990 levels, remaining in 35 $MtCO_2e$ in 2050 CO_2 emissions slightly below net-zero Remaining emissions from agriculture and aviation.	**In the UK,** CCS captures and stores an aggregated annual 175 MtCO2 in 2050 (from zero $MtCO_2$ in 2017). CCS to integrate with hydrogen, electrification and resource efficiency, the portfolio of options for emissions reduction: **CCS in electricity generation:** 57 Mt CO_2 captured and stored through fossil power generation with CCS. Decarbonised gas via CCS and hydrogen contributes with 5% for full (100%) electricity decarbonisation in 2050 and remaining emissions are of 3 Mt CO_2e **CCS in Hydrogen production:** 46 Mt CO_2 captured and stored through fossil hydrogen production with CCS **CCS in Industry:** 24 Mt CO_2 captured and stored **BECCS:** 44 $MtCO_2$ captured and stored. Bioenergy combined with CCS to produce electricity, biofuels for aviation and in buildings off the gas grid

3. The Current Status of CCS

The CCS concept, for long-term sequestration of CO_2, has been successfully demonstrated on a technical basis since 1996, however, scaling up deployment and applications outside of the chemical sector and oil and gas processing beyond EOR as a business model has been slow. The Global CCS Institute (GCCSI) notes that in 2010 ~10 Mt of CO_2/year CCS capacity was operational, with a further 150 Mt CO_2/year in some form of development, yet by 2020 only 39 Mt CO_2/year was in operation[7], with ~75 Mt CO_2/year capacity in some form of development (see Figure 4 of GCCSI [6]). This represents a decade of very limited progress in terms of CCS project development. Projects in development fell to as low as ~30 Mt CO_2/year in 2017 [27] reflecting various cancellations in early and advanced development projects. The IEA's 2019 scenarios for meeting SDGs considers 840 Mt CO_2/year of CO_2 capture (of which 81 Mt CO_2/year is BECCS and 189 Mt CO_2/year is used rather than stored) overall by 2030 [4], implying deployment averaging 80 Mt CO_2/year capacity per year over the coming decade. This is roughly equivalent to adding 25 projects globally each year with a capacity similar to the proposed Scotland CCS cluster (3-4 Mt CO_2/year) with the additional difficulty of the long deployment timelines for CCS projects. This will require overcoming the financial and risk barriers to the technology observed so far.

Carbon capture technology for use in the energy industry (primarily oil extraction) has been in place since the 1970s, with research into applications for long term sequestration accelerating through the 1980s (e.g. with the start of the MIT Carbon Capture and Sequestration Technologies programme in 1989). The role of CCS expressly for environmental goals was demonstrated in the 1996 Sleipner gas project [28], but clearer expectations around the role of CCS in climate policy became increasingly apparent around 2008. The UK Committee on Climate Change 'Building a Low Carbon Economy' in 2008 recommended CCS as an option for power generation (with coal and gas) and likely essential for some industrial applications [29]. This informed a policy process to develop CCS, firstly for coal power stations, pursuing deployment by the early 2020s [30]. A key international indicator for CCS expectations in this period was the G8 (Group of Eight) commitment to launch 20 large scale CCS projects by 2010 with broad deployment (19 to 43 large projects) of operational CCS by 2020 [31]. The IEA's CCS Roadmap in 2009 set a goal of 100 projects globally capturing 300 Mt CO_2/year by 2020 [4]. Deployment progressed slowly in relation to this, with only five projects developed by 2012. However, by 2014 the first commercial CCS power station at Boundary Dam in Canada was completed. In the UK two R&D competitions to develop demonstration projects in the UK between 2008 and 2015 produced significant research outputs on CCS application but ultimately did not lead to a demonstration project. The failure of the UK competitions

[7] Accounting for mothballed operations at Petra Nova and Lost Cabin facilities in 2020.

was primarily attributed to uncertainty around the economic feasibility of CCS, with a £1 billion state investment into CCS ultimately not materialising at the end of the second competition process [32]. The ownership structure (i.e. responsibility for the 'full chain' of CCS processes) expected of project developers is also considered a factor [33]. Additionally, a key driver of this initial round of investment in UK CCS was to mitigate carbon from coal power generation, which is now no longer a significant part of the UK electricity mix.

To date globally, 28 CCS plants are developed to the operational stage (although 2 are currently suspended), five of them with integrated dedicated geological storage and the remaining 22 using the CO_2 captured for enhanced oil/gas recovery (EOR/EGR) applications [6].

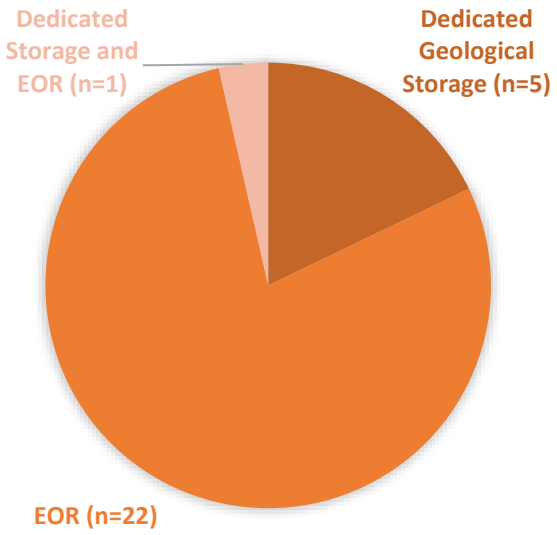


Figure 1: Operational CCS Projects by type of CO_2 storage. Based on the Global CCS Institute. The Global Status of CCS: 2020. (2020)

The CO_2-EOR process entails the injection of CO_2 in an oil reservoir, working as a solvent to swell and mobilise the oil previously trapped in rock's spaces and with the final purpose of increasing oil production in a well. The CO_2 is permanently trapped in the space that originally held the oil [27]. The global capture capacity of the operational CCS plants stands around 37 Mt CO_2/year, where approximately just 19% (~7 Mt CO_2/year) is used for the sole purpose of CO_2 emissions avoidance through dedicated CO_2 storage and the rest applied for EOR processes.

The GCCSI [6] also reports that two large-scale CCS facilities are under construction with an aggregated CO_2 capture capacity between 1.91 Mt CO_2/year and end-use applications in EOR. The expected start date of operation of these projects is in the late2020s. An additional 37 projects are in the pipeline, 13 of which are in advanced

development using a dedicated front end engineering design (FEED)[8] approach and comprising a mix of dedicated storage (seven), EOR (four) and under evaluation (two). From the 21 CCS projects in early development, the majority (16) are planning to have CO_2 dedicated geological storage.

The natural gas processing industry embeds the highest number of CCS plants (11 facilities in operation) using industrial separation to capture the CO_2 and the majority with EOR application eight). These industries can capture the CO_2 at relatively low costs due to its high concentration in the gas streams [27]. Other industry sectors with projects integrating CCS, whether for emissions mitigation or as an inherent stage of the production process, are the power generation sector (one), fertiliser production (four), hydrogen production for oil refining (three), synthetic natural gas production (one), ethanol production (three) and iron and steel production (one)[6]. The emphasis on using EOR applications for existing CCS plants is because the majority of these facilities are located in the US where onshore EOR is a long-established process, with many miles of existing CO_2 pipelines. Furthermore, in the absence of strict regulations and cost on CO_2 emissions, there is little incentive to develop CCS for mitigation. Hence, EOR is so far one of the economically feasible ways to capture and store CO2 while extracting more oil. It is therefore notable that at this stage CCS planned deployment remains dominated by EOR – which has a minor role in expected CCS scenarios by 2030 (see Section 2).

CCS deployment in Europe and the UK

Among the 28 operational large-scale CCS facilities worldwide, two are located in Norway (Sleipner: 1 Mt CO_2/year and Snøhvit: 0.7 Mt CO_2/year) capturing and storing 1.7 Mt CO_2/year of CO_2 from the natural gas processing industry in dedicated storage sites [6][4]. In addition to the two operating CCS projects, the Longship CCS project in Norway is projected to commence operation by 2024 and capture up to 0.8 Mt CO_2/year of CO_2 from the Norcem's cement factory and the Fortum waste-to-energy plant facility [34]. The CO_2 transportation and off-shore storage will be managed by the Northern Lights consortium through an open-access infrastructure using existing oil and gas infrastructure. In addition to the CO_2 captured from the capture plants in Norway, Northern Lights is expected to serve as transportation and storage for other capture sites across Europe [34].

Despite a regulatory framework for CCS being in place through the 2009 CCS Directive, CCS deployment in Europe outside of Norway has not yet materialised. Compared to other regions like North America with 12 CCS large-scale facilities in operation, the integration of CCS to current power and industry sectors in Europe has been much slower.

[8] **Front End Engineering Design** is an approach used to control project expenses and thoroughly plan a project before a fix bid quote is submitted. It is conducted after completion of Conceptual Design or Feasibility Study, and before the Engineering, Procurement and Construction.

Progress on CCS deployment in Europe is however projected to accelerate in the mid and later 2020's with as many as 10 large scale CCS projects (six in the UK, two in the Netherlands, one in Norway and one in 1 Ireland) being proposed. Most of these projects are to function as part of CCS hubs and clusters in industrial installations and using shared infrastructure for the CO_2 transportation and storage network to reduce costs of the CCS supply chain. This, however, represents the current best case, with the UK Government so far only committed to 'at least two' industrial hubs by 2030.

The operation of the planned CCS facilities is expected to capture up to 26.7 Mt CO_2/year; 22.7 Mt are planned for injection in dedicated geological storage sites, with 4Mt captured from Drax (in conjunction with bioenergy) under evaluation [6]. The total CO_2 storage capacity available in Europe is estimated by the GCCSI to be 300 Gt [6].

In relation to funding and policy aspects, 10 billion euros are expected to be available for the Innovation Fund, the largest European fund financing CCS, as part of the portfolio of low-carbon technologies and processes. CCS is also part of the current European Commission strategy to achieve climate neutrality by 2050, with contributions spanning between 52 to 606 $MtCO_{2/}$ year in 2050 across scenarios. It is anticipated to have a more limited capacity in the power sector, instead, its proposed role is more relevant as an industrial decarbonisation alternative and for hydrogen production.

Within the UK, there are five clusters which have received funding to develop cluster plans under the first stage of the Industrial Decarbonisation Challenge Fund; bids to the second stage deployment plans have been submitted and are expected to commence early 2021. The *Net Zero Teesside* project is one of the initial CCS clusters under development estimating to capture up to 6 Mt CO_2/year of CO_2 emissions from a new commercial-scale natural gas power plant, that has completed the Stage 2 Consultation stage of the 'Development Consent Order' process, and also from other existing industrial processes. This cluster is expected to start operation by 2030. Furthermore, the Zero Carbon Humber cluster, also under development, is planned to capture CO_2 up to 10 Mt CO_2/year when fully operational from a BECCS plant (Drax biomass-power station) and from the production of hydrogen to fuel the industry sector. The Acorn Full Scale CCS project plans to function as a major fossil fuel based-hydrogen production pathway with a CCS transport and storage hub located at St Fergus in Scotland. The project was awarded the first carbon dioxide appraisal and storage licence by the Oil and Gas Authority in the UK and has stated it could commence operation in 2025. The Net Zero Teesside and Acorn projects could use the Northern Lights open-access infrastructure as an alternative CO_2 transportation and storage option. The other two clusters receiving funding from the Industrial Decarbonisation Challenge Fund (stage 1) are the HyNet North West industrial cluster for hydrogen production and the South Wales Industrial Cluster.

CCS in the power sector

The abatement of fossil CO_2 emissions through CCS deployment in the power sector remains limited, with currently two large-scale CCS facilities incorporated into coal-fired power plants, both in North America. Together, these facilities have a combined capture capacity of 2.4 Mt CO_2/year and use the CO_2 captured for EOR. This deployment is considered to be significantly off-track to meet climate change targets [4]; compared for example to the target of 310 Mt CO_2/year for power generation alone in 2030 by the IEA's Sustainable Development Scenario [15]. This would require an increase in CCS capacity in the power sector of approximately 129 times the existing capture capacity from the two existing power plants with CCS integration.

The first large-scale CCS facility in the power sector consisted of the integration of a CCS system in the Unit 3 of the *Boundary Dam* coal-fired power plant in Canada. It started operation in 2014 with a capture capacity of 1 Mt CO_2/year, resulting in a cumulative 3.4 Mt CO_2 captured up to July 2020. The capture method is the Shell Cansolv post-combustion CO_2 capture technology with a target capture rate of 90% [35]. The CO_2 is compressed and transported to Weyburn oil field for EOR and a smaller portion is stored in a dedicated saline aquifer (Aquistore project) to monitor and evaluate the safety and permanency of the deep underground CO_2 storage. The capital cost of the plant was reported to be 600 million Canadian dollars (~455 million USD) [36] and a capture cost of USD 100 per tonne CO_2.

Several conditions enabled the deployment of Boundary Dam CCS, including the opportunity to sell the CO_2 captured for EOR; grant supports, subsidy provision by government, and the prospect of low-cost CO_2 transport and storage [27]. The key driver, however, was the environmental regulation introduced by the Canadian government to meet emissions performance standards consistent with natural gas generation, therefore the only options were to retrofit (addition of a CCS unit to an existing power plant instead of adding it to a new plant) with CCS, switch to natural gas or decommission the plant [37].

Petra Nova Carbon Capture is the second commercial coal-fired power plant with CCS integration, located in Texas, USA. It started to operate in 2017 with a capture capacity of 1.4 Mt CO_2/year. It has accumulated 3.4 Mt of CO_2 captured and stored for EOR during the third phase (demonstration and monitoring) of the project between 2017-2019 [27]. The facility is however currently offline due to low oil prices [6, 38]. The capital cost of the project was USD 334 million and the levelised capture cost for this plant reduced to USD 65 per tonne CO_2, compared to Boundary Dam (although modifying existing infrastructure may have contributed to cost savings). The capture method used is an advanced amine-based CO_2 absorption technology (KM-CDR Process) [39].

The rationale behind the deployment of the plant was also different from Boundary Dam, as Petra Nova was constructed as an enhanced oil recovery project and received a significant grant (USD 190 million) from the US Government Clean Coal Power Initiative Program [36]. Furthermore, it has received emissions credits. Operation of CCS at the plant has however been reportedly affected by low oil prices [38].

As such, at this point, CCS deployment in sectors that it is primarily envisaged for (particularly in Europe) – natural gas power CCS, fossil fuel hydrogen production, industrial capture outside of oil and gas sector and carbon dioxide removals – is currently minimal or non-existent. Therefore, while technological aspects for capture technologies, transport and storage have been demonstrated, integrated systems delivering CCS services for key decarbonisation activities remain a future prospect. In the next section, the future potential for fossil fuel CCS in the energy system is reviewed. It suggests a limited role for CCS in energy system decarbonisation over the coming decade (2020-2030), but renewed policy priorities to establish CCS processes by 2030.

4. The Future Potential of CCS

Despite its representation across most model pathways for meeting climate change goals, research evidence collated in Rogelj et al [2] identifies uncertainty around the future deployment of CCS given the slow pace of deployment and lack of incentives, policies and regulation for CCS implementation compared to what is expected to be delivered by CCS infrastructure. Given the prominence of CCS in most mitigation pathways and its current limited improvement, the large-scale deployment of CCS as an option depends on the further development of the technology for permanent CO_2 (as opposed to EOR) in the near term.

This section considers some of the issues CCS faces in meeting the expectations identified in the energy and climate scenarios it features in (Section 2), specifically around emissions, technical attributes, regulation, and cost and complexity.

BOX 1: Technical Attributes of CCS

Among the stages comprising CCS, the CO_2 capture is the most energy-intensive and costly, imposing a considerable energy penalty to the process [3]. Energy penalty is a common metric applied to the power generation sector that compares the performance (efficiency) of a plant with CCS compared to a similar one without it [5]. It can be interpreted as the additional energy input (fuel) required to maintain a power's plant output at the same level, or the loss of power output for a constant energy input [7].

There are various types of CO_2 capture technology, featuring inherent advantages and limitations, and at different stages of development; post-combustion, oxyfuel combustion and pre-combustion.

In the ***post-combustion capture technology***, the CO_2 is separated and captured, from the flue gases (nitrogen, water, CO_2, and other impurities) after the fuel combustion in a power plant or industrial process. The main advantage of this technology is the feasibility for retrofits of existing industrial plants without further large equipment investments and low impact on the process operation [3].

The main energy input is required in the form of low pressure steam for the solvent regeneration process, imposing a significant efficiency penalty. Part of the steam generated to produce electricity in the power plant is diverted for the amine solvent regeneration, thus imposing an energy penalty between 15-28% for pulverised coal power plants and 15-16% for natural gas combined cycle plants with integrated post-combustion capture [5].

In ***oxyfuel combustion capture***, fuel (coal, gas, or biomass) is burned in a mixture of oxygen and recycled CO_2 (to control the temperature inside the boiler) producing a gas mainly formed of CO_2 and water vapour. The CO_2 is separated afterwards by a condensation process [3].

The major advantage of this is simple and low-cost CO_2/H_2O separation. It also has the potential of retrofitting for existing power plants. The energy penalty (around 19%) is imposed by the energy-intensive air separation process [12]. Therefore the development of more efficient air separation systems might also enhance the overall process efficiency [3].

The ***pre-combustion capture technology*** entails a reaction between coal, natural gas or biomass and air, oxygen and/or stem to produce a syngas comprised mainly by CO, H_2, CH_4 and CO_2. The syngas reacts with steam in a water-gas shift reactor to produce CO_2 and more H_2. The CO_2 is later separated using physical or chemical absorption methods, resulting in two separate gas streams: a pure CO_2 gas and hydrogen-rich fuel.

Because pre-combustion capture involves steam reforming or gasification process, this route has limitations on the operating flexibility as gasification is a more complex and novel technology than combustion. The capital costs are higher forcing full load operation to produce syngas. The operating condition of the pre-combustion technology varies to post-combustion because in pre-combustion the syngas is at higher pressures (2-7 MPa) and high CO_2 concentration content, therefore the compression and desorption requirements are not so demanding, resulting in lower efficiency penalties [3]. Energy penalties range between 5-20% for Integrated Gas Combined Cycle (IGCC) power plants combined with pre-combustion capture CCS.

Emissions

Mitigating climate change in line with the goal of staying well below 2°C of warming depends on a timely transition to low carbon energy [40]. In contexts such as the UK, legislative targets require net-zero greenhouse gas emissions by 2050, which for the energy system means almost zero CO_2 emissions [19]. It is not only what is achieved by an endpoint target (such as 2050), but the extent to which cumulative CO_2 emissions – the primary driver of long term climate change [40] – are limited over time that ultimately matters. The emissions associated with a given future technology and its contribution to mitigation at a given time are therefore of particular importance. The remaining global carbon budgets published by the IPCC imply immediate and sustained reductions in emissions, with a reduction in global CO_2 of ~45% against a 2010 baseline required by 2030 for a chance of 1.5°C [14]. The EU is considering a mitigation target of over 55% relative to 1990 by 2030 and the UK recently updated its 2030 target to 68% cut in emissions by 2030 against the 1990 baseline [41], entailing significant additional progress on heating and transport by 2025 [21]. Analysis by Anderson et al suggests that mitigation rates in countries such as the UK should be even greater (~10% per annum, up from recent historical trend of 3% per annum), decarbonising energy systems by 2035 to 2040 [8]. By all measures, significant progress in energy system decarbonisation is required over the coming decade particularly in developed nations such as within Europe.

Within many of the pathways proposed for reaching these targets, CCS has various roles in industrial decarbonisation, power sector decarbonisation and CDR (see Section 2). CCS offers a means of capturing ongoing emissions of CO_2 from existing industrial processes such as iron & steel and cement, providing an option to decarbonise these typically hard to abate emissions. Hydrogen via electrolysis also offers an alternative to CCS based decarbonisation of steel production. The IEA World Energy Outlook 2019 reports that CCS together with energy and material efficiency supports the decarbonisation of heavy industries, such as cement, iron and steel production, and the refining sub-sector of oil and gas extraction [15]. In the IEA SDS, CCS contributes to 21% of savings in energy-related CO_2 emissions in industry [15]. They also note that the current pipeline of projects, however, is far short of what is required under this scenario to abate emissions from key industrial sectors of the economy [15]. Carbon dioxide removal with CCS is central to national net-zero targets in the UK [19]. In the case of energy provision through fossil fuel CCS, however, there are apparent limitations to the role that it may be able to play within highly constrained future carbon budgets.

In the case of natural gas CCS power stations, there are residual emissions that would contribute to direct territorial CO_2 emissions of at least 39 $kgCO_2e/MWh$ (assuming a 90% CO_2 capture rate) [42]. Upstream emissions of greenhouse gases (notably methane) associated with extraction, processing and transport increase with CCS

application due to increased energy use for capture and reduced efficiency meaning life cycle emissions of at least 123 kgCO_2/MWh [10].[9]

Steam methane reforming (SMR) and autothermal reforming (ATR) processes of transforming natural gas feedstock into hydrogen also entail greenhouse gas emissions in production and across the supply chain. The UK CCC estimates emissions savings on a whole life basis of 65% to 85% when switching from natural gas to hydrogen from fossil fuel CCS for home heating [11]. Producing fossil fuel-based hydrogen with CCS is estimated to produce 50 gCO_2/kWh to 188 gCO_2/kWh (process and supply emissions) [11]. Similarly, a report by Navigant reports a range of 51 gCO_2/kWh to 63 gCO_2/kWh for producing CCS derived hydrogen [43]. As such whether fossil fuel-based hydrogen is sufficiently low carbon – from UK Net Zero and relative to global remaining carbon budgets – to have a major role in energy provision is an important consideration.

With these considerations in mind, the IEAGHG note that scenarios for a constrained global carbon budget, especially for 1.5°C and high probability well below 2 °C cumulative budgets, have limited fossil fuel CCS energy production [42]. The UK CCC similarly concludes that hydrogen utilisation should be prioritised for niche functions and where derived from fossil fuel conversion would not have a widespread role in low carbon scenarios [11].

These emissions considerations assume a 90% to 95% CO_2 capture rate, which as discussed below, could in principle be increased (however with increased upstream emissions through increased fuel use). There may also be wider environmental impacts (as is the case with any scale-up of a technology) not captured in a global warming potential (CO_2e) focused assessment. However, the lack of sufficient data on natural gas CCS power station capture rates, CCS hydrogen production operations, or any CCS energy application with >90% capture rate, means that it is prudent to await these results before applying high capture rates to these emissions factors.

Potential higher capture rates (99%)

In power generation plants with CCS, the CO_2 capture rate has been historically fixed at 85% - 90% due to associated captures costs of flue gas streams with low CO_2 concentration (below mol-20%). The two large-scale power plants with CCS retrofit used this capture rate as target (*Boundary Dam* and *Petra Nova*) and IAMs used a 90% capture rate in their assessments, assuming 10% of residual emissions.

Recent studies by the IEAGHG [10] looking at the feasibility of reaching near zero emissions in fossil-CCS concluded that in theory there are no technical barriers to

[9] The data presented in table 9 of IEAGHG (2019) 'Towards zero emissions CCS in power plants using higher capture rates or biomass' provides this breakdown based on the best performing emissions data for natural gas fired turbines.

increasing the capture rate across the three main capture technologies. However, trade-offs should be considered as costs (total plant cost and levelised costs of electricity) are expected to increase, in some cases modestly, depending on the capture technology. Additionally, the plant's performance is expected to decline (i.e. higher energy penalties) and the indirect emissions from fossil fuel use increase. Alternatives to increasing the CO_2 capture rate above 90% and the implications of higher capture rates on costs and plant's performance are presented in more detail below for each of the three main carbon capture technologies. While optimisation for CO_2 capture at a CCS facility presents opportunities to mitigate direct emissions, it also has implications for indirect emissions and validation against actual performance is still required [10].

For ***post-combustion capture***, pathways for reaching higher CO_2 capture rates are through increasing the effectiveness of the CO_2 separation process or co-firing with biomass, which could result in relatively lower costs depending on the biomass type. The increase in costs will also depend on the type of power plant. In ultra-supercritical coal (USC) power-CCS plant with 99.7% CO_2 capture, the levelised cost of electricity (LCOE) can increase by 8% and the CO_2 avoided cost (CAC) by 6%. Further, co-firing with 10% of biomass in the same plant could increase, instead, the LCOE by just 2% and the CAC by 1.4%. In a CCGT-CCS plant, a 99% of CO_2 capture increases the LCOE by 6.6% and CAC by 7.8% [10]. Concerning the net plant efficiency, a 99% capture rate decreases the net plant efficiency by 5% in a USC power plant configuration and by 4.5% in a CCGT plant. The cofiring of biomass (10%) would avoid a further reduction in the plant's efficiency for a USC coal-CCS plant and a neutral CO_2 emission intensity with a 90% capture rate.

Pathways to increase the CO_2 capture rate in ***oxy-combustion capture process*** are achieved via a reduction in the inert gases of the CO_2 stream by using oxygen with higher purity and/or reducing the air leakage to the boiler [10]. CO_2 can also be recovered by passing the vent gases from CO_2 purification to a membrane separation unit [44]. From a performance and costs perspective, increasing the capture rate from 90% to 98% could reduce the plant's net electrical efficiency by -1% and increase the total plant costs (TPC) by 2% and the LCOE by 3%, while reducing the cost of CO_2 avoidance by -4%.

For **pre-combustion capture**, increasing the capture rate to 98.6% in a coal-based Integrated Gasification Combined Cycle power plant leads to a 2% reduction in the plant's electrical efficiency, and higher total plant costs by 4% and LCOE by 4.2%. These figures almost doubled the efficiency penalty and costs increase, compared to oxy-combustion capture, however, the CO_2 avoidance costs also decrease by around 3.6% [44]. Reducing the CO_2-slip emissions in the flue gas could be attained by improving the carbon conversion (water-gas shift reaction conditions) and the CO_2 separation process. As in other processes that increase the gross fuel input into the power plant to account for energy penalties of the capture stage, doing so has

consequences for environmental and human health impacts through the coal supply chain.

Table 2 collates performance data reported by the IEAGHG [10, 44]on the implication of higher CO_2 capture rates and/or biomass cofiring to reach near 100% CO_2 direct emissions reduction in comparison to standard CCS integration with 90% capture rate:

Table 2. Implications of higher CO_2 capture rates on plant net efficiency, LCOE and CAC

Capture technology	Characteristics	Change in plant efficiency	Change in TPC	Change in LCOE	Change in CAC
Post-combustion capture [10]	USC-power plant (99% capture rate)	↓ 5%	↑ 6.6%	↑ 8%	↑ 6%
	10% biomass cofiring (90% capture rate)	0%	↑ 1.9%	↑ 2%	↑ 1.4%
	NGCC power plant (99% capture rate)	↓ 4.5%	↑ 6.5%	↑ 6.6%	↑ 8%
Oxy-combustion capture [44]	SC-power plant (98% capture rate)	↓ 1.1%	↑ 2.2%	↑ 3%	↓ 4%
Pre-combustion capture [44]	Coal-IGCC plant (98.6% capture rate)	↓ 2.4%	↑ 4.1%	↑ 4.2%	↓ 3.6%

Overall, increasing the capture rate in oxy-fuel combustion and pre-combustion CCS would marginally increase costs and reduce the plant's efficiency, also the CO_2 abatement costs could decrease for both capture technologies. More detrimental results are observed for post-combustion capture plants using coal or natural gas and better results for biomass cofiring keeping the same 90% capture rate. Numbers are more favourable for oxy-combustion capture because of a relatively simpler and low-cost CO_2 separation process. IEGHG [10] also highlight that these findings need validation through demonstration in real-life operation across the different CO_2 capture routes and, that indirect emissions from the coal and/or natural gas power–CCS plant supply chains should be minimised in parallel to direct emissions in order to decrease total lifecycle emissions.

Global CO_2 storage capacity

CO_2 storage starts with the injection of the captured CO_2 into deep underground geological reservoirs, such as deep saline formations and depleted oil and gas reservoirs, for permanent storage. The porous rock layer is overlaid by an impermeable layer of rocks that seals the reservoir and prevents the upward migration of CO_2 and escape into the atmosphere.

The estimations of global CO_2 storage capacity vary hugely and have many uncertainties. These estimates indicate that capacity is potentially sufficiently large to meet the global demand for CO_2 storage [4, 5] [45]. Global estimates of storage capacity sit between 8,000 Gt and 55,000 Gt CO_2 [4] whereas 600-2,000 Gt of cumulative CO_2 are expected to be stored by 2100 to keep CO_2 concentrations

between 400-500 ppm [4] for global climate targets. A larger storage potential capacity exists for onshore reservoirs (6,000 Gt to 42,000 Gt) compared to offshore (2,000 Gt to 13,000 Gt) and the regions with largest capacities are in Eurasia, North America and Africa [4]. For context, annual global emissions of CO_2 for energy were at around 35 $GtCO_2$ in 2019 [46].

Emissions pathways consistent with 1.5 °C (with no or limited overshoot) indicate that CCS could produce up to 1,200 $GtCO_2$ for storage. On the other hand, IPCC 2005 estimates a technical potential of at least about 2,000 $GtCO_2$ of storage capacity in geological formations [47]. In general, the storage capacity of all these global estimates is larger than the cumulative CO_2 stored via CCS in 1.5°C pathways over this century.

This storage capacity varies within regions, with USA, China and West Europe accounting for almost half of the global CO_2 storage capacity under 1.5°C and 2°C scenarios. For the top five regions that include USA, China, Western Europe, India and Russia, the storage demand fits within the regional storage capacity except for Russia, where the CO_2 storage required for this region exceeds the estimated capacity for a 2°C scenario with 66% probability [45].

Overall, there is broad agreement on the match, at a global level, between the demand of CO_2 storage and the technical potential capacity of CO_2 storage in geological formations, at least for CO_2 storage operation until the year 2050 (IPCC[14] and GCCSI [6]). Under the IEA Sustainable Development Scenario, the demand of CO_2 storage required (220 Gt CO_2) between 2020-2070 could be met by the lower end of the estimated CO_2 storage capacity (8,000 Gt).

To attain a large annual CO_2 storage rate, the IEAGHG estimates that approximately 30-60 storage sites need to be characterised and deployed annually until 2050, with these numbers expected by the GCCSI to double when including negative emissions storage [27].

For certain regions, such as, in China, Japan and South Korea, the source-sink matching is more uncertain and could be potentially limited, compared to other regions where regional storage supply is more developed, i.e. North America, Europe and Brazil [5]. Furthermore, by 2100, there is more uncertainty on the real CO_2 storage capacity for different regions.

Detailed assessment and careful selection of the storage sites is considered essential to guarantee the safety and permanency of the CO_2 stored and to reduce risks of potential CO_2 leakage to the atmosphere or groundwater [4].

The costs associated with CO_2 storage are lower compared to the capture process, however, is considered an essential factor to CCS deployment in the coming decades [4]. CO_2 storage costs range between negative costs (approximately -30 USD/t CO_2) for EOR applications, to costs ranging between 10 USD/t CO_2 with60% of the onshore storage capacity, to even higher costs for offshore storage, 60% of offshore capacity

is available at costs below 60 USD/t CO_2. The cheapest options among the different reservoirs are the depleted oil and gas sites [4].

The development of CCS industrial clusters that pools the transport and storage demands to share the infrastructure is expected to contribute to reducing transport and storage costs [4].

Risks over CO_2 leakage and long-term geological stability

The leakage of CO_2 refers to the unintended escape of the fluid from the storage site.

One of the barriers identified to large-scale CCS deployment has been the risk associated with the safety of the CCS infrastructure, particularly during CO_2 transportation and storage[5, 48]. For instance, CO_2 leakage and over-pressurisation are common concerns underscored in public acceptance analysis [49].

Practical experience gained through the operation of many industrial-scale CCS projects in the oil and gas industry; in addition to pilot-scale research projects have provided further knowledge on the physical and chemical phenomena affecting the stability of a storage site. Advanced monitoring tools and modelling capability is also available to assess with more precision the behaviour of the CO_2 plume in the storage site [28]. These advances have provided a better understanding and common agreement on the safety of long-term storage and the low probability of CO_2 leakage if the storage sites are characterised, monitored and managed in an adequate manner [48].

On the other hand, the stability of a geological storage site can be managed through its local pressurisation, limiting the CO_2 injection into the well to prevent wellbore fracturing. Additionally, to oversee regional pressurisation of the storage sites, management strategies for pressure and waste brine disposal should be considered [5]. The absence of these strategies to control the reservoir pressurisation imposes limits to the CO_2 storage capacity, as pressures in the reservoirs need to maintained under certain values to avoid induce fractures or reactivate faults in the sealing caprock [5].

With regard to storage integrity, the IPCC SRCCS considered that "for well-selected, designed geological storage sites the vast majority of the injected CO_2 will gradually be immobilised by various trapping mechanisms and in that case be retained for millions of years. Because of the trapping mechanisms identified storage would become more successful over longer time frames" [47]. This body of research concluded that CO_2 storage is by and large a safe operation if storage sites are properly selected, characterised and managed, thus reinforcing the message in the IPCC SRCCS [47, 48].

Regulatory frameworks to monitor and oversee the safety of CCS infrastructure

A robust legal and regulatory framework is important to ensure appropriate site selection and safe operation of geological CO_2 storage sites. This already exists in

many countries, with the UK having launched a licencing process.[10] Project developers and public authorities have to address public concerns through effective stakeholder engagement [4].

To address and minimise the risks associated to CO_2 leakage during long-term storage, as well as the geological stability of the storage site, it is important that liabilities are allocated and managed among the stakeholders of the CCS supply chain.

Risks should be distinguished depending on their potential impacts, whether it is a local environmental and safety issue or a global "climate-related leakage risks [28]. Policymakers and project developers have agreed that practical, well-defined legislation and a strong global regulatory framework are necessary for CCS to reach its potential.

Programmes of Monitoring, Measurement, and Verification (MMV) are considered essential to ensure that CO_2 storage meets operational, regulatory and community expectations, using the experience of the oil, gas, and groundwater industries [5, 27].

Cost and Complexity

The financing of CCS projects has been an ongoing issue causing delays to project development. Most carbon capture projects developed to date have revenue from the utilisation of CO_2 in EOR, particularly in North America. For example, the Petra Nova CCS project's reliance on revenue from EOR is highlighted by its recent mothballing since the fall in oil prices in 2020 [38]. The development of Sleipner CCS projects in 1996 and Boundary Dam to CCS in 2014 can be attributed to tax and regulatory regimes in Norway and Canada [37] respectively that made CCS economically beneficial for the ongoing operation of the facility.

This is in part a reflection of the scale, complexity, and consolidated nature of CCS projects, which face similar challenges to nuclear in terms of deployment. For example, the capture, transport and storage aspects of CCS have been described as quite distinct, but co-reliant businesses which multiply the risks to a potentially unmanageable degree if a single developer responsible for the whole 'chain' is not in place to handle this [33, 50]. This has been an observed problem in the UK where the attribution of long term CO_2 storage liabilities to the private sector and ownership of the full-chain of CCS processes are seen as a barrier to development [33]. Research by Wilson et al [51] suggests that these 'lumpy' characteristics of technologies such as CCS can in part explain why more modular technologies such as solar photovoltaics, wind energy and battery storage have deployed at a faster rate. De-risking CCS sufficiently to facilitate the required capital investment into CCS infrastructure appears to be a core challenge that requires long term state intervention in some form (if EOR is not part of the business model). This seems particularly acute for 'transport and

[10] See https://www.ogauthority.co.uk/licensing-consents/carbon-storage/

storage' (T&S) operators for whom there are high up front capital costs with expected multi-decadal operating lifetimes [50, 52].

In relation to costs, the UK CCC estimated that in 2050 using CCS combined to mid-merit electricity generation would have CO_2 abatement costs ranging between 115-120 £/tCO_2 and generation costs around 108 £/MWh. However, if CCS would have to be part of firm low carbon power in gas-fired power plants abatement, costs would be lower 48 £/tCO_2 and generation costs around 70-80 £/MWh [19]. Although costs are expected to be higher for CCS as a mid-merit generation technology, this is considered to be the preferred alternative so renewables have higher priority over CCS and power-CCS would precede over unabated fossil-based power generation.

Support for new CCS will likely need to subsidise ongoing revenue for CCS enabled products (electricity, hydrogen, or carbon removal) or offer long term avoided costs (e.g. a carbon tax) to make industrial process capture attractive. The current Contracts for Difference (CfD) mechanism (essentially a guaranteed minimum price for electricity sold over a period of time), capacity and/or flexibility payments for electricity grid services (e.g. frequency response, black start, and inertia). CCS power generation in the UK is now not expected until 2030 and the form and scale of public subsidy is not clear. In the meantime, costs associated with technologies such as offshore wind have seen their levels of required support (as viewed through UK CfD payments) fall from over £100/MWh to less than £40/MWh. While capacity factors for offshore wind have improved, they do not provide dispatchable power equivalent to existing power stations. Capacity or other grid service payments may be needed to compete with low marginal costs per unit of electricity from renewables while valuing potential dispatch, inertia, and flexibility benefits of CCS power stations relative to renewables. Here too CCS may face increasing competition from energy storage and demand response offerings over the coming decade. The European Zero Emissions Platform review for the industry identified a likely need for state support for transportation and storage aspects of the CCS industry akin to electricity and water network investments [52]. This is a key issue as new CCS projects in the UK for long term geological storage are unlikely to progress until the policy and investment for T&S are agreed. A delay in agreeing to this will postpone the deployment of CCS further.

5. Summary

Highly constrained global carbon budgets for meeting the goals of the Paris Agreement require significant progress in energy sector decarbonisation by 2030, particularly in developed economies [8]. This is increasingly being reflected in national policies to increase the rate of decarbonisation in relation to 2030 as well as setting longer term targets. While the longer-term application of CCS in industrial processes and for carbon dioxide removal retains a significant role in climate scenarios, this is not necessarily the case for fossil fuel-based CCS in the energy sector (see Section 2). CCS deployment in the energy system for power, heat and transport decarbonisation has to-date been largely non-existent, with significant deployment now not expected

until 2030. As such the role of natural gas- and coal-based CCS for power generation has been downgraded in future energy pathway scenarios. In contexts such as Europe, with supra-national and national targets to cut emissions by over 50% against 1990 levels by 2030 – through which the energy sector would change significantly - CCS deployment is likely now too slow (see Section 3). Focus recently has in part shifted to the role of CCS with fossil fuel-based hydrogen as an alternative vector. There are at present disparities in the extent to which CCS is featured in future hydrogen pathways, relative to electrolysis based hydrogen and electricification alternatives. The European Commission [17] assume limited if any role for CCS in hydrogen provision, while in the UK its application varies across scenarios considerably [19, 26]. This reflects concern about residual emissions from capture and fuel supply stages of the CCS hydrogen life cycle in the context of constrained carbon budgets, and that commercial applications of this technology are still forthcoming (see Section 4). The technical feasibility of higher CO_2 capture rates (>95%) and application of capture throughout the fuel supply chain may address these issues, but until this can be demonstrated and costs are clarified it is prudent to have energy pathways without fossil fuel CCS in policy scenarios for meeting climate change goals.

Acknowledgements:
The authors would like to thank Dr Sarah Mander and Dr Clair Gough for their insight and comments in developing this report. We would also like to thank the anonomous peer reviewer for their helpful comments and challenges which have improved this work.

All views contained with this report are attributable solely to the named authors and do not necessarily reflect those of researchers within the wider Tyndall Centre for Climate Change Research.

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Bruce Robertson, LNG/Gas Analyst
Milad Mousavian, Energy Analyst
September 2022

Institute for Energy Economics and Financial Analysis
IEEFA.org

The Carbon Capture Crux

Lessons Learned

Executive Summary

Carbon capture and storage (CCS) is a 50-year-old technology with variable results in capturing and storing carbon dioxide. Project developers have almost always reused the captured carbon for enhanced oil recovery (EOR), producing oil and gas and more emissions.

Carbon capture's role has been rejigged as a climate solution in recent years with its diverse applications being proposed to decarbonise fossil fuel plants and hard-to-abate sectors.

Some widely cited authorities are fuelling the debate on the role of this technology as a climate solution, including the International Energy Agency in both its Energy Technologies Perspectives[1] report and Net Zero by 2050 report.

This push has given a platform to polarising views on carbon capture utilisation and storage (CCUS) and carbon capture and storage (CCS): is it a greenwash to extend the life of fossil fuel assets[2] or a panacea to avert catastrophic climate change consequences?[3]

Is CCS/CCUS a greenwash to extend the life of fossil fuel assets or a panacea to avert catastrophic climate change consequences?

This report aims to shed light on the different applications and conceptualisations of CCUS/CCS, demystifying the technology's applications, concepts and categorisations. It explains the dichotomy between enhanced oil recovery and carbon capture within dedicated geological structures, and the difference between carbon capture and utilisation (CCU), CCUS and CCS. It uses a four-tiered structure to provide an overview of all carbon capture applications, which includes gas processing, power generation, industry application/production, and carbon dioxide removal technologies (CDR).

Finally, 13 flagship cases (10 in operation, two that have failed and one that has been suspended) comprising about 55% of the total nominal capture capacity

[1] IEA. Energy Technology Perspectives. September 2020.
[2] Crikey. Vested interests: fossil-fuel fans will use IPCC report to peddle carbon capture scam. 9 August 2021.
[3] Global CCS Institute. IPCC Report Reaffirms Carbon Capture and Storage as a Critical Technology for Mitigating Climate Change. 5 April 2022.

operating worldwide have been reviewed in detail. The projects are flagship in different senses, with each of them having unique aspects of importance.

Our sample is comprehensive, enough to learn lessons about the whole sector. IEEFA estimates that the studied cases have captured more than two-thirds of all anthropogenic carbon dioxide captured in history.

Appendix 1 summarises our case studies.

What We Found

Further extrapolated in our conclusion at the end of this report, we found:

- Failed/underperforming projects considerably outnumbered successful experiences.
- Successful CCUS exceptions mainly existed in the natural gas processing sector serving the fossil fuel industry, leading to further emissions.
- The elephant in the room of the application of CCS/CCUS in the natural gas processing sector: Scope 3 emissions are still not being accounted for.
- Captured carbon has mostly been used for enhanced oil recovery (EOR): enhancing oil production is not a climate solution.
- Using carbon capture as a greenlight to extend the life of fossil fuels power plants is a significant financial and technical risk: history confirms this.
- Some applications of CCS in industries where emissions are hard to abate (such as cement) could be studied as an interim partial solution with careful consideration.

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Section 1: Introduction to Carbon Capture and its Applications

Although carbon capture utilisation and storage (CCUS) technologies have been in use for half a century, they have gained more traction in recent years. This is especially true after widely cited energy authorities, such as the International Energy Agency (IEA), pushed them more in their portfolio of climate solutions.

The IEA's Energy Technologies Perspectives (ETP)[4] report, published in 2020, emphasises the role of CCUS and carbon capture and storage (CCS) in the clean energy transition.[5] The IEA's seminal Net Zero 2050 report, published in 2021,[6] had similar messaging. The two reports helped rejuvenate the argument for CCUS/CCS as a climate solution.

The Intergovernmental Panel on Climate Change (IPCC)'s six assessment reports provided a platform for polarising voices on CCUS/CCS, namely whether it is

[4] IEA. Energy Technology Perspectives. September 2020.
[5] IEA. CCUS in Clean Energy Transitions – Part of Energy Technology Perspectives. September 2020.
[6] IEA. Net Zero by 2050. May 2021.

greenwashing to extend the life of fossil fuel assets[7] or a panacea to avert catastrophic climate change consequences.[8] The nuance of the arguments likely depended on where interests lie, and truth on such a divisive topic is, of course, complex.

The vastly diverse application of CCUS/CCS often muddles the understanding of the technologies, particularly for uninitiated stakeholders who may mistakenly think of CCUS/CCS as a single subject.

The vastly diverse application of CCUS/CCS often muddles the understanding of the technologies.

CCUS/CCS is not a monolithic topic. Each CCUS/CCS application is largely running on separate tracks of maturity and cost projection. It covers various technologies and processes, contrasting environmental and social risks and opportunities, and differing mitigation potentials across multiple applications.

This report sheds light on different applications and conceptualisations of CCUS/CCS from a historical perspective and reviews most real-world flagship cases. It provides stakeholders, investors and policymakers with historical lessons from this technology. The report also tries to answer questions on whether CCUS/CCS is a climate solution in different contexts.

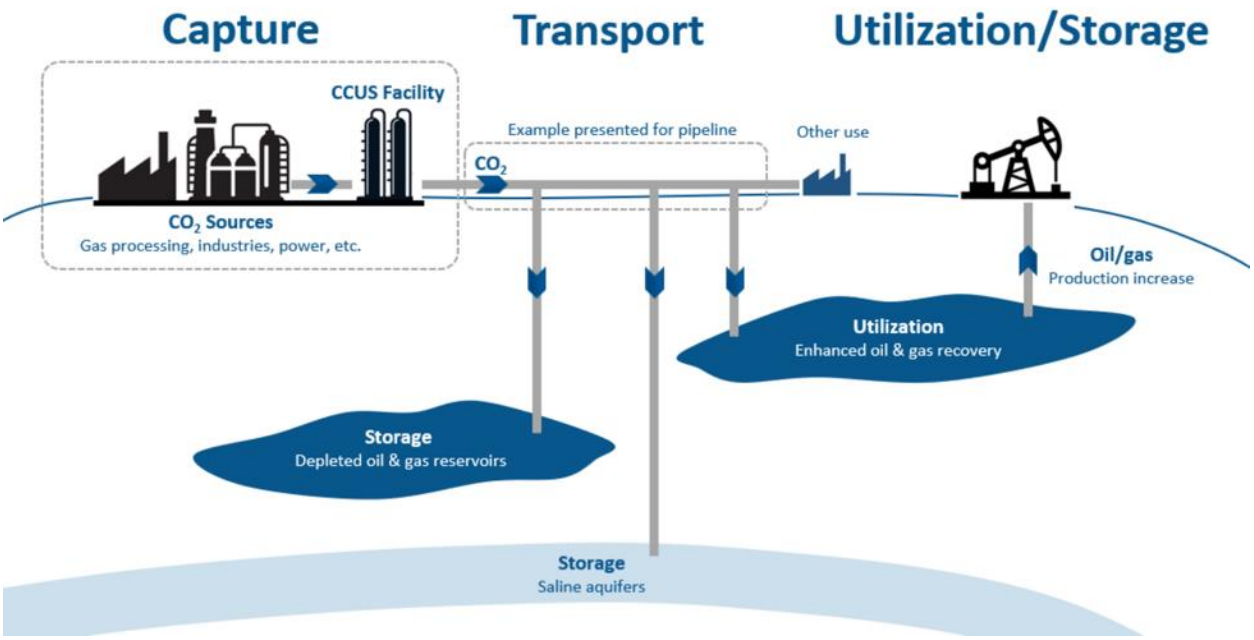
That the technology is in its infancy is not a realistic view. The climate change clock is ticking, and time is limited for trial and error. Stakeholders should take the experiences gained through half a century of utilising these technologies seriously in strategising future pathways for overcoming high emissions and climate change.

What are CCUS, CCS and CCU?

CCUS encompasses three distinct parts: capture, transport, and storage or utilisation, as depicted in Figure 1. Carbon dioxide (CO_2) captured from various stationary sources, such as chemical processes and power generation plants, is transported to sites and stored or utilised, mainly underground.

[7] Crikey. Vested interests: fossil-fuel fans will use IPCC report to peddle carbon capture scam. 9 August 2021.
[8] Global CCS Institute. IPCC Report Reaffirms Carbon Capture and Storage as a Critical Technology for Mitigating Climate Change. 5 April 2022.

Figure 1: CCUS Schematics



Source: IEEFA, Carbon Capture in the Southeast Asian Market Context. 2022.

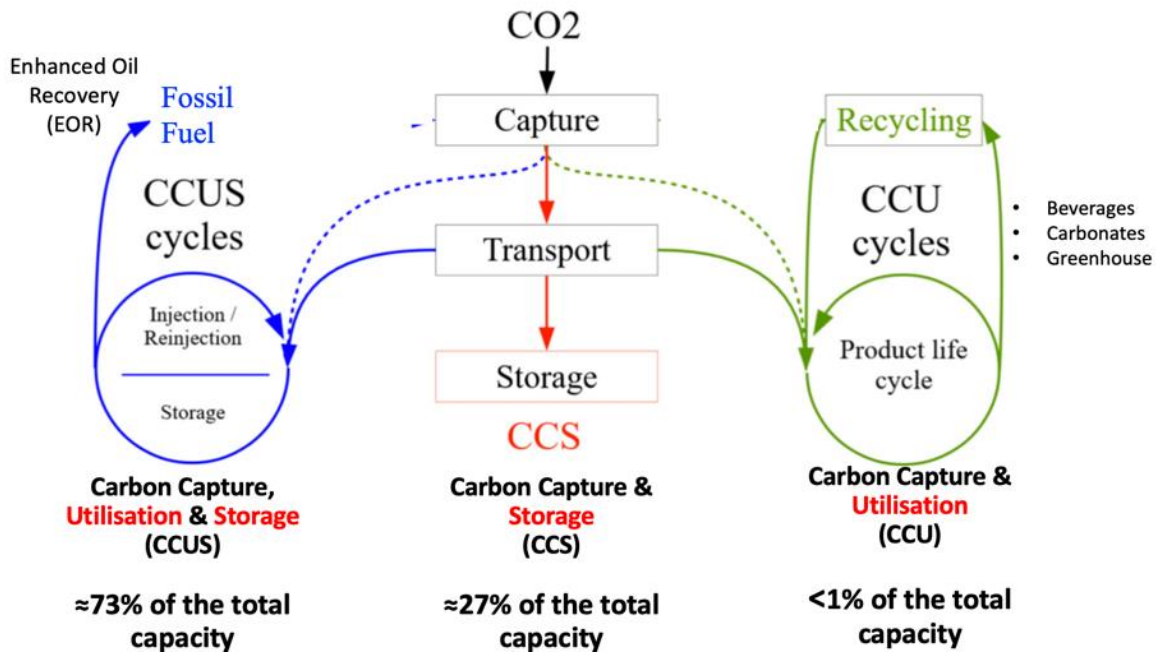
Often this CO_2 is sold as a commodity to oil and gas companies who use it to enhance their hydrocarbon production, hence the term enhanced oil recovery (EOR).[9] In this sense, carbon (C) is captured (C) and then utilised (U) by pumping it into the depleted oil and gas fields, pushing more oil and gas out of the wells and then stored (S) underground.

When CO_2 (C) is captured (C) and stored (S) underground in saline aquifers or other underground deposits and is not used for EOR, the process is called CCS.[10]

There is also a niche application of captured carbon (CC) for utilisation (U) and recycling into other valuable products, such as carbonates and beverages, and more recently products such as cement and plasterboard blocks.[11] This application is about capturing carbon and utilising it (CCU). However, compared to CCUS and CCS, the share of CCU is so far negligible (Figure 2).

[9] Global Carbon Capture Storage Institute (GCCSI). Global status of CCS 2021. 2021.
[10] From now on in this report, whenever the project is EOR, the term CCUS is used and if the project is not an EOR project and has a dedicated geological structure to store the carbon, the term CCS is used.
[11] Australian National University Reporter. Cementing the future of climate action. Winter 2021.

Figure 2: Conceptualisation of CCUS vs CCS vs CCU



Source: Sustainability Journal, MDPI, 2019.

Enhanced Oil Recovery: Injecting CO_2 to Emit CO_2

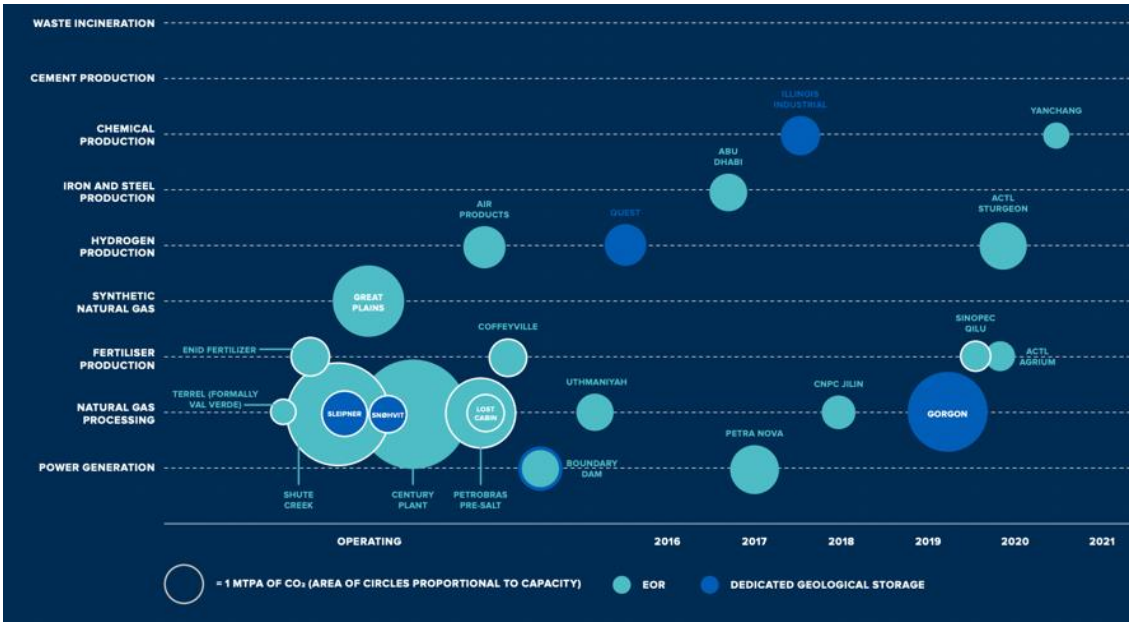
Historically, carbon capture applications have been dominated by enhanced oil recovery (EOR).

CCUS, or EOR with CO_2 (CO_2-EOR), is the largest industrial use of carbon dioxide. The basic idea is that oil and gas companies inject the pressurised CO_2 into existing oil and gas reservoirs to squeeze out more hydrocarbons.

Today, EOR is the only industrial use of CO_2 to have reached considerable scale—EOR projects use about 73% of the CO_2 captured each year globally in recent years.[12] The figure was higher in previous decades (see Section 2). Figure 3 shows the dominance of EOR in carbon capture project applications.

[12] Global CCS Institute. Global Status of CCS 2021. 2021, p. 63.

Figure 3: Dominance of Enhanced Oil Recovery in Carbon Capture Applications



Source: Global Status of CCS Report, Global CCS Institute, 2018.

EOR enhances the oil production rate from fields that have passed the maximum output rate. Therefore, oil producers can make money by revitalising oil fields with declining production rates.

However, EOR itself leads to CO_2 emissions both directly and indirectly. The direct impact is the emissions from the fuel used to compress and pump CO_2 deep into the ground. The indirect impact is the emissions from burning the hydrocarbons that could not have come out without EOR (so-called 'Scope 3 emissions'). When a car in the street or a jet plane uses EOR-induced oil, it still emits CO_2.

In sum, CO_2-EOR uses carbon dioxide to produce more oil rather than curbing its emissions. The additional oil produced this way either gets burned or used for industrial processes, both resulting in CO_2 emissions. Therefore, any claim that CO_2-EOR systems ultimately reduce CO_2 emissions by their nameplate capacity is an overstatement.[13]

About three-quarters of the CO_2 captured annually by multi-billion-dollar CCUS facilities, roughly 28 million tonnes (MT) out of 39MT total capture capacity, is

[13] Institute for Energy Economics and Financial Analysis (IEEFA). Boundary Dam 3 Coal Plant Achieves Goal of Capturing 4 Million Metric Tons of CO_2 But Reaches the Goal Two Years Late. April 2021.

reinjected and sequestered in oil fields to push more oil out of the ground. This oil then gets refined, burnt and, at least partially, returned to the atmosphere.[14]

According to ExxonMobil, the company has stored 120MT of CO_2, 40% of the total anthropogenic CO_2 that humans have captured.[15] Therefore, the inference is that the total cumulative captured CO_2 figure is 300MT.

Looking at the total anthropogenic carbon that humans have captured during the last 50 years demonstrates that carbon capture technology has been serving the oil industry. IEEFA has estimated that the vast majority of the total 300MT of captured carbon throughout history found its use in EOR (~80–90%), and a small proportion of carbon capture projects (~10–20%) have stored carbon in dedicated geological structures, without using it for EOR.

Table 1: Share of CCUS vs CCS in Capturing Carbon; 50-years Cumulative and 2021[16]

Carbon Capture Type	Accumulated Captured CO_2 (Million Tonnes)	Share of Current 39MTPA Capture Capacity (%)
Enhanced Oil Recovery (EOR) - CCUS	>240 MT (80-90%)	~73%
Dedicated Geological Storage - CCS	<60 MT (10-20%)	~27%
Total	~300	100

Source: ExxonMobil, Global CCS Institute Report 2021, IEEFA, IEEFA Estimates.

[14] Several pieces of research discuss the emissions profile of CO_2-EOR systems through different lifecycle periods and boundaries. Some of them show that the CO_2-EOR could be emission-positive in some long-term situations and some discuss the CO_2-EOR as being carbon negative. Most research papers generally compare the emission profile of two types of oil: the conventionally produced oil and the CO_2-EOR-produced oil and conclude that the CO_2-EOR type produces relatively less emissions compared to the conventional one as CO_2-EOR stores some of the injected CO_2 in the ground. It is a true but misleading comparison. In fact, the emission comparison should be between a CCS plant with a dedicated geological structure to sequester CO_2 and a CO_2-EOR system (a CCS plant which serves the oil recovery where the captured CO_2 is injected into the ground to produce more oil). In this case, the CO_2-EOR system would produce more emissions considering the Scope 3 emissions when the oil is burnt plus the amount of CO_2 that comes out with the oil during the recovery process and potential fugitive emissions along the way of CO_2 transportation.

[15] ExxonMobil. Carbon Capture and Storage.

[16] For some of the projects the data on the capturing performance is not available publicly and their average designed capture capacity based on the Global CCS Institute annual reports have been used as a proxy to estimate the volume of captured carbon. Apart from the normal estimation error, the calculated figures are the best estimates based on the available data.

Demystifying Carbon Capture Applications

As opposed to being a monolithic subject, CCUS is an aggregate of technology applications across varying sectors, each sector largely running in its own development tracks and with its own drivers and maturity level. While similarities in technology may exist among different CCUS applications, they may involve different technicalities and approaches.

The four main domains for categorising carbon capture applications are:

1. Gas processing
2. Power generation
3. Industry application/production
4. Carbon dioxide removal (CDR) technologies

Gas processing has been the main CCS application globally. The extracted raw gas has a CO_2 content that needs removal to produce a marketable gas for distribution through pipelines or liquefied in LNG plants for export. Producing the primary usable product (i.e., natural gas) is not possible without separating CO_2. That is why the sector has used carbon capture technology for decades, not necessarily as a climate-friendly solution. On top of that, selling the captured CO_2,[17] mainly to oil producers for EOR, has enhanced the economic viability of gas development projects.

Power generation is a newer use case of CCS to decarbonise the power sector. It is known as post-combustion carbon capture as it aims to capture the CO_2 after burning the fuel. Pre- and post-combustion capture describes the stage of CO_2 capture, whether before or after burning the fuel. The strategic value lies in the ability to retrofit existing fossil-fuelled power plants with carbon capture facilities. This application has shown that it is not commercially advanced and raises several environmental concerns. As previously reported, CCS for power has also faced technical challenges in meeting performance targets. It is not cost competitive with renewables and storage as a climate change mitigation option for the power sector.[18, 19]

CCS is not cost competitive with renewables and storage as a climate change mitigation option for the power sector.

[17] Geological Storage of Carbon Dioxide (CO_2). 3 – Modelling the injectivity, migration and trapping of CO2 in carbon capture and storage (CCS). 2013.
[18] IEEFA. Where's the Beef? Enchant's San Juan Generating Station CCS Retrofit Remains Behind Schedule, Financially Unviable. May 2021.
[19] Ahmed Abdulla, Ryan Hanna, Kristen R Schell, Oytun Babacan and David G Victor. Explaining successful and failed investments in U.S. carbon capture and storage using empirical and expert assessments. Environmental Research Letters, Volume 16, Number 1. 29 December 2020.

Industrial applications of CCS are very diverse. Companies use it to capture carbon from ethanol, methanol, fertiliser, blue hydrogen and syngas production plants. Also, its application extends to hard-to-abate industries, such as steel and cement production. Carbon capture is an established business in some industrial applications, such as fertilisers and ethanol, while other applications are exploring it for technical and commercial competitiveness at scale.

The conclusion about whether carbon capture technologies could be part of the solution for the decarbonisation of industries is not that straightforward. Using carbon capture technologies needs careful research for each application in different industries and business environments. In some applications, with current high commodity prices, using green hydrogen is starting to look more attractive. It is worth studying carbon capture as an interim solution in a few others.

Carbon dioxide removal (CDR) technologies—bioenergy with carbon capture and storage (BECCS) and direct air carbon capture and storage (DACCS)—are not well advanced technically and commercially. Theoretically, these technologies could offer environmental and social usefulness by capturing carbon from the atmosphere, thus providing the option of negative emissions, should they prove cost-competitive and commercially robust technologies. However, the operating capacity of CDR is virtually zero[20] compared to the 39 million tonnes per annum (Mtpa) CCS industry.

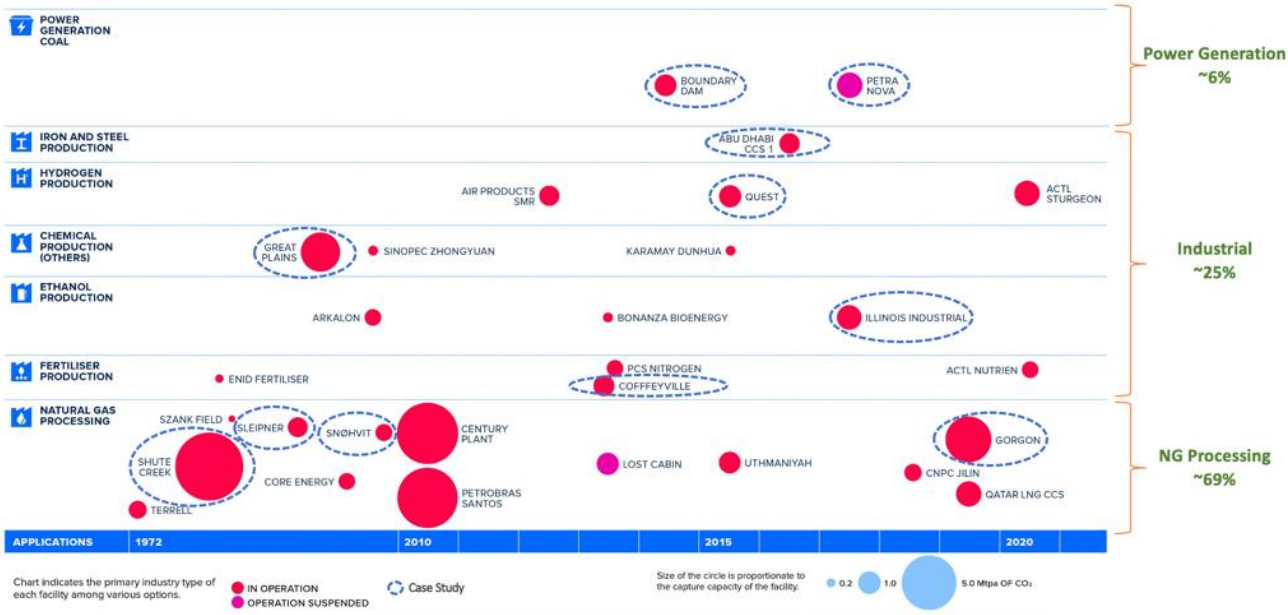
Thirteen Flagship Cases Reviewed

This report reviewed 13 operational large-scale CCS projects—including two flagship projects that failed and one that was mothballed—in terms of their history, economics and performance.[21]

As depicted in Figure 4, we fit sub-sectors identified by the Global CCS Institute into three of the four main categories of carbon capture applications. There is no category for CDR technologies in the figure as CDR is a nascent field and as noted above, the operational capacity of CDR is currently close to zero compared to the other technologies, with just one small project in Iceland.[22]

[20] For example, Orca, a direct air capture facility in Iceland that opened in September 2021, has the capacity to remove about 4000 tonnes of CO_2 a year—equivalent to the annual emissions of around 790 cars. Reuters. World's largest plant capturing carbon from air starts in Iceland. 14 September 2021.
[21] We include in our report two case studies, the Kemper Coal Gasification project and the In Salah CCS project—both of which failed—so they have not been depicted in Figure 4. Also, one of these 11 mentioned cases (Petra Nova) has been mothballed since mid-2020.
[22] Reuters. World's largest plant capturing carbon from air starts in Iceland. 14 September 2021.

Figure 4: Carbon Capture Case Studies



Source: Global CCS Institute 2021, IEEFA.

Natural gas processing dominates carbon capture projects with about 69% of total operational capacity worldwide. It is followed by industrial application, with about 25% of total capacity. Industrial applications with at least one operational CCS project include iron and steel, hydrogen, ethanol, fertiliser, and other chemical production. And a tiny proportion of about 6% is from the power generation sector. Considering the Petra Nova project shut down in 2020, the figure for power generation would be less than 3%.

In this report, we study five flagship projects in the *gas processing sector* to share the lessons from their technical performance and business processes. Four projects are operational, namely **Shute Creek** in the U.S., **Sleipner** and **Snøhvit** in Norway and **Gorgon** in Australia. The Norwegian cases are important as they have been among the few cases that could meet their designed capturing rate, mostly thanks to the unique regulatory/ business environment for Norway's oil and gas companies. Regarding their capture capacity, these four projects account for about half of the active CCS projects in the natural gas processing sector. Despite having some successful projects in this sector, several projects have underperformed their designed capture rate. We look at one such project, **In Salah** in Algeria.

Next we study three projects that have operated in the *power sector*: **Petra Nova** and **Kemper** in the U.S. and **Boundary Dam** in Canada. Petra Nova was mothballed indefinitely in 2020 and the Kemper coal gasification project failed. The report investigates the reasons. Petra Nova and Boundary Dam are the retrofits of two old coal power plants.

Finally, we have chosen five important projects to study for the *industrial applications* of carbon capture. We study these flagship cases in different sub-

sectors of the industry: the **Quest** project in the hydrogen production sub-sector; the **Great Plains CCUS** project in the chemical production sub-sector; the **Illinois Industrial CCS** project in the ethanol production sub-sector; **Coffeyville** in the fertiliser production sub-sector; and **Abu Dhabi CCUS** in hard-to-abate industries worldwide. These five projects account for about 65% of the current capacity of CCS/CCUS projects in industrial applications.

As this report analyses the carbon capture technology through a historical perspective and focuses on existing projects to derive lessons from failures and successes, it does not include any studies of CDR projects.

We cover all 13 flagship projects considering criteria such as their importance, availability of data, age, capacity and performance. Each project has had a unique aspect of importance, cumulatively accounting for around 55% of the total current operational capacity worldwide. Therefore, this sample is comprehensive enough to learn lessons about the whole sector.

IEEFA estimates that the studied cases have captured more than two-thirds of all 300MT of anthropogenic CO_2 in history.



Section 2. Carbon Capture Application in the Natural Gas Processing Sector

Gas processing has been the main CCS/CCUS application globally, with about 70% of current total operational capacity worldwide. Essentially for every 10 CCS/CCUS projects, seven projects are in the natural gas processing sector today.

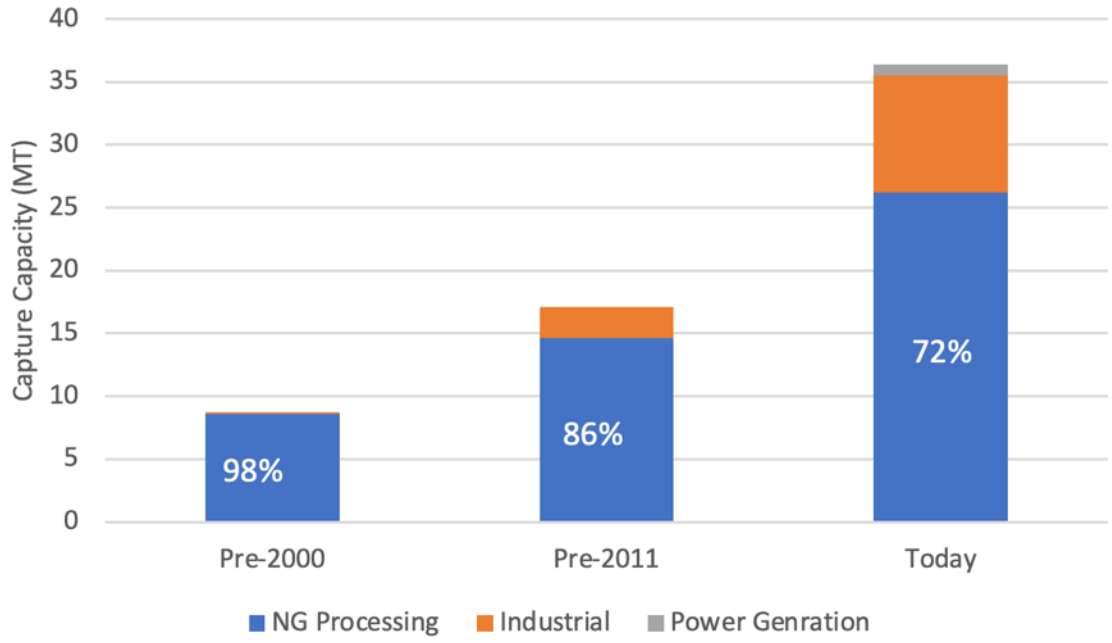
Looking back a decade, the figure was about 86% before 2011 and more than 98% pre-2000 (Figure 5). These figures demonstrate the historical dominance of natural gas processing as an application of carbon capture technology.

The key point about this application of CCS/CCUS is that producing the primary usable product (i.e., natural gas) is not possible without separating CO_2.

The extracted raw gas from any gas field has CO_2 content ranging from less than 3%[23] to 80%[24] in rare cases. This needs to be removed to produce a marketable gas for distribution through pipelines or liquefied in LNG plants for export. Therefore, capturing carbon was a part of the production process for oil and gas companies, regardless of the ultimate disposal or use of carbon dioxide (i.e., venting or using it for another purpose).

[23] IEEFA. Should Santos' Proposed Barossa Gas 'Backfill' for the Darwin LNG Facility Proceed to Development? March 2021.
[24] Energy Procedia. Worldwide development potential for sour gas. April 2011.

Figure 5: Historical Natural Gas Processing Share in CCS/CCUS Applications



Source: Global CCS Institute 2021,[25] IEEFA.

From a historical perspective, climate concerns did not figure in CCUS/CCS projects commissioned before the mid-1990s. In fact, the narrative around CCUS/CCS projects before the global community started to take climate change risks more seriously (i.e., since the Kyoto protocol of 1997) was more about economics than the environment. The only thing is that since the 1970s, oil and gas companies have decided to derive value from a CO_2 by-product, which used to be vented.

The reason was that in the 1970s and early 1980s, a massive supply shortage in the oil market—due to Iran's revolution and its consequent war with Iraq—pushed oil prices up dramatically. Oil companies, on the other hand, were seeking to increase the dropped production rate from their depleting oil wells in the U.S. Pumping CO_2 into the depleted wells to enhance the oil recovery was a promising solution.

Abundant captured CO_2 from the natural gas processing plants was among the most important driving forces behind developing CO_2-EOR technologies. Shute Creek Treating Facility in the U.S., the largest CCUS/CCS facility (7Mtpa) in the world, belongs to this era.

[25] Excluding suspended Lost cabin and Petra Nova Projects.

The economic narrative of using CO_2 for EOR gradually started to change in the 1990s towards an environmental one that sees carbon capture as a climate solution. The Sleipner project, commissioned in 1996, was the first carbon capture project with a dedicated geological structure (CCS), and the ultimate destination of captured CO_2 was a saline formation. Furthermore, it was the first project capturing CO_2 and not using it for EOR.

Due to the regulatory and business environment in Norway, Sleipner has been among the most successful projects of its kind, followed by another Norwegian project, Snøhvit, commissioned in 2007.

With the changing narrative, some authorities started to regulate oil and gas developments conditional on having a CCS facility to capture and sequester the CO_2 emissions of the field. The failed Gorgon project in Australia is an example.

Case Studies

In this section, we review Shute Creek, Sleipner, Snøhvit, and Gorgon in terms of their performance, history and economics.

Shute Creek

The Largest and the Third Oldest CCUS Project in the World

Shute Creek was commissioned in 1986 by ExxonMobil near the LaBarge field in southwest Wyoming, U.S. Gas from the field comprises just 21% methane (regarded as the marketable gas) and 65% CO_2—as such, it is considered among the highest CO_2 and lowest thermal energy content commercially produced gas in the world.

For Shute Creek's business model to work, considering revenue streams from selling products other than methane was inevitable. There was abundant CO_2 from LaBarge and, at the time of commissioning, nearby fields in Colorado and Wyoming were thirsty for CO_2 for enhanced oil recovery (EOR). Carbon capture was integral to the business model's cash generation.

Oil prices were high when the project was conceived in the early 1980s. After the project was commissioned, the tacit assumptions of long-term high oil prices and of oil producers' ongoing inflated demands for CO_2 for EOR were proved in error with two decades of a bearish oil market with low prices.

Shute Creek became a "Sell or Vent" project.

Shute Creek became a "Sell or Vent" project. It could either sell the CO_2 to third parties or vent the CO_2 when prices were low and EOR was uneconomic. The excess CO_2 that could not be sold for EOR has been vented over the years.

As part of the Shute Creek Treating Facility, the carbon capture plant originally captured about 4.3Mtpa.[26] In 2008, the Oil and Gas Conservation Commission questioned Exxon's effort to market the CO_2 and examined possible changes to the permit to vent. Exxon started an expansion project, completed in 2010, that delivered 50% more capture capacity (6–7Mtpa).[27]

With a nominal capacity of about 7Mtpa, Shute Creek is the world's largest CCS facility.[28]

[26] ZeroCO2.no. Shute Creek.
[27] Massachusetts Institute of Technology. LaBarge Fact Sheet: Carbon Dioxide Capture and Storage Project.
[28] Global CCS Institute. Global Status of CCS 2020. 2020.

The plant has captured more anthropogenic CO_2 than any other carbon capture project in the world[29] but it belongs to an era in which there was little public discussion about climate change and little climate-friendly motivation behind commissioning such projects.

Economics and Performance

The original cost for the whole Shute Creek Treating Facility, including the capturing facility, was US$170 million. In 2010 an extra US$86 million was provided to expand the carbon capture facility from 4.3Mtpa to 7Mtpa.[30]

In February 2022, ExxonMobil made the final investment decision to expand its carbon capture at La Barge by 1.2Mtpa at an estimated cost of $400m. It is expected that the expansion will be operational by 2025.[31]

The gas composition entering Shute Creek is 65% CO_2, 21% methane, 7% nitrogen, 5% hydrogen sulphide (H_2S) and 0.6% helium. The Shute Creek Treating Facility separates CO_2, methane and helium for sale. Concentrated acid gas stream, which includes 40% CO_2, is also injected into a carefully selected section of the same reservoir removing and storing approximately 0.4MT of CO_2 per year that is not sold for EOR.

The facility was not planned to have a dedicated geological structure for CO_2 storage, accounting for its "Sell or Vent" status. Were there a customer to buy the CO_2, it would be captured, compressed and transported. With fewer customers in the time of low oil prices, the excess captured CO_2 would be vented.

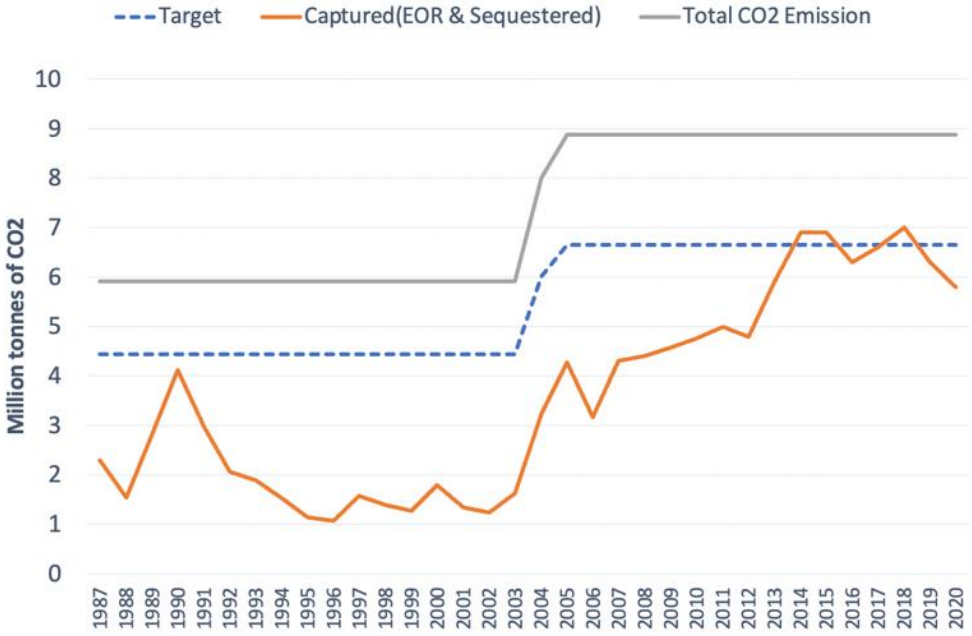
In the first 17 years of weak oil prices, from the beginning of the project to 2003, the plant rarely captured and sold more than 2Mtpa. Since then, soaring oil prices enabled Shute Creek to sell more of its CO_2 for EOR, volumes increasing until 2014 in step with historically high oil prices. From 2014 to 2020, despite oil prices starting to fall, ExxonMobil still managed to sell a high volume of CO_2 for EOR.[32]

Figure 6 summarises the performance of the Shute Creek CCUS plant over its 35-year lifetime. Despite its improved performance over recent years, the plant has reached its capturing capacity target (about 75% of total CO_2 emissions) in only a few of those years. At all other times, the plant has fallen short, mostly by a wide margin.

On average, the Shute Creek CCUS facility has fallen short of its capacity by about 36% over its lifetime, translating to approximately 66MT of CO_2 released into the atmosphere. Essentially, just half of CO_2 emissions captured and the other half vented.

[29] Global CCS Institute. Global Status of CCS 2021. 2021.
[30] IEEFA. Carbon Capture to Serve Enhanced Oil Recovery: Overpromise and Underperformance. March 2022.
[31] Exxon Mobil. ExxonMobil to expand carbon capture and storage at LaBarge, Wyoming, facility. 25 February 2022.
[32] ExxonMobil. Energy and Carbon Summary. 2021, 2020, 2019.

Figure 6: Capturing Performance Trend of the Shute Creek CCUS Plant (1987–2020)



Source: IEEFA Estimates, ExxonMobil Energy and Carbon Summary Reports 2019, 2020, 2021. -- Energy Procedia.

Figure 7 provides a lifetime performance snapshot of the Shute Creek CCUS plant.

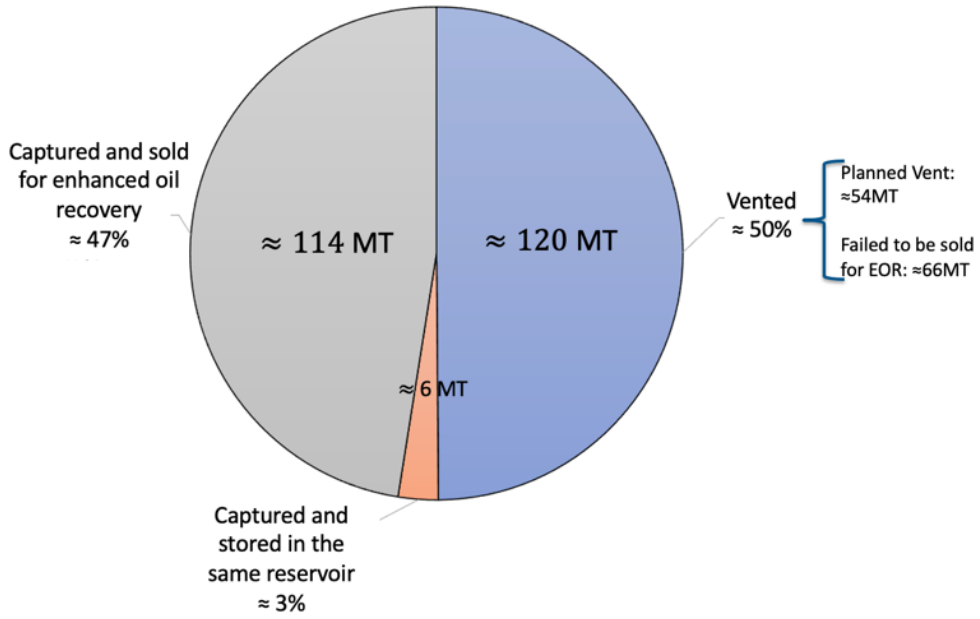
To the end of 2020, IEEFA estimates the treating facility on its own directly produced 240MT of CO_2, of which about 47% (114MT) was captured and used to recover oil (EOR).

Over its lifetime, about 3% of total CO_2 emissions has been sequestered in the same geological formation from which the feeding gas is extracted. The remaining 50% of the CO_2 content of the Shute Creek gas, estimated at about 120MT, has been vented. These numbers suggest that the CCUS plant has reduced the gas at the Shute Creek field only from extremely high CO_2 content (65%) to very high (33%).

To put it into perspective, that figure of 120MT is greater than the combined national emissions of Norway, Sweden and Finland in 2018, according to the World Bank.[33]

[33] The World Bank. CO_2 emissions(kt) – Norway, Sweden, Finland.

Figure 7: Shute Creek CCUS Lifetime CO_2 Capture Performance



Source: IEEFA Estimates, ExxonMobil Energy and Carbon Summary Reports 2019, 2020, 2021. – Energy Procedia.

Sleipner and Snøhvit: Norwegian Successful Experiences

Sleipner

Sleipner CO_2 Storage Project, commissioned in 1996 and located in the Central North Sea between the UK and Norway, was the world's first commercial carbon capture project with a dedicated geological structure for CO_2 sequestration.[34] It was also the world's first demonstration of CCS technology for a deep saline storage reservoir and the first large-scale CCS project to become operational in Europe.[35] To date, it has been among the world's most successful (if not the most successful) carbon capture projects, reaching its target capacity throughout many years of operation with no evidence of leakage or harmful CO_2 movement in the formation.

The natural gas produced from the Sleipner West field contains 4–9% CO_2, so needing to be reduced to less than 2.5% to produce marketable gas. The additional proportion of the CO_2 content of the extracted gas from the field is captured and pumped back to the Utsira geological storage, a 200–250 metres thick massive sandstone formation. The

[34] Massachusetts Institute of Technology. Sleipner Fact Sheet: Carbon Dioxide Capture and Storage Project.
[35] Global CCS Institute. Introduction to Industrial Carbon Capture and Storage. June 2016.

estimated storage capacity is 600 billion tonnes of CO_2. Studies have shown that there is no leakage of the CO_2 from this formation into other horizons.[36]

The main motivation for adding this extra step in the hydrocarbon processing facility there—instead of venting the gas—was the Norwegian CO_2 tax introduced in 1991.

The capturing and injection capacity of the project is between 0.85Mtpa[37] and 1Mtpa[38] as cited by different sources.[39, 40] The project stakeholders are Equinor as the operator (~58.3%), ExxonMobil (~17.2%), LOTOS Exploration and Production Norge (15%) and KUFPEC (~9.4%).[41]

The experience from Sleipner was effective in designing and implementing different regulatory frameworks for carbon storage around the world. For example, it was used as a guide for the EU Directive on geological storage of carbon dioxide (adopted by the European Parliament in 2009). Amendments to the London Protocol and the Convention for the Protection of the Marine Environment of the North-East Atlantic (or OSPAR Convention) to allow for CO_2 storage in offshore geological formations also used the Sleipner project as a benchmark.[42]

Snøhvit

Snøhvit is a liquefied natural gas (LNG) development in the Barents Sea off northern Norway, commissioned in 2007. The extracted gas contains 5–8% CO_2 by volume, which is solidified into dry ice under the pressure and temperature conditions of liquefying natural gas and therefore must be removed before the gas is processed into LNG.

As the Norwegian government mandated CCS as a condition to approve Snøhvit's licence, Equinor, the operator of the project, proceeded on a carbon capture project to avoid venting the separated CO_2 from the field. Instead of venting, after the unprocessed raw natural gas stream is transported 143km to shore into the Hammerfest LNG plant in the far north of the country to be liquefied, the removed CO_2 is pumped back to the Snøhvit field offshore through a separate pipeline, to be injected in the geological reservoir 2600 metres beneath the seabed. The company says "a shale cap which lies above the sandstone will seal the reservoir and ensure that the CO_2 stays underground without leaking to the surface".[43]

The LNG project consists of nine wells, eight for production and one for injecting CO_2. The removal process at the LNG plant is designed to capture 0.7Mtpa of CO_2 at full

[36] Massachusetts Institute of Technology. Sleipner Fact Sheet: Carbon Dioxide Capture and Storage Project.
[37] Global CCS Institute. Introduction to Industrial Carbon Capture and Storage. June 2016.
[38] Sintef. Sleipner partnership releases CO_2 storage data. 12 June 2019.
[39] Massachusetts Institute of Technology. Sleipner Fact Sheet: Carbon Dioxide Capture and Storage Project.
[40] Ola Eiken. Twenty years of monitoring CO_2 injection at Sleipner. In Thomas L. Davis, Martin Landrø, Malcolm Wilson (Eds). Geophysics and Geosequestration. Cambridge University Press. 9 May 2019.
[41] Equinor. Sleipner partnership releases CO_2 storage data. 12 June 2019.
[42] Institution of Civil Engineers. Sleipner carbon capture and storage project. 3 February 2017.
[43] Equinor. Carbon storage started on Snøhvit. 23 April 2008.

capacity. Injection of CO_2 started in April 2008, a year after the gas plant started production.[44] In early 2010, It was announced that it had discovered that there was less storage capacity than expected at the Snøhvit injection site.[45]

A fire in September 2020 at the Hammerfest LNG plant led to it being shut down for more than 18 months.[46] It has resumed operation recently and is preparing to produce LNG again.[47]

Economics and Performance

Stringent emission regulations were the key drivers behind these Norwegian CCS projects.

Carbon Dioxide Tax

The key drivers that enabled these two projects to proceed were the CO_2 tax and climate quota obligation, introduced by the Norwegian government in 1991 and 2005, respectively.

Stringent emission regulations were the key drivers behind these Norwegian CCS projects.

Norway was one of the first countries in the world to impose a CO_2 tax, legislated in the Act on Tax on CO_2 Emissions in Petroleum Activities on the Continental Shelf. This requires companies to pay a CO_2 tax on the combustion of gas, oil, and diesel in petroleum activities in the designated offshore area, as well as on CO_2 or natural gas emissions.[48]

For 2022, the tax rate is NOK 1.65 per standard cubic metre of gas or per litre of oil or condensate. For combustion of natural gas, this is equivalent to NOK 705 per tonne of CO_2. For emissions of natural gas, the tax rate is NOK 1066 per standard cubic metre.[49]

The government in its new climate plan for 2021–2030 has announced that the total CO_2 price of emissions will increase in line with the increase in the tax on non-ETS (Emissions Trading System) emissions subject to an emissions tax, so the total CO_2 price in 2030 will be about NOK 2000/tonne measured in fixed 2020 NOK—almost three times the current price.[50]

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[44] Global CCS Institute. Global Status of CCS: Special Report. Introduction to Industrial Carbon Capture and Storage. June 2016.
[45] Massachusetts Institute of Technology. Snohvit Fact Sheet: Carbon Dioxide Capture and Storage Project.
[46] Reuters. Norway LNG plant restart faces new delay in blow to Europe's gas supply. 31 January 2022.
[47] Offshore Engineer. Norway's Hammerfest LNG Plant Resumes Operation After 20-month Outage. 27 May 2022.
[48] Norwegian Petroleum. Emission to Air. Updated August 2021.
[49] Norwegian Petroleum. The Government's Revenues. Updated May 2022.
[50] Ministry of Climate and Environment. Norway's comprehensive climate action plan. 1 August 2021.

Quota Obligation

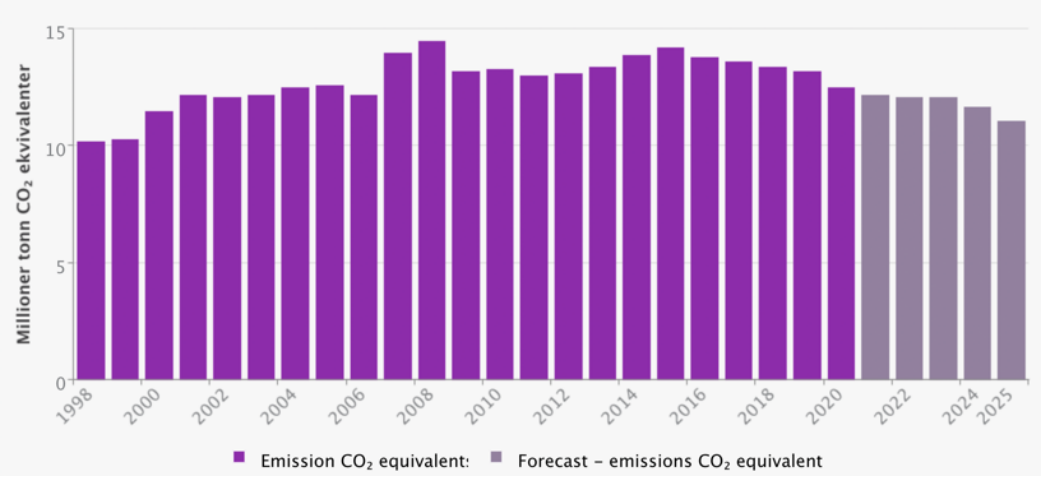
The Climate Quota Act, enacted in 2005, connects Norway to the EU's quota system for greenhouse gas emissions, and the country joined the European Emission Trading System in 2008. Norwegian companies are subject to the same quota obligations as those in the EU. The system is currently in its fourth period, which runs until 2030.[51]

The EU quota system establishes a maximum level of total emissions. This ceiling is reduced on an annual basis to ensure that the system contributes to the system's set emission target when the relevant quota period expires. Quotas are either auctioned or allocated free. In recent years, the CO_2 price in the EU quota system has been increasing, putting a greater burden on polluters.

The combination of the CO_2 tax and quota obligation means that the companies on the continental shelf are facing an extremely high price per tonne for emitting CO_2. The figure is significantly higher than the tax most companies in other sectors must pay in Norway and massively higher than the obligations on similar oil and gas companies in other countries with fossil-based economies.

With these instruments in place, emissions from the Norwegian petroleum sector have been virtually stable during the past decade (Figure 8) with relatively stable oil and gas production (Figure 9). Under the effect of coming, more stringent regulations, emissions are expected to decrease. The Norwegian Ministry of the Environment has described CO_2 taxes as the most important tool for reducing emissions.[52]

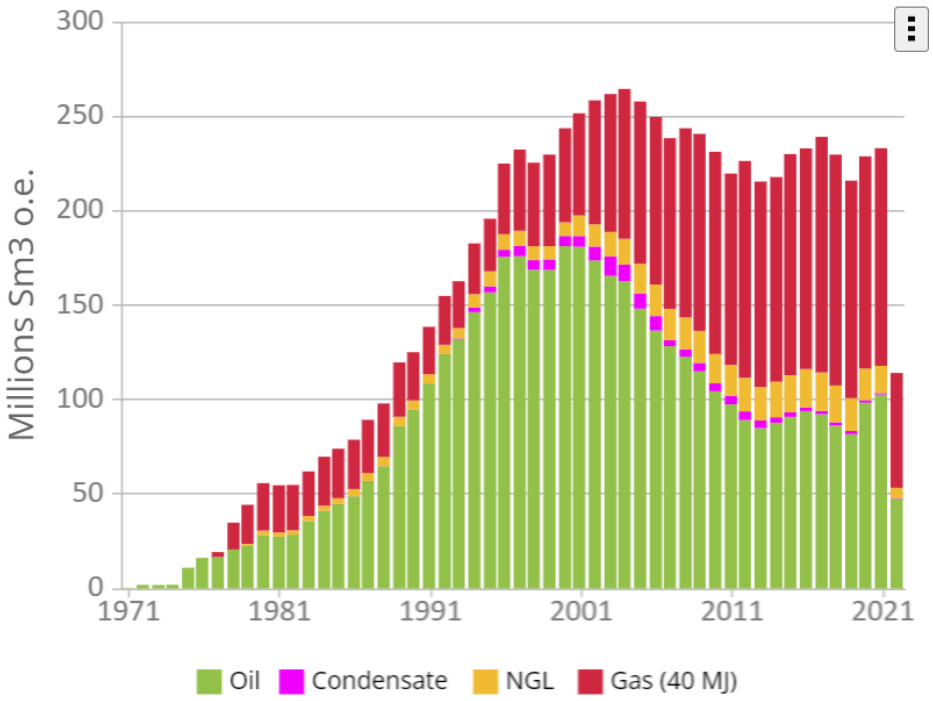
Figure 8: Emissions of Greenhouse Gases from the Norwegian Petroleum Sector



Source: Norwegian Petroleum, Emissions to Air.

[51] European Commission. EU action against climate change. EU emissions trading — an open system promoting global innovation. 2007.
[52] Norwegian Ministry of the Environment. Norway`s Fifth National Communication under the Framework Convention on Climate Change. Status report as of December 2009.

Figure 9: Norwegian Petroleum Production



Source: Norwegian Petroleum Directorate.

CCS Was Financially Viable for Norwegian Cases

The regulatory framework that was the main motivation for these CCS projects in turn made them economic and pushed the oil and gas industry to adopt CCS in extraction facilities.

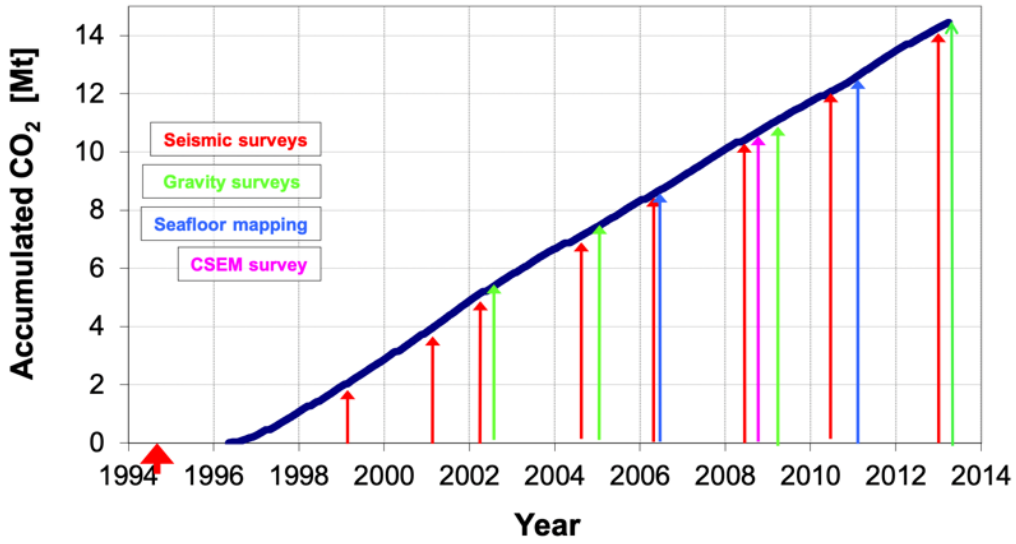
When the Sleipner CCS project was commissioned in 1996, five years after the Norwegian government introduced the carbon tax, the levy on natural gas processing in the North Sea petroleum extraction sector was US$49 per tonne of CO_2.[53] Had the operators vented, for example, 1MTof CO_2 in that first year, the tax bill would have been US$49 million. On the other hand, the additional investments to compress and inject the removed CO_2 amounted to about US$100 million in 1996).[54] Injecting CO_2 was estimated to cost about $17 per tonne.[55] Considering injection averaged about 0.9Mtpa, the partner companies could have recovered the capital cost and operating injection cost of the project in the first few years of the project.

[53] Annegrete Bruvoll og Bodil Merethe Larsen. Greenhouse gas emissions in Norway: Do carbon taxes work? Statistics Norway, Research Department. Discussion Papers No. 337. December 2002.
[54] Olav Skalmeraas. Vice President CCS, Statoil. Sleipner carbon capture and storage project. In ICE Group. 3 February 2017.
[55] Massachusetts Institute of Technology. Sleipner Fact Sheet: Carbon Dioxide Capture and Storage Project.

The same 'carrot and stick' measures applied to the Snøhvit project, with millions of dollars saved in avoiding the carbon tax while complying with stringent emission regulations.

The Sleipner CCS project has operated consistently near its capturing capacity. Figure 10 shows the project's capturing performance up to 2014. It demonstrates the steady performance of the carbon capture facility.

Figure 10: Sleipner CCS Injection and Monitoring History (1994–2014)



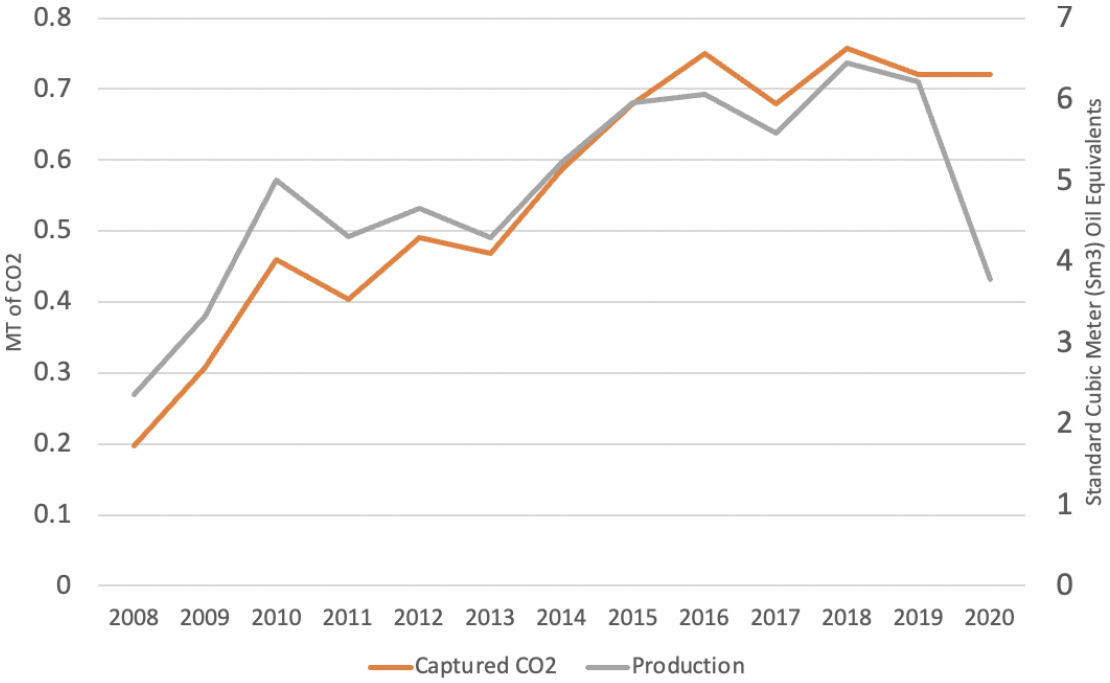
Source: Statoil, The Sleipner CCS Experience, 2014.

Snøhvit's capturing rate has been increasing since its commissioning in 2008, surpassing its capture target of 0.7Mtpa in recent years. Figure 11 shows the capture performance of the project. The reason that Snøhvit had been capturing less than its 0.7MT nominal capacity in the early years of the project was not due to its underperformance. This is evident from the gas production level of the project from which Snøhvit CO_2 is sourced (second axis of Figure 11). The correlation between the production and capturing rates confirms the steady performance of the carbon capture facility with its nominal capacity in recent years, where the production of the field stands at its maximum as well (Figure 11).

Since commissioning in 2008, Snøhvit has captured more than 7MT of CO_2, averaging 0.55–0.6MT annually.[56]

[56] Olav Skalmeraas. Sleipner carbon capture and storage project. 3 February 2017.

Figure 11: Snøhvit Project: Production vs Captured CO_2



Source: Norwegian Petroleum, Snøhvit. Environmental Science and Technology Letters, 2022.

Figure 12, based on Equinor's 2021 sustainability report, demonstrates the total CO_2 captured and stored per year by the projects it operates. Cumulative capacity of Snøhvit and Sleipner is depicted as the orange line in the graph. Other than in the past two years, there is a consistent trend in capturing carbon.

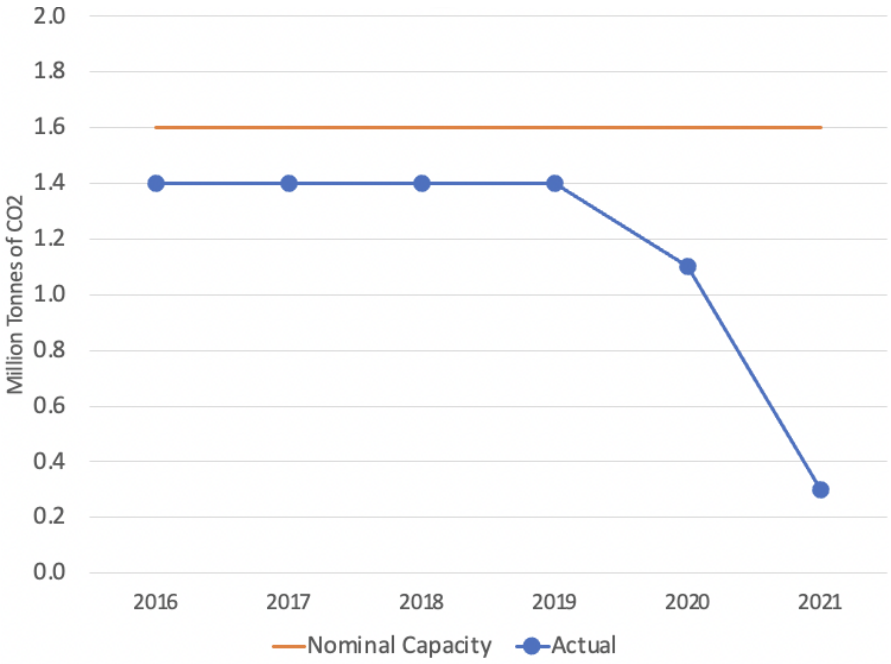
The drop in capturing rate in 2020 and 2021 was due to the fire in September 2020[57] in the Hammerfest LNG plant, which fed CO_2 back to Snøhvit. The low capture for those years is not related to the CCS plant underperformance.

Moreover, Sleipner field's production has been in its late tail phase[58] throughout the last decade, otherwise the capture figures of the two projects would be at their 1.6MT nominal capacity.

In the past two decades, several research efforts on these two projects have reported no leakage or harmful movement of stored CO_2 in the reservoirs.[59, 60]

[57] Upstream. Hammerfest LNG plant to restart next week after shutdown extended by six days. 16 May 2022.
[58] Norwegian Petroleum. SLEIPNER ØST. Website accessed August 2022.
[59] Andy Chadwick, Rob Arts, Ola Eiken, Paul Williamson and Gareth Williams. Geophysical monitoring of the CO_2 plume at Sleipner, North Sea: An outline review. 2006.
[60] Andy Chadwick, Benjamin Marchant, and Gareth Williams. CO_2 storage monitoring: leakage detection and measurement in subsurface volumes from 3D seismic data at Sleipner. 2014.

Figure 12: Snøhvit and Sleipner Projects: Carbon Capture Performance (2016–2021)



Source: Equinor Sustainability Report, 2021.

Gorgon

World's Largest CCS Project

The Gorgon LNG project on Barrow Island off the Pilbara coast of Western Australia is the world's largest such projects, with export capacity of 15.6MT of LNG and provides the state with up to 300 terajoules (TJ) of domestic gas daily.[61]

The plant was planned to be equipped and simultaneously started with the world's largest carbon capture project with dedicated geological structure in 2016.[62]

It has a nominal maximum capacity of 4Mtpa accounting for 40% of the capacity of all CCS projects with dedicated geological storage operating around the globe.[63] The Gorgon CCS project was initially planned to capture and inject underground more than

[61] WA Department of Mines, Industry Regulation and Safety. Gorgon Carbon Dioxide injection project. Website accessed August 2022.
[62] Massachusetts Institute of Technology. Gorgon Fact Sheet: Carbon Dioxide Capture and Storage Project.
[63] Global CCS Institute. Global Status of CCS 2021. 2020.

100 million tonnes of CO_2 over its life. This was supposed to reduce Gorgon's greenhouse gas emissions by about 40%.[64]

The CCS project was meant to start operations concurrently with the LNG plant in March 2016, though several technical problems meant CCS injection did not start until August 2019. As a result, the facility completely missed its targets for the first three and a half years.

The Gorgon Project is a joint venture between the Australian subsidiaries of Chevron, the operator (47.3%), ExxonMobil (25%), Shell (25%), Osaka Gas (1.25%), Tokyo Gas (1%) and JERA (0.417%).[65]

Economics and Performance

The Gorgon CCS project started with great fanfare, both as Australia's largest project and as the world's largest CCS project with a dedicated geological structure. It received $60 million from the Australian government as part of the Low Emissions Technology Demonstration Fund.[66]

The $3.1 billion Gorgon plant produced its first LNG cargo in March 2016[67] but the first CO_2 injection from its CCS facility[68] did not occur until three and a half years later. Start-up checks in late 2017 found leaking, corroded valves and excess water in the pipeline between the LNG plant and the injection wells, a potential cause of corrosion.[69]

Technical problems did not end there. In January 2021, it was reported[70] that the WA Department of Mines, Industry Regulation and Safety had ordered Gorgon to reduce the volume of carbon captured by the project, due to structural issues. Essentially, sand was blocking the well that reinjects water underground, compromising the crucial pressure management system.

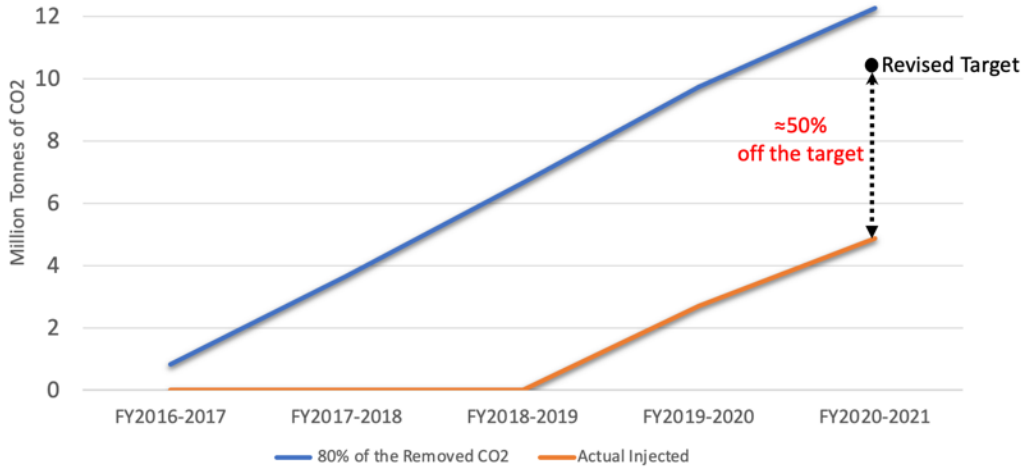
A closer look at Gorgon's CCS target and results demonstrates the project's considerable underperformance in the first five years. Calculated on a five-year rolling average commencing on 18 July 2016, Chevron committed to ensure that at least 80% of reservoir CO_2 removed during processing at the gas treatment plant, that would otherwise be vented to the atmosphere, would be injected underground.[71] On this

[64] Chevron. Gorgon Gas Development and Jansz Feed Gas Pipeline Five-year Environmental Performance Report 2015–2020. October 2020, p. 4.
[65] Chevron. Gorgon Carbon Capture and Storage Fact Sheet. 2021.
[66] Chevron. Gorgon Carbon Capture and Storage Fact Sheet. 2021.
[67] Chevron. Gorgon Carbon Capture and Storage Fact Sheet. 2021.
[68] Financial Times. Monster problem; Gorgon project is a test case for carbon capture. 26 July 2021.
[69] The West Australian. Carbon hiccup for Chevron with 5 million-tonne greenhouse gas problem at Gorgon LNG plant. 19 December 2017.
[70] Boiling Cold. Chevron's Gorgon emissions to rise after sand clogs $3.1bn CO_2 injection system. 12 January 2021.
[71] Chevron. Gorgon Gas Development and Janz feed Gas Pipeline Environmental Performance Report 2021. November 2021, p. 45.

basis, the Gorgon CCS plant should have captured at least 12.3MT of the removed CO_2 in its five years of operation.

The environmental performance reports show that the plant had injected only 4.9MT by July 2021. The shortfall from the five-year target is claimed to be 5.23MT CO_2.[72] Putting all this together, it can be inferred that the Gorgon CCS project's revised target for the first five-year period was about 10.1MT and it failed to meet this target by about 50% (Figure 13 shows the cumulative trend of Gorgon's sequestered CO_2 versus the cumulative target trend).[73]

Figure 13: Gorgon CCS Plant's Performance (Cumulative Trend, 2016–2021)



Source: Gorgon Environmental Performance Reports 2015–2020 & 2021

In the Gorgon 2021 environmental performance report, Chevron cited planned and unplanned maintenance among other causes for the underperformance of the plant.[74]

Gorgon's technical troubles and ongoing "unplanned" maintenance after five years illustrate some of the inherent and unique risks of CCS, despite the technology's decades of operation.

Gorgon has recently agreed to acquire and surrender credible greenhouse gas offsets recognised by the West Australian government to offset its target shortfall of 5.23MT of CO_2. Estimates of what this may cost Gorgon vary from US$100 million to US$184 million.

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[72] Chevron. Gorgon Gas Development and Janz feed Gas Pipeline Environmental Performance Report 2021. November 2021, p. 45.
[73] In its latest environmental performance report published in November 2021, four months after the first five-year period ended, Chevron stated that 5.5MT had been injected in the five years of the project's lifetime.
[74] Chevron. Gorgon Gas Development and Janz feed Gas Pipeline Environmental Performance Report 2021. November 2021, p. 44.

The project is expected to run for 40–45 years, after which there will be a closure period of 15 years. Post-closure, liability will be handed over to the WA government.

The project also has failed to reach its five-year rolling average (ending July 2022) target.[75]

Other Big CCS/CCUS Project Failures in the Natural Gas Processing Sector

Apart from the operating projects, several projects in this sector have failed or been suspended due to technical issues and/or environmental concerns. A case in point is the In Salah project in Algeria.

In Salah

The In Salah project in Algeria was a CCS project with a total cost of US$2.7 billion. Equinor (Previously Statoil) was the operator, and the announced capture capacity was 1–1.2Mtpa.[76]

Injection started in 2004 and was suspended in 2011 due to concerns about the integrity of the seal. Nevertheless, the project successfully stored 3.8MT of CO_2 in the Krechba Formation during its lifetime.[77]

Analysis of the reservoir, seismic and geo-mechanical data from 2010 led to the decision to suspend CO_2 injection in June 2011. Concerns about possible vertical leakage into the caprock led to an intensified R&D program to understand the geo-mechanical response to CO_2 injection at this site.[78]

Lost Cabin is another example of a project in which CO_2 injection was suspended in 2018. It was a CCUS project (CO_2-EOR) with a capacity of 0.9Mtpa started in 2013 in Fremont County, Wyoming, U.S. ConocoPhillips and Denbury were the companies involved in the project.[79]

Just after five years of operation, in 2018, a fire occurred at the Lost Cabin Gas Plant in Wyoming, resulting in the shutdown of the plant's CCUS facility. There was an expectation that operations would restart by the end of 2020 with a lower capture

[75] The Guardian. Gas giant Chevron falls further behind on carbon capture targets for Gorgon gasfield. 16 July 2022.
[76] In Salah Fact Sheet: Carbon Dioxide Capture and Storage Project.
[77] In Salah Fact Sheet. Carbon Dioxide Capture and Storage Project.
[78] In Salah Fact Sheet. Carbon Dioxide Capture and Storage Project.
[79] Lost Cabin Fact Sheet. Commercial EOR using Anthropogenic Carbon Dioxide.

rate of 0.7Mtpa.[80] But it did not happen, and the latest Global CCS Institute report, published in late 2021, still labels the project as suspended.[81]

Enhanced Oil Recovery Business Dominates Natural Gas Processing Sector

Natural gas processing has been the main CCS/CCUS application historically, with about 70% of current total operational capacity worldwide. The first CCUS project, Terrel, established in 1972, was in the U.S.

Developing such projects was not about environmental or climate concerns in the 1970s. Separating CO_2 from extracted raw gas is essential to producing marketable and flammable natural gas. It was/is a technical must.

Further, during the energy crisis in the 1970s and 1980s, the interest in capturing the separated CO_2 and selling it to oil companies to enhance the rate of their oil production started to increase. It was a win-win deal for both gas producers who could increase their revenue by selling a previously vented CO_2 to oil companies and for the oil companies who could revitalise their ageing depleted oil wells and get more oil out of them to sell in those eras of the bullish oil market. Hence, economics was the second incentive behind developing such projects in that era.

This is evident in the share of carbon capture projects servicing EOR activities (CCUS) compared to the carbon capture projects with dedicated geological storage for sequestering the carbon without using it for EOR(CCS). Nevertheless, more than 73% of operational projects in the natural gas processing sector remain dedicated to EOR projects.

More than 73% of operational projects in the natural gas processing sector remain dedicated to EOR projects.

And as EOR is about producing more oil and gas, encouraging investment in these fossil fuels negates the very initial claimed emission reduction goal for carbon capture technology.

Scope 3 Emissions—the Elephant in the Room

Gas processing CCS/CCUS covers a tiny proportion of the value chain emissions compared to CCS/CCUS in other sectors.

As gas processing CCUS is largely about 'capturing excess CO_2', it is obvious that CCUS in the sector is *not* about reducing Scope 3 emissions from the final

[80] Global CCS Institute. Global Status of CCS 2020.
[81] Global CCS Institute. Global Status of CCS 2021.

combustion/use of gas. Rather it is about minimising production-related Scope 1 emissions from gas with excessive CO_2 content. This is in contrast to most other CCUS applications in the industrial and power sector, which aim to minimise the emissions coming from the end consumption of fossil fuels, whether by combustion or as feedstock materials.[82]

Therefore, giving the green light to new oil and gas projects just because of CCS/CCUS promises attached to those projects is not climate friendly.

Even if the CCS/CCUS facilities work at their capacity (which was not the case historically, barring some exceptions), such projects could only manage a minor proportion of the value chain emissions they themselves produce by adding CCS/CCUS.

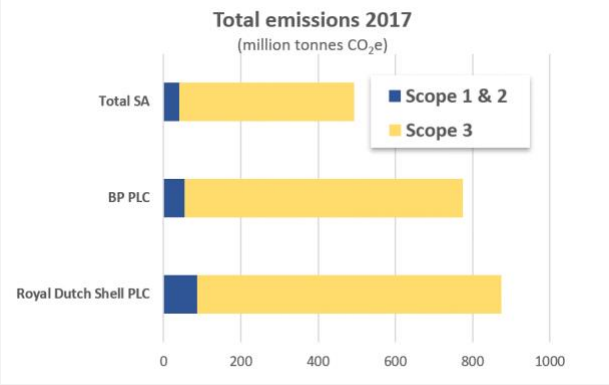
The gas burnt at the end of the value chain produces the biggest chunk of emissions, which CCU/CCUS proposals do not address.

Scope 1, 2 and 3 Emissions

Value chain emission of different products is categorized into three different scopes, as outlined by the Green House Gas (GHG) Protocol Corporate Standard.

Scope 1 emissions constitutes emissions from sources owned or controlled by the producer company. Scope 2 represents indirect emissions from purchased energy inputs such as electricity or heat which are not generated directly by the company. Scope 3 represents all other emissions in the value chain, including those located in the upstream (input) and downstream (output) part of the company's process.

Specific for companies involved in energy *extraction*, it is important to note that the end product emissions (Scope 3) constitute a much greater portion of the overall (Up to 90%). Below chart further illustrates the typical emission scopes for oil & gas companies.



Source: Trucost, S&P Global Market Intelligence.

[82] IEEFA. Carbon capture in the Southeast Asian market context: sorting out the myths and realities in cost-sensitive markets. April 2022.

Lessons Learned

In general, due to its association with EOR and historic capture rate issues,[83, 84] carbon capture in the natural gas processing sector has minimal environmental and social credibility as a decarbonisation option.

The most obvious point is that there is no more room for a new EOR project (CCUS) as it contradicts net-zero goals and emission reduction activities. In contrast, EOR has been the central part of the carbon capture application in this sector and others historically.

A new EOR project (CCUS) contradicts net-zero goals and emission reduction activities.

What about capturing and storing carbon without using it for oil production (CCS)?

As clearly stated in the seminal IEA's Net Zero 2050 report,[85] there should be no new oil and gas field developments if the world wants to reach net zero by 2050 and avert the catastrophic consequences of climate change. Therefore, any new oil and gas development should not get a green light, with or without CCS.

Even if a CCS project could capture a majority of the oil and gas facilities' emissions (which most projects show is unlikely), it could only capture 10–15% of the value chain emissions of oil and gas produced by those fleets (i.e., Scope 1 and 2 emissions). Roughly 80–90% of the emissions are Scope 3 emissions,[86] and CCS projects cannot do anything about that.

The niche remainder of existing gas processing units are not 'new' and would be operating through the next one or two decades until renewables, green hydrogen and battery technologies take up the whole energy system. They might provide cases to think about, but there are still risks associated with these.

There is no confidence that the proposed CCS projects could meet their designed capture rates. Except for a few successful cases in a unique regulatory environment, such as Norway, with high carbon taxes and stringent environmental regulations, the history of carbon capture technology is full of failed or underperformed projects. This report has studied some of the biggest ones.

There is also no room to bet billions of dollars on projects that could not meet expectations. Instead, there are proven, cost-effective, and established investment alternatives to battle climate change, such as solar and wind energy.

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[83] Robertson and Mousavian. IEEFA. Carbon Capture to Serve Enhanced Oil Recovery: Overpromise and Underperformance. March 2022, pp. 18–20.
[84] IEEFA. Gorgon Carbon Capture and Storage: The Sting in the Tail. April 2022.
[85] IEA. Net Zero by 2050. May 2021.
[86] Robertson and Mousavian. IEEFA. Santos 2022 climate change report. 1 April 2022.

The other problem with CCS projects is the availability of suitable geological storage locations nearby the projects to make the finance of CCS work.

Monitoring is another challenge—the trapped CO_2 underground needs monitoring for centuries to ensure it does not come back to the atmosphere. Leakages and fugitive emissions in the long term are serious risks. It is impossible to guarantee that the stored CO_2 will stay underground and not leak into the atmosphere. There are several real-world examples of failure in keeping gas underground. The best example is the California Aliso Canyon gas leak in 2015, the worst man-made greenhouse gas disaster in U.S. history when 97,000MT of methane leaked into the atmosphere.[87] The other one is the In Salah project in Algeria, which was a CCS project with a total cost of US$2.7 billion.[88] Injection started in 2004 and was suspended in 2011 due to concerns about the integrity of the seal and suspicious movements of the trapped CO_2 under the ground.

It is impossible to guarantee that the stored CO_2 will stay underground and not leak into the atmosphere.

There will always be a risk of such disasters for any CCS project. The IPCC's Carbon Dioxide Capture and Storage Special Report stated:

> *"CO_2 storage is not necessarily permanent. Physical leakage from storage reservoirs is possible via (1) gradual and long-term release or (2) sudden release of CO_2 caused by disruption of the reservoir."*[89]

The other challenge is liability. The question of who will be responsible for long-term monitoring of the geological structure is crucial. Large oil and gas companies mainly benefiting from the gas developments must be liable for any failure/leakage and monitoring costs of CCS projects, specifically if they get subsidies, grants and tax credits for capturing the carbon.

The most recent example of the liability challenge is the Gorgon CCS project discussed earlier. The expected project life is 40–45 years, after which there will be a closure period of 15 years. Post closure, the Western Australian government,[90] essentially taxpayers, take over the project's liability.

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[87] The Washington Post. California gas leak was the worst man-made greenhouse-gas disaster in U.S. history, study says. February 2016.
[88] Massachusetts Institute of Technology. In Salah Fact Sheet: Carbon Dioxide Capture and Storage Project.
[89] Intergovernmental Panel on Climate Change. Carbon Dioxide Capture and Storage Report. 2005.
[90] WA Department of Mines, Industry Regulation and Safety. Gorgon Carbon Dioxide injection project.



Section 3: Carbon Capture Application in the Power Sector

As one of the highest emitting sectors, the power sector (electricity and heat production) had the largest increase in CO_2 emissions by sector in 2021. This accounted for 46% of the global increase in emissions in 2021. CO_2 emissions from the sector neared 14.6 gigatonnes (GT), their highest ever level.[91]

Power plants inherently emit large volumes of CO_2.

Power plants inherently emit large volumes of CO_2. For example, a 1 gigawatt (GW) coal plant could emit 5–7MT of CO_2 annually.[92]

The most recent proposed application for CCS/CCUS is retrofitting existing, and usually old,

[91] IEA. Global Energy Review: CO_2 Emissions in 2021. March 2022.
[92] Global Energy Monitor. Estimating carbon dioxide emissions from coal plants. Accessed on 3 February 2022.

fossil-based power plants with carbon capture technology to reduce their staggering emissions.

CCUS for the power sector is more costly and complex than other applications due to the diluted CO_2 in the flue gas stream, as evidenced by the string of historical issues in retrofitting CCUS into power plants with several failed projects and cost blowouts. In contrast to gas processing and certain industrial processes that could generate exhaust gas with 40–90% CO_2 composition, coal plants emit gases that typically only contain 10–14% CO_2, while gas power plants generate 4–5% CO_2.[93] Small in concentration but large in terms of absolute volume globally.

Over the years, IEEFA has published a comprehensive body of knowledge in assessing the economics and viability of CCS/CCUS projects,[94] particularly its application in the power sector. Capturing CO_2 consumes a lot of energy, effectively reducing the amount of electricity delivered to consumers.[95] Under normal operation, power plants already consume a portion of the power they generate for self-use. CCS/CCUS impose additional energy penalties into the mix, typically by drawing steam or power to operate the capture process.

This also means that more fossil fuels will need burning to generate the same amount of electricity in a non-CCUS power plant. Decades of technological progress have been devoted to increasing coal power plant efficiency from the sub-38% of subcritical plants to the ~45% of Ultra Super Critical (USC) plants. A loss of 8–12% poses a substantial barrier for many CCS/CCUS applications.[96]

To be able to compete in the electricity market context, the high cost of CCS/CCUS projects will need compensation—by selling the captured CO_2, receiving government incentives, or charging a premium price to consumers. However, these pathways are not guaranteed and also could lead to financial instability for the project or environmental externalities in the case of using CO_2 for EOR.

Selling captured CO_2 for EOR contradicts the very goal of capturing carbon.

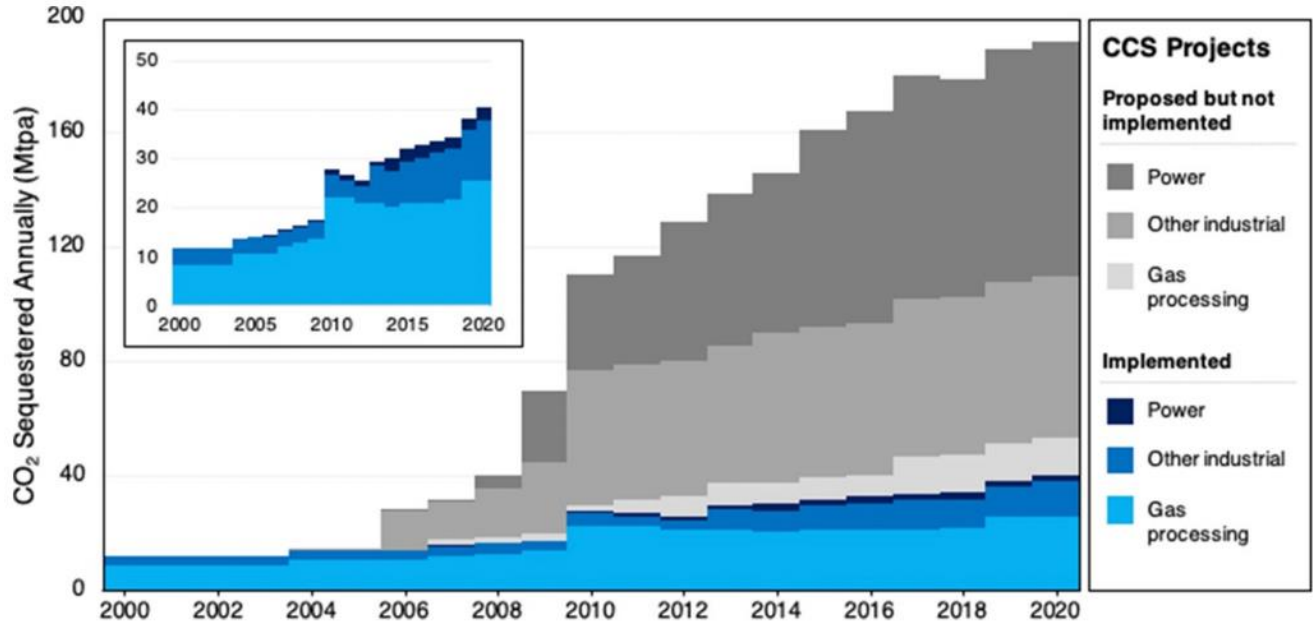
Government incentives could flow into fast-growing, efficient, and clean, renewable energy technologies and battery and storage sectors. Selling captured CO_2 for EOR contradicts the very goal of capturing carbon as it leads to producing fossil fuels. Moreover, considering the EOR business as a cash-generating business for power

[93] IPCC. Carbon capture utilization and storage. 2005. Energy Procedia. Comparison of solvents for post-combustion capture of CO_2 by chemical absorption. 2009.
[94] IEEFA. Carbon Capture and Storage.
[95] Energy consumption can be in the form of drawing steam from the power plant to heat solvent-based CCUS process.
[96] IEEFA. Carbon capture in the Southeast Asian market context: sorting out the myths and realities in cost-sensitive markets. April 2022.

plant owners is a flawed assumption. EOR activities highly correlate with oil prices, and the demand for CO_2 would be as volatile as oil prices. IEEFA has elaborated on this issue in previous research.[97]

Apart from the financial side, carbon capture has shown a track record of technical failures since 2000. Close to 90% of proposed CCS capacity in the power sector has failed at the implementation stage or was suspended early.[98] Figure 14 reflects the results of recent research by academic institutions and universities in Canada and the U.S. It depicts the failure of carbon capture technology in the power sector.

Figure 14: Global Implemented Annual CCS/CCUS Projects By Sectors



Source: Abdulla et al, 20201, Environmental Research Letters.

Globally, there is only one operating power generation CCUS, which is located at the Boundary Dam plant in Canada. A second CCUS plant, Petra Nova in the U.S., was operational between 2017 and 2020 and later reported to be "shut down indefinitely" after only four years.[99] Both of these plants have been studied in this report, and important lessons were elicited.

It might be the case that there are more proposals for CCUS projects in the power sector, especially as the narrative is becoming attractive in Southeast Asian countries with relatively young fossil power plant fleets. However, the historical lessons clearly suggest that no more greenfield coal or gas powerplants should be

[97] Robertson and Mousavian. IEEFA. Shute Creek – world's largest carbon capture facility sells CO2 for oil production, but vents unsold. March 2022.
[98] IOP Publishing. Explaining successful and failed investments in U.S. carbon capture and storage using empirical and expert assessments. 29 December 2020.
[99] Reuters. Problems plagued US CO_2 capture project before shutdown: document. 7 August 2020. Yahoo Finance. Power plant linked to idled US carbon capture project will shut down indefinitely – NRG. 30 January 2021.

greenlit just because of an embedded CCS facility in its design plans. Also, in the case of CCUS proposals for existing and ageing power plants, to prevent them from getting stranded, investors should know that these projects will likely face financial and technical difficulties that will put them in trouble. The era of fossil-based power plants is over, and renewable technologies plus storage capabilities are the future solutions serving net-zero goals.

Case Studies

In this section, only two carbon capture projects ever operationalised in the power sector have been studied. As the power sector has a track record of failures in utilising carbon capture technologies to curb emissions, the Kemper coal gasification power plant, one of the biggest failures that led to the most expensive power plant ever built, has also been studied.

Petra Nova

The Only Post-combustion Project in the U.S. Was Shut Down After Four Years

There have been only two post-combustion CCS plants commissioned to date. The Petra Nova project was the second and the only one operationalised in the U.S. It was designed to reduce carbon emissions from a power plant southwest of Houston, Texas. Project partners NRG Energy and JX Nippon Oil retrofitted one the boilers at the W. A. Parish Generating Station—with post-combustion carbon capture treatment technology to manage exhaust emissions.

The 45-year-old powerplant has a total capacity of 3.7GW and the CCS was fitted in January 2017 to a boiler in its Unit 8 with 240 megawatts (MW) capacity.[100]

Citing low oil prices during the COVID-19 pandemic, the plant was shut down in May 2020,[101] a common issue with CO_2-EOR projects that are typically very sensitive to oil price volatility.

The amine-based absorption technology, developed by Japanese technology giants Mitsubishi and Kansai Electric Power[102] removes CO_2 from the exhaust gas through a basic absorber-stripper system, then compresses it into liquid. The captured CO_2 was piped 130km away to the sandstone Frio Formation of the West Ranch oil field and after being used to increase the rate of oil recovery, was stored at a depth of about 1500 metres.

As with most CCS projects in North America, generating cash from selling CO_2 for EOR was one of the main incentives for launching this project.

[100] U.S. Department of Energy, Petra Nova – W.A. Parish Project.
[101] NRG. Petra Nova Status Update, August 2020.
[102] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Petra Nova W.A. Parish Fact Sheet: Carbon Dioxide Capture and Storage Project.

To meet the Clean Coal Power Initiative requirements of the U.S. Department of Energy (DOE), the Texas Bureau of Economic Geology established a scheme for monitoring CO_2 injection and movement beneath the rock structures.

Economics and Performance

Installing the Petra Nova carbon emissions reduction system cost about US$1 billion. Known funding sources were US$190 million provided by the DOE in the form of grants and appropriation, US$250 million by Japanese banks as a loan and US$300 million invested by NRG Energy and JX Nippon Oil.[103]

The main enabler in its business model was the revenue from selling captured CO_2 to the adjacent oil field. This project was expected to run for at least 20 years to enhance the rate of oil production in the West Ranch field from less than 1000 barrels per day to more than 15,000 per day. When the project was first proposed, oil prices were very high (US$100 per barrel) and the very optimistic and unrealistic assumption, given the global transition away from fossil fuels, was that the price would not drop. In 2017, the oil price was about US$50 per barrel and there was a net loss from oil production at the field.[104]

On 1 May 2020, NRG shut down Petra Nova, citing low oil prices during the COVID-19 pandemic.[105, 106] The plant had also reportedly suffered frequent outages and missed its carbon sequestration goal by 17% over its short three years life.

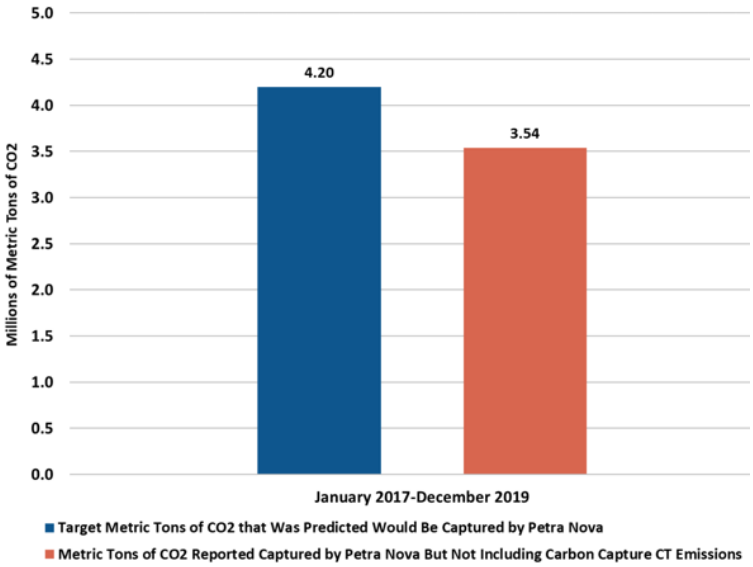
Petra Nova had reportedly suffered frequent outages and missed its carbon sequestration goal by 17%.

The plant was originally expected to capture at least 1.4 million metric tons of CO_2 annually (33% of carbon emission from unit 8 of the powerplant), or a total of 4.2 million metric tons from 2017 to 2019.[107, 108] However, as Figure 15 shows, the project fell well short of that goal during its first three years of operation. IEEFA estimated that the shortfall of 662,000 fewer tonnes in CO_2 captured would have cost investors about US$23 million. It was supposed to recover investment costs via.

[103] Forbes. Ambitious Texas Carbon Capture Project Turns Rocky For NRG At $50 Oil. January 2017.
[104] Forbes. Ambitious Texas Carbon Capture Project Turns Rocky For NRG At $50 Oil. January 2017.
[105] NRG. Petra Nova Status Update. August 2020.
[106] Reuters, Problems plagued U.S. CO_2 capture project before shutdown: document. August 2020.
[107] U.S. Energy Information Administration (EIA). Petra Nova is one of two carbon capture and sequestration power plants in the world. October 2017.
[108] U.S. Department of Energy, Office of Scientific and Technical Information (OSTI). W.A. Parish Post-Combustion CO_2 Capture and Sequestration Project, Final Public Design Report. February 2017.

If the 20-year prospective lifetime of the plant is considered,[109] the cost to investors would have been at least US$150 million.[110]

Figure 15: Projected vs Actual Amount of CO_2 Captured by Petra Nova CCS Plant



Source: U.S. Department of Energy, NRG, Inc.

Moreover, the net amount of CO_2 reduction by Petra Nova would be less than the cited 3.54MT as the plant's built-in gas turbine had emitted about 1.1MT of CO_2 by May 2020.

The Petra Nova CCS project met neither the investors' financial expectations nor the specified CO_2 capture, the pre-assumed high-capacity factor of the power plant or the expected EOR rates. Over the past four years, according to company financial reports, NRG recorded three separate impairment charges related to the plant and to Petra Nova Parish Holdings, the subsidiary that operates the facility. The impairments have totalled US$310 million.

Paradoxically, these projects needed the power plant to produce more CO_2 to sell to oil companies and make money. So, they need an unrealistically high capacity factor to run and generate electricity. While research shows the capacity factor for fossil-based power plant is declining around the world.[111]

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[109] Considering the full 20 years of operation for the plant is not a plausible assumption as it is highly correlated with oil price fluctuations, which practically shut down the plant just after three years. As the future unfolds a business model heavily reliant on a highly volatile oil price would not seem to be prosperous.

[110] Dennis Wamsted, David Schlissel. IEEFA. Petra Nova Mothballing Post-Mortem: Closure of Texas Carbon Capture Plant Is a Warning Sign. August 2020.

[111] Bruce Robertson, Milad Mousavian. IEEFA. Australia's Gas-fired Recovery Under Scrutiny Inaccurate Assumptions Behind Fossil Fuel Power Plants' Capacity Factor Leads to Financial Overvaluations. June 2021.

Based on the IEA Clean Coal centre report on CCS project costs published in 2020, the levelised cost of capturing CO_2 in Petra Nova was about $60–$70 per tonne. The real levelised cost would be much higher, however, as this study assumes an unrealistically high capacity factor of 85% for the plant.[112] Historical operation data shows the capacity factor of the plant to be about 63%.[113] The financial viability of similar projects, when sensitivity of cash flow is added to oil price fluctuations, must be questioned.

The validity of such projects, which use CO_2 to produce yet more fossil fuel, also must be challenged.

Boundary Dam

The Only Post-combustion CCS Plant in the World

The Boundary Dam Integrated Carbon Capture and Storage project was retrofitted to the lignite-fired Unit 3 of the 50-year-old Boundary Dam power plant in Saskatchewan, Canada. It was recognised as the first coal-fired power plant to use post-consumption CCS technology.[114]

Commissioned in October 2014, it is now the only operating coal-fired power plant in the world that captures CO_2. This project was re-sized from an earlier plan to build a 300MW clean coal facility, shelved by the previous provincial government because of its escalating cost (from US$1.5 billion to US$3.8 billion).

This smaller-scale project was initiated after the Canadian government gave the province C$240 million. It could capture CO_2 using post-consumption amine technology but also was equipped with facilities to capture sulphur dioxide and nitrogen oxides.[115]

Economics and Performance

The original estimated construction cost of the Boundary Dam project was US$1.3 billion but the ultimate figure was US$1.5 billion. Of the original estimate, US$800 million was for the CCS process, with the balance for retrofit costs.

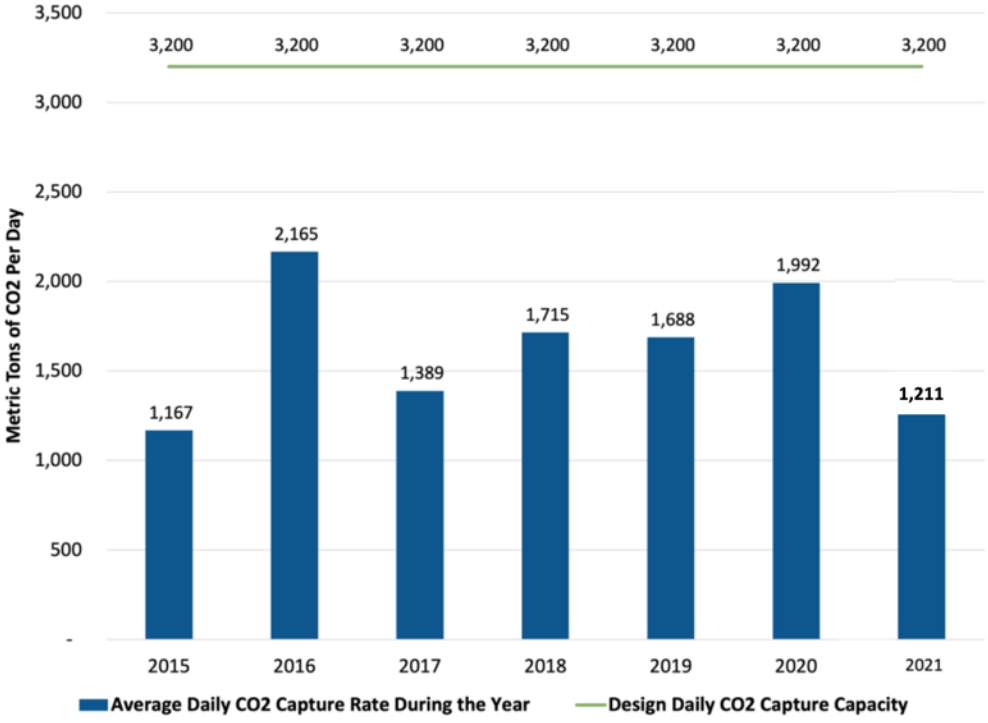
Besides selling electricity, the main revenue stream came from the contract with Cenovus Energy of Calgary, which were supposed to purchase the majority volume of 1Mtpa of captured CO_2 for EOR projects operated by Cenovus near the Weyburn oil field. While a majority of the 1Mtpa of CO_2 captured from Boundary Dam Unit 3 is expected to be sold for EOR operations at the Weyburn oil field, Aquistore provides a

[112] International Centre for Sustainable Carbon, Carbon Capture Utilisation and Storage – Status Barriers and Potential, CCC/304. July 2020.
[113] David Schlissel, IEEFA. Where's the Beef? Enchant's San Juan Generating Station CCS Retrofit Remains Behind Schedule, Financially Unviable. May 2021.
[114] The Globe and Mail, Energy and Resources. SaskPower unveils world's first carbon capture coal plant. October 2014.
[115] IEAGHG. Integrated Carbon Capture and Storage Project at Saskpower's Boundary Dam Power Station. August 2015.

facility for "buffer" storage against EOR sales fluctuations.[116] Cenovus also set up injection wells and built a 60km-plus pipeline connecting the Weyburn EOR project to Boundary Dam.[117]

The initial goal of the project was capturing about 1 million metric tons of CO_2 each year or 3200 tonnes daily. However, the plant has captured an average of slightly more than 615,000 metric tons annually. Data published by SaskPower, the operator of the project, suggests that the Boundary Dam 3's average CO_2 capture rate to date is about 50%, not the targeted 90%.[118] It has barely achieved the latter figure on any single day and has never done so over any extended period.[119] Despite SaskPower's announcement regarding improvements and upgrading facilities during plant outages, as Figure 16 shows, the plant still falls well short of the original daily goal.[120]

Figure 16: Projected vs Actual Boundary Dam CO_2 Daily Capture Rate



Source: SaskPower's Monthly Boundary Dam Status Updates

[116] Global CCS Institute. Aquistore: CO2 Storage at the World's First Integrated CCS Project – Project Summary Report. 2015.
[117] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Boundary Dam Fact Sheet: Carbon Dioxide Capture and Storage Project.
[118] SaskPower. BD3 Status Update: March 2021.
[119] IEEFA. Boundary Dam 3 Coal Plant Achieves Goal of Capturing 4 Million Metric Tons of CO_2 But Reaches the Goal Two Years Late. April 2021.
[120] SSRN. SaskPower's Boundary Dam Unit 3 Carbon Capture Facility – The Journey to Achieving Reliability. March 2021.

Consequently, it took until March 2021 for Boundary Dam 3 to capture 4 million metric tons of CO_2, a yield that should have been met more than two years earlier, in October 2018.

SaskPower had counted on sales of CO_2 at US$19 (C$25) a tonne for Cenovus Energy's Enhanced Oil Recovery project. Without such sales, SaskPower's income was down. And without the expected CO_2 volume, Cenovus Energy collected US$9 million (C$12 million) in payments under the penalty provisions in its CO_2 supply contract.[121] SaskPower also became embroiled in two separate legal disputes with contractors over payments.[122]

The levelised cost of capturing CO_2 in Boundary Dam 3 has been calculated at about $100–$120 per tonne. As with Petra Nova, the underlying assumption for this calculation is that the plant operates at 85% capacity factor—which does not match SaskPower's monthly operating reports. The $100–$120 figure could be considered as the lowest cost of capturing carbon for the lower bound of Boundary Dam 3's carbon capturing cost.[123]

This project, though still operating, is struggling to meet the pre-specified targets.

Kemper Coal Gasification CCS Plant

A Failure and the Most Expensive Power Plant Ever Built

Gas and electric utility Southern Company's Kemper facility was supposed to be a flagship "clean coal" project. Initially proposed in 2008, the greenfield project near Meridian, Mississippi, U.S., was pegged to cost less than US$3 billion and to be running in 2014. It did not unfold as envisioned. Not only was it delayed for more than three years and cost more than US$7 billion, but the company also cancelled the integrated gasification combined cycle (IGCC) and carbon capture portions of the project.

Kemper was designed as a first-of-a-kind plant with a system that produced gasified coal to be burned in a modified combined cycle gas power plant and a carbon capture system that would pull the CO_2 from the gasified coal pre-combustion.[124]

The gasification process and associated emissions controls were expected to produce marketable quantities of ammonia and sulphuric acid as well as the captured CO_2, which was slated for use in EOR.[125] The main argument in favour of the project was that the CO_2 capture would bring the plant's emissions down to levels comparable with conventional combined-cycle gas-fired generators.

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[121] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology, Boundary Dam Fact Sheet: Carbon Dioxide Capture and Storage Project.
[122] RenewEconomy. The fallout from SaskPower's Boundary Dam CCS debacle. November 2015.
[123] IEEFA. Where's the Beef? Enchant's San Juan Generating Station CCS Retrofit Remains Behind Schedule, Financially Unviable. May 2021.
[124] IEEFA. Holy Grail of Carbon Capture Continues to Elude Coal Industry. November 2018.
[125] U.S. Department of Energy. Southern Company – Kemper County, Mississippi.

Essentially, the Kemper gasification process turned the relatively straightforward operation of burning coal to boil the water, running the steam turbine and producing electricity into a complicated chemical process that strips gas from coal to be used in a combined cycle gas turbine (CCGT) accompanied by a steam boiler/generator that uses the heat created through the chemical syngas production for electricity production.[126] These complicated steps were essentially added to use the lignite coal extracted from the Mississippi mine, which has 4 billion tonnes of reserves. Lignite or so-called 'brown coal' is considered the most harmful type of coal for human health as its heat value relative to the amount of CO_2 and sulphur it releases is lower than all other grades of coal.[127]

Economics and Performance

Running Kemper's commercial scale on-site equipment, including coal gasification and carbon capture, was expected to consume 30% of the plant's 830MW gross output. A typical natural gas-fired plant consumes just 3–4% of its gross output to run internal equipment. The conventional combined-cycle gas units at Kemper came online in late 2013.[128]

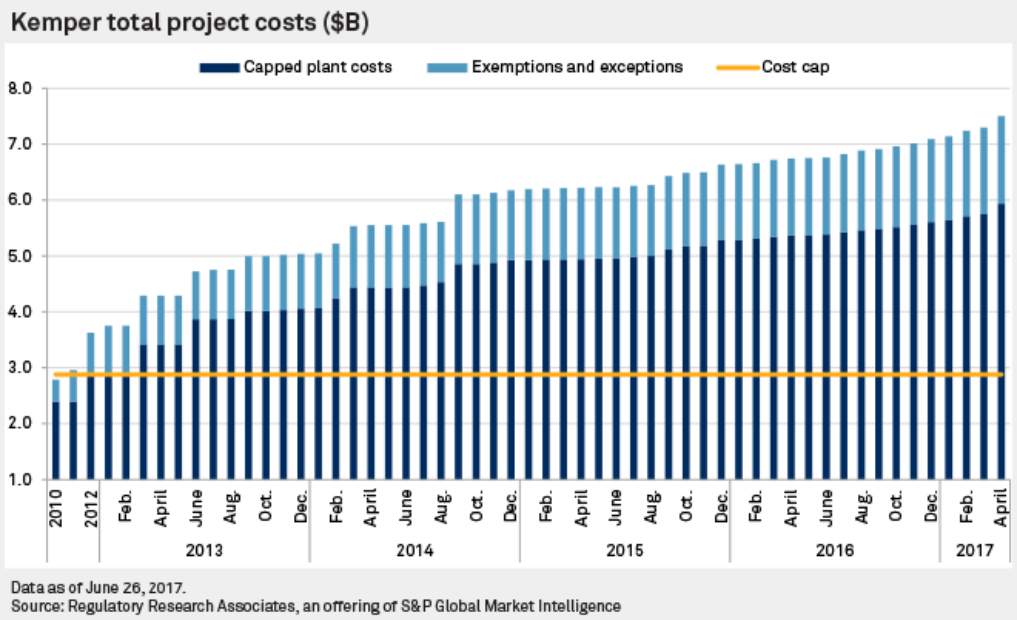
The Kemper project was approved in 2010 by the Mississippi Public Service Commission. Southern Company estimated the US$2.9 billion project would be in operation by the end of 2014. There was no reasonable estimate of either the cost or the commissioning date. Some consultants warned about cost underestimation at the time.[129]

Costs steadily increased as construction proceeded, as shown in Figure 17, and its commercial in-service date was repeatedly delayed. The "cost cap" represents that adopted by the Mississippi Public Service Commission, based on Southern Company's original cost estimate.[130]

Kemper began producing electricity in mid-2014 as a CCGT, burning natural gas, but problems with the operation of its unproven gasification systems—which were to have come online that same year—further added to costs and delays. These led to a 250% increase in the cost of the project, to US$7.5 billion.

[126] IEEE Spectrum. The Three Factors That Doomed Kemper County IGCC. June 2017.
[127] Heal. Lignite coal – health effects and recommendations from the health sector. December 2018.
[128] IEEFA. Holy Grail of Carbon Capture Continues to Elude Coal Industry. November 2018.
[129] Mississippi Public Service Commission. Direct Testimony of David A. Schlissel on Behalf of the Sierra Club. December 2009.
[130] IEEFA. Costly and Unreliable, Two Multibillion-Dollar American Coal-Gasification Experiments Prove the Case Against Such Projects. September 2017.

Figure 17: Kemper IGCC Project's Increasing Cost (US$)



Source: SNL Financial, a unit of S&P Global Market Intelligence.

These technical and financial failures led to the Mississippi Public Service Commission calling for burning coal to cease and for gas to be used in CCGT. The commission said Kemper's gasification technology would not be used or useful in serving Mississippi customers. It found the technology had not operated reliably and was not likely do so in the near future.[131]

The Kemper "clean coal" journey ended in 2017 with the failed coal gasification idea. Southern Company was left with the then most expensive power plant ever built.[132]

Lessons Learned

Using CCS/CCUS in the power sector is the latest application of the technology, which has been gaining traction recently.

Despite generous funding and numerous incentives to push the technology in this sector (such as the 45Q Tax Credit in the U.S.[133]), it has shown a disappointing track record of failures, with a majority of the proposed CCS/CCUS capacity failing at the implementation stage or getting suspended early. Looking at the historical trajectory, technical issues have been one of the most prominent barriers. A lot of projects failed to operate at their theoretically designed capturing rates. As a result,

[131] Southern Company. Southern Company and Mississippi Power announce suspension of gasification operations at Kemper. June 2017.
[132] Bloomberg. Coal's Best Hope Rising with Costliest U.S. Power Plant. April 2014.
[133] Global CCS Institute. 45Q: The "Most Progressive CCS-Specific Incentive Globally" Is Now Open for Business. 24 March 2021.

the 90% emission reduction target generally claimed by the industry has been unreachable in practice.

There has not been any operational project that could meet its capture target so far. Petra Nova, marketed as a flagship breakthrough in this area, underperformed by 17% in four years of its operation before being mothballed indefinitely in 2020. Boundary Dam 3, the only active carbon capture project in the power sector worldwide, has captured less than its pre-specified target by a wide margin (about 50%).

The 90% emission reduction target generally claimed by the industry has been unreachable in practice.

CCS/CCUS for the power sector is more costly and complex than other applications due to the diluted CO_2 in the flue gas stream, as evidenced in the string of historical issues in retrofitting carbon capture technologies into power plants with several failed projects and cost blowouts.

The financial side of the CCS/CCUS business in the power sector is also problematic. Capturing CO_2 consumes a lot of energy, effectively reducing the amount of electricity that can go to consumers. It imposes additional energy penalties into the mix, typically by drawing steam or power to operate the capture process.

In a competitive electricity market, the high cost of CCS/CCUS will lead to financial instability for the project or environmental externalities in the case of using CO_2 for EOR.

The investment cost for such complex facilities is also staggering. This is evident in the case of the Kemper coal gasification plant that left investors with the most expensive power plant ever built at US$7.5 billion.

All in all, the technology should not be marketed as a quick fix for power sector emissions and make policymakers feel relieved about the world-saving technology just around the corner. It has not worked financially or technically. Instead, we should address the root of the problem, which is fossil-based energy production. Embedding carbon capture technologies in the proposed plan for building power plants and promoting such new fossil-based fleets in emerging economies such as Southeast Asia would have a deteriorating effect on climate in the long term.

Proven, cost-effective and climate-friendly alternatives reduce the dependency on fossil fuels and the risk of ending up with billions of dollars of stranded assets.



Section 4: Carbon Capture Application in Industry

The application of carbon capture in heavy industries and chemical production is diverse and complex.

It is not a monolithic subject: each application has its own specifications and considerations. It covers various technologies and processes, contrasting risks and opportunities, and differing mitigation potentials across multiple applications. Some domains in this sector need greater exploration, such as CCU, which is about utilising and recycling captured carbon into other valuable products such as cement and plasterboard blocks.[134]

In this section, we categorise the industrial application of carbon capture technologies into three categories:

1. Hydrogen production
2. Chemical production
3. Hard-to-abate industries

[134] Australian National University Reporter. Cementing future climate action. 2021.

Hydrogen Production

Hydrogen could play an important role in decarbonising industries, but what colour of hydrogen?

Different colours are used to differentiate hydrogen production methods. Grey hydrogen production utilises natural gas using steam reformation. It is an energy-intensive process that emits a lot of carbon dioxide. Blue hydrogen, often touted as a clean energy alternative, is essentially the same as grey hydrogen. The difference is that carbon dioxide emissions are captured during production using carbon capture technologies. And green hydrogen is made by electrolysing water into hydrogen and oxygen with renewable energy.

Green hydrogen is the real climate-friendly solution.

History shows that capturing more than 90% of emissions from industrial processes is very unlikely. Hence, betting on blue hydrogen is not a promising solution and only keeps the fossil fuel status quo. Instead, green hydrogen, with its rapidly plunging cost, would be the clean alternative in industries that run or plan to run on hydrogen.

Chemical production mainly comprises the production of fertilisers, ethanol, methanol and syngas. We analyse the CCS application in each sub-sector by reviewing a project in each area. Results are mixed, with most projects underperforming by a considerable margin and few others presenting a relatively better performance. As hydrogen has an important role in many processes in different sub-sectors, pro-fossil fuel groups have pushed blue hydrogen. However, wherever hydrogen is applicable technically, green hydrogen would be the solution due to the financial and imminent cost-efficiency.

CCS/CCUS should not be an excuse to greenwash and encourage the establishment of new fossil-based fleets in different industries.

The final area of focus in the industrial application of carbon capture technology is the steel and cement industry, so-called hard-to-abate industries. These two industries constitute 13–14% of the total greenhouse gas emissions worldwide and are critical to decarbonising.[135] The only active CCUS project in this sector is in Abu Dhabi, United Arab Emirates. Although no official data on the performance or finance of the project are available, we reviewed this project based on different accessed sources that were publicly available. The steel sector is in the early years of utilising this technology. Studies could be done on probable projects. However, as the carbon capture technology in different sectors has not reached its target and hopes, investing in such a high-risk, capital-intensive technology in the short time we are left with does not seem to be a sustainable solution.

Instead, alternative methods of steel production, such as scrap steel recycling, emit about 80% less CO_2 per tonne of crude steel than other forms of steel production

[135] Imperial College London. 'Greening' cement and steel: 9 ways these industries can reach net zero. 28 March 2022.

used today. Green hydrogen leading to the production of "green steel"[136] also looks to be a more promising method to follow.

The cement industry is somehow different from all of the other applications of carbon capture technology, as CO_2 is an inevitable by-product of chemical reactions in cement production. Carbon capture technologies seem useful in this industry if they aren't used as an excuse to postpone other methods now under investigation to reinvent the processes and make cement production green.

All in all, compared to the natural gas processing and power sectors, there are few sub-sectors in the industrial application where carbon capture could be considered as an interim option for decarbonisation while the research and development studies being done in parallel reach readiness and maturity levels to be commercialised. Even in these sub-sectors, such as cement, rigorous environmental and technical conditions need to be satisfied.

Blue hydrogen is not "clean" hydrogen.

Hydrogen could play an important role in decarbonising some energy-thirsty industries, whether for sectors that are hard to electrify or to address seasonal energy storages.

Some companies use CCS to promote the expansion of hydrogen made from natural gas. This type of hydrogen is typically labelled blue hydrogen as opposed to green hydrogen, which is produced with renewable energy.

Blue hydrogen is emissions intensive.

Blue hydrogen is an emissions-intensive process, even with CCS. It is also currently uncompetitive with its green cousin as global gas prices soar. Recent research from Cornell and Stanford Universities found that:

> *"Considering both the uncaptured carbon dioxide and the large emissions of unburned, so-called 'fugitive' methane emissions inherent in using natural gas, the carbon footprint to create blue hydrogen is more than 20% greater than burning either natural gas or coal directly for heat, or about 60% greater than using diesel oil for heat."*[137]

Researchers at the Australian National University came to similar conclusions in a recent scientific paper published in January 2022.

> *"We find that emissions from gas or coal-based hydrogen production systems could be substantial even with CCS, and the cost of CCS is higher than often assumed."*[138]

[136] Fuel Cells and Hydrogen Joint Undertaking. Making Steel Green Through Hydrogen.
[137] Cornell Chronicle. Touted as clean, "blue" hydrogen may be worse than gas. August 2021.
[138] Science Direct. Clean Hydrogen? Comparing the emissions and costs of fossil fuel versus renewable electricity based hydrogen. January 2022.

Blue hydrogen is uneconomic in the face of high gas prices.

In addition, blue hydrogen seems to be no longer economic in the near future compared to green hydrogen. The gas market is global and very volatile. Prices can quickly fluctuate due to geopolitical issues, weather disruptions, supply and/or demand variations, etc. Blue hydrogen project economics are tied to this volatility. Expected production costs published only a year ago are significantly higher today, raising questions about continued policy support for the blue hydrogen technology. Unlike gas, renewables can be more regionally or locally located and are free from annual fuel cost dependency.

Green hydrogen projects can capitalise on this advantage and offer an alternative route to hydrogen production that generates near-zero emissions at a cost that could become cheaper than blue hydrogen no later than 2030. Although where possible, direct renewables use should be the alternative instead of producing green hydrogen.

Blue hydrogen's sensitivity to volatility in the gas market is alarming.[139] During 2021–2022, European gas prices have risen fivefold to more than €100/MWh, radically changing the cost dynamics for blue hydrogen. However, even with gas at €80/MWh, asset management company Alliance Bernstein has estimated blue hydrogen exceeds €6/kg.[140]

Blue hydrogen's sensitivity to volatility in the gas market is alarming.

Electrolyser costs are also falling fast. According to BloombergNEF's global head of strategy, Kobad Bhavnagri, green hydrogen's unit costs will be lower than US$2/kg by 2030 worldwide and US$1/kg by 2050.[141] Tenfold reduction in the cost of electrolysers and cheap renewable energy presents a "serious problem" for investments in blue hydrogen and will force gas companies to "think again", according to Bhavnagri.

[139] IEEFA. Russia sanctions and gas price crisis reveal danger of investing in "blue" hydrogen. May 2022.
[140] Reuters. Hydrogens civil war reveals its winner. 31 March 2022.
[141] Recharge News. 'White elephants' | Green hydrogen will be cheaper than blue H2 in all parts of world by 2030, says BNEF. 17 May 2022.

IEEFA has done extensive work on why blue hydrogen is not a climate solution from a technical, financial and environmental perspective.[142, 143, 144, 145, 146]

Case Studies

This section studies the following five important carbon capture projects in industrial applications: the Quest project is the project that has captured CO_2 more than any other CCS/CCUS project in the hydrogen production sub-sector; the Great Plains CCUS project is the largest and the oldest project in the chemical production (others) sub-sector producing Syngas; the Illinois Industrial CCS(IL-CCS), the largest and latest project commissioned in the ethanol production sub-sector; Coffeyville, the largest application of CCUS in the fertiliser production sub-sector; and Abu Dhabi CCUS is the only CCUS project operationalised in hard-to-abate industries worldwide.

These five projects account for about 65% of the current capacity of CCS/CCUS projects in industrial applications. IEEFA estimates that these five projects have captured 70–80% of all CO_2 captured by the industrial application of CCS/CCUS projects worldwide so far.

Quest CCS Project

The Athabasca Oil Sands Project, a joint venture between Shell Canada (60%), Chevron (20%) and Marathon Oil Sands L.P. (20%), proposed the development work in 2011 on a CCS project to help manage CO_2 from the Scotford Upgrader. This facility, near Fort Saskatchewan in Alberta, Canada, upgrades the extracted oil from the oil sands for refineries nearby. Shell started construction in September 2012 after receiving approval from Alberta's Energy Resources Conservation Board. The CCS plant was commissioned in August 2015 and reached commercial operation in Q4 of 2015.[147, 148]

Canadian Natural Resources Limited (CNRL) gained majority ownership of Quest in March 2017 as part of its C$12.7 billion acquisition of Shell's oil sands operations.[149] As of 2020, the Quest project ownership was 70% CNRL, 20% Chevron and 10% Shell.

[142] IEEFA. Blue Hydrogen Has Weak Case When It Comes to Emission Reductions. February 2022.
[143] IEEFA. Blue Hydrogen Has Extremely Limited Future in U.S. Energy Market. February 2022.
[144] IEEFA. Costs of Blue Hydrogen Production Too High Without Fiscal Life Support. February 2022.
[145] IEEFA. Reality Check on CO2 Emissions Capture at Hydrogen-From-Gas Plants. February 2022.
[146] IEEFA. Russia sanctions and gas price crisis reveal danger of investing in "blue" hydrogen. May 2022.
[147] Hydrocarbon Technology. Quest Carbon Capture and Storage Project, Alberta.
[148] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Quest Fact Sheet: Carbon Dioxide Capture and Storage Project.
[149] Financial Post. Shell mulls more carbon capture projects in Alberta as Quest hits 5 million tonne milestone. 10 July 2020.

The Quest project targeted the capture of up to 1.2Mtpa (a proposed 27MT over the project life) of CO_2 from the Scotford Upgrader and aimed to permanently store it deep underground, reducing 35% of the CO_2 of the upgrader.[150, 151] The carbon dioxide is captured from the Scotford steam methane reformer units, which produce hydrogen for upgrading bitumen. The CO_2 is then transported about 65km by underground pipeline to an injection location near the Scotford Upgrader and stored at 2300 metres in a geological formation.[152] The project's engineering, procurement and construction was managed by Fluor Canada.[153]

The project delivered 1Mtpa in the first five years of operation,[154] on the way to an estimated 10.8MT for the first decade of operation. The storage capacity of the field has been reported at 27MT and the project life has been estimated at about 25 years.

Economics and Performance

Construction of the Quest project cost C$790 million and the total capital cost over 2009–2015 was C$1395 million. Of this, more than 40% (C$573 million) was funded by the Canadian and Alberta governments. A double CO_2 credit was also agreed, using a C$30/t[155] price to give the project C$60/t CO_2 reduction credits (and additional government funding of C$26/t). It adds C$1985 million of estimated project receipts from the Alberta and Canada governments until the end of the project's life.

On this basis, the total estimated government subsidies over the project's life is C$2.56 billion or C$95/t.[156]

[150] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Quest Fact Sheet: Carbon Dioxide Capture and Storage Project.
[151] Global CCS Institute. Global Status of CCS 2020.
[152] Shell. Quest CCS Facility Captures and Stores Five Million Tonnes of Co2 Ahead of Fifth Anniversary. 9 July 2020.
[153] Fluor. Shell Quest Carbon Capture and Storage.
[154] Shell. Quest CCS Facility Captures and Stores Five Million Tonnes of Co2 Ahead of Fifth Anniversary. 9 July 2020.
[155] C$ per tonne of CO_2
[156] Quest Carbon Capture and Storage Project. Annual Summary Report – Alberta Department of Energy: 2017. March 2018.

Table 2: Financial Information of the Quest Carbon Capture and Storage Project

C$m	2009 Capex	2010 Capex	2011 Capex	2012 Capex	2013 Capex	2014 Capex	2015 Capex	2016 Opex	2017 Opex	2018-2025 Opex	2027-2040 Opex Etimated
Alberta Innovates	3	2	1								
Government of Canada				108			12				
Alberta Government				130	115	53	149	30	30	239	400
CO2 reduction credits *								3	36	466	781
Total Government Funding	3	2	1	238	115	53	161	33	66	704	1,182
Cummulative government funding	3	5	6	244	359	412	573	606	673	1,377	2,558
Cummulative government funding share	0.2%	0.4%	0.5%	17.5%	25.8%	29.6%	41.1%	43.2%	45.4%	62.5%	
Cummulative Capital Cost Implied	1,611	1,260	1,268	1,396	1,393	1,393	1,395	1,403	1,481	2,203	
CO2 stored (Mt) - actual or estimate							0.4	1.1	1.1	9.1	15.3
Cummulative CO2 stored (Mt)							0.4	1.5	2.6	11.7	27.0

* Double credits are received, valued at C$30/t * 2 = C$60/t

Total Capital Cost	1,395	C$m
Government subsidies	573	C$m
Cummulative government funding share	41.1%	

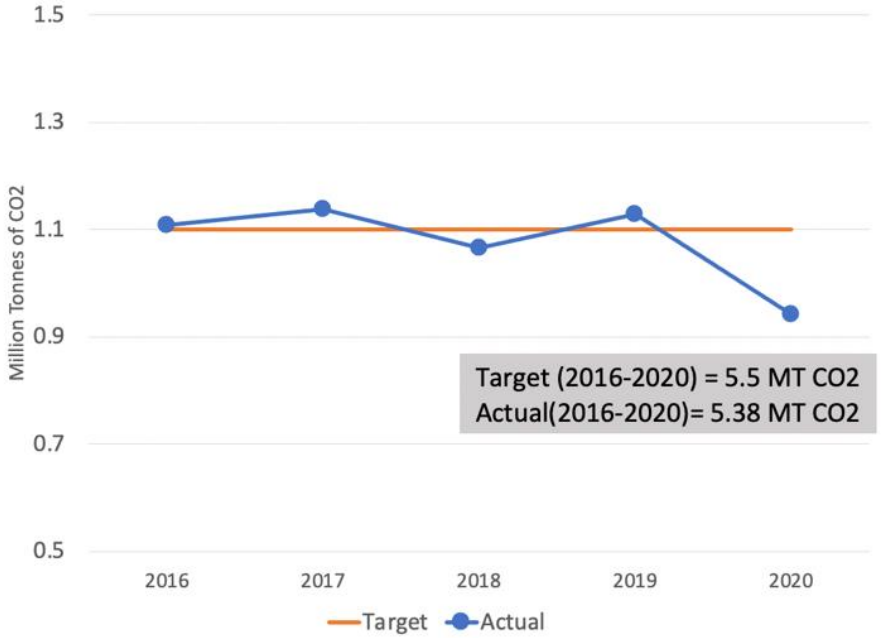
	2015-2025	2015-2040	
Capital Cost Total Subsidy	573	573	C$m
Operating Cost Total Subsidy	803	1,985	C$m
Total Subsdy	1,377	2,558	C$m
Expected CO2 captured	5.8	27.0	Mt
Subsidy per tonne	237	95	C$/t

Source: Shell Canada Energy, 2017 Annual Report

In terms of performance, Quest almost hit its yearly targets. The CCS plant was supposed to capture at least 1Mtpa and up to 1.2Mtpa. Taking the average of 1.1Mtpa as the target capture rate, to the end of 2020 it should have captured 5.5MT of CO_2. Based on the company's disclosures, the actual captured amount was 5.38MT; almost equal.

Figure 18 illustrates yearly amount captured and injected by the plant (orange line) versus the project's target (blue line). As depicted in the graph, the Quest plant largely performed at the targeted level until 2019. In 2020, the 15% drop in the injection rate reflects underperformance during the pandemic. However, the plant almost reached the overall pre-defined target after five years of operation.

Figure 18: Target vs Actual Capture Rate of Quest CCS Plant (2016–2020)



Source: Quest Annual Status Reports, IEEFA Analysis

The Real Amount of CO_2 "Avoided" Is Lower than What Was Just Captured

Limiting analysis to the cumulative amount of CO_2 captured by the plant is an incomplete conclusion about the performance of CCS plants as capturing operations produce additional CO_2 emissions.

The amount of CO_2 captured is not the net amount of CO_2 prevented from being emitted into the atmosphere. Any operation of the plant—such as absorbance, dehydration, compression, transport and injection—needs energy, the source of which is fossil fuel. That fuel and the fossil-based electricity used in each step produce CO_2 emission.

According to the Quest annual data, in the five years depicted in Figure 18 above, 1.16MT of CO_2 were emitted through the whole carbon capture and sequestration process (i.e., capture, transport and storage). So more than 21% of the 5.38MT of captured CO_2 was offset by the emitted CO_2.

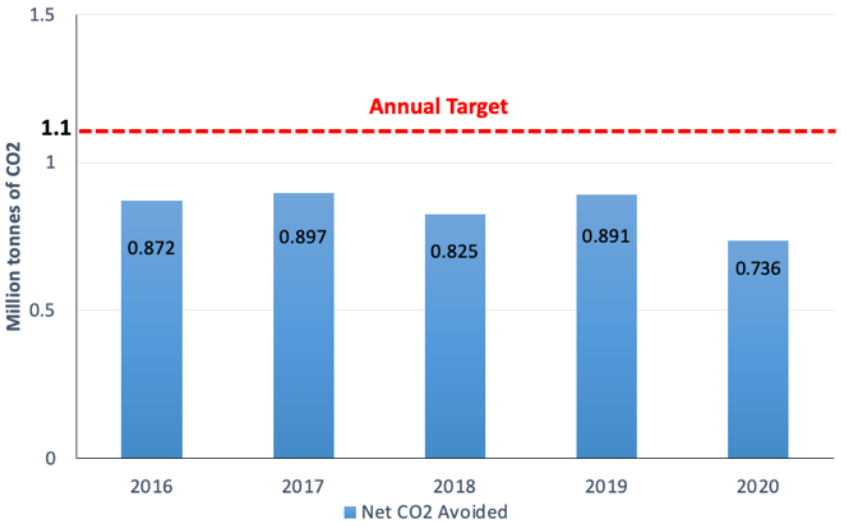
On this calculation, the net avoided CO_2 in the project's first five years was 4.22MT not 5.38MT. A similar calculation applies to each CCS plant that sources energy from fossil fuels. The 'net avoided CO_2' criterion reflects the real impact of CCS projects from an emissions reduction perspective.

Figure 19 compares the yearly amount of avoided CO_2 from the Scotford Upgrader with the target amount. For the Quest CCS operation, the net avoided amount did not exceed 0.9MT in any year, or only about 32% of the yearly CO_2 emission of the Upgrader and CCS plant together.

Extrapolating this trend and considering approximately 0.24MT of CO_2 emitted each year in capture, transport and storage indicate the CCS operation on its own would emit 6MT of CO_2 during the project's lifetime.

Accordingly, to the end of the project's life, the total amount of avoided CO_2 would be about 21MT instead of 27MT. Further, the government's subsidy per tonne of avoided CO_2 turns out to be C$120, considerably higher but more realistic than the C$95 figure.

Figure 19: Net CO_2 Avoided vs CO_2 Yearly Capture Target (2016–2020) – Includes Emissions from the CCS Operations



Source: Quest Annual Status Reports, IEEFA Analysis

Chemical Production (Ethanol, Fertiliser, Syngas etc.)

Chemical production could be the most convoluted application area for carbon capture technologies. This is because of the diversity of chemical products produced in this sector and of the technologies can be applied. It includes but is not limited to nitrogen-based fertilisers, such as ammonia and urea ammonium nitrate, ethanol and biofuel products, methanol, and reformed and synthetic gas. For many of the processes, blue hydrogen has been proposed. However, wherever hydrogen is applicable technically, green hydrogen would be the solution, not blue, due to the financial and emission reasons discussed earlier. For example, for nitrogen-based fertilisers, which need hydrogen to produce the final product, any type of coal gasification or petroleum coke gasification to produce hydrogen and then capture the released CO_2 with CCS facilities should not be greenlit. Instead, green hydrogen should be considered a climate-friendly alternative.

If there is no alternative to current processes in each of these applications, then carbon capture could be considered if:

- it does not promote EOR
- it does not extend or is used as an excuse to extend the life of any type of fossil asset
- a safe storage location is identified, and a long-term monitoring plan and compensation mechanism in case of failure are developed
- liability of the projects is not handed over to the taxpayers.

In the following section, three of the biggest CCS/CCUS projects ever built in each sub-sector of chemical production have been reviewed. All of these projects are located in the U.S.: the Great Plains Synfuels Plant producing syngas from lignite coal gasification, which is planned to be redeveloped into a blue hydrogen project; the Illinois Industrial Carbon Capture and Storage, the largest project of its kind tied with biofuel production; and finally, the Coffeyville Gasification Plant, the biggest CCUS project in the fertiliser production sector.

Great Plains Synfuels Plant

The Great Plains Synfuels Plant (GPSP) in Beulah, North Dakota, is a coal gasification plant that has produced synthetic natural gas (SNG) from lignite coal since 1984.

Coal gasification is a highly emitting process and lignite, also known as brown coal, used in this plant is considered the most harmful type of coal for human health due to the large amount of CO2 and sulphur it releases in combustion.[157]

Hence, the motivation behind such a heavily polluting project could be simply the abundance of cheap feedstock in the U.S. The National Energy Technology Laboratory (NETL) of the U.S. Department of Energy (DOE) estimates that about 200 years' worth of consumption remains in the U.S.[158]

Operated by the Dakota Gasification Company's (DGC), the GPSP is the only coal-to-SNG gasification plant in operation in the U.S. Annually, the plant consumes about 6MT of coal to produce 54 billion standard cubic feet of SNG as well as some chemical by-products.[159] The SNG (95% methane) is piped to the Northern Border Pipeline, which transports gas from Canada, Montana, and North Dakota to the Ventura, Iowa area, where it connects with numerous pipelines that supply the eastern U.S.

[157] Heal. Lignite coal – health effects and recommendations from the health sector. December 2018.
[158] National Energy Technology Library, U.S. Department of Energy. Hydrogen & Synthetic Natural Gas from Coal.
[159] National Energy Technology Library, U.S. Department of Energy. Great Plains Synfuels Plant.

After 16 years of operation and venting millions of tonnes of CO2, capturing and selling of CO2 to the nearby oil producers started in October 2000. The CO2 is pumped via an onshore 315km pipeline for EOR in two carbonate fields, the Cenovus Energy-owned Weyburn field (with demand rate of 6500 tonnes per day) and Apache company-owned Midale field (with demand rate of 1200 tonnes per day).[160]

CO_2 Leakage Case

Following claims of leakage from the Weyburn site in January 2011, operator Cenovus and the International Performance Assessment Centre for Geologic Storage of CO_2 (IPAC-CO_2) launched investigations. The "leaking" gas was discovered to be naturally occurring biogenic CO_2, originating from biological processes in the soil, rather than injected CO_2. The 2012 report discovered no potential CO_2 pathways from pipelines or other infrastructure.[161]

Economics and Performance

GPSP was commissioned by American Natural Resources company (ANR). However, as it was not easy to secure financing for such a huge project, ANR formed a partnership with several other natural gas utility companies which became known as the Great Plains Gasification Associates (GPGA). This allowed the U.S. DOE to back funding for the plant.[162]

The plant was built in response to the energy crisis of the 1970s.[163] Total cost for design and construction was roughly U$2 billion of which a $1.5 billion loan was guaranteed by the DOE.[164] Construction began in 1981.[165]

In addition, the CO_2 monitoring and storage project in Weyburn and Midale fields was conducted between 2000 and 2011 (at an estimated cost of U$70 million).[166] And the cost of pipeline was US$100 million.[167]

According to the DOE's NETL, the separated CO_2 was emitted into the atmosphere for the first 16 years of the project's lifetime due to lack of demand. In October 2000, the operator started capturing and selling CO_2 to oil companies for EOR in the nearby fields. The capacity at the beginning of the project was reported to be about 105 million standard cubic feet per day (~2Mtpa) or 60% of total CO_2 produced by the plant.[168] This

[160] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Weyburn-Midale Fact Sheet: Carbon Dioxide Capture and Storage Project.
[161] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Weyburn-Midale Fact Sheet: Carbon Dioxide Capture and Storage Project.
[162] National Energy Technology Library, U.S. Department of Energy. Great Plains Synfuels Plant.
[163] AP. North Dakota gas plant to be redeveloped for clean energy. 17 August 2021.
[164] AP. North Dakota gas plant to be redeveloped for clean energy. 17 August 2021.
[165] National Energy Technology Library, U.S. Department of Energy. Great Plains Synfuels Plant.
[166] Global CCS Institute. Introduction to Industrial Carbon Capture and Storage. June 2016.
[167] School of GeoSciences, University of Edinburg. Great Plains Synfuels Plant: Project Details.
[168] National Energy Technology Library, U.S. Department of Energy. Weyburn Project. n

capacity increased to about 3Mtpa in 2006 by installing the third CO_2 compressor to meet the needs of Apache Canada Ltd for EOR. Up to 2007, CO_2 sales exceeded 11MT.[169]

For the first six years of operation the carbon capture facility averaged 1.8–1.9Mtpa, very close to its nominal capture capacity.

No detailed data and information have been found regarding the plant's annual capture performance. Based on cumulative figures from the MIT CCS database[170] and National Petroleum Council report,[171] it had captured and transported nearly 38MT of CO_2 for geological sequestration up to 2020. Factoring in the capacity expansion to 3Mtpa in 2006, the total amount CO_2 captured and sold for EOR until 2020 was 27MT.

The average annual capture rate for the 14 years post-expansion has remained ~1.9 Mtpa, or about 1MT lower than the maximum capture capacity for these years.

The first hypothesis is that this underperformance could be due to lower gas production in the main synthetic gas production plant. Should this be the case, the CCS plant would not be underperforming. On the other hand, the alternative hypothesis is that CCS plant underperformance, technical problems or lack of demand from oil companies would result in the uncaptured CO_2 being vented into the air.

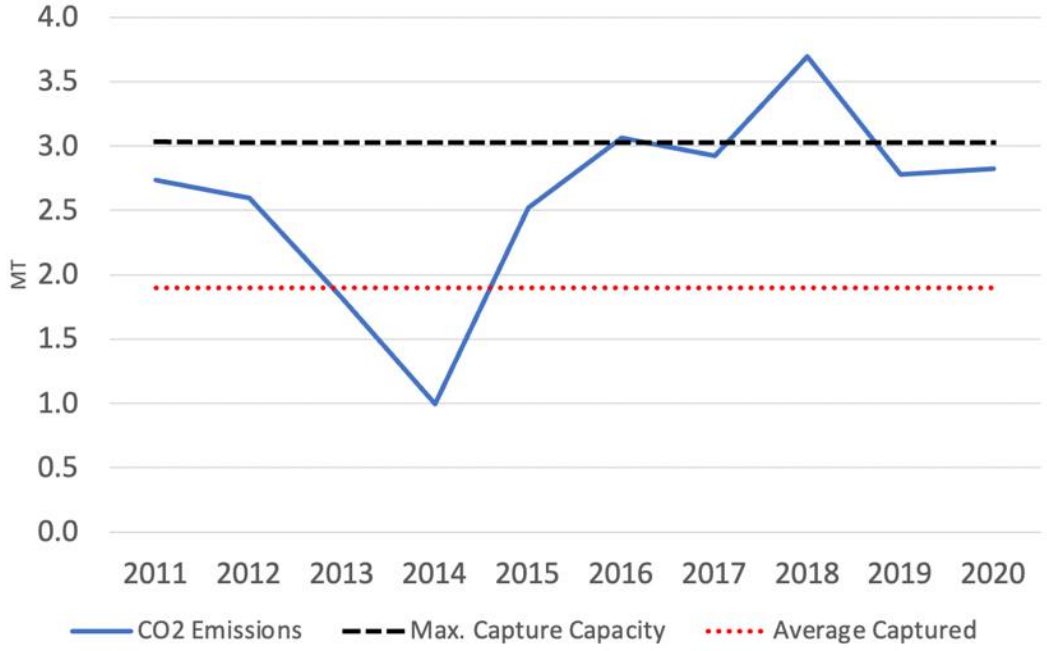
Looking at the U.S. Environmental Protection Agency (EPA) data of the plant's CO_2 emissions for the period 2011–2020 confirms the underperformance hypothesis.

Figure 20 shows the CO_2 emissions from the synthetic gas (syngas) production process (blue line), maximum capture capacity of the plant (black dotted line) and the average yearly captured CO_2 of the plant (red dotted line).

It essentially shows that during this decade the amount of CO_2 produced by the plant was higher than the average 2MT capture rate (2014 excepted). The CCS facility had the capacity to capture all of the CO_2 produced by the syngas process (but for 2018, when CO_2 production exceeded the maximum 3MT capturing capacity).

[169] National Energy Technology Library, U.S. Department of Energy. Weyburn Project.
[170] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Weyburn-Midale Fact Sheet: Carbon Dioxide Capture and Storage Project.
[171] National Petroleum Council. Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use and Storage. Appendix C – CCUS Project Summaries. December 2019 (last updated 12 March 2021).

Figure 20: Great Plains Synfuels Plant CO2 Emissions vs Capture Performance (2011–2020)



Source: National Energy Technology Laboratory (NETL), Department of Energy. U.S. Global CCS Institute. 2021. U.S. Environmental Protection Agency (EPA), Greenhouse Gas Reporting Program (GHGRP). IEEFA

The cumulative tallies for CO_2 captured and produced during 2011–2020 show that the CCS plant underperforms by about 25%. During the decade, it captured about 19MT of CO_2 to be sold for producing more oil and vented another 6–7MT. (Figure 21).

It is important to note that the overall figure for emitted CO_2 should be considerably higher as the above figures exclude the emissions from the CCS facility operations, potential leaks through pipelines and fixtures and the CO_2 emitted in reinjecting at the EOR point.

An Imminent Blue Hydrogen Redevelopment for Plant

In 2021, Bakken Energy and Mitsubishi Power Americas announced plans to purchase GPSP from Dakota Gasification Co., which is financially in trouble. The deal was expected to be finalised by April 2022.[172] It is part of a plan to create a hydrogen hub in Dakota.[173] It has been labelled "clean" hydrogen. However, the hub will focus on the production of blue hydrogen, derived from natural gas with CO_2 emissions captured, and sequestered underground or used for EOR. The hydrogen will come

[172] AP. North Dakota gas plant to be redeveloped for clean energy. 17 August 2021.
[173] AP. Companies aim to build 'clean hydrogen' hub in North Dakota. 3 June 2021.

from natural gas produced in North Dakota's oil fields or from gas from the Dakota Gasification plant, or a mix of both.

The hub is not a green hydrogen project as it is essentially producing gasified hydrogen and capturing its CO_2 by-product. Blue hydrogen is neither a climate-friendly solution or an economically sound choice compared to green hydrogen, as discussed earlier.

Illinois Industrial Carbon Capture and Storage (IL-CCS)

In 2011, Archer Daniels Midland (ADM), one of the world's largest agribusiness companies, started the Decatur carbon capture project with partners. As part of the U.S. DOE's Regional Carbon Sequestration Partnerships initiative, and with funding from the DOE, it started as a research and development project in industrial CCS, in Illinois.

Having passed pre-specified targets for capturing carbon and showing no CO_2 leakage, the project moved ahead to the design and implementation phases and captured and stored 1MT of CO_2 from 2011 to 2014.[174]

With the successful completion of the Decatur demonstration project, ADM and corporate partner Schlumberger Carbon Services continued on to the larger- scale Illinois Industrial Carbon Capture and Storage (IL-CCS) plant with a 1Mtpa capturing and storing capacity. Started in 2017, as the world's first large-scale CCS project from a biofuel source, it relied on the Mount Simon Sandstone saline formation as its dedicated geological structure to store the captured carbon. The CO_2 not being used for EOR was to be stored more than 2000 metres underground.[175]

The gas from the ADM biofuel plant is a >99% pure CO_2 stream that is a by-product of fuel-grade ethanol production via anaerobic fermentation of corn stover (harvest remnants).[176]

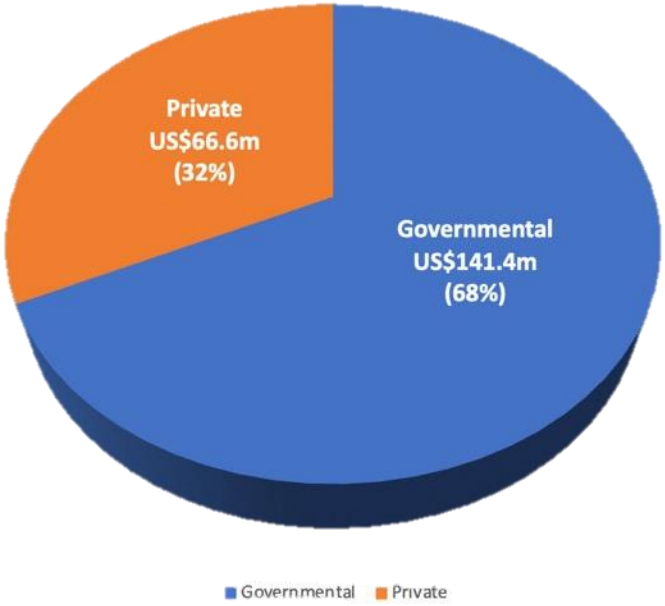
Economics and Performance

Following the success of the Decatur project, backed by about US$106 million in federal funding and US$21 million from the corporate partners, site characterisation and permitting of IL-CCS was finished in 2014 and the project started to capture and inject CO_2 in 2017.

[174] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Illinois Industrial Carbon Capture and Storage (IL-CCS) Fact Sheet: Carbon Dioxide Capture and Storage Project.
[175] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Illinois Industrial Carbon Capture and Storage (IL-CCS) Fact Sheet: Carbon Dioxide Capture and Storage Project.
[176] Carbon Capture and Sequestration Technologies, Massachusetts Institute of Technology. Illinois Industrial Carbon Capture and Storage (IL-CCS) Fact Sheet: Carbon Dioxide Capture and Storage Project.

The cost of the project was US$208 million, of which US$141.4 million came via the DOE's CCS grants. Essentially, the project was 68% government funded (Figure 21).[177, 178, 179]

Figure 21: IL-CCS Finance Portfolio



Source: U.S. Spending.gov.

Looking at total CO_2 emissions of the ADM biofuel plant, the figure is four to five times higher than the designed capture target of 1Mtpa. On average, the plant has emitted 4.5MT of CO_2 annually. In the best-case scenario, if the CCS facility could capture at its theoretical capacity, it would contain only 22% of the plant's CO_2 emissions. This illustrates how technically and economically challenging it is to reach capture rates of >80% that are usually claimed for CCS facilities. The technical difficulty is evident in the quote by engineering consultancy WSP, advisor to ADM for a carbon reduction feasibility study in 2020:

> *"The ability to capture stack emissions and sequester them is likely 10 years out, due to the technology and energy needed to separate and process the stack gas sufficiently to inject the CO_2 in the sequestration well."*[180]

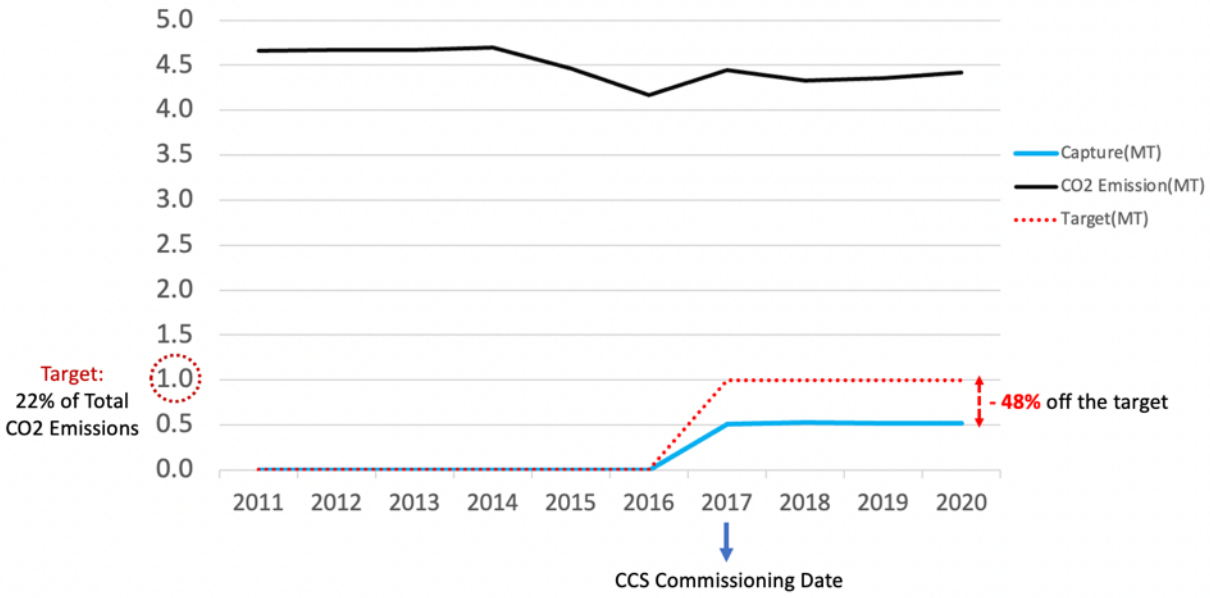
Moving from theory to practice, the reality is even starker. EPA data illustrate that the CCS facility has been performing at about half of its designed capacity since the beginning of the project (Figure 22).

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[177] Midwest Center for Investigative Reporting. Despite hundreds of millions in tax dollars, ADM's carbon capture program still hasn't met promised goals. 19 November 2020.
[178] USASpending.gov.
[179] AIChE Academy. Successful Demonstration of Illinois Industrial Carbon Capture and Storage in a Saline Reservoir. 2018.
[180] Archer Daniels Midlands. Carbon Reduction Feasibility Study. 30 March 2020.

The facility is underperforming by 48% to the end of 2020,[181] meaning that it could capture and sequester only up to 12% of the total CO_2 emissions of the ADM biofuel plant. The emission problem is still there and, essentially, the US$200m-plus CCS retrofit could not solve that.

Figure 22: CO_2 Emissions vs Capture Performance of the IL-CCS Plant (2011–2020)



Source: Global CCS Institute. 2021. U.S. Environmental Protection Agency (EPA), Greenhouse Gas Reporting Program (GHGRP).

Coffeyville Resources Nitrogen Fertilizers Plant

Coffeyville Resources Nitrogen Fertilizers Plant incorporated in 2003[182] in Kansas, U.S., produces ammonia and urea ammonium nitrate (UAN) fertilisers. It gasifies petroleum coke to produce hydrogen, from which it synthesises ammonia and UAN fertilisers. An oxygen separation plant provides oxygen for the gasifiers, as well as nitrogen needed downstream for reaction with hydrogen to produce ammonia. Syngas is cleaned in a dual-stage acid gas removal process, delivering Hydrogen sulfide (H_2S) and CO_2 in separate streams.

A proportion of the separated CO_2 is used to produce UAN but most of the gas was vented in the first decade of the plant's operation.

[181] The data was accessible through until end of 2020.
[182] Bloomberg. Coffeyville Resources Nitrogen Fertilizers.

The plant produces about 5% of total UAN demand in the U.S. and is close to extensive fertiliser markets in the Midwest, lowering the distribution costs of its products.

In 2011, subsidiaries of Chaparral Energy and CVR Energy (the owner and operator of the Coffeyville plant) reached a purchase and sale agreement to capture CO_2 from the plant, which Chaparral needed for EOR operations in north-eastern Oklahoma. The plant started to capture CO_2 in June 2013. Under the agreement, the majority of the plant's CO_2 was planned to be captured by Chaparral, which constructed a CO_2 compression facility at the plant site and installed about 110km of pipeline to deliver it to its North Burbank Unit in Osage County in Oklahoma.[183]

Economics and Performance

Blue Source, LLC, a carbon-reduction advisory company, initiated the idea of capturing greenhouse gas from the fertiliser plant and injecting it into ageing petroleum fields to boost oil output. With Chaparral Energy and CVR Energy, it planned and executed the CCS retrofitting and construction of the pipeline. The project was estimated to cost between US$50 million and US$$80 million.[184] The project was finished, and injection started in 2013.[185]

U.S. EPA data for total CO_2 produced by the fertiliser plant is shown in Figure 23 (orange line). However, as a step in the UAN production process, part of the CO_2 produced during the acid gas removal process is then used in production of UAN. Hence, the net emitted CO_2 is lower than the total CO_2 produced. Based on industry averages[186] and scattered data publicly available on the facility's UAN production figures,[187] the average CO_2 produced (excluding the amount used in UAN production) is an estimate (blue line).

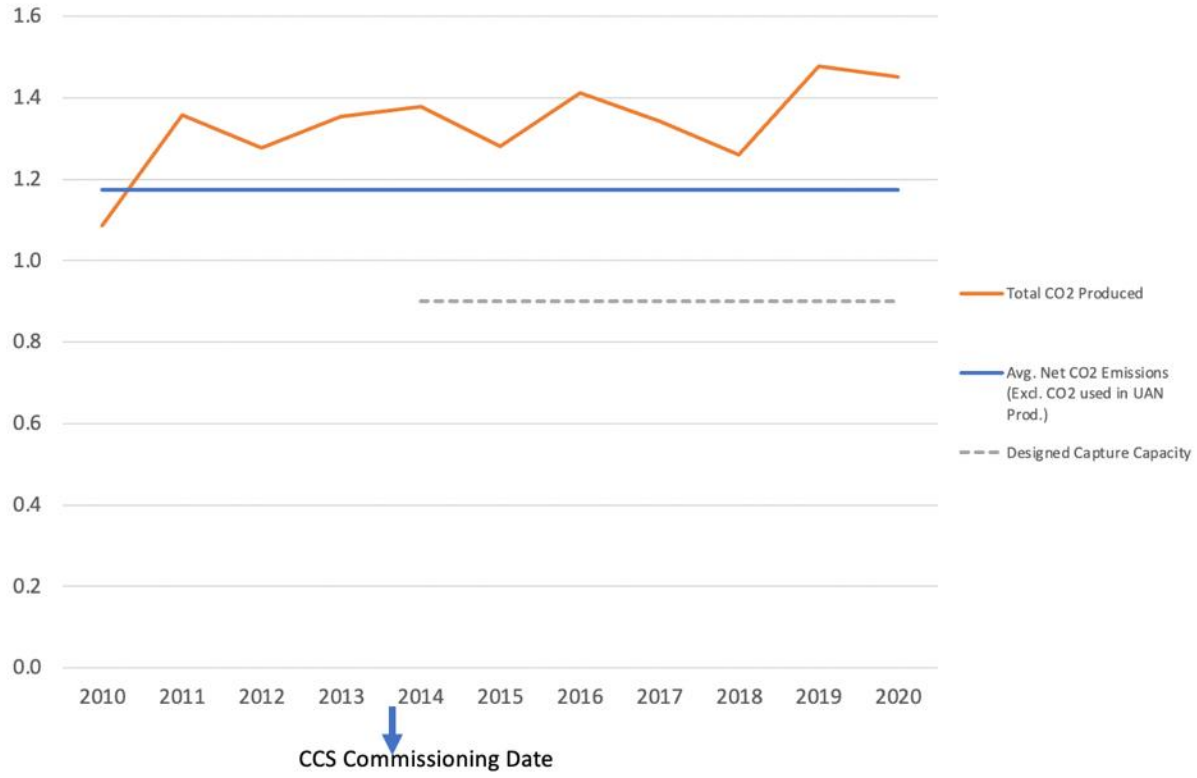
No public data has been found on the yearly capture performance of the plant over its whole lifetime. For illustration, the maximum capture capacity of the plant (Figure 23, grey dotted line) accounts for up to 80% of its CO_2 emissions. Some research shows that the plant could have overperformed during 2017–2019 by about 16%, which is an acceptable result.[188] However, the question remains as to whether the plant has achieved maximum capacity each and every year since 2013, given very few CCS/CCUS projects have done so historically. Also, it is notwithstanding that captured CO_2, when used for EOR, at least partly negates the original figure of reduced carbon.

As most of the CO_2 created in these plants assist in the production of hydrogen to be used in fertiliser production, replacing green hydrogen with current processes of producing syngas hydrogen from petroleum coke seems to be more efficient and climate friendly than the technically challenging and extremely expensive carbon

[183] National Energy Technology Library, U.S. Department of Energy. Coffeyville Resources Nitrogen Fertiliser Plant.
[184] Reuters. Blue Source to capture Kansas CO2, up oil output. 21 August 2007.
[185] ZeroCO2.no. Coffeyville Gasification Plant.
[186] International Fertiliser Society. The Carbon Footprint of Fertiliser Production: Regional Reference Values. 2019.
[187] National Energy Technology Library, U.S. Department of Energy. Coffeyville Resources Nitrogen Fertiliser Plant.
[188] ACS Publications. An Estimate of the Amount of Geological CO2 Storage over the Period of 1996–2020. 19 July 2022.

capture solutions. Considering the falling cost of green hydrogen and recent astronomical gas prices, it would soon also be a more economical option compared to blue hydrogen.

Figure 23: Coffeyville CCS CO_2 Emissions vs Maximum Capturing Capacity (2010–2020)



Source: MIT. CCS database. U.S. Environmental Protection Agency (EPA), Greenhouse Gas Reporting Program(GHGRP). International Fertilizer Society(IFS), 2018.

Hard-to-abate Industries (Steel and Cement)

Source of ~14% of Global CO_2 Emissions

Steel and cement are named hard-to-abate industries as it is technically and financially difficult to completely electrify them using renewable energy. Yet, according to Imperial College London, cement and steel production contribute to 6.5% (2.3 billion tonnes) and 7% (2.6 billion tonnes) of global CO_2 emissions, respectively.[189] That is partly owing to the large quantities of use of these materials: concrete is the second-most-consumed product on the planet, after clean water. It is also due to their carbon-intensive manufacturing: the chemical reactions and the burning of fossil fuels to deliver the extreme temperatures required all release CO_2.

[189] Imperial College London. 'Greening' cement and steel: 9 ways these industries can reach net zero. 28 March 2022.

Carbon capture has been discussed recently as one of the solutions contributing to decarbonising these heavy polluting industries.

There is only one operating CCUS plant in the steel sector and no commercialised CCS plant in the cement industry.

There is no public data on the performance and finance of the only operating CCUS project in Abu Dhabi, United Arab Emirates. Hence, there is not much to learn from the history of the application of CCS/CCUS in this industry. However, the technical failures of CCS/CCUS in other sectors are alarming. This is important as the time to reach net zero targets is very limited, and there is little room for trial and error. Nevertheless, there is a lot of research and development going on to decarbonise these two industries with different options[190, 191] and CCS/CCUS has been considered as one of the alternatives.

There is only one operating CCUS plant in the steel sector.

Steel

There are three main steel production processes.

1. The most widespread is the integrated blast furnace and basic oxygen furnace process (BF-BOF), in which iron oxide is reduced to iron inside the blast furnace with coke (derived from coking coal) as a reducing agent. The product of the blast furnace, carbon-rich pig iron, is then processed into steel in a basic oxygen furnace, where oxygen is blown through the molten pig iron to reduce its carbon content. In 2020, global crude steel production totalled 1.88 billion tonnes, and of this, 73% came via the BF-BOF process.[192]

2. A second primary steelmaking pathway is to produce direct-reduced iron (DRI), which is then further processed into steel in an electric arc furnace (EAF). DRI is produced by directly reducing iron ore without melting, usually using a mixture of carbon monoxide and hydrogen derived from natural gas. Although, these can also come from gasified coal. This method provides the final steel product with around 36% less CO_2 emissions.[193]

[190] Imperial College London. 'Greening' cement and steel: 9 ways these industries can reach net zero. 28 March 2022.
[191] IEEFA. Green steelmaking will need technology and mining advances. 1 July 2022.
[192] World Steel Association. World Steel in Figures 2021 now available. 3 June 2021.
[193] IEEFA. Iron Ore Quality a Potential Headwind to Green Steelmaking. 28 June 2022.

DRI does not use coking coal. An increasing number of steel companies are seeking to develop technology that uses 100% hydrogen in the DRI-EAF process—potentially zero-carbon green hydrogen, produced via renewable energy-powered electrolysis.[194] And due to the reasons discussed earlier, green hydrogen is the fuel for heavy industries' future. Any type of coal gasification/methane reformation to produce hydrogen and then capturing its carbon with CCS/CCUS—that is, blue hydrogen—does not seem to be a climate saviour or cost-efficient option.

3. As an alternative to primary steel manufacture, recycling scrap steel is an option with around 80% lower CO_2 emissions.[195] Also called secondary steelmaking, this technology does not require iron ore or coking coal. An electric arc furnace is charged with steel scrap, which is melted to form new steel. Renewable energy can power EAFs, reducing carbon emissions for the scrap EAF process to almost zero. Although there are limitations on the volume of available scrap and some quality issues, even a little increase in this type of production instead of BF-BOF would be a gamechanger.

Although there is a long way to go in the steel sector, green hydrogen seems to be a more promising pathway than CCS. As discussed, it will be a cost-effective option in the next few years.

The steel sector is in the early years of utilising this technology. Studies could be done on probable projects. But, as carbon capture technology in different sectors has not reached its target and hopes, investing in such a high-risk, capital-intensive technology in the short time we are left with does not seem a sustainable solution.

Green hydrogen seems to be a more promising pathway than CCS.

Instead, alternatives such as scrap steel recycling or green hydrogen leading to the production of "green steel"[196] looks a more promising path to follow.

Cement

The cement industry is somehow different from all of the other applications of carbon capture technology, as CO_2 is an inevitable by-product of chemical reactions in cement production. The process is known as calcination when crushed limestone is heated and releases calcium oxide (CaO) and CO_2.[197]

$$CaCO_3 + heat \rightarrow CaO + CO_2$$

[194] IEEFA. Iron Ore Quality a Potential Headwind to Green Steelmaking. 28 June 2022.
[195] IEEFA. The facts about steelmaking: Steelmakers seeking Green Steel. 2022.
[196] Fuel Cells and Hydrogen Joint Undertaking. Making Steel Green Through Hydrogen.
[197] University of Mosul. Calcination of Limestone.

The heat for the process and the chemical reaction itself produce CO_2.

Second only to water, concrete is the most consumed material in the world.[198] Considering these two facts, it is one of the most challenging industries to decarbonise.

Carbon capture technologies seem to be useful in this industry if they are not used as an excuse to postpone other methods now under investigation to reinvent processes and make cement production green.

For example, one of the recent innovations in this sector is using the captured carbon in other industries to produce cement and plasterboard blocks.[199] These processes are worth being funded and studied.

Abu Dhabi CCUS Plant (Al Reyadah)

The First and Only CCUS Plant in the Steel Sector

The Abu Dhabi CCUS plant, commissioned in 2016 in Mussafah, Abu Dhabi, United Arab Emirates, is the only commercial-scale CCUS facility in the world that captures CO_2 from the flue gas of a steel production facility. The final application of the captured CO_2 is EOR in the Abu Dhabi National Oil Company's (ADNOC) nearby oil fields.[200]

The main objectives of the project were reducing the carbon footprint of the United Arab Emirates, implementing EOR in subsurface oil reservoirs, and freeing up natural gas that would have been used for oil field pressure maintenance.[201] From the emissions perspective, such objectives seem incompatible with climate targets, as the CO_2 is used to increase oil production and free up other emission-intensive fossil fuels.

Economics and Performance

The project cost was US$122 million,[202] and it was developed by Abu Dhabi carbon capture company Al Reyadah, a joint venture between ADNOC and clean energy company Masdar,[203] with respective stakes initially of 51% and 49%. ADNOC bought out Masdar's share in January 2018.[204]

[198] Engineering Failure Analysis. Cement and concrete as an engineering material: An historic appraisal and case study analysis. 2014.
[199] Australian National University Reporter. Cementing future climate action. 2021.
[200] The University of Edinburgh. School of Geoscience. Al Reyadah: Project Details.
[201] Carbon Sequestration Leadership Forum. Al Reyadah Carbon Capture, Use, and Storage (CCUS) Project. May 2017.
[202] The National News, Business. Abu Dhabi starts up world's first commercial steel carbon capture project. 5 November 2016.
[203] Power Engineering International. MENA's first CCUS project now operational. 6 January 2017.
[204] The University of Edinburgh. School of Geoscience. Al Reyadah: Project Details. 2022.

The project includes capturing, compressing and dehydrating the CO_2 and then conveying it via a 43km underground pipeline for EOR injection to ADNOC's North East Bab (NEB) (Al Rumaitha) and Bab onshore oilfields.

The project was set to capture and transport 800,000 tonnes per year of CO_2 and, tentatively, was part of an overall master plan to create a CO_2 network and hub for managing future CO_2 supply and injection requirements in the United Arab Emirates.[205]

Technically, the plant is the largest CO_2 project of any type in the Persian Gulf region,[206] the Middle East's first commercial-scale CO_2 capture plant and the project with the world's highest pressure (240 bar) CO_2 transfer pipeline at the time of commissioning. ADNOC has announced plans to expand the capacity of this program by more than 500%, aiming for 5MT of CO_2 annually by 2030.[207]

Phase 2 of the project, set for commissioning in 2025,[208] aims to capture 1.9 to 2.3Mtpa CO_2 from its gas processing plant for EOR in the same reservoir. At the same time, the company plans to increase production to 5 million barrels of oil equivalent (boe) daily in 2030.[209]

The CO_2 to be captured by CCS plant(s) would have a considerable contribution to expanding that production, raising the question yet again: Is using CCS for EOR really reducing emissions?

Lessons Learned

Steel and cement are responsible for 13–14% of total global emissions, and the demand for these two materials is increasing. Therefore, decarbonising these two crucial industries is necessary if the world wants to reach net-zero emissions by 2050. CCUS/CCS has been proposed as one of the pathways for pursuing the decarbonisation of these two industries.

The application of CCUS/CCS in the steel and cement sector is a relatively new area with only one ~6-year-old operating project in Abu Dhabi with no publicly published data on its performance. Essentially, there is not much to learn from the application of CCS/CCUS in these two industries. However, based on limited knowledge of the technology trajectory in other applications with common processes as these industries, as well as other solutions being developed and researched in parallel, future CCS/CCUS application in the steel and cement industry could be projected to some extent.

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[205] Carbon Sequestration Leadership Forum. Al Reyadah Carbon Capture, Use, and Storage (CCUS) Project. May 2017.
[206] Global CCS Institute. Building Momentum for CCS in the Gulf Region and Around the Globe. 2020.
[207] Hydrocarbon Processing. ADNOC announces expansion of carbon capture program. February 2020.
[208] International Association of the Oil and Gas Producers. Global CCUS Projects. 2021.
[209] Drilling Contractor, Increased hydrocarbon production, sustainability programs go hand in hand to create a resilient upstream. 27 April 2021.

Green hydrogen or recycling scrap steel should be prioritised in the steel sector over CCUS/CCS to capture carbon from gasification, reformation, or burning fossil fuels.

In the cement sector, however, as CO_2 is the by-product of the fundamental chemical reaction of producing cement, CCUS/CCS projects could be considered cautiously. Other innovative methods should be pursued to reinvent the whole process toward green and zero-emissions cement.[210] For example, one recent innovation in this sector is using the captured carbon in other industries to produce cement and plasterboard blocks.[211] Cambridge University researchers have proposed zero-emissions cement.[212] Both innovations are worth exploring.

Meanwhile, carbon capture could be used as long as the captured carbon is not used for EOR. CCUS/CCS also should be used only if the technical performance reaches close to nominal capture capacities, in contrast with general trends throughout history. Also, it could be considered an interim option as long as it does not distract financial flows from fundamental and innovative solutions to reinventing the cement production process.

[210] UK FIRES. Cambridge engineers invent world's first zero emissions cement. 4 May 2022.
[211] Australian National University Reporter. Cementing future climate action. 2021.
[212] UK FIRES. Cambridge engineers invent world's first zero emissions cement. 4 May 2022.

Conclusion

Failed/Underperforming Projects Considerably Outnumbered Successful Experiences

The immediate inference from the projects reviewed is that the number of failures and the underperformance of these projects with carbon capture technology has outnumbered the successful projects considerably. Ten of the 13 flagship projects reviewed, comprising 90% of the total capture capacity in our sample, have failed or are underperforming mostly by large margins.

While a limited sample, predominantly focusing on projects in operation, additional research[213] looking (from a different angle) at the number of failures of all of the proposed/initiated projects since 2000 conveys, in essence, a similar message. Further, recently published research by the Imperial College London[214] on the capture performance of operating projects since 1996 confirms the underperformance of most projects against their designed/claimed capture capacity.

Successful CCUS Exceptions Mainly Existed in the Natural Gas Processing Sector Serving the Fossil Fuel Industry, Leading to Further Emissions

The natural gas processing sector historically dominates the application of carbon capture technology. Extracted raw gas has a carbon dioxide (CO_2) content that needs removal to produce a marketable (methane) gas for distribution through pipelines to customers or liquefied in LNG plants for export.

Producing the primary usable product (i.e., natural (methane) gas) is impossible without separating CO_2. This explains why the sector has been using carbon capture technology for decades, not necessarily as a climate-friendly solution, but as an inevitability to produce the fossil-fuel natural gas. On top of that, selling the captured CO_2 primarily to oil producers for enhanced oil recovery improves the economic viability of gas development projects. Sleipner and Snøhvit have two of the most successful among the few successful projects in the history of carbon capture being used in this sector.

The IEA's Net Zero by 2050 report, one of the seminal energy transition roadmap documents worldwide, has explicitly expressed alarm about the danger of developing any new oil and gas projects globally. It emphasised not developing any new oil and gas projects if the world wants to reach net zero by 2050.

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[213] IOP Publishing. Explaining successful and failed investments in U.S. carbon capture and storage using empirical and expert assessments. 29 December 2020.
[214] ACS Publications. An Estimate of the Amount of Geological CO2 Storage over the Period of 1996–2020. 19 July 2022.

The Elephant in the Room of the Application of CCS/CCUS in the Natural Gas Processing Sector: Scope 3 Emissions Are Still Not Being Accounted for

Gas processing CCS/CCUS covers a tiny proportion of the value chain of emissions compared to CCS/CCUS in other sectors. As gas processing CCUS is largely about 'capturing excess CO_2', it is obvious that CCUS in the sector is not about reducing Scope 3 emissions from the final combustion/use of gas. Rather, it is about minimising production-related Scope 1 emissions from gas with excessive CO_2 content. This is in contrast to most other CCUS applications in the industrial and power sector, which aim to minimise the emissions coming from the end consumption of fossil fuels.

As such, giving the green light to new oil and gas projects just because of CCUS/CCS promises attached to those projects is not climate friendly. Even if the CCS/CCUS facilities work at their capacity (which has not been the case historically, barring some exceptions), such projects could only manage a minor proportion of the value chain emissions of themselves by adding CCS/CCUS.

The gas burnt at the end of the value chain produces the most significant chunk of emissions.

The gas burnt at the end of the value chain produces the most significant chunk of emissions, which CCU/CCUS proposals do not address.

Captured Carbon Has Mostly Been Used for Enhanced Oil Recovery (EOR): Enhancing Oil Production Is Not a Climate Solution

Today, EOR is the only industrial use of CO_2 to have reached a considerable scale. In recent years, EOR projects have used about 73% of the CO_2 captured globally each year. This figure was greater in previous decades.

EOR enhances the oil production rate from fields that have passed the maximum output rate. The basic idea is that oil and gas companies inject the pressurised CO_2 into existing oil and gas reservoirs to squeeze out more hydrocarbons. Oil producers can make money by revitalising oil fields with declining production rates.

EOR itself leads to CO_2 emissions. CO_2-EOR uses carbon dioxide to produce more oil rather than curbing its emissions. The additional oil produced this way either is burned or used for industrial processes, both resulting in CO_2 emissions. Therefore, any claim that CO_2-EOR systems ultimately reduce CO_2 emissions by their nameplate capacity is an overstatement.

About three-quarters of the CO_2 captured annually by multi-billion-dollar CCUS facilities, roughly 28MT out of 39MT total capture capacity, is reinjected and sequestered into oil fields to push more oil out of the ground. This oil then gets refined, burnt and, at least partially, returned to the atmosphere.

IEEFA has estimated that the vast majority of the total captured carbon throughout history found its use in EOR (~80–90%), and a small proportion of carbon capture projects (~10–20%) have stored carbon in dedicated geological structures, without using it for EOR.

Relatively speaking, carbon capture and storage with dedicated geological structures (CCS) is better than CCUS, which is essentially EOR. Any carbon capture project with the final goal of enhancing oil production would not be a climate solution, regardless of whether the carbon capture facility could reach its capture capacity.

Using Carbon Capture as a Greenlight to Extend the Life of Fossil Fuels Power Plants Is a Financial and Technical Risk: History Confirms this

CCS/CCUS for the power sector, one of the most recent proposed applications of carbon capture technology, is more costly and complex than other applications due to the diluted CO_2 in the flue gas stream. This is evident by the string of historical issues in retrofitting CCS/CCUS into power plants with several failed projects and cost blowouts. In contrast to gas processing and certain industrial processes that could generate exhaust gas with 40–90% CO_2 composition, coal plants emit gases that typically only contain 10–14% CO_2, while gas power plants generate 4–5% CO_2. While this may seem small in concentration, it is large in terms of absolute volume globally.

Capturing CO_2 consumes a lot of energy, effectively reducing the amount of electricity delivered to the consumers. This also means that more fossil fuels will need to keep burning to generate the same amount of electricity in a non-CCUS power plant.

Capturing CO_2 consumes a lot of energy.

To compete in a competitive electricity market context, the high cost of CCS/CCUS will need compensation by selling the captured CO_2, receiving government incentives, or charging a premium price to consumers. However, these pathways are not guaranteed and could also lead to financial instability for the project or environmental externalities, especially in the case of using CO_2 for EOR. Government

incentives should instead flow into fast-growing, efficient, and clean renewable energy technologies and the battery and storage sectors.

Further, apart from the financial argument, carbon capture has shown a track record of technical failures since 2000. Close to 90% of proposed CCS capacity in the power sector has failed at the implementation stage or was suspended early.

Some Applications of CCS in Industries Where Emissions Are Hard to Abate (Such as, Cement) Could be Studied as an Interim Partial Solution with Careful Consideration

Industrial applications of CCS are very diverse. Carbon capture is an established business in some industrial applications, such as fertilisers and ethanol, while other applications are exploring it for technical and commercial competitiveness at scale.

The conclusion about whether carbon capture technologies could be part of the solution for the decarbonisation of industries is not that straightforward. Using carbon capture technologies needs careful research for each application in different industries and business environments. In some applications, with the current high commodity prices, using green hydrogen is a better way to go rather than blue hydrogen.

History shows that capturing 90% (or more) of emissions from industrial processes is very unlikely. Hence, betting on blue hydrogen is not a promising solution and only keeps the fossil fuel status quo. Instead, green hydrogen, with its rapidly plunging cost, would be the clean alternative in industries that run or plan to run on hydrogen.

It is, however, worth studying carbon capture as an interim solution in some sectors, such as cement.

This report studies five flagship cases in different sub-sectors that account for about 65% of the total existing industrial carbon capture capacity. Chemical production mainly comprises the production of fertilisers, ethanol, methanol, and syngas. We analyse the CCS application in each sub-sector by reviewing a project in each area. The results are mixed, with most projects underperforming by a considerable margin and few others presenting a relatively better performance. As hydrogen has an important role in many processes in different sub-sectors, pro-fossil fuel groups have pushed for blue hydrogen. However, wherever hydrogen is applicable technically, green hydrogen would be the better solution due to the financial and imminent cost-efficiency.

The final area of focus in the industrial application of carbon capture technology is the steel and cement industry, so-called hard-to-abate industries. Steel and cement are responsible for 13–14% of total global emissions, and the demand for these two materials is increasing. Therefore, decarbonising these two crucial industries is necessary if the world aims to reach net-zero emissions by 2050.

The steel sector is in the early years of utilising carbon capture technology. Studies could be done on probable projects. However, as carbon capture technology in different sectors has *not* reached its target and hopes, investing in such a high-risk, capital-intensive technology in the short time before needing to reach net zero by 2050 does *not* seem to be a sustainable solution. Instead, alternative methods of steel production such as scrap steel recycling emit about 80% less CO_2 per tonne of crude steel than other forms of steel production used today, and green hydrogen leading to the production of "green steel"[215] looks like a more promising method to follow.

The cement industry is somehow different from all of the other applications of carbon capture technology, as CO_2 is an inevitable by-product of chemical reactions in cement production. Carbon capture technologies seem useful in this industry if they aren't used as an excuse to postpone other methods now under investigation to reinvent the processes and make cement production 'green'.

In all of these industrial applications, CCS/CCUS could be studied if:

- it does not promote EOR
- it does not extend or is used as an excuse to extend the life of any type of fossil asset
- a safe storage location is identified, and a long-term monitoring plan and compensation mechanism in case of failure are developed
- the liability of the projects is not handed over to the taxpayers.

Lessons Learned: Insights for the Way Forward

The natural gas processing and power sector, where carbon capture technologies would extend the life of fossil fuel assets (even if its use could overcome historical technical and financial issues), is not in line with net zero goals.

There are a few sub-sectors for industrial application, however, where carbon capture could be considered an interim option for decarbonisation if it doesn't distract the research and development studies being done in parallel to reinvent the production process. Even in such sub-sectors, such as cement, the technical prosperity of the technology is uncertain. Considering the climate clock is ticking, rigorous environmental and technical conditions need to be satisfied if these few applications are to be greenlit.

The application of CCUS/CCS in the steel and cement sector is a relatively new area with only one ~6-year-old operating project in Abu Dhabi with no publicly published data on its performance. Essentially, there is not much to learn from the application of CCS/CCUS in these two industries. However, based on limited knowledge of the technology trajectory in other applications but with common processes as in these industries, as well as other solutions being developed and

[215] Fuel Cells and Hydrogen Joint Undertaking. Making Steel Green Through Hydrogen.

researched in parallel, future CCS/CCUS applications in the steel and cement industry could be projected to some extent.

Green hydrogen or recycling scrap steel should be prioritised in the steel sector over CCUS/CCS to capture carbon from gasification, reformation, or burning fossil fuels.

In the cement sector, as CO_2 is the by-product of the fundamental chemical reaction of producing cement, CCUS/CCS projects could be considered cautiously. Other innovative methods should be pursued to reinvent the whole process toward green cement. Meanwhile, carbon capture could be used as long as the captured carbon is not used for EOR. CCUS/CCS should only be used if the technical performance reaches close to nominal capture capacities, contrasting with general trends of its application throughout history. Also, it could be considered an interim option as long as it does not divert financial flows from fundamental and innovative solutions reinventing the cement production process.

For other industrial applications, wherever hydrogen is applicable technically, green hydrogen seems to be the way to go due to the financial and imminent cost-efficiency.

Appendix 1

Project	Flagship Aspect	Year Capturing Started	Type	Country	Size[216] (Mtpa)	Sector	Performance Against Designed Capture Rate[217]	Comment
Abu Dhabi	The first and only CCS plant in the steel sub-sector	2016	Enhanced oil recovery (CCUS	UAE	0.8	Industrial (hard-to-abate sector)	No data has been published publicly	The project is 100% government owned
Boundary Dam	The only project operating in the power sector worldwide	2014	Mostly enhanced oil recovery (CCUS)	Canada	1	Power sector	Under-performing by about 50%	A 50-year-old coal power plant retrofitted with the carbon capture facility
Coffeyville	The largest project operating in the fertiliser production sub-sector	2013	Enhanced oil recovery (CCUS	U.S.	0.9	Industrial (chemical production)	No public data was found on the lifetime performance. Only some research shows that the plant over-performed during 2017–2019 by about 16%.	The CO_2 was vented until the year 2013, then some agreements with nearby oil companies were finalised to sell the CO_2
Gorgon	Largest and one of the more recent CCS projects in the world	2019	Dedicated geological structure (CCS)	Australia	4	Gas processing sector	Under-performing by about 50%	Started after 3.5 years delay with a track record of technical failures. Compensating under-performance will cost up to US$184 million.
Great Plains	The largest carbon capture project in all sectors other than natural gas processing	2000	Enhanced oil recovery (CCUS)	U.S.	3	Industrial (chemical production)	Lifetime under-performance of 20–30%	The project started capturing CO_2 16 years after the syngas plant was commissioned. In 2022, it has been planned to be redeveloped into a blue hydrogen project.
Illinois Industrial Carbon Capture and Storage (IL-CCS)	The largest and the latest project commissioned in the ethanol production sub-sector	2017	Dedicated geological structure (CCS)	U.S.	1	Industrial (chemical production)	Under-performing by about 45–50%	The project was 68% government funded. It has only captured about 12% of the yearly total CO_2 emissions of the biofuel plant so far
In Salah	One of the largest operating CCS projects of our time	2004	Dedicated geological structure (CCS)	Algeria	1.1	Gas processing sector	Failed after seven years of operation	Started in 2004. Concerns about possible vertical leakage into the caprock led to investigations, and finally, the project was suspended in 2011

[216] There are different sizes for some projects in different sources. In those cases, the average size has been considered.
[217] For some of the projects, scattered data from different sources has been complied to calculate the performance. An estimated interval is provided for the performance.

Kemper	It was planned to be a first-of-a-kind plant, capturing CO_2 from producing gasified coal, and using gas in the modified gas power plant to produce electricity	2014 (without Carbon Capture)	Enhanced oil recovery (CCUS)	U.S.	3	Power sector	Failed to be started	Technical problems led to a 250% increase in the previously estimated cost of the project from U$3b to US$7.5 billion. The carbon capture idea was cancelled in 2017. It was the most expensive power plant ever built.
Petra Nova	The only project in the power sector in the U.S.	2017	Enhanced oil recovery (CCUS)	U.S.	1.4	Power sector	Under-performed by 17% in four years of its operation and then shut down.	It was mothballed indefinitely in 2020 citing low oil prices during the COVID-19 pandemic
Quest	One of the operating projects in the hydrogen production sub-sector operating at its design capacity	2015	Dedicated geological structure (CCS)	Canada	1.1	Industrial (hydrogen production)	Performing close to the capture capacity	The project got off the ground thanks to huge government funding estimated at C$95 per tonne of CO_2 captured until the end of the project's lifetime. It captures 35% of the CO_2 emissions of the oil upgrader.
Shute Creek	Largest and one of the oldest carbon capture projects in the world	1986	Enhanced oil recovery (CCUS)	U.S.	7	Gas processing sector	Lifetime under-performance of 36%	It is estimated that the lifetime under-performance of the project against its capturing capacity is approximately equivalent to the combined emissions from Sweden and Denmark in 2019
Sleipner	First commercial carbon capture project with a dedicated geological structure worldwide	1996	Dedicated geological structure (CCS)	Norway	0.9	Gas processing sector	Performing close to the capture capacity	It is among a few successful cases located in Norway. An exceptionally high carbon tax and stringent regulatory environment linked to the ETS are among the drivers. The gas project is in its tail of production lifetime.
Snøhvit	One of the two successful Norwegian carbon capture projects	2007	Dedicated geological structure (CCS)	Norway	0.7	Gas processing sector	Performing close to the capture capacity	It is one of the successful cases which is located in Norway. An exceptionally high carbon tax and stringent regulatory environment linked to the ETS are among the drivers.

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About the Authors

Bruce Robertson

Energy Finance Analyst – Gas/LNG, Bruce Robertson has been an investment analyst, fund manager and professional investor for over 36 years. He has worked with Perpetual Trustees, UBS, Nippon Life Insurance and BT. (brobertson@ieefa.org)

Milad Mousavian

Energy Analyst Milad Mousavian has been a consultant and researcher in the area of energy transition and climate finance/economics. He has a Master's in Economics from the University of Melbourne and in Energy Systems. (mousavianmilad@gmail.com)

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Cite this: *Energy Environ. Sci.*, 2019, **12**, 3567

The health and climate impacts of carbon capture and direct air capture

Mark Z. Jacobson

Data from a coal with carbon capture and use (CCU) plant and a synthetic direct air carbon capture and use (SDACCU) plant are analyzed for the equipment's ability, alone, to reduce CO_2. In both plants, natural gas turbines power the equipment. A net of only 10.8% of the CCU plant's CO_2-equivalent (CO_2e) emissions and 10.5% of the CO_2 removed from the air by the SDACCU plant are captured over 20 years, and only 20–31%, are captured over 100 years. The low net capture rates are due to uncaptured combustion emissions from natural gas used to power the equipment, uncaptured upstream emissions, and, in the case of CCU, uncaptured coal combustion emissions. Moreover, the CCU and SDACCU plants both increase air pollution and total social costs relative to no capture. Using wind to power the equipment reduces CO_2e relative to using natural gas but still allows air pollution emissions to continue and increases the total social cost relative to no carbon capture. Conversely, using wind to displace coal without capturing carbon reduces CO_2e, air pollution, and total social cost substantially. In sum, CCU and SDACCU increase or hold constant air pollution health damage and reduce little carbon before even considering sequestration or use leakages of carbon back to the air. Spending on capture rather than wind replacing either fossil fuels or bioenergy always increases total social cost substantially. No improvement in CCU or SDACCU equipment can change this conclusion while fossil fuel emissions exist, since carbon capture always incurs an equipment cost never incurred by wind, and carbon capture never reduces, instead mostly increases, air pollution and fuel mining, which wind eliminates. Once fossil fuel emissions end, CCU (for industry) and SDACCU social costs need to be evaluated against the social costs of natural reforestation and reducing nonenergy halogen, nitrous oxide, methane, and biomass burning emissions.

Received 24th August 2019,
Accepted 21st October 2019

DOI: 10.1039/c9ee02709b

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Published on 21 October 2019. Downloaded by Stanford Libraries on 12/4/2019 4:28:01 PM.

Broader context

The Intergovernmental Panel on Climate Change concludes that carbon capture and storage/use (CCS/U) and synthetic direct air carbon capture and storage/use (SDACCS/U) are helpful technologies for avoiding 1.5 °C global warming. However, no study has evaluated their performance or social cost compared with merely replacing fossil with renewable electricity. Here, data from CCU and SDACCU equipment powered by natural gas are evaluated. Only 10.8% of the CCU plant's CO_2-equivalent (CO_2e) emissions and 10.5% of the CO_2 removed from the air by SDACCU are captured over 20 years; only 20–31% are captured over 100 years. Moreover, both plants increase air pollution and social cost *versus* no capture. Powering the equipment with wind instead of gas reduces CO_2e but allows the same pollution as and increases the social cost *versus* no capture. Replacing coal with wind (without capture) reduces CO_2e, pollution, and social cost substantially. In sum, spending on capture rather than wind replacing fossil or bioenergy always increases social cost. No improvement in CCU or SDACCU equipment can change this conclusion while fossil emissions exist. Once fossil emissions end, CCU (for industry) and SDACCU social costs must be evaluated against those of reforestation and reducing nonenergy halogen, nitrous oxide, methane, and biomass burning emissions.

Introduction

Carbon capture and storage (CCS) and use (CCU) involve the installation of equipment in a coal, natural gas, oil, or biomass electric power or heat generating facility to remove carbon dioxide (CO_2) from the exhaust and either sequester it underground or in a material (CCS) or sell it for industrial use (CCU).

Synthetic direct air carbon capture and storage (SDACCS) or use (SDACCU) is the removal of CO_2 from the air by chemical reaction. Upon removal, the CO_2 is either sequestered (SDACCS) or sold (SDACCU). SDACCS differs from natural direct air carbon capture and storage (NDACCS), which is the natural removal of carbon from the air by either planting trees or reducing biomass burning.

Department of Civil & Environmental Engineering, Stanford University, Stanford, CA, USA. E-mail: jacobson@stanford.edu

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Both CCS/U and SDACCS/U have been proposed as technologies to reduce atmospheric CO_2 and global warming. For example, IPCC[1] states that "capture, utilization, and storage" (CCS/U) can help reduce 75–90% of global CO_2 emissions and that it is "technically proven at various scales." They also identify SDACCS as a method to limit warming to 1.5 °C.

Historically, researchers have assumed CCS/U removes 85–90% of CO_2 exhaust with an energy penalty of ~25%.[2–4] An energy penalty is the additional electricity required to run the carbon capture equipment per unit electricity produced by the power plant for normal electricity consumption. However, until recently,[5] no public data from a commercial power plant with CCU were available to test these numbers. Similarly, until recently,[6] no data were available to evaluate an operating SDACCU plant. Models have also not evaluated the social cost of air pollution that CCS/U and SDACCS/U increase due to their energy use. Air pollution already kills 4–9 million people worldwide annually.[7] Evaluating the emissions and social (energy plus health, plus climate) cost of any proposed technology is critical given the enormous cost of eliminating world emissions (~$100 trillion – Table S9 of ref. 8).

Prior studies have also not evaluated the opportunity cost of using renewable electricity to power CCS/U or SDACCS/U equipment instead of using the renewable electricity to displace fossil fuel power plants. Given limited national budgets, the enormous cost of reducing global air pollution and carbon emissions, and limitations in land areas available in each country to install renewables to replace fossil energy, it is essential to compare the air pollution and carbon emissions of using renewables to power carbon capture equipment with, instead, displacing fossil fuel electricity directly with renewables, thus avoiding emissions in the first place.

Coal-CCU plant

This study first quantifies the carbon dioxide equivalent (CO_2e) emissions from a retrofitted pulverized coal boiler connected to a steam turbine at the W. A. Parish coal power plant near Thompsons, Texas. The plant was retrofitted with carbon capture (CC) equipment as part of the Petra Nova project and began using the equipment during January 2017. The CC equipment (240 MW) receives 36.7 percent of the emissions from the 654 MW boiler. The equipment requires about 0.497 kWh of electricity to run per kWh produced by the coal plant (Table 2, footnote g). A natural gas turbine with a heat recovery boiler was installed to provide this electricity. A cooling tower and water treatment facility were also added. The retrofit cost $1 billion ($4200 per kW) beyond the coal plant cost.[9]

CO_2 from the gas turbine is not captured. Natural gas production also has upstream CO_2e emissions, including CH_4 leaks, which are not captured. Upstream CO_2 and CH_4 emissions from the coal plant are also uncaptured. Table 1 shows the January through June CO_2 coal combustion emission data[5] from the plant before (in 2016) and after (in 2017) the addition of the CC equipment. The table also shows the gas combustion emissions from powering the CC equipment. The table then

Table 1 Columns a–d: raw emissions for January through June 2016 and 2017 from the 654 MW (-all-coal) Petra Nova coal-CCU unit.[5] The 2016 data are before carbon capture was added. The 2017 data include combustion CO_2 from the coal plant and, separately, from the natural gas combined cycle turbine installed to run the CC equipment. Columns e–h: emissions (in units of kg-CO_2 per MWh) for the 240 MW (coal-CC) portion of the 654 MW coal unit subject to carbon capture in 2016 and 2017. Column e equals column (a) multiplied by K = 0.4536 kg lb^{-1}. Column f equals $[b - a(1 - F)]K/F$, where b and a are the CO_2 stack emission rates for each month in 2017 (column b) and 2016 (column a), respectively, and F = 0.367 = 240 MW/654 MW is the fraction of the coal unit subject to carbon capture. Column g equals column c multiplied by K/F

	(a) 2016 coal CO_2 no CC lb-CO_2 per MWh-all-coal[5]	(b) 2017 coal CO_2 with CC lb-CO_2 per MWh-all-coal[5]	(c) 2017 gas CO_2 with CC lb-CO_2 per MWh-all-coal[5]	(d) 2017 total CO_2 with CC lb-CO_2 per MWh-all-coal = $b + c$	(e) 2016 coal CO_2 no CC kg-CO_2 per MWh-coal-CC = aK	(f) 2017 coal CO_2 with CC kg-CO_2 per MWh-coal-CC = $[b - a(1 - F)]K/F$	(g) 2017 gas CO_2 with CC kg-CO_2 per MWh-coal-CC = cK/F	(h) 2017 total CO_2 with CC kg-CO_2 per MWh-coal-CC = f + g
Jan	2060	1500	220	1720	934.4	242.2	271.9	514.1
Feb	2110	1615	225	1840	957.1	345.2	278.1	623.3
Mar	2130	1950	60	2010	966.2	743.7	74.2	817.8
Apr	2050	1550	155	1705	929.9	311.8	191.6	503.4
May	2010	1640	160	1800	911.7	454.4	197.8	652.2
Jun	1950	1550	155	1705	884.5	390.1	191.6	581.7
Average	**2052**	**1634**	**163**	**1797**	**930.6**	**414.6**	**200.9**	**615.4**

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translates the emissions from the full 654 MW coal unit to the 240 MW portion of the unit subject to CC. When upstream emissions are excluded, the CC equipment captures an average of only 55.4% (Table 2) of coal combustion CO_2 (rather than 90%) and only 33.9% of coal plus gas combustion CO_2.

Table 2 and Fig. 1 expand results from Table 1 to account for upstream emissions from the mining and processing of coal and natural gas. The CC equipment reduces coal and gas combustion plus upstream CO_2 a net of only 10.8% over 20 years (Fig. 1) and 20% over 100 years. 20 years is a relevant time frame to avoid 1.5° global warming and resulting climate feedbacks.[1]

When wind, instead of gas, is used to power the CC equipment, CO_2e decreases by 37.4% over 20 years and 44.2% over 100 years compared with no CC (Table 2 and Fig. 1). The CO_2e decrease exceeds that in the CCU-gas case because wind powering CC equipment case does not result in any combustion or upstream emissions from wind, as seen in Fig. 1.

However, using the wind electricity that powers the CC equipment instead to replace coal electricity directly at the same plant reduces CO_2e by 49.7% compared with no CC (Table 2 and Fig. 1). It is not 100% because only the wind used to run the capture equipment replaces coal. More wind would be needed to replace the whole coal plant. This third strategy is the best for reducing CO_2e among the three cases. Using solar PV to replace coal directly results in a similar benefit as using wind.

But, CO_2e is only part of the story. Because CCU equipment does not capture health-affecting air pollutants, air pollution emissions continue from coal and rise by about 25% compared with no capture from the use of natural gas to run the Petra Nova equipment (Table 2). Even when wind powers the CC equipment, air pollution from the coal plant continues as before (but not from using the new wind turbine). Only when wind partially replaces the use of coal itself does air pollution decrease by $\sim$50% (Table 2).

The equipment cost of new coal and wind electricity in the U.S. are a mean of \$102 per MWh and \$42.5 per MWh, respectively.[10] The capital cost of CC equipment, \$4200 per kW,[9] is about 74% the capital cost of a new coal plant (\$5700 per kW),[10] suggesting that new coal plus CCU is 1.74 $\times$ \$102 per MWh/\$42.5 per MWh = 4.2 times the equipment cost of new wind. Since CC equipment reduces only 10.8% of coal CO_2e over 20 year and 20% over 100 year, the equipment for coal-CCU powered by natural gas alone costs 39 and 21 times that of wind-replacing coal per mass-CO_2 removed over 20 and 100 years, respectively.

Major additional social costs associated with coal electricity generation are air pollution and climate costs. The health cost of coal emissions in the U.S. is calculated as a mean of \$80 per MWh, which is much lower than the world average (\$169 per MWh, Table 2, footnote m). Since the use of CC equipment requires 50% more electricity than the coal plant produces but the health cost of natural gas emissions are about half those of coal, the use of gas to run the CC equipment increases health costs by $\sim$25% compared with no capture (Table 2, row o). Mean climate costs of U.S. emissions are estimated as \$152 per MWh, close to the world mean of \$160 per MWh (Table 2, footnote m). CC equipment with natural gas is estimated to reduce this cost by only 10.8% and 20% over 20 and 100 years, respectively (Table 2, row n).

In sum, the total social cost (equipment plus health plus climate cost) of coal-CCU powered by natural gas is over twice that of wind replacing coal directly (Table 2 and Fig. 1). Moreover, the social cost of coal with CC powered by natural gas is 24% higher over 20 years and 19% higher over 100 years than coal without CC. Thus, no net social benefit exists of using CC equipment. In other words, from a social cost perspective, using CC equipment powered by natural gas causes more damage than does doing nothing at all.

When wind powers CC equipment, the social costs are still 6% and 2% higher over 20 and 100 years, respectively, than not using CC (Table 2 and Fig. 1). Although wind-powering-CC decreases CO_2e, thus climate cost, compared with coal without CC, wind-CC allows the same air pollution emissions from coal as no CC, and the cost of the wind plus CC equipment outweighs the CO_2e cost reduction (Fig. 1).

Only when wind replaces coal electricity production directly does the total social cost drop 43% compared with no CC (Table 2). This is the best scenario. A similar benefit occurs if wind replaces natural gas and no CC is used.

Some may argue that (a) the six months of data with *versus* without the CC equipment are insufficient for drawing conclusions about this plant and (b) future plants may improve upon the Petra Nova plant. Whereas both points are valid, in order for the social cost of using the CC equipment powered by natural gas to be less than that of doing nothing, the CO_2e reemitted by the Petra Nova plant would need to be 37% or less instead of 89.8% over 20 years. However, this is all but impossible, because 59.2% of the re-emissions is due to upstream coal and gas emissions and natural gas combustion emissions, so little to do with how effective the CC equipment is at capturing carbon. In other words, even if the CC equipment captured 100% of the stack CO_2, which no-one is proposing is feasible, the reemissions would still be 59.2%. This is because controlling 100% of the coal stack emissions can reduce only 40.8% of the total upstream plus stack coal emissions due to the additional upstream and combustion emissions of the gas plant over a 20 year time frame. As such, the data indicate that no technological improvement will result in the social cost of using CC equipment powered by natural gas being less than that of not using the equipment.

When CC is powered by wind, it is theoretically possible, albeit challenging, to reduce the total social cost below that of no CC. However, it is impossible to reduce the total social cost below that of wind replacing coal electricity directly because wind-powering-CC also incurs a CC equipment cost and never reduces air pollution or mining from coal, whereas wind replacing coal incurs no CC equipment cost and eliminates coal air pollution and mining.

SDACCU plant

This section evaluates the efficiency of CO_2 removal from the air by an SDACCU facility,[6] where electricity for the air capture

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Table 2 Comparison of relative CO_2e emissions, electricity use, and electricity social costs among three scenarios related to the Petra Nova coal-CCU facility, each over a 20 year and 100 year time frame. The first scenario is using natural gas to power the carbon capture (CC) equipment. This is based on data from the Petra Nova facility (Table 1). The second scenario is running the CC equipment with onshore wind instead of natural gas. The third is using the same quantity of wind electricity required to run the CC equipment to instead replace coal electricity from the coal plant. In all cases, the additional energy required to run the CC equipment is equivalent to 49.7% of the energy output of the coal plant (footnote g). The coal plant has a nameplate capacity of 654 MW, but only 240 MW (36.7%) is subject to CC. The numbers in the table are all based on the portion subject to CC. All emission units (including of natural gas emissions) are g-CO_2e per kWh-coal-electricity-generation

	Coal with gas-powered CC 20 year	Coal with gas-powered CC 100 year	Coal with wind-powered CC 20 year	Coal with wind-powered CC 100 year	Wind used for CC replacing coal + remaining coal 20 year	Wind used for CC replacing coal + remaining coal 100 year
(a) Upstream CO_2 from coal[a]	97.2	97.2	97.2	97.2	48.9	48.9
(b) Upstream CO_2e of leaked CH_4 from coal[b]	353	140	353	140	177.6	70.4
(c) Coal stack CO_2 before capture[c]	930.6	930.6	930.6	930.6	468.1	468.1
(d) Total coal CO_2e before capture (a + b + c)	1381	1168	1381	1168	695	587
(e) Remaining stack CO_2 after capture[d]	414.6	414.6	414.6	414.6	—	—
(f) CO_2 captured from stack (*c*–*e*)	516.0	516	516	516	—	—
(g) Percent stack CO_2 captured (f/c)	55.4	55.4	55.4	55.4	—	—
(h) CO_2 emissions gas combustion[e]	200.9	200.9	0	0	0	0
(i) Upstream CO_2e of CH_4 from gas leaks[f]	139.2	55.03	0	0	0	0
(j) Upstream CO_2 from gas mining, transport[g]	26.85	26.85	0	0	0	0
(k) Total CO_2e emissions (a + b + e + h + i + j)	1,232	934.5	865	652	695	587
(l) Percent of coal CO_2e re-emitted (k/d)[h]	**89.2**	**80.0**	**62.6**	**55.8**	**50.3**	**50.3**
(m) Percent of coal CO_2e captured (100-l)	**10.8**	**20**	**37.4**	**44.2**	**49.7**	**49.7**
(n) Relative CO_2e to original (l/100)[i]	0.892	0.80	0.626	0.558	0.503	0.503
(o) Relative air pollution to original[j]	1.25	1.25	1.0	1.0	0.503	0.503
(p) Energy required relative to original[k]	1.497	1.497	1.497	1.497	1	1
(q) Private energy cost per kWh relative to original[l]	1.74	1.74	1.74	1.74	0.71	0.71
(r) Social cost before changes ($ per MWh)[m]	334	334	334	334	334	334
(s) Social cost after changes ($ per MWh)[n]	413	399	353	342	189	189
(t) Social cost ratio (s/r)	1.24	1.19	1.06	1.02	0.57	0.57

[a] Coal upstream emissions are estimated as 27 g-CO_2 per MJ = 97.2 g-CO_2 per kWh.[11] Upstream emissions include emissions from fuel extraction, fuel processing, and fuel transport. Upstream CO_2 emissions (from the portion of the coal plant not replaced) for the wind-replacing some coal cases (last two columns) are the same as in the other cases, but multiplied by 0.503, which equals 1 minus the fraction of coal electricity used to run the carbon capture equipment, which is derived in footnote g. Since the electricity used to run the CC equipment is used to replace coal in this case, upstream coal emissions are reduced accordingly. [b] For coal, the 100 year CO_2e from CH_4 leaks is estimated from (ref. 12, slide 17). The emission factor is derived from that number and the 100 year GWP of CH_4, 34 from ref. 13. The 20 year CO_2e is then derived from the resulting emission factor (4.1 g-CH_4 per kWh) and the 20 year GWP of CH_4, 86. Emissions in the wind cases are reduced as described under footnote a. [c] The average coal stack emission rate for the Petra Nova facility in 2016, prior to the addition of CC equipment, is from Table 1, column e. In the wind-replacing-coal cases (last two columns), the emission rate is reduced as described under footnote a. [d] The coal-stack CO_2 remaining after capture is from Table 1, column f. [e] The natural gas combustion emissions resulting from powering the CC equipment is from Table 1, column g. [f] Natural gas upstream leaks are obtained by dividing the raw emission rate of CO_2 from natural gas for each month January through June 2017 from Table 1 (in kg-CO_2 per MWh-coal-electricity) by the molecular weight of CO_2 (44.0098 g-CO_2 per mol) to give the moles of natural gas burned per MWh-coal-electricity. Multiplying the moles burned per MWh by the fractional number of moles burned that are methane (0.939)[14] and the molecular weight of methane (16.04276 g-CH_4 per mol) gives the mass intensity of methane in the natural gas burned each month (kg-CH_4-burned per MWh-coal-electricity). The upstream leakage rate of methane is then the kg-CH_4-burned per MWh-coal-electricity multiplied by $L/(1-L)$, where $L = 0.023$ is the fraction of all methane produced (from conventional and shale rock sources) that leaks,[15] giving the methane leakage rate in kg-CH_4 per MWh-coal-electricity. This leakage rate is conservative based on a more recent full-lifecycle leakage rate estimate of methane from shale rock alone of $L = 0.035$.[16] Using the latter estimate would result in CCS/U with natural gas re-emitting even more CO_2e than calculated here. Multiplying the kg-CH_4 per MWh-coal-electricity by the 20- and 100 year GWPs of CH_4 (86 and 34, respectively)[13] gives the CO_2e emission rate of methane leaks each month. The monthly values are linearly averaged over January through June 2017. [g] The non-CH_4 upstream CO_2e emissions rate is estimated as 15 g-CO_2 per MJ-gas-electricity = 54 g-CO_2 per kWh-gas-electricity.[11] Multiplying that by 0.497 MWh-electricity from natural gas per MWh-coal-electricity produced gives 26.8 kg-CH_4 per MWh-coal-electricity. 0.497 MWh-electricity from natural gas per MWh-coal-electricity produced, or 49.7%, is calculated by dividing the average gas combustion emission from Petra Nova (200.9 g-CO_2 per kWh-coal from the present table) by the combustion emissions per unit electricity from a combined cycle gas plant (404 g-CO_2 per kWh-natural-gas). [h] The percent CO_2 reemitted for the wind cases (last two columns) equals row k for the wind cases divided by row d for either of the non-wind cases. [i] CO_2e emissions relative to coal with no CC equipment. [j] Air pollution emissions relative to coal with no CC equipment. In the natural gas cases, all air pollution from coal emissions still occurs. Although gas is required to produce 0.497 MWh of electricity for the CC equipment per MWh of coal electricity, gas is assumed to be 50% cleaner than coal, so the overall air pollution in this case increases only 25% relative to the no CC case. In the wind-CC cases, all upstream and combustion emissions from coal still occur. [k] The electricity required (for end-use consumption plus to run the CC equipment) in all CC cases is 49.7% higher than with no CC. In the wind-replacing coal case, no electricity is needed to run the CC equipment, but electricity is still needed for end use. [l] The private energy cost in all CC cases is assumed to be 74% higher than coal with no CC because the CC equipment (including the gas plant) costs $4200 per kW, which represents about 74% of the mean capital cost of a new coal plant ($5700 per kW) from.[10] For simplicity, it was assumed that the cost of a wind turbine running the CC equipment was the same as of a gas turbine running the equipment. In the wind-replacing-coal cases, the cost of coal was assumed to be a mean of c = $102 per MWh and of wind, w = $42.5 per MWh.[10] The final ratio was calculated as $(0.503c + 0.497w)/c$. [m] The social cost before changes is the private energy cost of new coal without CCU [$102 per MWh from ref. 10] plus air pollution mortality, morbidity, and non-health environmental costs of coal power plant emissions in the U.S. plus the global climate costs of U.S. emissions ($152 per MWh).[18] U.S. coal power plant emissions health costs are estimated as $80 per MWh, which is twice the background grid health cost of $40 per MWh.[17] In the worldwide average, from the same source, the health cost of background grid emissions is estimated as $169 per MWh, so use of the U.S. number here is likely to underestimate the health costs of using carbon capture outside the U.S. [n] The social cost after changes is the sum of the private energy cost multiplied by row q, the air pollution health cost multiplied by row o, and the climate cost multiplied by row n.

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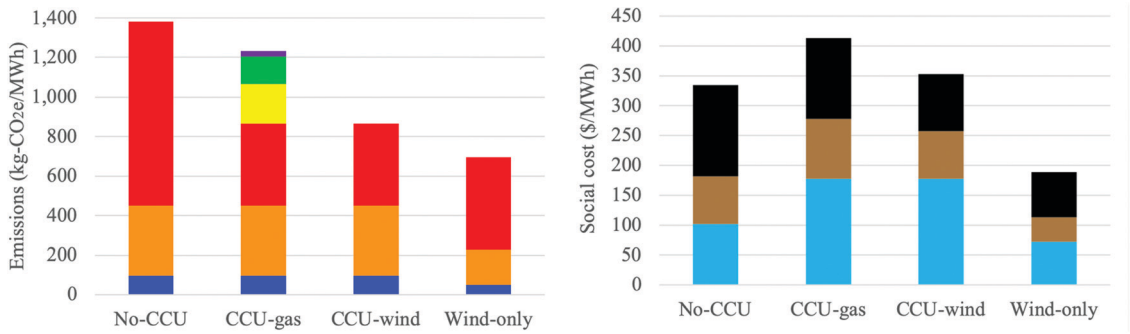


Fig. 1 Left: CO_2e emissions, averaged over 20 years, from the Petra-Nova coal plant before (No-CCU) and after (CCU-gas) the addition of CCU equipment powered by natural gas. Also shown are emissions when the CCU equipment is powered by wind energy (CCU-wind) and when the portion of wind energy used to power the CCU equipment is instead used only to replace a portion of the coal power (thus some power is generated by coal and some by wind). Blue is upstream CO_2e from coal mining and transport aside from CH_4 leaks; orange is upstream CO_2e from coal mining CH_4 leaks; red is coal combustion CO_2; yellow is natural gas combustion CO_2; green is CO_2e from natural gas mining and transport CH_4 leaks; and purple is natural gas mining and transport CO_2e aside from CH_4 leaks. Right: Mean estimate of social costs per unit electricity over 20 years generated by the coal plant (in the first three cases) or the residual coal plant plus replacement wind plant (fourth case) for each of the four cases shown on the left. Light blue is the cost of electricity generation plus CCU equipment; brown is air pollution health cost; and black is 20 year climate cost. All data are from Table 2.

(AC) equipment is provided by a natural gas combined cycle turbine.

Table 3 indicates that, averaged over 20 and 100 years, 89.5% and 69%, respectively, of all CO_2 captured by the AC equipment is returned to the air as CO_2e. The emissions come from mining, transporting, processing, and burning the natural gas used to power the equipment.

In comparison with taking no action, using SDACCU equipment powered by natural gas also increases air pollution due to the combustion and upstream emissions associated with natural gas. With no action, SDACCU further incurs an equipment cost. Thus, although SDACCU powered by natural gas reduces some CO_2e, the equipment cost and air pollution cost far outweigh that decrease, resulting in a near doubling of the total social cost per MWh of electricity use relative to the health and climate cost per MWh of coal power plant emissions (Fig. 2).

Even when zero re-emissions occur, such as when wind powers the SDACCU equipment, the mean social cost of using SDACCU still exceeds that of doing nothing (Fig. 2). On the other hand, using wind to replace coal electricity instead of to run the AC equipment eliminates CO_2e and air pollution emissions and their associated costs from the coal. The resulting social cost is $\sim$15% of that from wind powering SDACCU equipment (Table 3 and Fig. 2). A similar result is found when wind replaces a natural gas plant instead of a coal plant. In fact, there is no case where wind powering an SDACCU plant has a social cost below that of wind replacing any fossil fuel or bioenergy power plant directly. The reasons are that wind-powering-SDACCU always incurs an SDACCU equipment cost that wind alone never incurs and SDACCU always allows air pollution and mining to continue whereas wind always eliminates air pollution and mining.

Discussion

Tables 1–3 suggest virtually no carbon benefit of and greater air pollution damage from CCS/U and SDACCS/U before considering the disposition of the captured CO_2.

Three reasons this result has not been identified previously, aside from the lack of data, are that previous studies and models did not consider upstream fossil emissions, the air pollution social cost resulting from the additional energy needs, or the higher fossil emissions due to using renewable electricity for CC or AC equipment instead of to displace fossil electricity. Air pollutants not captured by CC or AC equipment from fossil or bioenergy plants include CO, NO_x, SO_2, organic gases, mercury, toxins, black and brown carbon, fly ash, and other aerosol components.

Ref. 4 found that even after assuming 90% capture by equipment (and ignoring upstream and combustion emissions to run the capture equipment), renewables return better on investment than CC. The results here suggest that a specific coal-CCU plant reduces only 10.5% and 20% of the plant's overall CO_2e over 20 and 100 years, respectively, while increasing air pollution and land degradation (from additional mining). More than half the re-emissions are due to upstream coal and gas emissions and natural gas combustion emissions to run the CC equipment. In addition, CC always incurs an equipment cost and never reduces air pollution, whereas renewables have no such equipment costs and always reduce air pollution. For all these reasons, renewables replacing fossil fuels or bioenergy are a lower social-cost investment to address climate than even[4] found.

SDACCS/U powered by natural gas similarly increases air pollution by increasing fossil energy consumption and upstream mining. Clean electricity used to run SDACCS/U equipment does not increase air pollution but keeps it the same. However, the social cost of using that clean electricity to replace fossil fuels or bioenergy is always lower than the social cost of using the electricity to run SDACCS/U equipment. The reasons are that SDACCU equipment always incurs a cost that renewables never incur and SDACCU always allows air pollution and fuel mining to continue, whereas renewables eliminate air pollution and fuel mining.

The results here are independent of the fate of the CO_2 after it leaves the CC equipment, thus apply to CC with bioenergy (*e.g.*, BECCS/U) or cement manufacturing. The CC equipment

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Table 3 Comparison of relative CO_2e emissions, electricity private costs, and electricity social costs among three scenarios related to the carbon engineering SDACCU plant, each over a 20 year and 100 year time frame. The first scenario is using an on-site natural gas (NG) combined cycle turbine to power the direct air capture (DAC) equipment. The DAC equipment does not capture the gas emissions; if it did, the results would be the same, since if the equipment captured turbine CO_2 emissions, it would not capture the equivalent CO_2 from the air. The third scenario involves using the same wind turbine electricity to instead replace coal power generation without using AC equipment. All emission units (rows a–f, i) are kg-CO_2e per MWh

	DAC with NG elec. 20 year	DAC with NG elec. 100 year	DAC with wind elec 20 year	DAC with wind elec. 100 year	Wind replacing coal 20 year	Wind replacing coal 100 year
(a) SDACCU removal from air[a]	825	825	825	825	—	—
(b) CO_2 emissions combined cycle gas turbine[b]	404	404	—	—	—	—
(c) Upstream CO_2e of CH_4 from gas leaks[c]	280	111	—	—	—	—
(d) Upstream CO_2 from gas mining, transport[d]	54	54	—	—	—	—
(e) Emission reduction due to replacing coal with wind[e]	0	0	0	0	−1381	−1168
(f) All emissions (b + c + d + e)	738	569	0	0	−1381	−1168
(g) Percent CO_2 returned (f/a)	**89.5**	**68.9**	**0**	**0**	—	—
(h) Percent CO_2 captured (100-g)	**10.5**	**31.1**	**100**	**100**	—	—
(i) Absolute emission reduction (a–f)	87	256	825	825	1381	1168
(j) Low SDACCU ($ per tonne-CO_2-removed)[a]	94	94	94	94	—	—
(k) High SDACCU ($ per tonne-CO_2-removed)[a]	232	232	232	232	—	—
(l) Low private electricity cost (aj/1000) ($ per MWh)[f]	78	78	78	78	29	29
(m) High private electricity cost (ak/1000) ($ per MWh)[f]	191	191	191	191	56	56
(n) Health cost of background grid ($ per MWh)[g]	40	40	40	40	40	40
(o) Ratio health cost of scenario to of background grid[h]	3	3	2	2	0	0
(p) Health cost of scenario (no) ($ per MWh)	120	120	80	80	0	0
(q) Climate cost of background grid ($ per MWh)[i]	152	152	152	152	152	152
(r) Ratio climate cost of scenario to of background grid[j]	0.937	0.781	0.403	0.294	0	0
(s) Climate cost of scenario (qr) ($ per MWh)	142	119	61.2	44.6	0	0
(t) Low social cost ($ per MWh) (l + p + s)	340	316	219	202	29	29
(u) High social cost ($ per MWh) (m + p + s)	454	430	333	316	56	56
(v) Low social cost ratio (row t-SDACCU/u-wind)	6.1	5.6	3.9	3.6	—	—
(w) High social cost ratio (row u-SDACCU/t-wind)	15.6	14.8	11.5	10.9	—	—

[a] Ref. 6. Assumes values for DAC with wind electricity are the same as DAC with natural gas electricity. [b] Ref. 19. [c] Same methodology as in Table 2, footnote f, but using the CO_2 combustion emissions from row (b) here. [d] Ref. 11. [e] Assumes wind that would otherwise be used to run the SDACCU equipment instead directly replaces coal electricity, its upstream CO_2 combustion, its upstream CH_4 leaks, and its stack combustion CO_2 emissions. The overall emission rates from coal are obtained from Table 2, row d. [f] Low and high wind electricity costs for wind-replacing coal are from.[10] Others are from the formula provided. [g] The U.S. health cost of $40 per MWh for the background grid per MWh is from ref. 17. [h] The ratio of the health cost in the scenario to that of the background grid is defined as zero for the wind-replacing coal case, since wind produces zero emissions during its operation. In comparison, wind running SDACCU equipment allows those coal emissions, which are about twice background grid emissions per unit energy, to continue, so the factor in that scenario is 2. Natural gas running SDACCU equipment not only allows those coal emissions to continue, but it also produces 50% more emissions, assumed equal to background grid emissions per MWh, so the factor in that scenario is 3. [i] The U.S. climate cost of $152 per MWh for the background grid is from ref. 17 and 18. [j] The ratio of the climate cost of the scenario to that of the background grid is defined as zero for the wind-replacing coal case, since wind produces zero emissions during its operation. For the other cases, it is simply the absolute CO_2e emission reduction in the case minus that in the wind case all divided by that in the wind case, where all values are from row i.

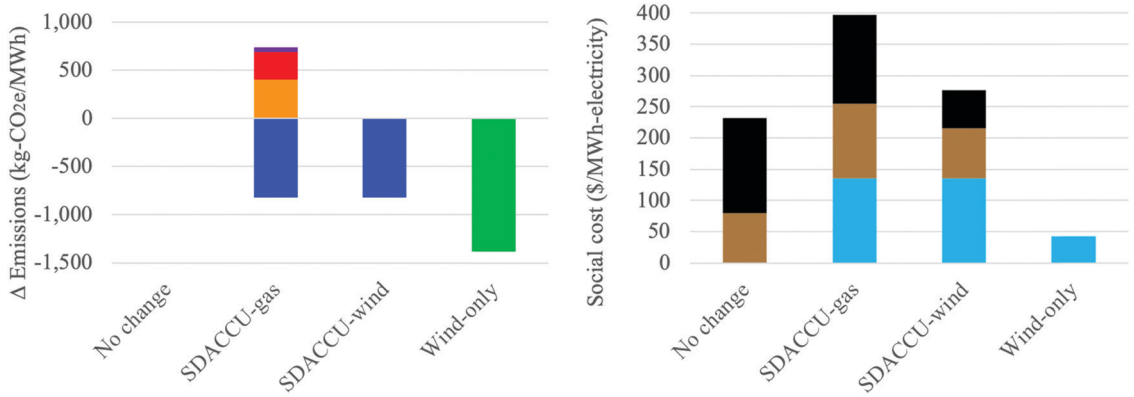


Fig. 2 Left: Change in CO_2e emissions, averaged over 20 years, per unit electricity needed to run SCACCU equipment resulting from either no action (no-change), using an SDACCU plant with equipment powered by natural gas (SDACCU-gas), using an SDACCU plant with equipment powered by wind (SDACCU-wind), and using the same quantity of wind required to run the SDACCU equipment but to replace coal power directly (wind-only). Blue is the removal of CO_2 from the air by the SDACCU equipment; orange is the natural gas turbine emissions; red is the CO_2e from natural gas mining and transport CH_4 leaks; purple is natural gas mining and transport CO_2e aside from CH_4 leaks; and green is the CO_2e emission reduction due to replacing coal power with wind power. Right: Mean estimate of social costs per unit electricity over 20 years for each of the four cases shown on the left. Light blue is the cost of equipment (either air capture equipment plus gas turbine, air capture equipment plus wind turbine, or wind turbine alone); brown is air pollution health cost; and black is 20-year climate cost. All data are from Table 3, except that the costs in the no-change case are the health and climate costs of coal power plant emissions ($80 per MWh health cost and $152 per MWh climate cost – Table 2, footnote m). Such emissions costs are used as the background because the wind-only case removes such emissions.

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always requires energy. If the energy comes from a fossil fuel, mining and combustion emissions from the fuel cancel most CO_2 captured. If it comes from a renewable, total social costs are still always greater than using the renewable to replace fossil fuels or bioenergy directly.

When the fate of captured CO_2 is considered, the problem may deepen. If CO_2 is sealed underground without leaks, little added emissions occur. If the captured CO_2 is used to enhance oil recovery, its current major application, more oil is extracted and burned, increasing combustion CO_2, some leaked CO_2, and air pollution. If the captured CO_2 is used to create carbon-based fuel to replace gasoline and diesel, energy is still required to produce the fuel, the fuel is still burned in vehicles (creating pollution), and little CO_2 is captured to produce the fuel with. A third proposal is to use the CO_2 to produce carbonated drinks. However, along with the issues previously listed, most CO_2 in carbonated drinks is released to the air during consumption. In addition, the quantity of CO_2 needed for carbonated drinks is small compared with the CO_2 released by fossil fuels globally.

Another argument for using SDACCS/U is that it will be needed for removing CO_2 from the air once all fossil fuels are replaced with renewables. If renewables are then used to power SDACCS/U they can reduce CO_2 without incurring an air pollution cost. However, the question at that point is whether growing more trees, reducing biomass burning, or reducing halogen, nitrous oxide, and non-energy methane emissions is a more cost-effective method of limiting global warming.

In sum, SDACCS/U and CCS/U are opportunity costs, not close to zero-carbon technologies. For the same energy cost, wind turbines and solar panels reduce much more CO_2 while also reducing fossil air pollution and mining, pipelines, refineries, gas stations, tanker trucks, oil tankers, coal trains, oil spills, oil fires, gas leaks, gas explosions, and international conflicts over energy. CCS/U and SDACCS increase these by increasing energy use and always increase total social costs relative to using renewables to eliminate fossil fuel and bioenergy power generation directly.

Author contributions

M. Z. J. performed the research and wrote the paper.

Data and materials availability

Virtually all data are provided within the paper and references therein but any data not provided may be obtained from the author.

Conflicts of interest

Author declares no competing interests.

Acknowledgements

This paper was not funded by any entity.

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by
Richard B. Kuprewicz
President, Accufacts Inc.
kuprewicz@comcast.net
March 23, 2022

This report is developed from information clearly in the public domain. The views expressed in this document represent the opinion of the author.

I. Introduction

Accufacts Inc. ("Accufacts") was asked to review and comment on various aspects related to carbon dioxide transmission pipeline safety and federal pipeline safety regulations within the U.S. In recent years there has been considerable discussion about how to address carbon dioxide emissions and global warming through carbon capture, utilization, and sequestration (aka "CCUS" or "CCS"). CCS efforts are intended to help mitigate climate change by capturing carbon dioxide emissions both before and after they are released to the atmosphere and permanently storing such material deep in underground geological structures.

The federal Pipeline Safety Act ("PSA") directs the U.S. Department of Transportation ("DOT") to issue detailed safety standards with regard to the design, construction, operation, and maintenance of CO_2 pipelines.[1, 2] In turn, the DOT has delegated its authority to the Pipeline and Hazardous Materials Safety Administration ("PHMSA"). The PSA's broad mandate is supplemented by detailed federal regulations.[3] The PSA expressly prohibits state and local regulation that interferes with or supplements federal safety standards for interstate pipelines.[4] States meeting certain conditions may supplement federal pipeline safety regulation on their intrastate pipelines as long as such state regulations are not in conflict with federal pipeline safety regulations.

The U.S. has the most mileage of CO_2 transmission pipelines in the world, consisting of approximately 5,150 miles, out of a total 229,287 miles of hazardous liquid transmission pipelines within the U.S.[5] The vast majority, if not all, of these CO_2 existing pipelines are driven by enhanced oil recovery ("EOR") efforts that increase oil production utilizing CO_2 in a supercritical state. Most of this supercritical state CO_2 comes from high pressure higher purity natural underground source domes. It is an excellent solvent for EOR efforts, but the CO_2 must be injected into oil fields as a supercritical fluid.

CCS efforts are driven by an entirely different purpose such that CO_2 used for CCS could be shipped as a gas or a non-supercritical liquid. However, current federal safety regulations regulate only pipelines that transport supercritical CO_2 containing over 90% carbon dioxide molecules, and not pipelines that ship CO_2 in these other lower concentrations or forms, leaving a large regulatory gap. Moreover, even the regulations for supercritical CO_2 pipelines are incomplete or inadequate and place the public at

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[1] 49 U.S.C. § 60101 *et seq*.
[2] 49 U.S.C. § 60102(a) and (i).
[3] 49 C.F.R. Part 195.
[4] 49 U.S.C. § 60104(c) ("A State authority may not adopt or continue in force safety standards for interstate pipeline facilities or interstate pipeline transportation.")
[5] PHMSA reporting database, "Hazardous Liquid Pipeline Miles and Tanks," as of January 31, 2022 for CO_2 commodity at: https://portal.phmsa.dot.gov/analytics/saw.dll?Portalpages&PortalPath=%2Fshared%2FPDM%20Public%20Website%2F_portal%2FPublic%20Reports&Page=Infrastructure.

great risk, especially from the tens of thousands of miles of CO_2 pipelines that may be driven by CCS efforts.[6]

A flurry of multibillion dollar CO_2 pipeline proposals have recently been announced, likely driven by enhanced tax credit incentives provided by Internal Revenue Code § 45Q.[7, 8, 9] Congress provided these enhancements in the Bipartisan Budget Act of 2018, and expanded by the Infrastructure Investment and Jobs Act of 2021 ("Acts of 2018 and 2021").[10] As intended, these laws accelerated CCS and CO_2 pipeline development efforts, because they make such credits more available and valuable to certain generators of CO_2 emissions and require projects to start construction by January 1, 2026.[11] Since most carbon dioxide emitters are likely considerable distances from suitable deep, permanent underground storage sites, it is understandable that CO_2 transmission pipelines may be needed between emitters and these storage sites. If CO_2 pipeline mileage increases as projected, the CO_2 pipeline network could soon rival the existing oil and natural gas pipeline networks in size and complexity. PHMSA would be faced with the greatest and fastest pipeline expansion in the history of the U.S. pipeline industry, and many of these pipelines could threaten the safety of countless individuals and communities.

This report is intended to increase regulator and public awareness of the regulatory challenges posed by this proposed massive expansion in CO_2 pipeline mileage and the unique safety risks of transporting CO_2, especially in its supercritical state. It focuses on a higher-level review of the more technical pipeline safety matters, based on decades of pipeline safety experience including pipeline failure investigations, process engineering and process safety management practice, as well as years of experience in processing and handling many tons of liquid CO_2. This report also makes specific recommendations for improvements in federal pipeline safety regulations needed to fill regulatory gaps and ensure public safety. The proposed CO_2 pipeline boom presents

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[6] For one perspective see what I would call a planning study from Princeton University, "Net-Zero America - Potential Pathways, Infrastructure, and Impacts," Final Report, October 29, 2021, pp. 212 – 219 of 348, indicating a possible need of over 60,000 new miles of CO_2 pipelines by 2050.

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[10] 26 U.S.C. § 45Q.

[11] I.R.C. § 45Q.

PHMSA with an unprecedented challenge; hopefully, this report will help PHMSA rise to this challenge.

II. A brief history of U.S. federal CO_2 pipeline safety regulation

PHMSA and its predecessor agencies, such as the Office of Pipeline Safety, have historically relied on more prescriptive minimum safety approaches. In the past several decades federal minimum pipeline safety regulations have, by the industry's lobbying, shifted to more "performance-based" approaches that rely heavily on certain industry standards or recommended practices, some of which are incorporated by reference into federal pipeline safety regulation.[12] This industry driven shift can result in changes in pipeline safety regulations without proper public input. A prime example may be in the development of CO_2 transmission pipeline safety regulations that historically have been a very small percentage of overall transmission pipeline mileage in the U.S. This country may be facing a significant increase in CO_2 transmission pipeline mileage without appropriate pipeline safety regulatory development or enactment, leaving the country and the public ill prepared for a tsunami of CO_2 pipeline construction.

Congress, in Section 211 of the Pipeline Safety Reauthorization Act of 1988, required that the DOT regulate carbon dioxide transported by pipeline facilities. Part of this concern was driven by a 1986 natural carbon dioxide release event in Lake Nyos, Cameroon spanning many miles with over 1,700 fatalities, underscoring the dangers and possible consequences of CO_2 releases.[13] On July 12, 1991, federal regulators issued a minimalist final rule that mainly added the words "and carbon dioxide" to existing federal minimum pipeline safety regulations developed for hazardous liquid petroleum pipelines (49CFR§195). It opted to not issue standards specifically applicable to supercritical CO_2 pipelines due to the small number of already existing and anticipated CO_2 pipelines. Even though the situation is about to change dramatically, PHMSA has not proposed to review and overhaul its CO_2 pipeline standards, such that these limited regulations are still in effect today.[14] As a result, many of PHMSA's regulations no longer are adequate to protect public safety.

For example, under federal regulations "carbon dioxide" is defined as follows:

> "Carbon Dioxide means a fluid consisting of more than 90 percent carbon dioxide molecules compressed to a supercritical state."[15]

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[12] 49CFR§195.3 What documents are incorporated by reference partly or wholly in this part?

[13] Federal Register / Vol. 56, No. 113 / Wednesday, June 12, 1991/Rules and Regulations, Research and Special Programs Administration (RSPA), DOT, Docket No. PS-112, Amendment 195-45, RIN 2137-AB72, 49CFR Part 195, "Transportation of Carbon Dioxide by Pipeline," final rule.

[14] *Ibid*, p. 26924.

[15] 49CFR§195.2 Definitions.

The above definition is clearly not appropriate to deal with CCS CO_2 pipelines, nor is that its intent as demonstrated further in this report.

Existing U.S. CO_2 transmission pipelines are primarily located in sparsely developed or more rural locations and, as mentioned previously, involve approximately 5,150 miles moving CO_2 mostly from natural underground sources/domes to EOR projects. The current definition of "carbon dioxide" does not include pipelines that transport supercritical carbon dioxide streams in which CO_2 makes up less than 90 percent of the stream. It also excludes pipelines that transport CO_2 as a non-supercritical liquid or gas. In 1991, there were only a very limited number of pipelines transporting CO_2 in these other forms that apparently didn't justify the need for federal regulation, which is not the case now.

In 2011, Congress, in the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, Section 15, mandated that the Secretary of Transportation "prescribe minimum safety standards for the transportation of carbon dioxide by pipeline in a gaseous state." As a result, PHMSA issued a report in early 2015 entitled "Background for Regulating the Transportation of Carbon Dioxide in a Gaseous State."[16] Unfortunately, PHMSA never issued new regulations for transportation of CO_2 as a gas.

Thus, PHMSA currently has no regulations applicable to pipelines transporting CO_2 as a gas, liquid, or in a supercritical state at concentrations of CO_2 less than 90 percent. This regulatory gap means that current federal pipeline safety regulations are clearly inadequate because CO_2 pipeline companies could develop CO_2 gas and liquid pipelines that fall outside of this narrow federal rule. The definition of "carbon dioxide" should be modified so that all CO_2 transmission pipelines are regulated by federal law and held to appropriate minimum safety standards. Otherwise, CO_2 pipelines could be designed, constructed, operated, and maintained with no federal or state oversight.

III. CO_2 transmission pipelines can take on three basic forms

CO_2 transmission pipelines can be designed to transport carbon dioxide either as a supercritical state fluid, a liquid (aka in a subcritical or chilled state), or as a gas. Within the industry the term "dense phase" is often used to label CO_2 pipelines operating in either a supercritical state fluid or in a liquid phase as explained below. It is odd that the proposed new CO_2 transmission pipeline applications recently reviewed have not clearly stated in what phase they are designed to operate, their temperature ranges, nor their quality requirements.[17] The key characteristics of supercritical, liquid, and gaseous CO_2 transmission pipelines are summarized below.

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[16] PHMSA report dated February 2015, posted to the 2016 docket under PHMSA-2016-0049-001 at www.regulations.gov.

[17] For example, see Summit Carbon Solutions, "Application to the South Dakota Public Utilities Commission for a Permit for the SCS Carbon Transport LLC (SCS) Pipeline Under the Energy Conversion and Transmission Facility Act – Document Number: SCS-0700-ENV-05-PE-009-A," dated February 7, 2022.

i. Supercritical state CO_2 transmission pipelines

Pure CO_2 has a critical temperature of about 88 ºF (33 ºC) and a critical pressure of approximately 1070 psia, or pounds force per square inch absolute (73 atm). At temperatures and pressures above these critical values, CO_2 is not technically a liquid and instead is in a supercritical state as a dense phase "fluid" or vapor with properties between that of a liquid and a gas. This supercritical fluid will not condense to liquid within the pipeline, as long as the temperature remains above the critical temperature, no matter how high the pressure is increased above the critical pressure. If the temperature along a supercritical state pipeline drops below the critical temperature, part of the fluid will condense to liquid with a higher density than the fluid. If the pressure along a supercritical state pipeline drops below 1070 psia, part of the CO_2 will convert to a gas/liquid mixture depending on the temperature.

The primary reason that the existing 5,000 or so miles of CO_2 pipelines transport CO_2 in a supercritical state is because CO_2 in this state is an excellent solvent having no liquid surface tension. It readily dissolves oil trapped in porous rock. In contrast, CO_2 destined for sequestration could be transported as a gas or liquid, because sequestration does not, as a practical matter, need the CO_2 to be in a supercritical state, and federal law does not require transportation in a supercritical state. In fact, a clever pipeline operator could employ loopholes to avoid federal pipeline safety oversight by PHMSA. Clearly the sources and needs of CO_2 for EOR are not the same as those for the CCS objective, which is to remove CO_2 from the atmosphere.

CO_2 supercritical fluid transmission pipeline operating pressures usually range from 1,200 to 2,200 pounds force per square inch gauge, or psig. The higher pressure is set based on the maximum operating pressure ("MOP") usually related to a pipe specification limit.[18] There are a minor number of CO_2 supercritical state pipelines that have been designed to operate at much higher MOPs (*e.g.*, 3200 psig). Moving CO_2 as a dense phase supercritical state fluid permits the use of pumps along a pipeline instead of compressors that would be needed to move the material if it were a gas. For pipelines, the use of pumps to move higher density fluids requires smaller, less complex, equipment that is more efficient in moving mass along a pipeline than compressors (*i.e.*, pumps are cheaper to build, install, maintain, and operate than compressors). In addition, the higher MOPs of supercritical state CO_2 pipelines permit them to utilize smaller diameter pipe, albeit much stronger pipe, to move the same tonnage of CO_2 as compared to shipment as a gas. In contrast, gas pipelines require larger diameter pipe to move the same tonnage, because they must usually operate at pressures lower than the supercritical pressure (1070 psig), otherwise some of the CO_2 could convert to a liquid

[18] MOP stands for maximum operating pressure for liquid pipelines and is defined in federal minimum pipeline safety regulations that provide conditions for "normal" operation of pipelines. Pipelines are permitted to exceed MOP within certain limits, under certain situations.

(depending on the temperature along the pipeline) and such liquid slugs would severely damage/destroy the compressors used in gas pipelines.

While there are many cost/efficiency advantages to moving CO_2 in a supercritical state, there is one well known threat associated with supercritical state operation. A CO_2 pipeline operating in a supercritical state can be more prone to pipe running ductile fractures than hazardous liquids or natural gas pipelines. Running ductile fractures are unusual and particularly dangerous fractures that can "unzip" a CO_2 transmission pipeline for extended distances exposing great lengths of the buried pipeline. These extreme rupture forces throw tons of pipe, pipe shrapnel, and ground covering, generating large craters along the failed pipeline. It is well known that CO_2 pipelines operating in dense phase, either supercritical or as a liquid, are particularly susceptible to such running ductile fractures. Although current federal regulations recognize this risk, they do not contain any detailed requirements that specifically identify how to address fracture propagation threats. Though there are various approaches well known in the industry (*i.e.*, pipe steel fracture toughness parameters, usually for new pipe, and/or mechanical arrestors such as valves, thicker/tougher pipe transitions) such approaches should be specifically mentioned in safety regulation.[19] To address this risk, PHMSA should revise federal regulations, especially for supercritical CO_2 pipelines, to specifically mitigate the effects of these fracture propagation forces. The current regulations do not adequately address these CO_2 fracture risks.

ii. Liquid CO_2 transmission pipelines

Subcooled or subcritical state means to transport CO_2 as a liquid that usually requires chilling and/or cooling of the stream slightly below ambient temperatures to assure the pipeline is operated in one phase, that of a liquid. For new pipelines this also may require the use of pipeline insulation, though not always, to reduce temperature increase of the CO_2 along the pipeline, assuring it stays as a liquid. It is important that cooling stay well above the pipe carbon steel brittle transition temperature of approximately - 20 ºF to avoid the threat of catastrophic pipeline rupture. Despite these obstacles, transporting CO_2 as a liquid, basically at its highest density, which is typically about double the density of CO_2 fluid in its supercritical state, allows the pipeline transportation of more tonnage of carbon dioxide with even smaller diameter pipe than a supercritical state operation, as well as lower MOPs. Because the liquid phase operation also has a lower viscosity, a liquid CO_2 pipeline system for a given length can utilize a fewer number of pump stations that can have major advantages over supercritical state or gas pipeline approaches needed to move similar tonnage of CO_2. For CCS objectives, liquid phase CO_2 transmission pipelines additional efficiency over their supercritical state or gas counterparts may justify the additional cooling infrastructure along such

[19] 49 CFR§195.111 Fracture propagation. The regulation states in full: "A carbon dioxide pipeline system must be designed to mitigate the effects of fracture propagation." Thus, pipeline safety law contains no detailed standards to prevent running ductile fractures leaving much room for misinterpretation.

pipelines. It is worth emphasizing that PHMSA chose to not issue regulations for CO_2 pipelines designed to operate as a liquid, so such pipelines are currently unregulated.

iii. CO_2 gas transmission pipelines

New pipelines designed to move CO_2 as a gas in a transmission pipeline is not likely, given that the system must be operated at lower pressures. For a CO_2 gas pipeline, the MAOP must not exceed approximately 1,000 psig at normal operating temperatures, so that the CO_2 is maintained as a gas and does not convert to a liquid as this could be disastrous for the pipeline's compressors.[20] For an equivalent daily CO_2 tonnage pipeline capacity, the requirement to keep design pressure lower drives such new gas pipeline approaches to much higher pipe diameters than their liquid or supercritical state pipeline alternatives. However, specific situations may exist where existing liquid or larger diameter natural gas pipelines could be "repurposed" into primarily CO_2 gas service.[21] Such change in service, will most likely be highly limited in its pipeline mileage and, in my opinion, should exceed the requirements identified in ADB-2014-04, addressing repurposing of natural gas pipelines or liquid pipelines. For example, an Advisory Bulletin, or ADB, does not carry the force of promulgated pipeline safety regulation but is issued to more quickly alert pipeline operators of PHMSA concerns on certain issues. ADB-2014-04 does not address, nor was it intended to address, the specific additional challenges associated with unique fracture propagation risks associated with CO_2 transmission pipelines as previous discussed. While there are unique situations where nonoperating or underutilized pipelines exist, there are several factors that can make repurposing of such pipelines to CO_2 gas service economically attractive, given the billions of dollars in tax credit incentives associated with CCS under the Acts of 2018 and 2021, and the associated start construction deadline. The critical deadlines to meet tax credit triggers could make timing of such conversions more favorable than routing and construction of new CO_2 pipelines for CCS. Such pipeline conversions would be at much greater risk of failure from CO_2 service than conventional hydrocarbon or new construction CO_2 pipelines, given the unique and increased potential for CO_2 pipeline ruptures from various risks associated with CO_2 operation. Only time will tell, given the economic temptations and timing thresholds, whether such repurposing of an existing transmission pipeline to CO_2 service will prove practical for CCS utilization.

[20] MAOP stands for maximum allowable operating pressure, which is the standard for gas pipelines and is defined in federal minimum pipeline safety regulations that provide conditions for "normal" operation of pipelines. Pipelines are permitted to exceed MAOP within certain limits, under certain situations.

[21] See DOT PHMSA, Advisory Bulletin, ADB-2014—04, "Pipeline Safety: Guidance for Pipeline Flow Reversals, Product Changes and Conversion to Service," Docket No. PHMSA–2014–0040, Sept 12, 2014.

IV. CO_2 transmission pipelines pose different risks than traditional hydrocarbon transmission pipelines

Carbon dioxide gas is odorless, colorless, doesn't burn, is heavier than air, and is an asphyxiant and intoxicant, making CO_2 pipeline releases harder to observe and avoid especially as a released plume spreads and migrates well off the pipeline right-of-way. CO_2 properties differ from those for materials moved in hazardous hydrocarbon liquid or natural gas transmission pipelines. CO_2 pipeline releases significantly increase the possible "affected" or "potential impact" area identified in federal regulations addressing hydrocarbon transmission pipelines upon pipeline rupture release, and CO_2 pipeline ruptures have a greater potential to endanger the public. Current federal pipeline safety regulations do not incorporate these important CO_2 differences to assure safety to the public. Federal pipeline safety regulatory changes are warranted if CO_2 pipeline mileage is to be increased dramatically in the U.S., especially under CCS. CO_2 transmission pipelines have many unique failure dynamics such that a rupture may impact significantly greater geographic areas than hydrocarbon pipelines. In particular, a combination of CO_2 phase/temperature changes may result in explosive pipe release forces as the CO_2 converts to gas. Moreover, CO_2's lack of odor and invisibility means that it may not be possible for citizens and first responders to determine if they are in a hazard area before they are harmed, unless they have access to a CO_2 detection meter. It is important that anyone using such CO_2 detection meters assure that such equipment has been properly calibrated/maintained and users properly trained in their use and limitations. Once a CO_2 pipeline release has been warmed by the surrounding environment, it travels unseen influenced by gravity, terrain, and the wind, preferentially settling in low spots, displacing air and providing no warning to persons and animals caught in the invisible release plume. Hydrocarbon pipeline releases that haven't ignited, can usually be detected by unusual smell or sight, which makes CO_2 pipeline releases different and harder to detect by emergency responders or the public.

During a CO_2 pipeline rupture release, multiple phase changes can result not only in the significant lowering of temperature near the pipe failure site, but also the likelihood of solid CO_2 formation (i.e., dry ice). Dry ice particles within the fluid can contribute to fogging in the air and ground around the pipeline release, as well as the formation of dry ice within the pipeline upstream/downstream of the pipe failure site that can impact the rate of release out of a pipe failure. Such dry ice blockage can result in temporary restriction/blockage within the pipe, affecting release rate, especially for smaller diameter transmission pipelines experiencing rupture fracture.

In CO_2 pipelines experiencing smaller, slower rate releases, often called leaks, such as through minor holes or cracks, the resulting lower rate CO_2 rich clouds may disperse/dissipate after a short time. In much larger rate releases, such as pipeline rupture fractures caused from various anomalies or pipeline threats, the resulting release of cold gas and dry ice solid mixtures can be quite dangerous (see video of

DNV rupture failure test of an CO_2 8-inch diameter pipeline).[22] The CO_2 released from a pipeline will be heavier than air, and the high-rate release from a pipe rupture will form cold dense gas fog clouds comprised of dry ice particles and visible water vapor as the humidity in the air condenses from the extreme cooling. Such high-rate releases can produce areas of low visibility from "fog," both from dry ice particles and water condensation. The CO_2 pipeline rupture fog becomes transparent when eventually warmed by the surrounding environment. Upon warming, the CO_2 plume can flow considerable distances from the pipeline unobserved, traveling over terrain, displacing oxygen while settling or filling in low spots. Oxygen displacement can starve gasoline or diesel powered equipment, such as first responder and private vehicles, causing such equipment to malfunction or even shut off, and cause pilot lights on furnaces, stoves, and natural gas fireplaces to go out. Oxygen displacement by CO_2 gas can cause asphyxiation of humans and animals, that can lead to death. Further, CO_2 gas can cause disorientation, confusion, and unconsciousness, which can be dangerous for persons caught in the plume, especially those who are driving, using power equipment, or exposed to cold weather. Cooling of a CO_2 release can also impact the rate of release and exacerbate pipe fracture propagation during rupture. Clearly, dispersion modeling for analyzing potential impact areas for CO_2 pipeline failures and their related released gas plumes, must consider the propensity of heavier than air CO_2 gas to displace oxygen and to follow the terrain as terrain factors can play a critical role in evaluating a potential area and receptors that could be affected by a CO_2 pipeline release. It is vitally important to not underestimate the potential distance that a CO_2 pipeline rupture plume can reach and affect, especially in nonlevel terrain. Additional safety margins should be employed in populated areas when using dispersion modeling results for CO_2 pipeline releases.

Before the U.S. is blanketed with a major increase in CO_2 transmission pipeline mileage driven by CCS efforts, substantial changes need to be implemented in federal pipeline safety regulations specifically addressing the unique dangers of CO_2 in transmission pipelines in any phase. CO_2 is not flammable. It doesn't burn or explode/detonate from ignition, so heat radiation is not an issue of concern as in conventional hydrocarbon pipelines. CO_2 can, however, generate similar overpressure "blast" forces upon pipeline rupture (from the high-rate releases associated with pipeline fracture failure, see previous referenced 8-inch CO_2 pipeline rupture test). CO_2 pipeline rupture and resulting rapid "blast like" expansion forces dissipate quickly with distance from the pipeline but can easily extend well beyond the pipeline right of way. The areas potentially impacted by ruptures of oil and gas transmission pipelines are well defined in current federal regulations, which estimate how far liquid hydrocarbon will spread and the blast or burn radius resulting from a natural gas pipeline rupture. The danger zone for human life for hazardous hydrocarbon liquid and natural gas pipeline releases is generally measured in feet, albeit many thousands of feet for larger diameter higher pressure pipelines.

[22] Video of 2013 DNV Spadeadam Research and Testing test experiment of dense phase CO_2 8-inch buried pipeline rupture, https://www.dnv.com/oilgas/laboratories-test-sites/dense-phase-spadeadam-video.html.

In contrast, a CO_2 pipeline's impact area may be measured in miles, not feet. This is likely because:

- CO_2 pipeline ruptures can release many tons of CO_2,
- the compressed CO_2 will expand into gas phase upon pipeline rupture and fill a much larger volume that it did inside the pipe, and
- the CO_2 may not disperse quickly because it is heavier than air, meaning that it will tend to flow toward and settle in low lying areas including ravines, valleys, and basements.

Current federal pipeline safety regulations do not provide any methodology for assessing the hazard zone for CO_2 pipelines or require that pipeline operators adequately address this risk.

V. Impact of impurities on CO_2 pipelines

The amounts and types of impurities in a CO_2 stream can have an impact on pipeline design and approaches. Current CO_2 pipeline regulations, which only address CO_2 pipelines greater than 90% CO_2 concentration compressed to a supercritical state, make no mention as to the level of non-CO_2 impurities such as H_2S, which can be lethal even in very low parts per million concentrations. Also, impurities can affect the range of safe operating pressures. Most of the natural sources of CO_2 for existing pipelines contain CO_2 well above 90%, but this may not be the case for all CO_2 streams captured from industrial facilities. Federal regulation should be modified to adequately regulate CO_2 pipelines used for CCS, and subsequent transportation by transmission pipeline, especially because CCS pipelines may operate differently from those used for EOR. Such federal regulatory improvements should focus on public safety for all forms/phases of CO_2 transmission pipelines. There are some very pure sources of CO_2 emitters, such as ethanol plants and some hydrogen reformers, that emit very high concentrations of CO_2 to the atmosphere that require very little, if any, impurity treatment to prepare for pipeline transportation for CCS.[23] Unlike most of the currently existing CO_2 pipelines whose sources are underground natural gas domes or reservoirs, CSS pipelines may be supplied from various sources where the concentration of CO_2 is quite low and needing concentration, processing, and treatment for contaminant removal before it may be safely transported by pipeline.

There appears to be no transmission pipeline in the U.S. that transports pure CO_2, although there are pipelines that move very high concentrations of CO_2, well above 90%, containing only small levels, of impurities, especially those from natural sources of CO_2. Such CO_2 rich sources can still contain impurities, such as hydrogen sulfide, methane, carbon monoxide, oxygen, nitrogen oxide, sulphur oxide, hydrogen, or

[23] My experience is that purity from such CO_2 specialized emitters can exceed 99.9 % with trace impurities.

water.[24] The types and amounts of impurities in a CO_2 rich pipeline is largely driven by the source of CO_2, and proper operation of associated upstream treatment equipment to assure the material meets pipeline quality specifications, which is not always assured. At relatively low levels of impurities, such as at trace or levels in the lower parts per million, the specific effects of the impurities on the overall stream critical thermodynamic properties (such as enthalpy, entropy, density, and viscosity), are not significantly impacted. However, higher impurity concentrations, such as impurities measured in percentage concentrations should not be ignored as they can impact the critical pressure, but more importantly the critical temperature, such that even a percent or two change in impurity levels can result in unexpected phase change from dense phase fluid to other phases. Such phase changes may impact the system hydraulics, and to some extent the rupture release dynamics should the pipeline fail.

Two impurities that might be possible in CO_2 pipelines merit mention given their unique dangers to pipelines and the public: water and H_2S. CO_2 pipelines are usually made from carbon steel and require special maximum water quality specifications typically measured in the part per million, or its equivalent, that prevents the possibility of free water forming anywhere in the pipeline system. The presence of free water in a CO_2 stream permits the formation of carbonic acid in the pipeline, an acid that has a ferocious appetite for carbon steel. Given the rapidity and unpredictability at which carbonic acid can attack pipelines, prudent CO_2 pipeline operators have voluntarily established maximum water quality limitations for their input streams. Given the risks associated with carbonic acid attack, PHMSA should not leave this critical factor to company discretion, but instead should adopt federal regulations that specify a maximum water quality limitation for CO_2 pipelines.

Hydrogen sulfide, or H_2S, is mentioned here because of a curious item identified in an article related to a supercritical state CO_2 pipeline rupture failure in Mississippi in early 2020.[25] The observations noted in the article by responders of a "green cloud" from the pipeline release, is a possible indication of high levels of H_2S. Further investigation indicates that the source of the CO_2 (Jackson Dome) has levels of H_2S at 5 percent, or 50,000 ppm. In contrast, the Centers for Disease Control and Prevention states that a level of 300 parts per million is "immediately dangerous to life or health."[26] While the H_2S level that transitions into "sour" gas is not defined in federal

[24] For example, see Suoton P. Peletire, Nejat Rahmanian, Iqbal M. Mujtaba, "Effects of Impurities on CO_2 Pipeline Performance, Chemical Engineering Transactions," Vol. 57, 2017.

[25] Dan Zegart Huffpost article, "The Gassing of Satartia," August 26, 2021 at https://www.huffpost.com/entry/gassing-satartia-mississippi-co2-pipeline_n_60ddea9fe4b0ddef8b0ddc8f,

[26] https://www.cdc.gov/niosh/idlh/7783064.html. It is my understanding that while a few states have attempted to impose H_2S limits on intrastate pipelines, there is no such federal pipeline safety regulation limiting H_2S on transmission pipelines, even though there are OSHA H_2S limits on workplace workers, much lower than 300 ppm.

pipeline safety regulations, serious questions need to be raised about this specific CO_2 pipeline operation.

For CCS generated CO_2, from fuel combustion emission, an expected source for CCS, H_2S is not a likely contaminant of the stream with trace levels of H_2S in the less than 1 ppm to be expected. Treatment for the removal of water and water quality enforcement control limitations, however, are critical for CCS pipelines transporting CO_2 from combustion sources. Yet, current federal pipeline safety regulations also do not require that this risk be addressed.

VI. Areas needing additional federal pipeline safety focus for CO_2 pipelines

Based on my experiences, the following are my preliminary observations on specific areas where CO_2 pipeline safety regulation improvement efforts should focus.

1. **PHMSA should update the definition of carbon dioxide in current regulation.**
   The current "carbon dioxide" definition incorporated into pipeline safety regulation is driven by EOR and does not or may not apply to all CO_2 pipelines that may be developed for CCS projects. Federal regulations need to be modified to assure that federal standards apply to all CO_2 transmission pipelines that transport CO_2 for CCS projects, including all supercritical, gas, and liquid CO_2 transmission pipelines.

2. **PHMSA needs to identify in regulation the potential impact areas for CO_2 pipeline ruptures.**
   The unique, and potentially very large impact areas for CO_2 pipeline ruptures need to be developed, defined, and promulgated into pipeline regulations. As mentioned previously, these areas are most likely to be measured in miles, not feet.

3. **Specific CO_2 pipeline federal regulations should not be based solely on industry Recommended Practices.**
   Changes in the CO_2 pipeline safety regulation are needed and should be prescribed to avoid misinterpretation or misuse. Recent efforts by many in the industry to rely on more performance-based standards, even those incorporated by reference, have proven ineffective and disastrous. Such industry efforts also remove an important party to pipeline safety regulatory development, the public. Ironically, it is the public that has the most to lose from inadequate pipeline safety regulation if such referenced citations are not clear, relevant, effective, and cannot be enforced in assuring pipeline safety.

4. **PHMSA should specifically identify how to incorporate fracture propagation protection on CO_2 transmission pipelines.**
   Given the differential propensity for CO_2 pipelines to propagate fractures along the pipeline upon rupture, regulations should specifically list pipeline design methods to arrest CO_2 fracture propagation.

5. **PHMSA should mandate the use of odorant injection into CO_2 transmission pipelines.**
   Given the inability to detect or observe a CO_2 pipeline release, it is time to require the use of odorant injection in such pipelines, especially those pipelines that are not in unpopulated areas, to assist the public in identifying dangerous releases.

6. **PHMSA should require CO_2 pipeline operators to update their required procedural manuals related to coordination with local emergency response agencies for CO_2 pipeline ruptures.**
   The major differences and uniqueness of CO_2 pipeline releases compared to hydrocarbon pipelines require that pipeline operators improve the sections of their federally mandated operation, maintenance, and emergencies procedural manuals for emergency response to CO_2 pipeline ruptures.[27] In particular, operators must be required to periodically and fully inform, train, and equip key local officials and emergency responders with regard to special response actions unique to CO_2 pipeline releases. Moreover, upon a rupture, pipeline operators must inform state and local emergency personnel so that they can quickly and adequately protect impacted citizens and themselves.

7. **PHMSA should establish regulations setting specific maximum contaminant impurities for CO_2 pipelines.**
   Given the various sources and the unique risk associated with the introduction of water into a CO_2 pipeline, PHMSA should prescribe the maximum concentration of water allowed in them. This requirement goes well beyond a quality specification given the ability of water to rapidly cause CO_2 pipeline failures in unpredictable ways. Given the wide range of impurity sources for CO_2 streams for CCS, PHMSA should review a full range of limits for all common impurities and consider establishing maximum levels for all impurities that pose a safety risk in federal pipeline safety regulations.

8. **PHMSA should strengthen federal regulations for conversion of existing pipelines to CO_2 pipeline service.**
   It is not clear whether the public interest is best served by CO_2 shipment in existing transmission pipelines converted to CO_2 service. Further, the general conditions of PHMSA's advisory bulletin are not adequate for conversion to CO_2 pipelines. PHMSA should fully investigate the risks of such conversions and issue regulations appropriate to the serious risks that could result from repurposing a pipeline for CO_2 service.

VII. Conclusions

Current federal minimum pipeline safety regulations focus on higher concentration CO_2 pipelines transporting CO_2 in a supercritical state for use in oil production. Such

[27] 49CFR§195.402 and 49CFR§192.605 Procedural manual for operations, maintenance, and emergencies.

regulations are incomplete or in conflict with the intent of CCS, to reduce CO_2 content in the atmosphere to address global warming. Federal pipeline safety regulation concerning CO_2 pipelines need specific changes to address the likely expansion of CO_2 transmission pipeline mileage expected by CCS efforts enhanced by the Acts of 2018 and 2021.

Certain manufacturing processes, such as ethanol and some hydrogen reforming refinery units, produce CO_2 emission that are very pure CO_2, with only trace amounts of contaminants, that are higher priority choices for CCS and associated pipelines, most likely new liquid transmission pipelines, especially under the immense tax credits associated with the Acts of 2018 and 2021. Current federal pipeline safety regulations, however, are not adequate to deal with the additional pipeline risks associated with the expected significant increase in associated CO_2 transmission pipelines under CCS.

The country is ill prepared for the increase of CO_2 pipeline mileage being driven by federal CCS policy. Federal pipeline safety regulations need to be quickly changed to rise to this new challenge, and to assure that the public has confidence in the federal pipeline safety regulations.[28]

Richard B Kuprewicz

Richard B. Kuprewicz
President,
Accufacts Inc.

[28] Disclosure: The author prepared this report for the Pipeline Safety Trust but retained full editorial control. The author received compensation from the Pipeline Safety Trust and the Bold Alliance for the preparation of this report.

frontiers in Earth Science

ORIGINAL RESEARCH
published: 10 December 2020
doi: 10.3389/feart.2020.611010

Groundwater Anomaly Related to CCS-CO_2 Injection and the 2018 Hokkaido Eastern Iburi Earthquake in Japan

Yuji Sano[1,2], Takanori Kagoshima[1,3], Naoto Takahata[1], Kotaro Shirai[1], Jin-Oh Park[1], Glen T. Snyder[1,4], Tomo Shibata[5], Junji Yamamoto[6], Yoshiro Nishio[7], Ai-Ti Chen[8], Sheng Xu[2], Dapeng Zhao[9] and Daniele L. Pinti[10]*

[1]Atmosphere and Ocean Research Institute, University of Tokyo, Kashiwa, Japan, [2]Institute of Surface-Earth System Science, Tianjin University, Tianjin, China, [3]Graduate School of Science and Engineering, University of Toyama, Toyama, Japan, [4]Department of Chemistry, Gakushuin University, Tokyo, Japan, [5]Institute for Geothermal Sciences, Kyoto University, Beppu, Japan, [6]University Museum, Hokkaido University, Sapporo, Japan, [7]Faculty of Agriculture and Marine Sciences, Kochi University, Nangoku, Japan, [8]Department of Geosciences, National Taiwan University, Taipei, Taiwan, [9]Department of Geophysics, Tohoku University, Sendai, Japan, [10]Geotop, Research Center on the Dynamics of the Earth System, Université Du Québec à Montréal, Montreal, QC, Canada

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Edited by:
Giovanni Martinelli, National Institute of Geophysics and Volcanology, Italy

Reviewed by:
Tiziano Boschetti, University of Parma, Italy
Walter D'Alessandro, National Institute of Geophysics and Volcanology, Italy

****Correspondence:***
Yuji Sano
yujisano128@g.ecc.u-tokyo.ac.jp

Specialty section:
This article was submitted to Geochemistry, a section of the journal Frontiers in Earth Science

Received: *28 September 2020*
Accepted: *09 November 2020*
Published: *10 December 2020*

Citation:
Sano Y, Kagoshima T, Takahata N, Shirai K, Park J-O, Snyder GT, Shibata T, Yamamoto J, Nishio Y, Chen A-T, Xu S, Zhao D and Pinti DL (2020) Groundwater Anomaly Related to CCS-CO_2 Injection and the 2018 Hokkaido Eastern Iburi Earthquake in Japan. Front. Earth Sci. 8:611010. doi: 10.3389/feart.2020.611010

Carbon capture and storage (CCS) is considered a key technology for reducing CO_2 emissions into the atmosphere. Nonetheless, there are concerns that if injected CO_2 migrates in the crust, it may trigger slip of pre-existing faults. In order to test if this is the case, covariations of carbon, hydrogen, and oxygen isotopes of groundwater measured from Uenae well, southern Hokkaido, Japan are reported. This well is located 13 km away from the injection point of the Tomakomai CCS project and 21 km from the epicenter of September 6th, 2018 Hokkaido Eastern Iburi earthquake (M 6.7). Carbon isotope composition was constant from June 2015 to February 2018, and decreased significantly from April 2018 to November 2019, while total dissolved inorganic carbon (TDIC) content showed a corresponding increase. A decrease in radiocarbon and $\delta^{13}C$ values suggests aquifer contamination by anthropogenic carbon, which could possibly be attributable to CCS-injected CO_2. If such is the case, the CO_2 enriched fluid may have initially migrated through permeable channels, blocking the fluid flow from the source region, increasing pore pressure in the focal region and triggering the natural earthquake where the brittle crust is already critically stressed.

Keywords: Hokkaido earthquake, carbon capture and storage-CO_2 injection, groundwater, carbon isotopes, radiocarbon

INTRODUCTION

There is a global consensus that some form of carbon capture and storage (CCS) technology is necessary to reduce CO_2 emission associated with fossil fuel combustion into the atmosphere (IPCC Special Report, 2005). The majority of research into this technology has focused on securely isolating CO_2 from the Earth's surface and storing it in a reservoir which is sealed by an impermeable cap rock (Johnson et al., 2005; Michael et al., 2011). This strategy should prevent CO_2 from leaking into the closest areas around the injection well but it may promote horizontal flow of CO_2-rich fluids through available permeable horizons. Interactions between injected fluids and high angle faults may result in

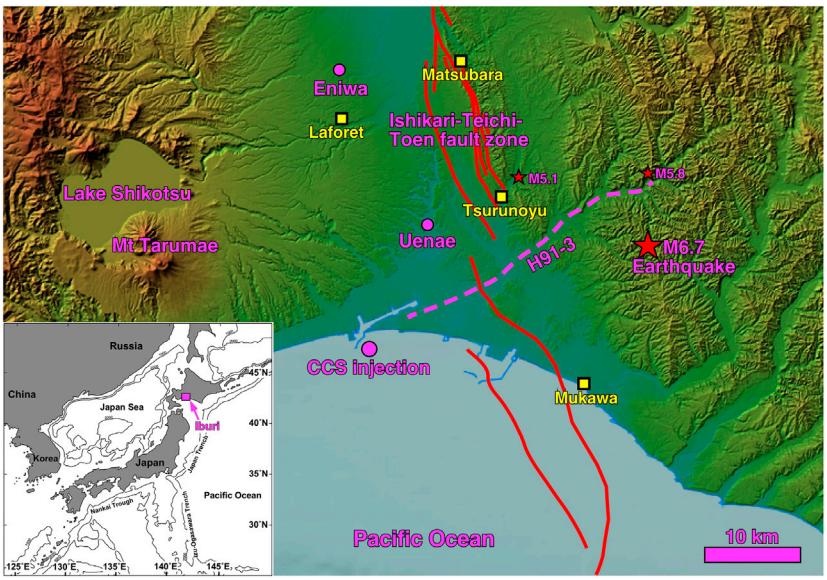


FIGURE 1 | Location of Uenae and Eniwa sampling wells in the Hokkaido Iburi region; the CCS-CO_2 injection point (purple dots); and main shock epicenter (M6.7) of the 2018 Hokkaido Eastern Iburi earthquake (red star). Two additional red stars denote the epicenters of the M5.1 earthquake on July 1st, 2017 and of the largest (M5.8) aftershock on February 21st, 2019. The red lines represent active faults in the Ishikari-Teichi-Toen fault zone (ITTFZ). The purple dashed line denotes the seismic reflection transect H91-3. Yellow squares show hot springs sampled for helium isotopes. The inset map shows the location of the Iburi region in Hokkaido, Japan.

fluid accumulation and increases in pore pressure in the region around the area. This increase in pressure may propagate to much deeper regions where the brittle crust is already critically stressed and perhaps trigger slippage of pre-existing faults (Zoback and Gorelick, 2012). This mechanism is similar to the triggering of anthropogenic seismicity during high-pressure hydraulic injection experiments (Grigoli et al., 2018). However, to date, there are no case studies reported on the possible environmental consequences of CCS-CO_2 injection.

The 2018 Hokkaido Eastern Iburi earthquake (M6.7) occurred on September 6th, 2018 in Northern Japan, close to the major active Ishikari-Teichi-Toen Fault Zone (ITTFZ), with a focal depth of 37 km (Asano and Iwata, 2019). The earthquake triggered large landslides and caused severe damage to the surrounding area with 36 casualties. Uniform strain accumulation was observed in this area from data collected by a global navigation satellite system in very recent years (Ohzono et al., 2019). The large-scale Tomakomai CCS demonstration project, built in the same region, was initially suspected to have indirectly caused the earthquake (KIKO network, 2019). The Japan CCS Co. Ltd.—the company that developed the project - reported that the CO_2 injection point was too far from the epicenter to produce any appreciable amount of strain change or to induce an earthquake (Japan CCS, 2019). However, many concerns still exist regarding the potential relationship between large-scale CO_2 injection and local earthquakes, and given that there is little consensus as to the potential consequences, further study is needed. Deep wells close to the CCS site may provide direct evidence of the CO_2 leakage that can potentially trigger natural earthquakes.

TABLE 1 | Temperature, pH and chemical compositions of groundwater samples in Hokkaido, Japan.

Site	Uenae	Eniwa
Date	2019 May 28th (H18)	2018 October 4th (H6)
Temperature (°C)	9.0	8.2*
pH	6.3	7.3
Na (mmol/L)	1.11	0.42
K (mmol/L)	0.16	0.046
Mg (mmol/L)	0.19	0.13
Ca (mmol/L)	0.61	0.27
Cl (mmol/L)	1.05	0.20
NO_3 (mmol/L)	0.48	0.18
SO_4 (mmol/L)	0.38	0.11

Estimated by annual mean temperature and geothermal gradient in the region.

GROUNDWATER SAMPLES

We collected groundwater samples from wells used for producing commercial bottled mineral water at Uenae and Eniwa sites, located 13 and 29 km from the CCS Tomakomai site, respectively (**Figure 1**). Commercial water has a precise production date and both the chemical compositions and stable isotopic composition are well preserved (Tsunogai and Wakita, 1995; Onda et al., 2018), with the exception of helium because of the high permeability of this gas through PET bottles. We purchased as many bottles as possible covering a period of three years before and a year and half after the M6.7 earthquake. Both wells are 90–100 m deep and tap a volcanic-sedimentary aquifer belonging to the Shiatsu pyroclastic flow, which erupted in the Late Pleistocene (Nakagawa et al., 2018). High-quality drinking

mineral water is available from altered ignimbrite units. Chemical compositions of representative samples from Uenae and Eniwa sites are listed in **Table 1** together with temperature and pH. Twenty-one untreated bottled water samples were analyzed for carbon, hydrogen and oxygen isotopes. The samples cover the period from June 2015 to February 2020, and include the critical period between April 2016 and December 2019, when a total of 300 kilotons of CO_2 were injected, as well as the timing of the M6.7 Hokkaido earthquake event in September 2018.

Carbon, Hydrogen, Oxygen, and Helium Isotopes, and ^{14}C Activity Measurements

We have carefully selected unopened mineral water bottles to avoid contamination by air CO_2, which has a different isotopic composition than dissolved carbonates. Carbon isotopes were measured at the Atmosphere and Ocean Research Institute, University of Tokyo, Japan with a conventional continuous flow mass spectrometer (Delta V plus, Thermo Fisher) after standard decarbonation with phosphoric acid. Experimental details followed the methodology provided in Zhao et al. (2019). The $^{13}C/^{12}C$ ratios were calibrated against our in-house standard, converted to conventional V-PDB units, and expressed as δ values in per mil (‰). Total Dissolved Inorganic Carbon (TDIC) concentrations were estimated by a peak height method with standard samples of known amounts of TDIC. Experimental errors on carbon isotopes and TDIC concentrations were calculated by repeated measurements of standard samples. Hydrogen ($^2H/^1H$) and oxygen ($^{18}O/^{16}O$) isotopes of water were measured with a cavity ring-down spectrometer without any preprocessing at Geotop, Université du Québec à Montréal, Canada, using a Los Gatos LGR-T-LWIA-45-EP, and then verified at the Atmosphere and Ocean Research Institute, University of Tokyo, Japan (Onda et al., 2018) using a L2120-I Analyzer (PICARRO Co. Ltd.). They were calibrated against in-house standards, converted to the conventional V-SMOW units, and expressed as δ values in per mil (‰). Experimental errors on hydrogen and oxygen isotopes were calculated by repeated measurements of standard samples. TDIC was precipitated and purified. It was then reduced into pure amorphous carbon and the $^{14}C/^{12}C$ ratios were measured with a compact AMS system at the Institute of Surface-Earth System Science, Tianjin University, China (Dong et al., 2019). Extracted helium and neon from spring water samples were purified with hot Ti getters and charcoal traps held in liquid nitrogen. The $^4He/^{20}Ne$ ratios were measured by online QMS, and helium was separated from neon by a cryogenic charcoal trap. The $^3He/^4He$ ratios were measured with a noble gas mass spectrometer (Helix SFT, Thermo Fisher). Experimental details are provided in Sano et al. (2008).

Tomakomai Carbon Capture and Storage Demonstration Project

A large-scale CCS demonstration project was undertaken by the Japanese government in the Tomakomai site in Hokkaido, Japan (**Figure 1**). Intensive stakeholder engagement was implemented by the Japan CCS company because the operation was taking place in the port area close to a highly populated city. The CO_2 source was offgas derived from a hydrogen production unit of an oil refinery located in the region. A high purity CO_2 (>99%) was recovered from the offgas by an amine scrubbing process and the gaseous CO_2 was compressed and then injected into two different offshore geological reservoirs (Yamanouchi et al., 2011; Sawada et al., 2018). The host reservoirs are the shallow Moebetsu Formation located at a depth of approximately 1000 m below the seabed and the deep Takinoue Formation with the depth of 2400 m. The former is a Lower Quaternary saline aquifer composed of 200 m thick sandstone, while the latter is a Miocene saline aquifer which consists of volcanic and volcaniclastic rocks with a thickness of 600 m. A schematic diagram of geological section is referred from Tanaka et al. (2017) and reproduced in **Supplementary Figure S1**. The CO_2 injection of the shallow reservoir started in April 2016 and continued until November 2019. A total of 300 kilotons of gaseous CO_2 was injected gradually (**Supplementary Figure S2**). A smaller amount of CO_2, approximately 100 tons, was injected into the deeper reservoir.

DISCUSSION

Temporal Variations of Stable and Radioactive Isotopes in Groundwater

The $\delta^{13}C$ values and the TDIC contents, δ^2H and $\delta^{18}O$ values, and ^{14}C activity were measured in commercially-bottled groundwater as stated above, and are listed in **Table 2**. The $\delta^{13}C$ value of the TDIC in Uenae well groundwater was constant at −17.8 ± 0.2‰ from June 2015 through February 2018, and then decreased to −18.8 ± 0.2‰ with some fluctuation (**Figure 2A**). The TDIC concentration at Uenae was also constant from June 2015 to February 2018, and increased significantly in December 2018, which is the inverse of the observed trend for $\delta^{13}C$ (**Figure 2B**). On the other hand, the $\delta^{13}C$ of TDIC in groundwater from the Eniwa well decreased over time, from −18.5‰ to −20.9‰, except for October 2017, while TDIC concentration remained constant at 0.68 ± 0.03 mmol/L, except for the most recent sample. Injected CO_2 was the by-product of a hydrogen production unit of an oil refinery (Sawada et al., 2018). Its $\delta^{13}C$ value should therefore have been lighter than −25‰ (Hoefs, 2018) and its ^{14}C activity close to zero, because fossil fuels are too old to contain any anthropogenic ^{14}C. Injection began in April 2016 and reached 100 kilotons of CO_2 in November 2017 (**Supplementary Figure S2**), which is approximately one third of the total injected amount (Tanaka et al., 2014; Japan CCS, 2020). There was no heavy rain or flooding in the region during this period. Additionally, there is no large bridge or dam construction close to the observation wells that could have altered the groundwater system and triggered the earthquake (Gupta and Iyer, 1984). The Uenae site is located in non-volcanic frontal arc region, even though it is close to the volcanic front. There is no known cause, and no physical or chemical processes, capable of changing geochemical parameters such as carbon isotopes of groundwater except for oxidation of organic matter.

TABLE 2 | Hydrogen, oxygen and carbon isotopes together with total DIC contents of groundwater samples in Hokkaido, Japan.

Code	Date	δ^2H* (‰)	$\delta^{18}O$* (‰)	δ^{13} (‰)	TDIC* (mmol/L)	C-14 (pMC)
Uenae						
H7	28/06/2015	−59.47	−8.64	−17.69	0.79	
H8	19/09/2016	−60.39	−8.57	−17.78	0.79	101.10
H9	13/02/2018	−60.45	−8.36	−17.93	0.75	100.91
H10	19/04/2018	−61.21	−9.18	−18.17	0.82	
H11	03/07/2018	−60.90	−8.85	−18.50	0.82	
H12	12/07/2018	−60.93	−9.07	−18.11	0.81	
H13	07/08/2018	−61.01	−8.96	−18.33	0.80	
H14	13/09/2018	−60.80	−8.83	−18.04	0.81	100.43
H15	18/10/2018	−62.17	−9.30	−18.63	0.84	100.23
H16	06/12/2018	−61.98	−9.18	−18.22	0.80	
H17	25/12/2018	−62.15	−9.23	−18.76	0.84	100.07
H18	28/05/2019	−61.74	−9.29	−18.46	0.80	100.16
H20	20/09/2019	−60.79	−9.29	−18.32	0.82	
H21	13/11/2019	−60.67	−9.20	−18.43	0.82	
Eniwa						
H1	21/06/2016	−62.79	−9.12	−18.53	0.71	
H2	04/11/2016	−63.25	−9.36	−18.81	0.67	
H3	01/07/2017	−63.57	−9.53	−19.02	0.69	
H4	22/10/2017	−64.29	−9.61	−19.75	0.68	
H5	22/04/2018	−64.37	−9.44	−19.56	0.71	
H6	04/10/2018	−64.68	−9.54	−19.85	0.64	
H19	18/02/2020	−64.55	−9.98	−20.86	0.79	

**Experimental errors of each values are as follows: δ^2H (0.6‰), $\delta^{18}O$ (0.2‰), $\delta^{13}C$ (0.2‰), TDIC (0.2 mmol/L).*

There may be a deep magmatic carbon component in the region close to Uenae (Marumo et al., 1995; Nitta and Inoue, 2011). The $\delta^{13}C$ values of approximately −4‰ in magmatic CO_2 is much heavier than that of present groundwater TDIC. Addition of a magmatic component should increase $\delta^{13}C$ values of our samples. However this is not the case. The observed increase in TDIC contents at Uenae may be attributable to the CO_2 injected at the Tomakomai site, because of the concomitant decrease in $\delta^{13}C$ (**Figure 2A**), which is also observed in the ^{14}C activity of the total carbonate (**Supplementary Figure S3**). It is possible to calculate $\delta^{13}C$ values of CO_2 in the samples under the chemical and isotopic equilibrium of groundwater (Barbieri et al., 2020). When we take into account the mass balance equation of TDIC, Mg^{2+}, Ca^{2+}, SO_4^{2-} using data set of **Table 1** and assuming the $\delta^{13}C$ value of −7‰ in local carbonate rock (Nitta and Inoue, 2011), $\delta^{13}C$ values of hypothetical CO_2 gas in the Uenae sample would become approximately −50‰, much lighter than those of present groundwater TDIC. This may be attributable to the discrepancy between the referred local carbonate and the true $\delta^{13}C$ value of calcite in aquifer system.

At the Uenae site, both δ^2H and $\delta^{18}O$ groundwater values were constant at −60.1 ± 0.5‰ and −8.52 ± 0.15‰, respectively, from June 2015 to February 2018 (**Figures 2C,D**). These values then fluctuated and decreased significantly down to −62.2‰ and −9.3‰, respectively, from April 2018 to December 2018. These variations are similar to those of the carbon isotopes, and may be attributable to groundwater mixing with light δ^2H and $\delta^{18}O$ of summer precipitation in the region (Kawaraya et al., 2016; **Supplementary Figure S4**). At Eniwa, δ^2H values decreased slightly from −62.8‰ to −64.3‰ and consistently from June 2016 to February 2020, while $\delta^{18}O$ values remained constant with the value of −9.43‰ except for the most recent sample of −9.98‰. These oxygen isotope values may be explained by the mixing of local surface meteric water and a deep high temperature water (Nitta and Inoue, 2011).

Potential Triggering Mechanism of the Hokkaido Earthquake

Previous studies have indicated a high probability that earthquakes are triggered by the injection of large volumes of CO_2 into the brittle crust (Zoback and Gorelick, 2012; Nicol et al., 2011). In this case study, the possible link between groundwater geochemical anomalies, the Hokkaido earthquake, and the CCS-CO_2 injection was examined. **Figure 3** shows a schematic vertical cross-section of the studied region before the CCS CO_2 injection of April 2016 (Stage 1), including two features: **Figure 3A** (top) is P-wave velocity (Vp) structure of the crust and uppermost mantle in the region (Kobayashi et al., 2019). A part of this figure (red square) is enlarged in **Figure 3B**, which shows geological structure of the seismic section along H91-3 in **Figure 1** (Yokokura et al., 2014). The CO_2 injected in the Moebetsu and Takinoue Formations are shown by broken curves. ITTFZ and Uenae indicate the major active fault system and the monitoring well, respectively. There may be upward natural fluid flows by buoyancy through a fault system as well as permeable aquifer (black arrows in **Figures 3A,B**) where a deeper flow (**Figure 3A**) was suggested by a seismological study (Hua et al., 2019). The upper boundary of Takinoue Formation is consistent with the active fault in the left side of diagram, but it is discrepant in the right. The branch position is approximately 1 km left side beneath the Uenae site.

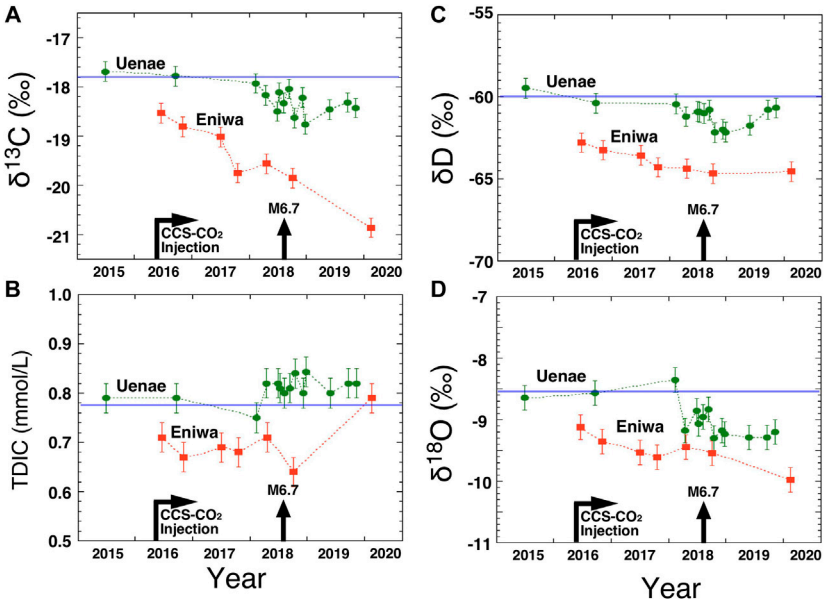


FIGURE 2 | Temporal variations of **(A)** $\delta^{13}C$ values of total carbonate in mineral water **(B)** total dissolved inorganic carbon (TDIC) concentration (mmol/L), **(C)** $\delta^{2}H$, and **(D)** $\delta^{18}O$ values of mineral water. Error bars show 2σ values. Blue lines represent averages of three samples (2015, 2016, and april 2018) from the Uenae well. Start dates of CCS-CO_2 injection and origin time of M6.7 earthquakes (M6.7 in **Figure 1**) are indicated by arrows in **(A)** and **(D)**.

Figure 4 shows the cross-section of two years after the injection of CO_2 (Stage 2), which is also immediately before the M6.7 earthquake. This indicates a geochemical model explaining the possible role of CO_2 in triggering the M6.7 earthquake, together with the distribution of earthquake occurred in the region and the hypothetical CO_2 accumulation zone. A large amount of CO_2, up to the 100 kilotons injected by the Tomakomai CCS project at the time, may have accumulated below the cap rock. Regional CO_2 monitoring indicates no apparent CO_2 leakage immediately above or in the vicinity of the cap rock (Sawada et al., 2018; Japan CCS, 2019). Long before the M6.7 earthquake, a seismic reflection survey was conducted along transect H91-3 by the National Institute of Advanced Industrial Science and Technology, AIST (Yokokura et al., 2014), as illustrated in **Figure 1**. The seismic survey revealed a low-angle fault, starting from the CCS-CO_2 injection area and dipping eastward (orange dotted line in **Figures 3A**,**4A**,**5A**). Generally speaking, a fault plane is a mechanically weak and possibly a more permeable surface than the surrounding region. There was upward natural fluid flow though the low-angle fault and Takinoue Formation (black arrows in **Figure 3B**). Injected CO_2 of Takinoue layer could be dissolved in local saline groundwater and make a high-pressure gas-water mixture, which can not go downward but may have temporally interrupted the fluid flow and the internal pressure could be buildup in the region. The increased pressure may propagate into deeper part, that is reverse direction of natural fluid flow, subject to the trajectory of pink dotted arrows in **Figures 4A,B**. Then dilatation may occur in the fault system (Arrows in circles in **Figure 4B**). The presence of this increase of pore pressure is suggested by the increase of natural earthquakes that took place along the fault in 2017 and 2018, when compared to those in 2016 (see **Supplementary Figure S5**).

The major part of the CO_2 injected in the Moebetsu Formation may be mixed with saline water which subsequently moved along the permeable layer towards the east as indicated by green arrow in **Figures 4A,B**. Most of the CO_2-fluid (gas-water mixture) may arrive at the area beneath the Uenae site, where there is no permeable connection between the Moebetsu Formation and shallow volcanic-sedimentary aquifer. Our sampling well taps the latter aquifer. Some part of CO_2-fluid may travel further eastward and will arrive at the region beneath the ITTFZ. When the high-pressure fluid encountered another high angle fault, which is possibly part of the ITTFZ, the CO_2-fluid may have accumulated in the region (**Figures 4A,B**), building up the pore pressure. There may be a pre-existing fault closer to the seismogenic fault of the M6.7 earthquake, at the western edge of the low-Vp zone (**Figure 4A**). In addition, low Vp/Vs was identified east of the slip area, suggesting the presence of water or fluid (Kobayashi et al., 2019). Before the M6.7 earthquake, there may have been natural upward fluid flow in the region parallel to the seismogenic fault (Hua et al., 2019). When the anthropogenic CO_2-fluid accumulated above this area, natural fracture flow may have been blocked, increasing pore pressure in the region. This increase as well as hydrological perturbations in the Takinoue Formation may have propagated to a much deeper region, and high pressure finally arrived at the focal zone of the M6.7 earthquake, again this is the reverse direction of natural fluid flow (dotted line in **Figure 3A**). It may have induced dilation of fault system and then have triggered the natural slip of pre-existing faults in a region where the brittle crust was already critically stressed.

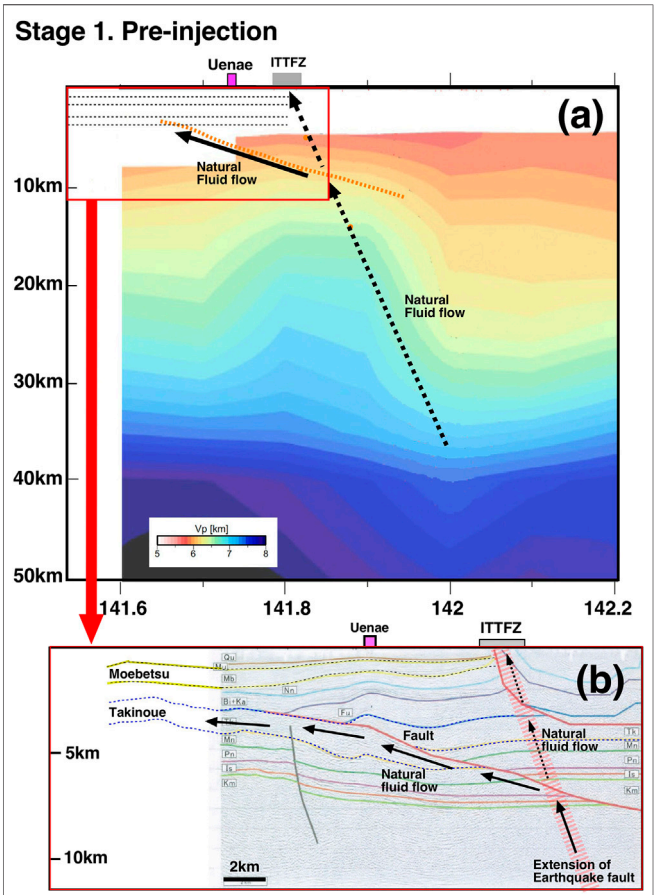


FIGURE 3 | Schematic vertical cross-section of the Hokkaido Iburi region along the H91-3 seismic profile of **Figure 1**, and its extension southwest and northeast before CCS-CO_2 injection **(A)** P-wave velocity (Vp) structure of the crust and uppermantle in the region. The orange dotted curve shows a fault determined by seismic reflection survey, which corresponds to the red solid line in bottom figure. The black solid and dotted arrows show possible natural fluid flows in the region supported by a seismological study. **(B)** Modified subsurface structure of the seismic section along H91-3 in **Figure 1** reported by Yokokura et al. (2014). Red square of top figure is enlarged here. The red solid line is the active fault. Uenae and ITTFZ denote the position of Uenae site and ITTFZ.

Part of CO_2-fluid may have ascended through the ITTFZ fault zone by buoyancy and introduced into the Shiatsu aquifer at a 90–100 m depth, where the Uenae monitoring well draws groundwater (green arrows in **Figures 4A,B**). The increase in TDIC concentration and the concomitant decrease in $\delta^{13}C$ values and ^{14}C activity in the Uenae mineral water would be caused by the injected low-$\delta^{13}C$ and ^{14}C-free CO_2. Concordant with the TDIC concentration and carbon isotopic variation, both $\delta^{2}H$ and $\delta^{18}O$ values also decrease over time (**Figure 2**). Their relationship has a slope of 2.2 in the $\delta^{18}O$-$\delta^{2}H$ diagram (**Supplementary Figure S4**), departing from the Global Meteoritic Water Line, which has a slope of 8. This suggests that the water carrying the injected CO_2 may have a low $\delta^{18}O$ value, and is then mixed with Uenae groundwater, which recharges possibly in the region (**Supplementary Figure S4**).

Figure 5 shows the cross-section after the M6.7 earthquake. The aftershock distribution of the M6.7 event coincides closely with the seismogenic fault. It is worth noting that the extension of the seismogenic fault estimated from the source fault model (Asano and Iwata, 2019) of the M6.7 earthquake (solid red line in **Figure 5A**) connects the epicenter with the ITTFZ at the surface (wide dotted red line; **Figure 5B**). Aftershocks of the M6.7 event terminated at a depth of ~10 km, where the pore pressure was high and the region may be ductile due to the interruption of natural fluid flow by CO_2 injection. After the earthquake, new fluid flow may occur beneath the ITTFZ (**Figures 5A,B**), which will be discussed in the latter section.

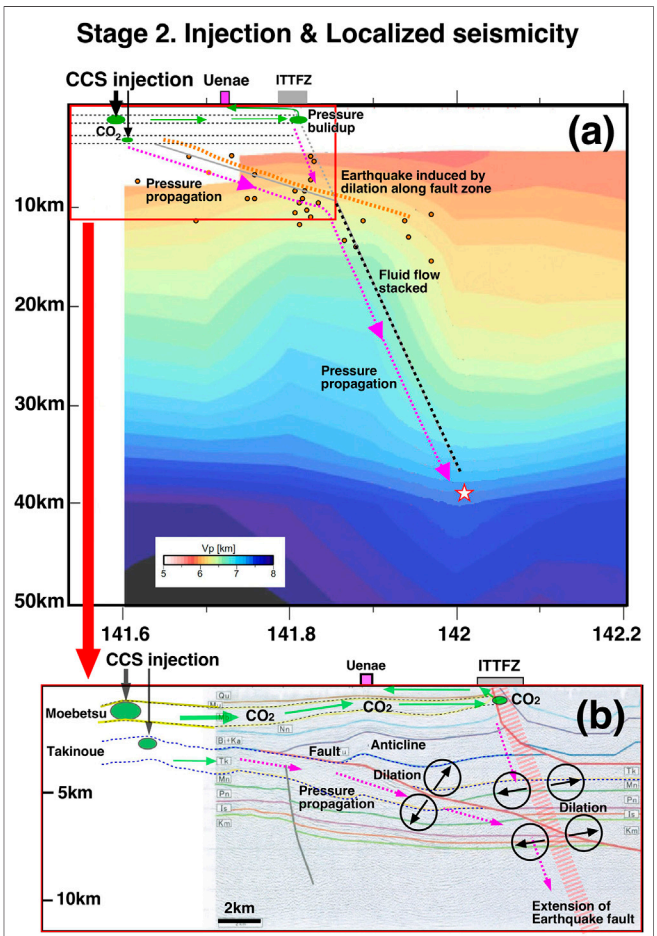


FIGURE 4 | Schematic vertical cross-section of the Hokkaido Iburi region along the H91-3 seismic profile of **Figure 1**, and its extension southwest and northeast in two years after CCS-CO_2 injection and immediately before the M6.7 earthquake **(A)** P-wave velocity (Vp) structure of the crust and upper mantle in the region. The red dotted arrows and gray thin line show possible pressure propagation and a pre-existing fault in the region, respectively. The orange dotted curve denotes a fault found by seismic reflection survey. Orange dots are possibly induced earthquakes by dilation along fault zone. **(B)** Modified subsurface structure of the seismic section along H91-3 in **Figure 1** reported by Yokokura et al. (2014). Red square of top figure is enlarged here. The green solid arrows and red dotted arrows show movement of CO_2 fluid and direction of pressure propagation, respectively. Arrows in circles indicate the dilation due to pore pressure.

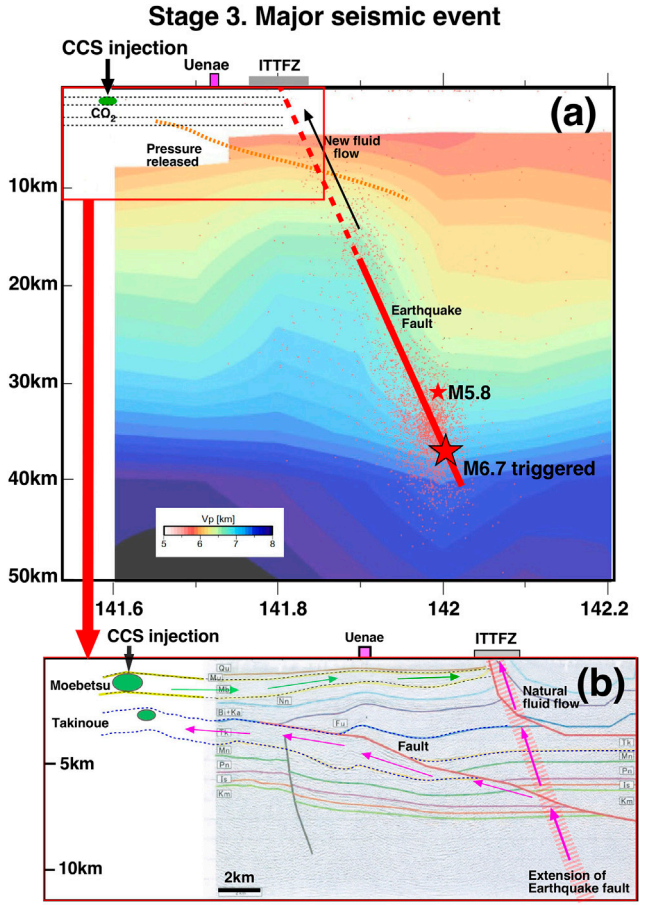


FIGURE 5 | Schematic vertical cross-section of the Hokkaido Iburi region along the H91-3 seismic profile of **Figure 1**, and its extension southwest and northeast soon after the M6.7 earthquake **(A)** P-wave velocity (Vp) structure of the crust and uppermantle in the region. The red solid line and dotted line show earthquake fault and hypothetical new fluid flow, respectively. The orange dotted curve denotes a fault found by seismic reflection survey. Distributions of small red dots are aftershocks. A large red star indicates the position of main shock (M6.7). **(B)** Modified subsurface structure of the seismic section along H91-3 in **Figure 1** reported by Yokokura et al. (2014). Red square of top figure is enlarged here. The red solid arrows and green arrows are direction of CO_2 fluid movement and possible pressure propagation.

Velocity of Anthropogenic Fluid Flow

In the proposed geochemical model, the velocity of the CO_2-fluid flow should correspond with the sequence of events (i.e., the injection of CO_2, the groundwater anomaly, and the M6.7 earthquake) for it to be considered realistic (**Figures 3–5**). In the case of the Uenae well, the carbon anomaly began in April 2018, while CO_2-injection began in April 2016. The total distance from the CCS injection point to Uenae is estimated to be ca. 30 km along the trajectory of movement simulated in the model (green arrows in **Figure 4A**). The average fluid velocity is then calculated to be approximately 40 m/day. This value is higher than the typical confined groundwater velocity of 1 m/day (Shibasaki, 1981), but is consistent with the maximum velocity calculated for Japanese sedimentary basins of 40 m/day (Shibasaki, 1981) and the value > 50 m/day of volcanic CO_2-fluid flow observed at the 1986 eruption of Izu-Oshima volcano in Japan (Sano et al., 1988; Sano et al., 1995). If we assume a velocity of 40 m/day, the first phase of injected CO_2 may have arrived at the build up and accumulation zone (**Figure 4A**) in September 2017, which is one year before the M6.7 earthquake. This may have been a sufficient amount of time for pore pressure to build up in the deep focal region. Considering a high-pressure injected CO_2 and enhanced permeability along the fault plane, one may assume a faster velocity than 40 m/day, similar to the case of above Izu-Oshima volcano. During the great 2011 Tohoku-Oki earthquake (Mw 9.0), a velocity of 4 km/day was estimated for the upward migration of mantle fluids along the fault plane at the subducting plate interface (Sano et al., 2014). This value is two orders of magnitude greater than 40 m/day. If this higher fluid flow rate is applied to our model, the injected CO_2-fluid phase could have reached the accumulation point within 5 days of injection. On the other hand, a groundwater flow rate from ITTFZ to the Uenae well may be slower than 40 m/day. Therefore, either groundwater anomalies might have not yet have appeared in the more distant Eniwa well after the M6.7 earthquake, because the distance between the two wells is ca. 20 km (**Figure 1**), or significant increase of total carbonate in February 2020 (**Figure 2B**) may be due to the CCS-CO_2 injection.

TABLE 3 | Helium isotopes and helium/neon ratios of natural springs after the M6.7 earthquake in Hokkaido, Japan.

Code	Date	$^3He/^4He$ (Ra)	Error 1 σ	$^4He/^{20}Ne$	cor $^3He/^4He$* (Ra)
Matsubara					
H22	22/09/2018	0.50	0.02	1.22	0.36
H23	18/03/2019	0.49	0.04	1.16	0.34
H24	05/11/2019	0.89	0.04	0.40	0.68
Tsurunoyu					
H25	22/09/2018	0.14	0.02	3.29	0.06
H26	04/11/2019	0.42	0.03	0.85	0.15
Laforet					
H27	22/09/2018	0.65	0.04	15.8	0.64
H28	12/12/2018	0.67	0.04	6.41	0.66
H29	18/03/2019	0.68	0.04	2.41	0.64
H30	05/11/2019	0.68	0.04	20.4	0.68
Mukawa					
H31	12/12/2018	0.06	0.05	4.93	0.01
H32	19/03/2019	0.05	0.02	34.0	0.04
H33	04/11/2019	0.09	0.01	36.1	0.09

**ASW correction is following Sano and Fischer (2013).*

Natural Fluid Flow Paralleling the Seismogenic Fault

For the model to be valid, it must be assumed a fluid flow through a pre-existing fault plane (**Figures 3A,B**), before the M6.7 Eastern Iburi earthquake. The fluid in the source zone may have originated from the dehydration of the subducting Pacific slab beneath southern Hokkaido, a phenomenon clearly identified by low-seismic velocity anomalies, high attenuation, and high Poisson's ratio (Hua et al., 2019). Tomography suggests that the fluid from the slab dehydration ascended through the forearc mantle wedge and then entered the seismogenic fault in the crust, triggering the 2018 Eastern Iburi earthquake. The same mechanism also caused the 1995 M7.2 Kobe earthquake (Zhao et al., 1996), as well as the

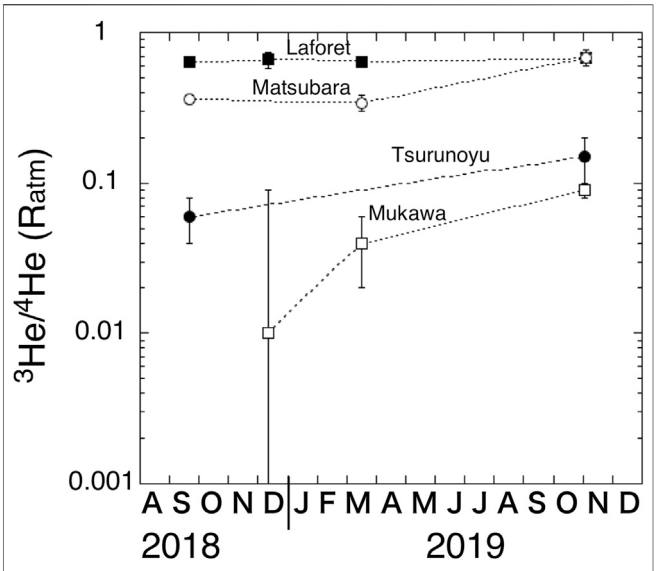


FIGURE 6 | Temporal variations of air-corrected ^{3}He/^{4}He ratios and normalized to the air ratio (Ratm = 1.382 × 10^{-6}), measured in natural springs after the M6.7 earthquake at Mukawa, Tsurunoyu, Matsubara, and Laforet in Hokkaido, Japan. Error bars are 2σ.

2000 M7.3 western Tottori earthquake and the 2016 M6.6 central Tottori earthquake in southwestern Japan, where the Philippine Sea plate is subducting (Zhao et al., 2018). If this is the case, the deep fluid would have a mantle helium signature with a high ^{3}He/^{4}He ratio (Sano and Fischer, 2013). We collected hot and mineral spring water samples from four sites around the ITTFZ after the M6.7 Eastern Iburi earthquake (**Figure 1**) and measured the ^{3}He/^{4}He and ^{4}He/^{20}Ne ratios at different sampling times (**Table 3**; **Figure 6**). At three sites close to the ITTFZ (Matsubara, Tsurunoyu, and Mukawa), the air-corrected ^{3}He/^{4}He ratios increased significantly after the M6.7 earthquake. In September 2018, the ^{3}He/^{4}He ratio is 0.36 ± 0.03 Ra at Matsubara and 0.06 ± 0.02 Ra at Tsurunoyu. Immediately after the M6.7 earthquake, in November 2019, the ratio increased to 0.68 ± 0.08 Ra at Matsubara and 0.15 ± 0.05 Ra at Tsurunoyu; it was 0.01 ± 0.08 Ra at Mukawa in December 2018, but increased to 0.09 ± 0.01 Ra in November 2019. In contrast, the ratio is almost constant, at 0.66 ± 0.04 Ra, at the Laforet site located far from the ITTFZ (**Figure 1**). These results suggest that a mantle helium component was slightly enriched in the ITTFZ subsurface region fluids after the M6.7 earthquake. Before CCS-CO_2 injection, there may have been steady state fluid flow including a small mantle helium component (**Figures 3A,B**). Immediately before and during the M6.7 event, the natural fluid flow may have been interrupted by high pore pressure caused by CO_2 accumulation (**Figures 4A,B**). Consequently, the surface manifestation of mantle helium may have ceased or have been weakened. After the M6.7 earthquake, new channels may have been created from the deep crust to the ITTFZ subsurface region. The ^{3}He/^{4}He ratios of natural springs then increased significantly because of the connection to the mantle source (**Figure 6**). Therefore, the overall variation of the measured helium isotopes in groundwater supports the proposed geochemical model of the M6.7 Eastern Iburi earthquake triggering.

Relationship Between δ^{13}C and ^{14}C Activity of Groundwater Carbonate

There is a simple correlation between observed δ^{13}C values and ^{14}C activity of total carbonate in groundwater samples from the Uenae well (**Supplementary Figure S6**) with a correlation coefficient, r^2 = 0.85. There may be three independent carbon components in subduction-type region (Sano and Marty, 1995): 1) surface carbon (a mixture of organic and marine carbonate carbon) with intermediate δ^{13}C (−10‰ in surface meteoric water by Nitta and Inoue, 2011) and high ^{14}C; 2) anthropogenic (CCS injection) carbon with low δ^{13}C (−25‰) and low ^{14}C; and 3) deep-seated carbon (possibly derived from the mantle) with high δ^{13}C (−6‰) and low ^{14}C. The correlation between δ^{13}C and ^{14}C may be explained by the binary mixing of the surface and anthropogenic CCS carbon from September 2016 to May 2019. Even though there is an increase of mantle helium component in hot and mineral springs close to the ITTFZ region (**Figure 6**), a substantial amount of deep-seated carbon was not introduced into the Uenae aquifer after the M6.7 earthquake, which should have made the δ^{13}C value higher. This mechanism should be studied more precisely in future work.

CONCLUSION

In conclusion, secular variations of carbonate contents, carbon isotopes (δ^{13}C), and ^{14}C activity in groundwater at the Uenae well, southern Hokkaido, Japan may have some relation to the CO_2 injection from the Tomakomai CCS demonstration project in the area. Considering the position of the pre-existing fault, the natural earthquakes that occurred between 2016 and 2017, and the crustal structure of the region, the injected CO_2 fluid may have interrupted a natural fluid flow in the deep Takinoue Formation and may have increased pore pressure in the area. The injected CO_2 fluid in the shallow Moebetsu Formation, may have flowed into the region just beneath ITTFZ region. The accumulation of CO_2-fluid could have potentially interrupted the natural upward fluid flow, thereby increasing the pore pressure in the focal area, and possibly triggering the 2018 Hokkaido Eastern Iburi earthquake. A part of CO_2-fluid may be incorporated in the aquifer of the Uenae site and may have induced chemical and isotopic variations of the groundwater. Future projects should consider regional sampling of noble gas and stable isotopes to confirm the potential influence of carbon sequestration on seismicity.

DATA AVAILABILITY STATEMENT

The original contributions presented in the study are included in the article/**Supplementary Material**, further inquiries can be directed to the corresponding author.

AUTHOR CONTRIBUTIONS

YS designed the study. YS, TK, TS, and A-TC conducted field trips and sample collection. KS measured carbon isotopes and carbonate

contents in groundwater. NT analyzed groundwater oxygen and hydrogen isotopes. NT, TK, and A-TC measured helium isotopes and helium/neon ratios of hot spring samples. SX analyzed C-14 of carbonate in groundwater. JY and YN provided geological interpretations of the area. J-OP and DZ provided the seismological model and implication. YS, GS and DP wrote the manuscript. All authors contributed to the final manuscript preparation.

FUNDING

This work was partly supported by a research grant from the Japan Society for the Promotion of Science (17H00777).

ACKNOWLEDGMENTS

We gratefully acknowledge the regional mineral water companies for groundwater sampling. We thank KT for reviewing the paper and TM for help with analyzing hydrogen and oxygen isotopes of water samples. J-FH is thanked for hydrogen and oxygen isotopic analyses at Geotop in Montreal, Canada. We thank reviewers for constructive comments.

SUPPLEMENTARY MATERIAL

The Supplementary Material for this article can be found online at: https://www.frontiersin.org/articles/10.3389/feart.2020.611010/full#supplementary-material

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Conflict of Interest: The authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

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IEEFA op-ed: Reality of carbon capture not even close to proponents' wishful thinking

Guest editorial in the Denver Post by IEEFA's director of resource planning analysis, David Schlissel

August 4, 2019 (Denver Post) — Jon Caldara's op-ed on **Xcel's Colorado Energy Plan** attacks the utility company and the broader environmental community, saying that the latter is motivated primarily by feelings of virtue rather than cold hard facts. Guess what? The facts are not in Caldara's favor.

The only evidence Caldara presents for his opposition to the planned closure of two of the Comanche coal-fired plants is a study done for the U.S. Department of Energy by a former DOE employee.

Worse, a detailed review of the study shows that it is fatally flawed, based on overly optimistic and unsupported assumptions about the construction costs of carbon capture equipment as well as the effectiveness of such technology.

Further, the DOE-commissioned study completely ignores the fact that the financial viability of the entire project depends on being able to sell the captured carbon dioxide (CO_2) for use in enhanced oil recovery activities. When the additional oil produced through this oil recovery is burned or used as a chemical feedstock, it, in turn, would emit substantial amounts of CO_2, thereby offsetting reductions in emissions at the plant.

On the cost question, the DOE-commissioned report rests on the assumption that the carbon capture equipment could be built for 45 percent less than the only comparable unit currently operational in the U.S., a much smaller facility in Texas called Petra Nova that was launched late in 2016. The Petra Nova facility cost $1 billion (or roughly $4,400 per installed kilowatt). The DOE study asserts that the Comanche project could be built for just $2,450 per kw — but offers no evidence to support such a drastic reduction in cost.

The study also asserts that, on average, the Comanche plant would operate with a 75 percent capacity factor (that is, it would produce 75 percent of the electricity it is theoretically capable of producing during a given year) after the carbon capture retrofits are completed. A check of actual plant operating data conducted by the Institute for Energy Economics and Financial Analysis shows that since 2010 it has only achieved a 75% capacity factor in a single year — to assume that Comanche would perform this well on a consistent basis after all the new CO_2 capture equipment is installed is highly unrealistic.

Similarly, officials from the DOE have reported that the average cost of capturing CO_2 at Petra Nova is about $60 per ton. However, again with no actual experience on which to base its analysis, the study assumes that the cost of capturing CO_2 at Comanche can be cut to between $36.42 and $39.70 per metric ton — a reduction of about 40% made, not by hands-on experience but by computer keystrokes.

Some of this assumed cost reduction can be traced to the study's projection that the new Comanche CO_2 capture equipment will operate at 90% effectiveness. When NRG built the Petra Nova plant it made similar projections.

However, results from the first two years of full operation show that the Texas facility captured between 65% and 70% of the CO_2 at the plant, and that does not take into account the emissions from the natural gas turbine used to run the carbon capture equipment. Factoring those emissions into the equation lowers the effective capture rate to about 50%.

Performance at another plant, this one in Saskatchewan, Canada, has been similar. That plant, Boundary Dam Unit 3, was also built with the promise that it would capture 90% of the unit's annual emissions, but overall, the plant has a capture rate of about 51%.

Here again, reality trumps Caldara's wishful thinking. If Caldara is truly interested in cold hard facts, he would be better off doing a little more research.

*This article appeared in the Denver Post on August 4, 2019 under the headline: **Reality of carbon capture not even close to proponents' wishful thinking**. David Schlissel was invited to submit a response to an editorial by Jon Caldera that argued against the closure of two coal-fired power plants and in favor of funding carbon capture storage to make the plants more economically viable. The original article was entitled: **Xcel Energy should consider carbon capture to save the planet and our pocketbooks**

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Stanford News (http://news.stanford.edu/)

OCTOBER 25, 2019

Stanford study casts doubt on carbon capture

Current approaches to carbon capture can increase air pollution and are not efficient at reducing carbon in the atmosphere, according to research from Mark Z. Jacobson.

BY TAYLOR KUBOTA

One proposed method for reducing carbon dioxide (CO_2) levels in the atmosphere – and reducing the risk of climate change – is to capture carbon from the air or prevent it from getting there in the first place. However, research from **Mark Z. Jacobson (https://profiles.stanford.edu/mark-jacobson)** at Stanford University, **published (https://pubs.rsc.org/en/content/articlelanding/2019/ee/c9ee02709b/unauth#!divAbstract)** in *Energy and Environmental Science*, suggests that carbon capture technologies can cause more harm than good.

"All sorts of scenarios have been developed under the assumption that carbon capture actually reduces substantial amounts of carbon. However, this research finds that it reduces only a small fraction of carbon emissions, and it usually increases air pollution," said Jacobson, who is a professor of civil and environmental engineering. "Even if you have 100 percent capture from the capture equipment, it is still worse, from a social cost perspective, than replacing a coal or gas plant with a wind farm because carbon capture never reduces air pollution and always has a capture equipment cost. Wind replacing fossil fuels always reduces air pollution and never has a capture equipment cost."



(https://news.stanford.edu/wp-content/uploads/2020/10/Roadmap-featured.jpg)

Research by Mark Z. Jacobson, professor of civil and environmental engineering, suggests that carbon capture technologies are inefficient and increase air pollution. Given this analysis, he argues that the best solution is to instead focus on renewable options, such as wind or solar, replacing fossil fuels. *(Image credit: Getty Images)*

Jacobson, who is also a senior fellow at the **Stanford Woods Institute for the Environment (http://woods.stanford.edu/cgi-bin/index.php)**, examined public data from a coal with carbon capture electric power plant and a plant that removes carbon from the air directly. In both cases, electricity to run the carbon capture came from natural gas. He calculated the net CO_2 reduction and total cost of the carbon capture process in each case, accounting for the electricity needed to run the carbon capture equipment, the combustion and upstream emissions resulting from that electricity, and, in the case of the coal plant, its upstream emissions. (Upstream emissions are emissions, including from leaks and combustion, from mining and transporting a fuel such as coal or natural gas.)

Common estimates of carbon capture technologies – which only look at the carbon captured from energy production at a fossil fuel plant itself and not upstream emissions – say carbon capture can remediate 85-90 percent of carbon emissions. Once Jacobson calculated all the emissions associated with these plants that could contribute to global warming, he converted them to the equivalent amount of carbon dioxide in order to compare his data with the standard estimate. He found that in both cases the equipment captured the equivalent of only 10-11 percent of the emissions they produced, averaged over 20 years.

This research also looked at the social cost of carbon capture – including air pollution, potential health problems, economic costs and overall contributions to climate change – and concluded that those are always similar to or higher than operating a fossil fuel plant without carbon capture and higher than not capturing carbon from the air at all. Even when the capture equipment is powered by renewable electricity, Jacobson concluded that it is always better to use the renewable electricity instead to replace coal or natural gas electricity or to do nothing, from a social cost perspective.

Given this analysis, Jacobson argued that the best solution is to instead focus on renewable options, such as wind or solar, replacing fossil fuels.

Efficiency and upstream emissions

This research is based on data from two real carbon capture plants, which both run on natural gas. The first is a coal plant with carbon capture equipment. The second plant is not attached to any energy-producing counterpart. Instead, it pulls existing carbon dioxide from the air using a chemical process.

Jacobson examined several scenarios to determine the actual and possible efficiencies of these two kinds of plants, including what would happen if the carbon capture technologies were run with renewable electricity rather than natural gas, and if the same amount of renewable electricity required to run the equipment were instead used to replace coal plant electricity.

While the standard estimate for the efficiency of carbon capture technologies is 85-90 percent, neither of these plants met that expectation. Even without accounting for upstream emissions, the equipment associated with the coal plant was only 55.4 percent efficient over 6 months, on average. With the upstream emissions included, Jacobson found that, on average over 20 years, the equipment captured only 10-11 percent of the total carbon dioxide equivalent emissions that it and the coal plant contributed. The air capture plant was also only 10-11 percent efficient, on average over 20 years, once Jacobson took into consideration its upstream emissions and the uncaptured and upstream emissions that came from operating the plant on natural gas.

Due to the high energy needs of carbon capture equipment, Jacobson concluded that the social cost of coal with carbon capture powered by natural gas was about 24 percent higher, over 20 years, than the coal without carbon capture. If the natural gas at that same plant were replaced with wind power, the social cost would still exceed that of doing nothing. Only when wind replaced coal itself did social costs decrease.

For both types of plants this suggests that, even if carbon capture equipment is able to capture 100 percent of the carbon it is designed to offset, the cost of manufacturing and running the equipment plus the cost of the air pollution it continues to allow or increases makes it less efficient than using those same resources to create renewable energy plants replacing coal or gas directly.

"Not only does carbon capture hardly work at existing plants, but there's no way it can actually improve to be better than replacing coal or gas with wind or solar directly," said Jacobson. "The latter will always be better, no matter what, in terms of the social cost. You can't just ignore health costs or climate costs."

This study did not consider what happens to carbon dioxide after it is captured but Jacobson suggests that most applications today, which are for industrial use, result in additional leakage of carbon dioxide back into the air.

Focusing on renewables

People propose that carbon capture could be useful in the future, even after we have stopped burning fossil fuels, to lower atmospheric carbon levels. Even assuming these technologies run on renewables, Jacobson maintains that the smarter investment is in options that are currently disconnected from the fossil fuel industry, such as reforestation – a natural version of air capture – and other forms of climate change solutions focused on eliminating other sources of emissions and pollution. These include reducing biomass burning, and reducing halogen, nitrous oxide and methane emissions.

"There is a lot of reliance on carbon capture in theoretical modeling, and by focusing on that as even a possibility, that diverts resources away from real solutions," said Jacobson. "It gives people hope that you can keep fossil fuel power plants alive. It delays action. In fact, carbon capture and direct air capture are always opportunity costs."

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Media Contacts

Taylor Kubota, Stanford News Service: (650) 724-7707, **tkubota@stanford.edu (mailto:tkubota@stanford.edu)**

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frontiers in Energy Research

ORIGINAL RESEARCH
published: 15 May 2018
doi: 10.3389/fenrg.2018.00040

Bearing the Cost of Stored Carbon Leakage

Adriano Vinca[1,2]*, *Johannes Emmerling*[1,3] *and Massimo Tavoni*[1,3,4]

[1] *Fondazione Eni Enrico Mattei , Milan, Italy,* [2] *International Institute for Applied System Analysis, Laxenburg, Austria,*
[3] *Centro-Euro Mediterraneo per i Cambiamenti Climatici, Milan, Italy,* [4] *Politecnico di Milano, Milan, Italy*

Carbon capture and sequestration (CCS) is considered a key technology for stabilizing climate change. However, leakage of CO_2 from stored carbon can potentially undermine the value of carbon storage as a mitigation option. Thus, monitoring and verifiability of CO_2 storage should be encouraged through policy provisions such as accounting and pricing of leaked emissions. Here we assess different institutional and economic mechanisms for accounting for carbon leakage. Using an integrated assessment model we quantify the impacts on the climate, the economy and the mitigation strategies. Results show that carbon leakage can reduce the share of fossil based CCS by up to 35%, if it is controlled and correctly priced. Biomass based CCS is less affected. Accounting for leakage leads to an increase of climate policy costs of up to 0.4 percentage points due to increased emissions.

Keywords: carbon leakage, CCS, CO_2 geological storage, integrated assessment model, climate mitigation

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Edited by:
Sonia Yeh,
Chalmers University of Technology, Sweden

Reviewed by:
Phil Renforth,
Cardiff University, United Kingdom
Tobias Proell,
Universität für Bodenkultur Wien, Austria
David Daniels,
United States Energy Information Administration, United States
Jennifer Wilcox,
Colorado School of Mines, United States

***Correspondence:**
Adriano Vinca
vinca@iiasa.ac.at

Specialty section:
This article was submitted to Energy Systems and Policy, a section of the journal Frontiers in Energy Research

Received: *09 February 2018*
Accepted: *24 April 2018*
Published: *15 May 2018*

Citation:
Vinca A, Emmerling J and Tavoni M (2018) Bearing the Cost of Stored Carbon Leakage. Front. Energy Res. 6:40. doi: 10.3389/fenrg.2018.00040

HIGHLIGHTS

- Carbon leakage from CCS can lead to up to 25 $GtCO_2$ of additional emissions throughout the twenty-first century for a leakage rate of 0.1% per year.
- CCS deployment is lowered, by as much as 30% (Fossil) and 10% (BECCS), when leakage is taken into account.
- Carbon prices increase by around 5 per cent. Overall policy costs increase by about 0.2–0.4 percentage points.
- If not taken into consideration nor priced, leakage contributes to an additional 0.01–0.02 degrees of temperature increase.
- China, Latin America, the U.S., and Canada have the highest expected leakage.

1. INTRODUCTION

The increasing awareness of possibly irreversible damages of global warming has pushed both public opinion and governments toward the support of increasingly stringent climate mitigation measures. However, the path toward climate change policies is correlated to both technological and economic challenges (IPCC, 2014). Among typical mitigation strategies, Carbon Capture and Storage (CCS) and Carbon Dioxide Removal (CDR) represent valuable alternatives to renewable energy sources. According to existing studies IPCC (2014), the CCS potential will have an important role in reducing the carbon intensity of electricity. CCS might thus represent a considerable share

of emission reduction in the energy sector (Metz et al., 2005; Finkenrath, 2011; NAS, 2015; GCCSI, 2016).

CCS and CDR can also help reduce the costs of mitigation. Nonetheless, their development has not been as fast as expected in the last decades (Davidson et al., 2017). This low deployment can be associated with the absence of adequate incentives, lack of public acceptance, and to technological uncertainties associated with CCS (IEA, 2016; Lipponen et al., 2017). Among these barriers, carbon leakage from stored CO_2 could counteract the usefulness of carbon sequestration to help limiting global temperature increase (van der Zwaan and Smekens, 2009). In this paper, we analyze the impact of CO_2 leakage on the propsects of CCS in the power sector and the economic costs of mitigation[1].

We evaluate different policy provisions to help take leakage into account. Several problems can arise with leakage. Estimating its size is difficult and costly, since monitoring techniques have focused on small scale case studies so far (Romanak et al., 2012; Dethlefsen et al., 2013). A second source of uncertainty is related to the economic liability of leaked emissions (Wilson et al., 2003; Imbus et al., 2013). Finally, leakage might depend on the stringency of the climate policy. To address these questions, we use an integrated assessment model to examine three main dimensions: climate targets, leakage rates and policy provisions to counteract it. We consider the 2 and 1.5°C temperature increase targets by 2100, a range of possible leakage rates consistent with the literature, and different cases of pricing and liability of carbon leakage in the atmosphere. On this last point, we analyze whether leaked CO_2 is (a) not monitored nor taken into account in the carbon budget, (b) taken into account for the chosen carbon budget, but not priced at the carbon price, e.g., due to institutional or technological constraints, or (c) taken into account in the carbon budget and priced at the carbon price. These three cases allow us to disentangle the importance of monitoring and pricing leaked emissions.

2. BACKGROUND INFORMATION

2.1. CO_2 Transportation and Storage

Carbon dioxide, once removed from the exhaust gases of a power plant, can be re-used for industry purposes or stored (GCCSI, 2011). Capture, transportation, and storage or use each require the construction and maintenance of additional infrastructure, along with associated costs (Metz et al., 2005; GCCSI, 2011; Benson et al., 2012). After storage, transporting CO_2 to storage or use sites is the next important cost component. Although transportation through pipelines of dense supercritical CO_2 appears to be the most convenient technology for inland transport, other options, including shipping, are conceivable for particular cases (e.g., remote offshore distances) (Cole et al., 2011; ZEP, 2011). The costs for pipeline transportation comprise both capital costs (e.g., pipeline construction, pipe coating, protection systems) and operations costs (e.g., surveillance, maintenance, expert supervision) (McCoy and Rubin, 2008).

When it comes to the options for carbon storage, here we focus on geological storage, which comprises several different storage options under ground. Among the different storage options, only a few are considered reliable for large scale injections: underground saline aquifers, depleted or expiring oil and gas fields, and coal beds. Deep saline aquifers are geological formations of porous rocks, permeable and saturated with water, that allow the withdrawal of non-potable water (IEAGHG, 2008). Also oil and gas fields where extraction is declining are interesting options for CO_2 storage. Enhanced oil recovery (EOR) consist of injecting CO_2 in declining oil fields to boost oil extraction due to fluid pressure. Being an economically convenient technique, it has already been used in the U.S. for many decades. However, traditional EOR was not intended to maximize carbon storage, and the amount of CO_2 trapped has always been relatively low (Godec et al., 2011; IEA, 2015). Depleted oil or gas fields can be reliable storage sites, as they have naturally stored natural gas for thousands of years and have been geologically fully characterized. Coal seams that are uneconomic to mine may still contain methane trapped in coal pores, which may be released via Enhanced Coal Bed Methane (ECBM) recovery (IEA-ETSAP, 2010). Similar to EOR, ECBM consists of injecting CO_2 into the the coal bed, some of which displaces the CH_4 and remains sequestered in its place. Other potential CO_2 storage options, such as CO_2 mineralization or deep ocean storage, although considered important potential future storage options by some sources (Sanna et al., 2014; Romanov et al., 2015), are excluded from the current study due to their high current and uncertain future costs, public acceptance issues, and uncertain impacts on ecosystems (IEA, 2008).

Since estimating global or regional available storage capacity requires extensive investigation of vast geological areas and the use of advanced measurement processes, the uncertainty on available capacity is still high. Dooley (2013) considers a theoretical global capacity of 35,300 $GtCO_2$, which is reduced to an effective and then practical potential of 13,500 and 3,900 $GtCO_2$, respectively. In the IEAGHG (2011, 2016) reports, an average global availability of 11,152 $GtCO_2$ is estimated, which is an order of magnitude that is accepted also by other authors (Hendriks et al., 2004; Koelbl et al., 2014).

With regard to the geological storage costs, the variability in the literature is even higher, since many studies describe specific sites, which can have different properties one from another, such as the storage type, regional geology, and pre-built infrastructure. For example, Rubin et al. (2015) estimates a cost range of between 1 and 18 $\$/tCO_2$. Similar values are reported in IEAGHG (2011) and ZEP (2011)[2]. Concerning ECBM and EOR storage options, the estimated costs range from negative to high positive values, depending on whether the process is used to boost gas or oil extraction, or to optimize CO_2 storage (Gale, 2004; Koelbl et al., 2013, 2014).

2.2. Carbon Leakage

With the term leakage, or seepage, we refer to undesired CO_2 losses to the atmosphere due to infrastructure or

[1]Note that we therefore do not consider direct air capture (DAC) or other CDR options, which face additional technical and other uncertainties.

[2]Every cost in this study is expressed in 2005 US Dollars.

storage malfunctions. Leakage could occur during CO_2 transportation, underground injection, or after storage. Leakage from transportation is due to pipeline losses, but can be considered unlikely due to pipeline monitoring systems that measure pressure losses (GCCSI, 2014). The injection process can also lead to unwanted CO_2 leakage: injection requires a wellbore, a conduit where upward flows are possible. Finally, undesired loss of CO_2 from storage sites can occur due to imperfect storage sealing. Pipeline and injection losses are referred to as instantaneous leakage, as they take place at the same time period of capture and before the CO_2 is stored. On the contrary, seepage from storage sites is delayed in time, meaning that CO_2 can also leak from under ground several years after being captured. In this case, leakage is related to the cumulative quantity of CO_2 that has been stored in the past. This aspect is critical as one of the main issues related to CCS deployment is the long term suitability of storage options (Metz et al., 2005; van der Zwaan and Gerlagh, 2009b). Moreover, there is still high uncertainty about the true reliability of storage sites. As the long term response of storage sites could hinder CCS effectiveness as a mitigation option, we focus our attention on storage leakage.

The damages that leakage might cause can be distinguished between local and global (Wilson et al., 2003). From the local point of view, meaning a few kilometers around the storage site, concentrated CO_2 leakage could be harmful for people and livestock. Another problem caused by CO_2 losses is ground water contamination. Seepage could reach groundwater aquifers, rather than reaching directly the atmosphere surface (Bielicki et al., 2015; Deng et al., 2017). This would lower the aquifer water pH and could lead to the release of harmful metals, an effect known as acidification (Little and Jackson, 2010). Alternatively, acidification might also occur during the injection in saline aquifers, degrading the well cements (Celia et al., 2015). These local issues might raise discussions on storage management and public acceptance, however they have less consequences at a global level. By contrary, this article focuses on CO_2 leakage into the atmosphere as a global issue that contributes to global warming. In particular, the prospect of leakage could hinder the mitigation potential of fossil fuel CCS, hampering its future deployment. Consequently, it would lead to an increase in climate policy costs (van der Zwaan and Smekens, 2009). For this reason it is important to understand the magnitude of leakage, which is captured typically through the leakage rate, that is, the rate at which CO_2 leakage occurs at a specific storage site per year in terms of the stored carbon.

Bielicki et al. (2015) summarizes results on percentage of stored emissions from the storage sites, with different levels of permeability and compares the results with the U.S. Department of Energy aim of not more than 1% leaked CO_2 in total (Bielicki et al., 2016). Assuming a pessimistic estimate of rock permeability equal to $10^{-10}m^2$, 10% of stored volumes are expected to leak within 30 years, with permeability of $10^{-12}m^2$, the leaked emissions decrease to about 0.1% during the same period. However, an evaluation of leaked quantities over larger time horizons like 100 or 1,000 years, which are the time frames usually considered by institutions like the DOE or IPCC, is still missing. According to Bielicki et al. (2015) only the case with $10^{-12}m^2$ permeability would conform to the storage permanence goal of 1% leakage. These permeability assumptions have been tested in the GCAM model by Deng et al. (2017), obtaining leakage over the twenty-first century of between ~0.003 and ~0.2%[3]. Another finding is that with a low injection rate, leakages are higher at the beginning, while in the long term this might change. The behavior of leakage rates could therefore depend also on time: in particular, the percentage of CO_2 lost with respect to the total stored amount could exponentially decay or show an S-shaped behavior. These complex paths try to replicate some important geological and fluid-dynamic aspects of CO_2 leakage. For example, the exponentially decaying curve stands for a storage site where CO_2 leaks at first easily, then increasingly more scarcely due to the fact that only the best trapped CO_2 remains in the storage site. An S-shaped curve would represent the CO_2 leaking through multiple layers of media (van der Zwaan and Gerlagh, 2009a,b). However, as in van der Zwaan and Smekens (2009), leakage rate could be also reasonably well approximated as a constant percentage of the cumulative stored quantity within each storage site. Summing up, according to the IPCC (Metz et al., 2005), storage sites are probably reliable and safe, meaning they release very low or practically zero leakages. van der Zwaan and Smekens (2009) suggest a maximum acceptable value for the leakage rate below 0.5% per year, while for Bielicki et al. (2015) lower leakage rates are conceivable. In this study we therefore consider the maximum leakage rate of 0.1% per year, which implies leakage of 9.5% over a century, while a more reasonable leakage rate that we test is 0.01%/*year*, which leads to a theoretical leakage of 1% of injected CO_2 over 100 years[4].

As leakage remains uncertain, it is of vital importance to ensure effective and reliable monitoring systems that consistently measure CO_2 flows. In recent years, several studies have addressed the issue of monitoring leakage flows to the atmosphere or affecting underground aquifers (Benson and Hepple, 2005; Dethlefsen et al., 2013). Monitoring seepage implies scanning a large area of land in proximity of storage sites, and there is not a consolidated or standardized approach yet, rather a number of research and demonstration projects (Jones et al., 2009; Etheridge et al., 2011; Romanak et al., 2012). Moreover, to guarantee an effective control on storage sites, the responsibilities and consequences of seepage must be clearly outlined, covered through appropriate regulation and, if applicable, covered under carbon pricing schemes (Imbus et al., 2013). Problems can arise when private companies or public institutions responsible for the injected CO_2 do not monitor adequately, leading to undetected leakage. Considering the long term outlook, some regulations envisage a transition in responsibilities from private operators to governments after a certain number of years (e.g., 50 years) or in case of company closures. Furthermore, assuming leakage occurs and is correctly detected and measured, someone has to pay for local damages

[3]Note that these values are modeled leakage rates over the century and thus depend on the timing and deployment of CCS and carbon storage.

[4]These values per century are theoretical, meaning the amount of gas that would leak if it was all stored on the first year. The real leakage per century will depend on the intertemporal storage profile of the model, see **Figure 2**.

and for the cost of global externality it is generating. In the case of a carbon pricing scheme, the latter cost is set by the carbon price. Also in this case, dodging responsibility by private or public authority would inhibit the economic benefits of CCS or CDR.

Not all countries have appropriate or specific regulation to address the safety and liability issue. Liu et al. (2016) provides a review of existing regulations in some developed countries and compares them with general Chinese environmental regulation. As an example, EU regulation establishes the payment for emissions credits in the Emissions Trading System (ETS) system for the storage operator (EU, 2009). Other useful measures are insulation of the perforation of the well, re-injection in more safe sites and insurance plans, also for companies that go bankrupt (Lackner and Brennan, 2009; Imbus et al., 2013). In conclusion, we have seen how important it is to assign responsibilities for monitoring and compensate leakage damages. Therefore, we included these aspects in this exercise, developing some scenarios that mimic successful or failed monitoring, pricing, and management of stored emissions.

3. METHODOLOGY

We use an integrated assessment model (IAM) to simulate the impact of leakage on the set of mitigation strategies. IAMs are tools which are routinely used to evaluate global climate policies. Currently, many integrated assessment models use aggregated storage cost and availability curves, notably the ones from Hendriks et al. (2004). For this exercise, we disaggregated the storage according to different types of storage including their respective potential and costs. Moreover, transportation costs also vary according to the storage site considered. Finally, we added leakage from the different storage sites and assessed a set of scenarios capturing different climate policies, leakage rates, and options to consider leaked carbon emissions. We use the WITCH (World Induced Technical Change Hybrid) integrated assessment model in this study.

WITCH is a global integrated assessment model with two main distinguishing features: a regional game-theoretic setup, and an endogenous treatment of technological innovation for energy conservation and decarbonization (Emmerling et al., 2016). A top-down inter-temporal Ramsey-type optimal growth model is hard linked with a representation of the energy sector described in a bottom-up fashion, hence the hybrid denomination. The regional and intertemporal dimensions of the model make it possible to differentiate and assess the optimal response to several climate and energy policies across regions and over time. The non-cooperative nature of international relationships is explicitly accounted for via an iterative algorithm which yields the open-loop Nash equilibrium between the simultaneous activity of a set of representative regions. Regional strategic actions interrelate through greenhouse gas (GHG) emissions, dependence on exhaustible natural resources, trade of fossil fuels and carbon permits, and technological research and development (R&D) spillovers. R&D investments are directed toward either energy efficiency improvements or development of carbon-free breakthrough technologies. Such innovation accumulates over time and spills across countries in the form of knowledge stocks and flows. R&D investments, along with investments in energy technologies and the final goods sector, are endogenously determined in the intertemporal optimization. Within the energy sector, for new renewable energy sources (wind and solar), battery development, and advanced biofuels, learning is also taken into account through one or two factor learning curves, which determine future capital costs. The competition for land use between agriculture, forestry, and bioenergy, which are the main land-based production sectors, is described through a soft link with a land use and forestry model (GLOBIOM, Global Biosphere Management Model). A climate model (MAGICC) is used to compute climate variables from GHG emission levels, and an air pollution model (FASST) is linked to compute air pollutant concentrations.

Concerning CCS in the model, we consider four coal technology options (including the possibility of retrofitting existing plants), one gas and one biomass technology with carbon capture. The model includes seven types of storage (saline aquifers, EOR sites, depleted oil and gas fields, all either onshore or offshore, and onshore ECBM sites), each characterized by a maximum available capacity, a storage cost and an average distance from power plants. Apart from storage costs for the different types, all values are regionally differentiated. Finally, we account for an average specific transport cost dependent on the distance calibrated as $c'_{tr} = 0.006667\$/tCO_2\ km$ (Rubin et al., 2015). The total cost of captured CO_2 transport and storage $C_{t\&s}[\$/year]$ is therefore evaluated according to the following equation, where the dimensions are time (t), regions (n), and type of storage (k_{st}):

$$C_{t\&s}(t,n) = \sum_{k_{st}} Q_{st}(k_{st},n,t) \cdot \left(c'_{tr} \cdot l_{tr}(n,k_{st}) + c_{st}(k_{st}) \right) \quad (1)$$

Here, Q_{st} $[GtCO_2/year]$ represents the yearly quantity of CO_2 captured by CCS plants, l_{tr} [km] represents the average distance, and c_{st} $[\$/tCO_2]$ the storage cost. We consider an annual leakage rate λ_{lk} of between $0.0\%/year$ and up to $0.1\%/year$ and include leaked emissions in the model. The cumulative amount of CO_2 stored CUM_{st} $[GtCO_2]$ is therefore calculated based on annual stored values, considering that the model is run at a time step of 5 years, and including possible leakage every time period:

$$\begin{aligned} CUM_{st}(k_{st},n,t+1) \;=\; & CUM_{st}(k_{st},n,t) \cdot (1-\lambda_{lk}(k_{st},n,t))^5 \\ & + 5 \cdot Q_{st}(k_{st},n,t) \end{aligned} \quad (2)$$

Here, λ_{lk} stands for the leakage rate, or the percentage of CO_2 stored in the previous year that is lost due to leakage and emitted in the atmosphere. This set of equations allow us to represent the transport and storage chain as a single cost function, differentiated across regions. The cost function for each storage type follows a step increase in function of the cumulative stored quantity, where each step means a switch from a cheap but

replete storage type to the immediate next, more expensive site. Finally, annual leaked emissions Q_{leak} are computed as follows:

$$Q_{leak}(n,t) = \sum_{k_{st}} \lambda_{lk}(k_{st},n,t) \cdot CUM_{st}(k_{st},n,t) \quad (3)$$

It should be noted that Q_{leak} in period t is accounted for based on CUM_{st} in t, which is not including the emission captured in the same period, but only until $t-1$. This is to represent delay in leakage.

4. SCENARIO DESIGN

Based on this model implementation of storage, transportation, and leakage of CO_2, we explore a set of 31 scenarios to capture the following dimensions: leakage rates, climate targets, and policy provisions. We implement different leakage rates (LR) starting from zero leakage, 0.01%, 0.05%, and up to 0.1% per year.

Secondly, we consider different stringency of climate policies, represented by carbon budgets covering total CO_2 emissions from fossil fuels and industrial processes from 2010 to 2100. In addition to the business as usual (BAU) case without a future climate policy, we consider cases of 550, 1,000, and 1,600 $GtCO_2$ corresponding to roughly 1.5, 2.0, and 2.5°C of global warming in 2100, according to the definition in the IPCC AR5 report (Edenhofer et al., 2014; Vuuren et al., 2017)[5]. When running these scenarios, the model sets a constraint on emitted CO_2 equal to the budget and solves finding the cost optimal solution for attaining the target.

Finally, we differentiate the economic and policy treatment of carbon leakage emissions. In particular, we consider whether or not (a) leaked emissions are priced (through a carbon tax or the price of emission permits) or not, and (b) the leaked emissions are included in the carbon budget of the policy maker. Four cases are possible based on these distinctions: In the first case (NN), leakage is not taken into account in the policy target nor priced, e.g., due to technical, institutional, or political barriers. This case allows us to assess the climatic impact of leakage if it is not taken into account for climate targets, nor in emission pricing schemes. The other limiting case, where pricing and monitoring are effective (YY), constitutes the first best case where the actual climate target is attained, and leakage is treated the same way as other carbon emissions and priced at the marginal cost of abatement. The two remaining cases represent different institutional, economic, and technological situations: In the YN case, leakage is anticipated for the climate policy goal, while due to monitoring or institutional constraints, the source cannot be taxed or held accountable. Hence, in this case, other mitigation options are required to counteract leakage emissions. Hypothetically, in the fourth situation (NY), on the other hand, pricing leakage emissions is possible and implemented, but the climate policy does not take leakage into account a situation which is not realistic and hence we do not consider it here.

[5]The IPCC AR5 Scenarios Database documents the long-term scenarios as reviewed in the Fifth Assessment Report (AR5) of Working Group III of the Intergovernmental Panel on Climate Change (IPCC) (Edenhofer et al., 2014).

TABLE 1 | Scenarios considered (31 in total).

(A) THREE CASES REPRESENTING LEAKAGE MONITORING AND LIABILITY

monitoring \ liability	No	Yes
No	**NN** leakage not accounted in carbon budget, nor priced	[Not realistic]
Yes	**YN** leakage accounted in carbon budget, but not priced	**YY** leakage accounted in carbon budget and correctly priced

(B) BAU AND THREE CARBON BUDGETS [$GtCO_2$ BY 2100]

Climate target
BAU
1,600
1,000
550

(C) FOUR LEAKAGE RATES

Leakage rate (%/year)
0.00%
0.01%
0.05%
0.10%

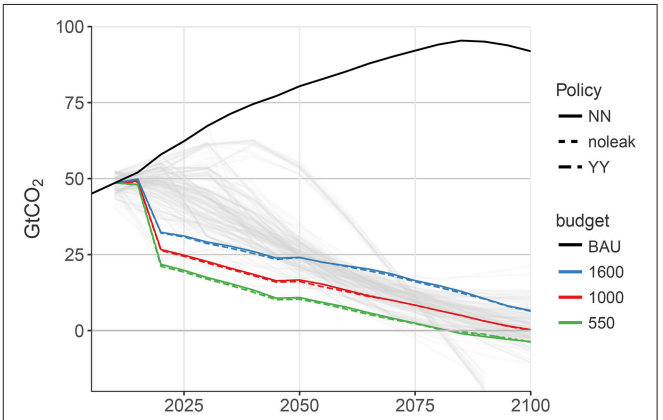


FIGURE 1 | Global greenhouse gas emissions ($GtCO_{2eq}$) across scenarios. For target different from BAU, leakage is set to 0 or 0.1%/*year*. In gray are plotted the scenarios form the AR5 Scenario Database in line with the 2°C.

As summarized in **Table 1**, we consider three different policy prescriptions (NN, YN, YY) for three different carbon budgets (1600, 1000, 550 $GtCO_2$) and three leakage rates (0.01, 0.05, 0.1 %/*year*, total: 27 scenarios), in addition to the four scenarios without leakage (BAU, 1,600, 1,000, 550).

5. RESULTS

The different sets of scenarios show different patterns in terms of emissions, CCS deployment, and economic costs. Firstly, looking at overall greenhouse gas emissions, **Figure 1** shows the no leakage and high leakage scenarios and compares them to the scenarios of the AR5 database that are consistent with the two degree target (Edenhofer et al., 2014). Overall, emissions

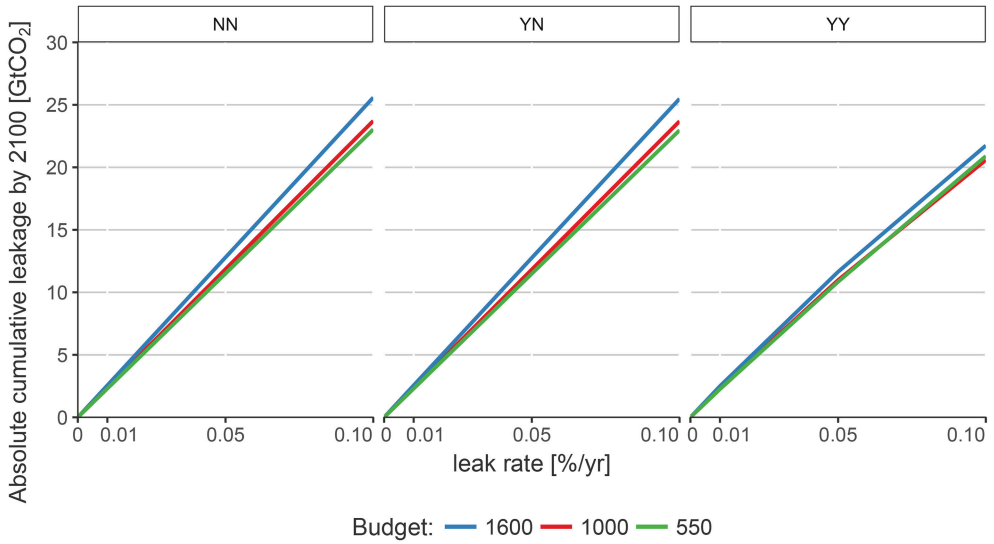


FIGURE 2 | Cumulative leaked emissions in the different scenarios [$GtCO_2$]. Captured emissions are around 700–750 $GtCO_2$ for NN and YN scenarios and 650–700 $GtCO_2$ for the YY scenario.

are only mildly affected by carbon leakage at the global scale, and the mitigation pathways are dominated by the stringency of the carbon budgets. In particular in the 550 scenarios, total emissions become negative toward the end of the century. The difference between cases where leakage (set as 0.1%/*year* of stored CO_2) is well accounted for (YY) and when it is not (NN) is small compared to total emissions, though still visible.

Looking closer at the leaked emissions, one can see that leakage can contribute to emissions as shown in **Figure 2**. The amount of leakage over this century in the NN and YN scenarios ranges from 2.5 $GtCO_2$ (for a leakage rate of 0.01%/*year*) to around 25 $GtCO_2$ for a leakage rate of 0.1%/*year*. Moreover, while it is quite similar for the different climate targets, it shows the highest values always for the 1,600 $GtCO_2$ scenario, where fossil-based CCS is widely deployed. Comparing the leakage to the amount of captured emissions for the NN and YN scenarios (around 700–750 $GtCO_2$), we get around 0.5% of leakage until 2100 for the low leakage rate, and 3% for the high leakage rate cases. These values are virtually unchanged in the YN and NN scenarios, where leakage is not priced and hence does not affect CCS deployment. However, in the YY scenario, when the effect and cost of leakage are fully accounted for, the model responds with a reduction in leakage, linked to a reduction in CCS technology adoption and captured emissions. For the highest leakage rate of 0.1%, captured emissions are lowered by about 5–10 $GtCO_2$ across the different climate targets. The percentage of leaked emission on the total captured between 2015 and 2100 is however similar to the previous scenarios. If compared to Deng et al. (2017), our results show higher percentage of emission leaking over the century given similar leakage rates. This is due to their assumption that most of leaked emissions do not reach the surface, but are priced and thus have a negative impact on CCS deployment.

Leaked emissions have an impact on the climate, in terms of CO_2 concentrations and global temperature increase, shown in **Figure 3**. In absolute terms, variations in global mean temperature increase in 2100 are relatively small, of the order of magnitude of 0.01°C when leaked emissions are not monitored. For the YN and YY scenarios where leakage is accounted in the carbon budget target, the results show a small temperature decrease with increasing leakage rate. This can be explained due to different timing of emissions, notably due to the early shift to zero carbon technologies replacing CCS. While overall the temperature effect is relatively small, it still implies further exacerbation of global warming when leakage is not accounted in the budget, which might be relevant for the most stringent scenarios.

Figure 4 shows that the reduction in CCS (in terms of capacity reduction by 2100) is linked to the leakage rate, and to whether it is priced and accounted for in the carbon budget: only in the case where the costs of leaked emissions are accounted for in the economy through carbon pricing (YY) is CCS substantially reduced. Therefore, in the scenarios where countries do not pay for their leaked emission, CCS is not affected, both in the case where seepage is considered in the carbon budget or not (YN and NN scenarios). This result can be explaind since leakage can not be directly linked to the storage owners and the capturing power plant. The CCS reduction is particularly high for fossil fuel based CCS where the reduction reaches between 10 and up to 35 per cent of the capacity without leakage. Bio-energy with carbon capture and storage (BECCS), on the other hand, shows reductions lower than 10%. That is, for biomass CCS, leakage seems to provide a less important barrier, even with a leakage

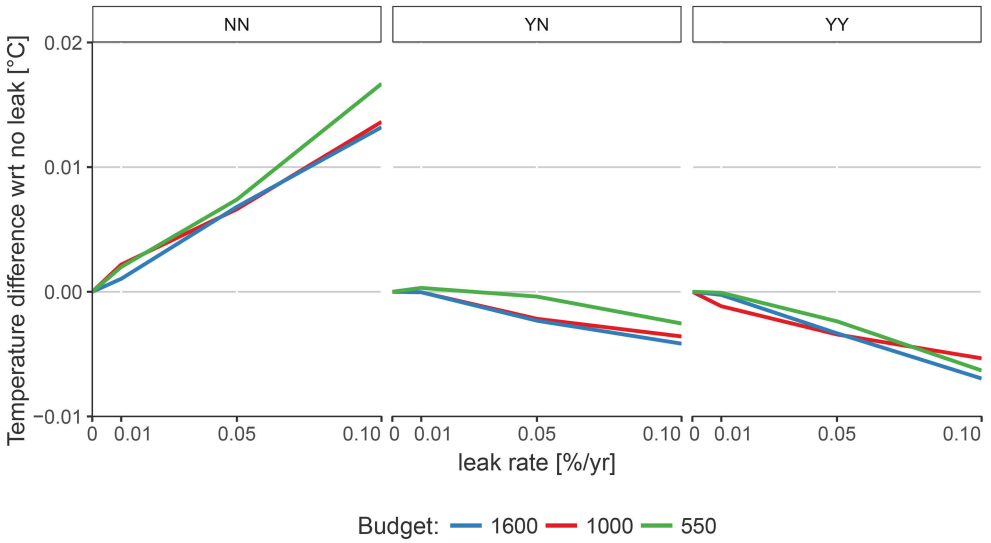


FIGURE 3 | Global mean temperature increase compared to no leakage case [°C].

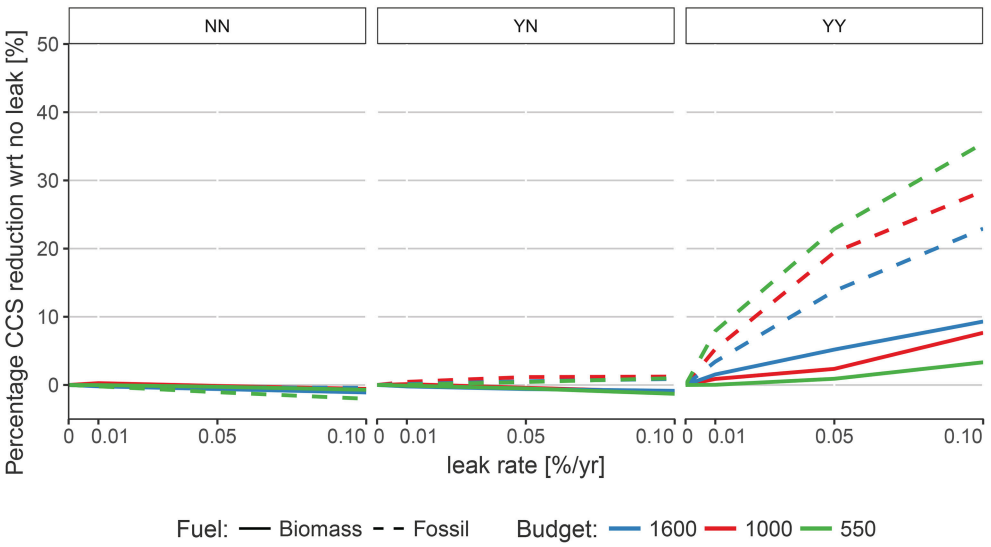


FIGURE 4 | Capacity reduction in CCS compared to no leakage case [%]. The reference values of total installed capacity by 2100 in case of zero leakage are: 61 *TW* (biomass) and 52 *TW* (fossil) for the 1,600 scenario, 63 *TW* (bio) and 37 *TW* (fossil) for 1,000 $GtCO_2$ and 75 *TW* (bio) and 25 *TW* (fossil) in the 550 $GtCO_2$ case.

rate of 0.1% per year, especially in the most stringent 1.5°C scenario. Moreover, it is interesting to note that the ordering across stringency of the climate targets is reversed for fossil fuel and biomass based CCS: The more stringent the scenario considered, the lower the impact on BECCS and the higher the reduction of fossil based CCS. This result is in line with the intermediary role of fossil fuel based CCS found e.g., in Rogelj et al. (2015), van der Zwaan and Smekens (2009) and Deng et al. (2017), even if these two latter studies did not consider stringent scenario such as the 1.5°C (550 $GtCO_2$).

In terms of economic costs of carbon leakage, we first look at the implied carbon price required to meet the different climate targets. **Figure 5** shows the increase in carbon price with respect to the no leakage cases, noticeable for scenarios where leakage is included in the carbon budget. The standard carbon prices in the three scenarios in the year 2020 to implement the carbon budgets of 1,600, 1,000, and 550 $GtCO_2$ are 79, 164, and 318 $\$/tCO_{2eq}$ respectively, and grow at a rate of 5% per year[6]. Comparing to these default scenarios the leakage cases, first note that the NN scenario does not show any change in the carbon price as leakage increases, since it is not considered for the policy

[6]Note that therefore the relative difference in carbon prices shown in **Figure 5** are constant over time and across regions.

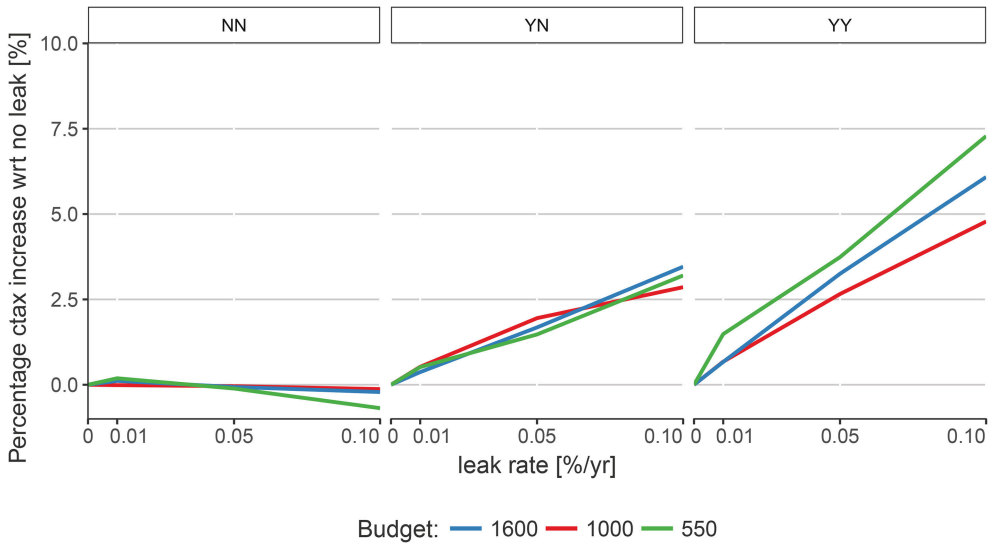


FIGURE 5 | Relative increase of the carbon price compared to no leakage case [%]. The carbon prices in 2,020 for 1,600, 1,000, and 550 $GtCO_2$ (no leakage case) are 79, 164, and 318 $\$/tCO_{2eq}$ respectively.

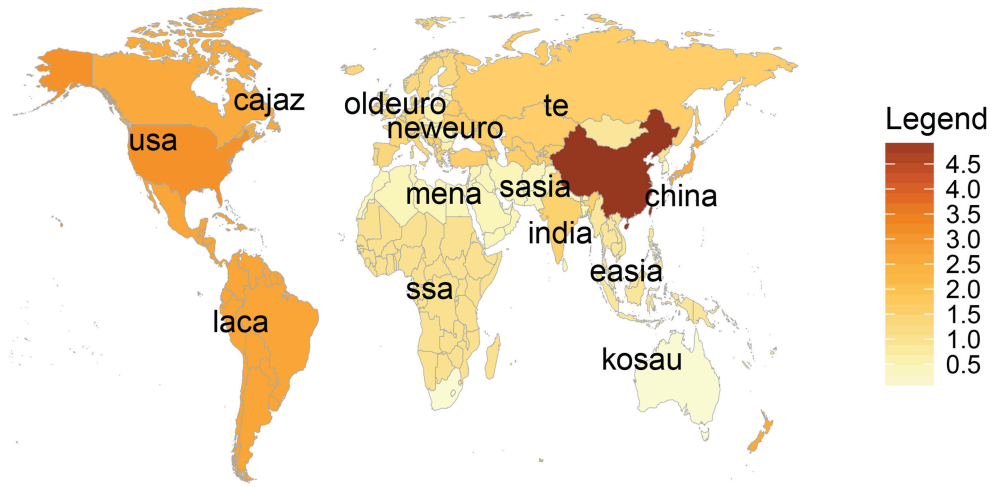


FIGURE 6 | Cumulative leaked emissions by 2100 in the scenario 550, NN and leakage rate of 0.1 $\%/year$ [$GtCO_2$].

design. When seepage affects the carbon budget available for each climate policy, it becomes necessary to mitigate this effect using other technological strategies more expensive than CCS. This results in an increase of carbon price in the YN and YY scenarios, which ranges from 2.5 to 7.5%. When leakage is not priced (YN), it still leads to a higher carbon price due to the reduced global carbon budget, albeit to a lesser extent, resulting from higher mitigation effort based on the most cost-effective mitigation options available. When it is also priced, the cost-effective potential of CCS is significantly reduced, resulting in higher use of more expensive mitigation options such as energy efficiency improvements or renewable energy sources. Across carbon budgets, it should be noted that, although the relative variation in the carbon tax is similar, in absolute value it differs significantly.

The previous results showed how uncontrolled seepage would affect global climate and how, even well monitored leakage might be binding for CCS development and would lead, globally, to a more expensive energy system. Now we focus on the regionally differentiated modeling results, focusing here on the most stringent scenario (550) and using the 0.1% leakage rate, while for smaller rates the results scale down almost linearly as shown before.

As shown in **Figure 6**, the cumulative leaked emissions are not evenly distributed across regions: China, the United States, Canada/Japan (cajaz), and Latin America (laca) countries are

expected to extensively use CCS power plants, and therefore are projected to leak more than 2 $GtCO_2$, with China reaching 5 $GtCO_2$ by 2100 (see **Table 2** for the description of the regions).

Given the relatively high carbon price required to achieve the stringent climate policy targets, leakage can imply substantial additional costs of emissions, according to the carbon price in place. In the aforementioned regions with high projected leakage potential, this amounts to values between 75 and 200 billion USD over the century, with exception of 550 billion for China, see the left panel in **Figure 7** (all values reported there refer to NPV cumulative values from 2015 to 2100, discounted at a 5% discount rate). In the scenario 550, NN with high leakage, the (discounted) yearly value of leaked emissions in 2100 reaches up to 12 billion USD in China and about 7 billion USD in Latin America. Globally, the yearly leakage in 2100 of 0.78 $GtCO_2$ amounts to a discounted value of 54 billion USD. Given the relatively small carbon budget consistent with the 1.5 degree scenario, the additional 25 $GtCO_2$ of leaked carbon emissions associated with the high leakage rate (0.1%/*year*) scenario represent a significant cost, with particular economic implications for some regions. Moreover, we can compare which regions have to bear the additional costs if, while initially not being priced, now leaked emissions are accordingly priced and the climate target is the same, i.e., moving from scenario YN to YY. The right part of **Figure 7** shows the additional cost of leakage emissions when they are priced at the global carbon price (YY) compared to the case where they are not (YN): almost all regions show a negative difference, meaning that they reduce expenses when leakage is well regulated. In Canada/Japan (cajaz), including the leakage costs in the economy does not lead to a large CCS reduction. Therefore, the higher carbon price in the YY scenario results in higher costs for the country. This occurs mainly because the use of BECCS late in the century seems essential for these countries. In countries where CCS is only marginally profitable, its optimal deployment is reduced facing leakage, and hence the required carbon price is slightly higher, while leakage is significantly reduced. Since the latter effect dominates, those countries gain in terms of the value of carbon.

These are the value of losses that would not be payed by companies or countries in absence of regulation. But they can also be seen as a waste of money for a country which is investing in climate mitigation policies, and the cost of re-abating leaked emission. Moreover, other costs, like local or climate change damages are not accounted in this estimation, therefore the real economic loss might be even higher. Note that in both cases the carbon price increases with leakage rate, as more expensive low carbon technologies are installed to compensate seepage. However the YY scenario represents a perfect regulation system where CCS owners pay for the leaked emissions, so that use of CCS is reduced and the carbon price increases further. This behavior is considered more convenient than continuing using CCS and paying for leakage. The difference in total leakage costs can be considered as the regional gain or loss if leakage is well regulated or not. Moreover, we also compare the GDP of all scenarios to

TABLE 2 | Regions of the WITCH model.

WITCH region	Description
usa	United States of America
oldeuro	Western Europe (EU15+EFTA)
neweuro	Eastern Europe (EU12+European EITs excluding FSU countries)
kosau	South Korea, South Africa, Australia
cajaz	Canada, Japan, New Zealand
te	Non-EU Eastern European countries, including Russia
mena	Middle East and North Africa
ssa	Sub Saharan Africa
sasia	South Asia (except India)
china	China, including Taiwan
easia	South East Asia, including Indonesia
laca	Latin America, Mexico and Caribbean
india	India

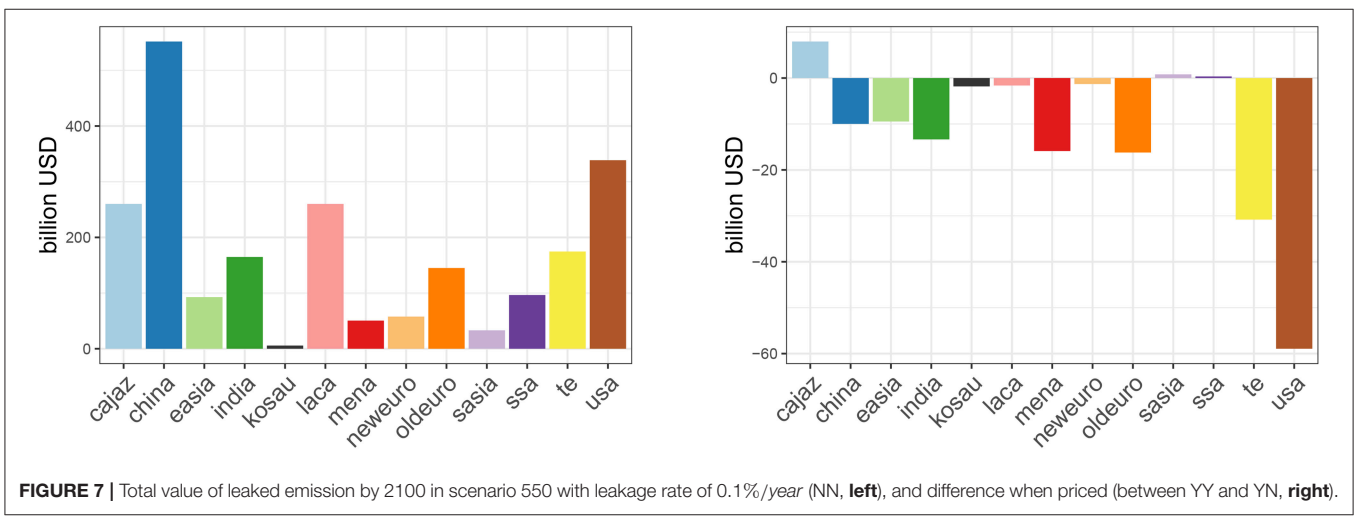


FIGURE 7 | Total value of leaked emission by 2100 in scenario 550 with leakage rate of 0.1%/*year* (NN, **left**), and difference when priced (between YY and YN, **right**).

TABLE 3 | Policy Cost with respect to BAU for different leakage rates and pricing policies [% of GDP].

Leakage rate	0	0.01%/year		0.05%/year		0.1%/year	
CB\policy		YN	YY	YN	YY	YN	YY
1,600	3.38	3.39	3.40	3.42	3.47	3.46	3.54
1,000	5.64	5.66	5.68	5.72	5.75	5.77	5.86
550	8.52	8.53	8.55	8.56	8.68	8.64	8.86

analyze the changes in policy costs with respect to the BAU scenario. **Table 3** reports the policy cost for the aforementioned scenarios. We confirm the above mentioned trend of policy cost[7] increasing with leakage rate and from zero leakage case to YY setting. Overall, policy costs increase in the range of 0.1–0.2% in the YN case due to the higher mitigation effort needed. If moreover leakage is priced, they increase by a further 0.1-0.2 percentage points. For instance, in the stringent 550, YY scenario and for a leakage rate of 0.1%, the costs of staying below 1.5° increase from 8.5% to almost 8.9% due to leakage.

6. CONCLUSION

The purpose of this work is to expand the assessment of leakage impact on CCS deployment and climate policies. We consider different institutional and economic settings reproducing issues in monitoring and paying for possible leakage. Furthermore, we perform analysis over leakage rates, and over three different climate scenarios, including the 1.5 and 2°C temperature increase target by 2100, particularly relevant after the Paris agreement in 2015. The results show that carbon leakage can lead to up to 25 $GtCO_2$ of additional emissions throughout the twenty-first century for a leakage rate of 0.1% per year, which represents about 3% of total captured emissions. Considering a more optimistic leakage rate (0.01%), only 0.5% of injected emissions would leak by 2100. If accounted for in the carbon budget and priced, CCS deployment is expected to be lowered by up to 35% (fossil) and 10% (BECCS) for high leakage rates. This means that CCS remains an important technology for mitigation in the power sector, notably coal and gas based in less stringent scenarios, and biomass fueled for the 1.5°C scenario. Due to more early-on abatement, considering leakage leads to slightly lower global warming in the long run. If not taken into consideration nor priced, on the other hand, it leads to an around 0.01–0.02 degrees higher global mean temperature. Overall, policy costs increase by about 0.2–0.4 percentage points (of GDP loss) due to considered leakage. In terms of regional distribution, China, Latin America, the U.S., and Canada have the highest leakage amount to be expected by 2100. The associated economic value of this quantity ranges across regions from 70 to more than 200 billion USD. Finally, we demonstrated how appropriate monitoring and accounting of leakage imply a reduction in use of CCS and also economic saving for most countries.

[7] measured as NPV of GDP differences in global GDP discounted at a 5% rate.

AUTHOR CONTRIBUTIONS

AV contributed to developing the idea, methodology, model design and execution, writing and revising the manuscript; JE contributed to developing the idea and methodology, supervised model design and execution, writing and revising the manuscript; MT have supervised the work, providing suggestions on the research scope and revisions.

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Conflict of Interest Statement: The authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

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Illustration by Hokyoung Kim for HuffPost

The Gassing Of Satartia

A CO2 pipeline in Mississippi ruptured last year, sickening dozens of people. What does it forecast for the massive proposed buildout of pipelines across the U.S.?

By Dan Zegart
August 26, 2021

It was just after 7 p.m. when residents of Satartia, Mississippi, started smelling rotten eggs. Then a greenish cloud rolled across Route 433 and settled into the valley surrounding the little town. Within minutes, people were inside the cloud, gasping for air, nauseated and dazed.

Some two dozen individuals were overcome within a few minutes, collapsing in their homes; at a fishing camp on the nearby Yazoo River; in their vehicles. Cars just shut off, since they need oxygen to burn fuel. Drivers scrambled out of their paralyzed vehicles, but were so disoriented that they just wandered around in the dark.

The first call to Yazoo County Emergency Management Agency came at 7:13 p.m. on February 22, 2020.

“CALLER ADVISED A FOUL SMELL AND GREEN FOG ACROSS THE HIGHWAY,” read the message that dispatchers sent to cell phones and radios of all county emergency personnel two minutes later.

First responders mobilized almost immediately, even though they still weren't sure exactly what the emergency was. Maybe it was a leak from one of several nearby natural gas pipelines, or chlorine from the water tank.

through the hills above town, less than half a mile away. Denbury Inc, then known as Denbury Resources, operates a network of CO2 pipelines in the Gulf Coast area that inject the gas into oil fields to force out more petroleum. While ambient CO2 is odorless, colorless and heavier than air, the industrial CO2 in Denbury's pipeline has been compressed into a liquid, which is pumped through pipelines under high pressure. A rupture in this kind of pipeline sends CO2 gushing out in a dense, powdery white cloud that sinks to the ground and is cold enough to make steel so brittle it can be smashed with a sledgehammer.

Even Durward Pettis, a contract welder for Denbury and chief of the local Tri-Community Volunteer Fire Department, didn't figure out that the mystery fog was CO2 for a full 15 minutes. He'd directed first responders to set up three roadblocks to prevent traffic from entering the area. But it wasn't until 7:30 p.m. that word went out that they'd need self-contained breathing apparatus, or SCBA, to enter Satartia and evacuate the town's 42 residents, many of them elderly, and about 250 others who lived just outside town. By then, rescuers and residents were already in motion, fleeing the gas or evacuating others.

Even once Pettis figured it out, none of the sheriffs' deputies and volunteer firefighters had any emergency training in CO2 leaks. Neither did staff at two area hospitals, which had detrimental consequences for gas victims, according to interviews with many of the 49 who were hospitalized.

"It was bad enough that I thought my mama wouldn't make it, and she still has trouble breathing," said Army veteran Hugh Martin, who fled Satartia in a pickup truck with his 78-year-old mother as he struggled to remain conscious. "She never had asthma or COPD, now she's on inhalers full time."

Even months later, the town's residents reported mental fogginess, lung dysfunction, chronic fatigue and stomach disorders. They said they have trouble sleeping, afraid it could happen again.

investigation into the Satartia pipeline rupture, and the safety of CO2 pipelines. It is based on interviews with more than 60 witnesses, victims, first responders, lawyers, medical and toxicological experts, pipeline and petroleum experts, and public health officials; and a review of medical records, police and fire reports, 911 recordings, emergency dispatch logs, internal documents from the Mississippi Emergency Management Agency and the state Department of Environmental Quality, as well as federal pipeline incident reports.

Meanwhile, the federal government is taking the first steps to vastly increase the size of the nation's carbon dioxide pipeline network as a way of fighting climate change. Our investigation reveals that such pipelines pose threats that few are aware of and even fewer know how to handle.

"We got lucky," said Yazoo County Emergency Management Agency director Jack Willingham, who oversaw the rescue effort. "If the wind blew the other way, if it'd been later when people were sleeping, we would have had deaths."

A Deadly Gas

Carbon dioxide has long been used to euthanize laboratory rodents and other small animals, a practice animal welfare organizations now consider inhumane due to the suffering the gas inflicts on the animals. Each year, CO2 accidents kill about 100 workers worldwide — often in basements of restaurants that use CO2-charged systems for their bar mixers — or in industrial accidents.

Carbon dioxide is an asphyxiant that displaces ambient oxygen, making it more difficult to breathe. Smaller exposures cause coughing, dizziness and a panicky feeling called "air hunger." As CO2 concentrations get higher and exposure times longer, the gas causes a range of effects from unconsciousness to coma to

performance and inducing a confused, drunken-like state.

Denbury's entire business is built around piping carbon dioxide to oilfields and a few industrial users in two operational centers in the Gulf Coast and the Rockies. It owns or has an interest in 14 oil fields in Mississippi, Texas and Louisiana, which are connected by five CO2 pipelines spanning 925 miles. Among its properties is Tinsley Field, adjacent to Satartia, which became Mississippi's first commercially successful oil field in 1939.



Left: The Tinsley oil field in Tinsley, Mississippi, on July 23, 2021. Right: A CO2 gas pipeline remains active in Satartia, Mississippi, that same day.
Rory Doyle for HuffPost

In 2007, Denbury built its 31-mile Delta pipeline to connect Tinsley to the Jackson Dome, an extinct volcano under Jackson, Mississippi, whose 4.6 trillion cubic feet of naturally occurring CO2 gas supplies all of the company's fields. Denbury extended the Delta line 77 miles to Louisiana's Delhi field in 2009.

Denbury uses the CO2 for enhanced oil recovery, or EOR, which uses the gas to flush more oil out of wells. About 20% to 40% of the oil in a field can be recovered through conventional drilling and injecting water into the reservoir. Injecting CO2 after that can increase the yield up to 60%.

Tinsley itself suffered a sizeable CO2 "blowout" — where injected CO2 explodes out of the ground along with water, mud and drilling fluids — in 2011 that took 37 days to bring under control, sickened one worker, and killed deer, birds, fish and other animals.

Denbury had already had two other blowouts in Mississippi, one requiring the evacuation of local homes in Amite County in 2007. Another underground CO2 blowout at Delhi field in 2013 lasted for more than six weeks and contaminated the air with unsafe levels of both CO2 and methane.

Denbury and other companies that do EOR are well versed in the dangers of CO2. At Denbury's Heidelberg Field in eastern Mississippi, signs warn of a CO2 hazard and say SCBA must be worn, and there are muster stations where workers gather if there is a release. The company also has safety pamphlets on its website — one for the public called "Pipeline Safety Is Everybody's Responsibility" and another for first responders titled, "AWARE: Tactics for Responding to a CO2 Pipeline Leak." None of the emergency workers interviewed for this story had seen either.

While the risks of CO2 exposure were well established, the Satartia gassing was the first known instance of an outdoor mass exposure to piped CO2 gas anywhere in the world, according to Marcelo Korc, chief of the World Health Organization's Climate Change and Environmental Determinants of Health Unit, whose staff researched injuries from CO2 pipeline leaks in response to an inquiry from HuffPost.



The sun sets on the village of Satartia alongside the Yazoo River in July.
Rory Doyle for HuffPost

Korc's staff also found that CO2 from the Jackson Dome is contaminated with hydrogen sulfide, a deadly gas that likely worsened residents' symptoms and also accounts for the gas cloud's odor and greenish color, since pure CO2 is odorless and colorless.

Denbury declined to answer specific questions for this story, sending only a statement:

> *On February 22, 2020, at approximately 7:00 p.m., Denbury Enterprises' Delta pipeline experienced a sudden rupture and release of CO2 gas near Satartia, Mississippi. Before, during, and after the event, Denbury's main*

release and the surrounding environment. Denbury and its personnel were quickly in the community, working directly with nearby leadership and any individual residents affected by the event to ensure that any needs arising from the event were met. We have continued to work closely with the community and have made significant contributions to local emergency response organizations to support the important role they play in keeping the community safe. Denbury has cooperated fully with all federal, state, and local agencies who responded to the incident. The federal agency charged with regulating the pipeline continues its review and investigation of the incident, and Denbury continues to cooperate fully with their efforts.

Beyond the suffering of those who lived through it, the fact that the Biden administration is poised to commit unprecedented billions to carbon capture and sequestration (CCS) technology — putting CCS at the center of the country's strategy for reducing greenhouse gas emissions — further magnifies the importance of Satartia's CO2 accident.

The historic hike in federal support for CCS infrastructure includes taking the first steps toward the construction of a continent-spanning network of pipelines in order to move America's many millions of tons of CO2 to storage areas where, theoretically, the gas can be injected deep underground and sequestered indefinitely.

Some experts estimate this network will need to be as large as or even larger than the 2.6 million miles of existing petroleum pipelines. Meanwhile, there are only 5,000 miles of existing CO2 lines, meaning there is little experience with a wide range of operational — and safety — issues likely to arise from such a massive new system.

Nevertheless, Biden's climate team; his Department of Energy and three of its former secretaries; most utilities; the coal industry and the governments of several coal states; ExxonMobil, the rest of Big Oil and other major industrial corporations; several climate NGOs; the AFL-CIO; and a bipartisan group that

some form.

“We want to build more pipes,” DOE Secretary Jennifer Granholm told a reporter in June. “There’s a lot of jobs that are associated with decarbonizing … and I think pipes are one of those opportunities.”

But the rush to build and operate an integrated CCS and pipeline system has so far taken place with little examination of the safety issue, as the people of Satartia learned.

Korc of the WHO worried that the basic science done long ago on many toxic chemicals, including petroleum products, has never been done for CO2.

“The exposure studies simply don’t exist,” he said.

Satartia was, in effect, an unwitting case study for a monumental project.



Gas victim DeEmmeris Burns in July 2021, near the site where he was rescued in Satartia.
Rory Doyle for HuffPost

“They Can’t Come Evacuate Y’all”

DeEmmeris Burns was returning to his mother’s house in Satartia from a fishing trip with his brother Andrew Burns and cousin Victor Lewis when they heard an explosion and then a deafening roar, like a jet engine. The stench of rotten eggs filled the car.

DeEmmeris Burns immediately thought: pipeline explosion. He knew there was one nearby, but other than its approximate location, knew nothing else about it.

They were driving on Perry Creek Road, a gravel and dirt country lane that hugs its namesake waterway and passes close to but below the location of the pipe rupture. They were almost at his mother’s house.

explosion.

“You got to get out. We’re close, we’re coming to get you,” Burns shouted over the roar of escaping gas.

On the other end of the call, 65-year-old Thelma Brown was trying to figure out why her son sounded so strange. He was hollering, breathing heavily, not making sense. She knew the pipeline he was talking about; it runs about half a mile from her house. But she hadn’t smelled anything. She heard her son frantically repeating, “Cut the air! Cut everything off! Cut the air!” And then, silence.

She tried calling him back. No answer. She rang the other two men’s cell phones, but got nothing.

Inside the car, the three men rolled up the windows to keep out whatever it was they were driving through. Then the engine died.

“Hunh,” Burns said. “Car shut off.”

Minutes later, Thelma’s sister, Linda Garrett, who lived just down the road, smelled the gas and called too. Thelma repeated what her sons had told her before their call dropped.

Garrett hung up with Thelma and called 911, but the dispatcher didn’t seem to know about a gas leak.

“Do I need to be getting out of here?” Garrett asked. The 911 operator said she’d call her back and let her know.

“She can’t breathe. She’s on the floor right now”

0:00 / 3:43

Garrett noticed her own breathing was becoming labored. Then her daughter Lynett Garrett and 14-year-old granddaughter, Makaylan Burns, who had been out picking up a pizza for dinner, staggered in the door.

Makaylan seemed to be in full-blown respiratory distress, and Lynett was unable to talk. She pounded on the dining room table and panted.

“What is it? What’s wrong? What is it?” Garrett shouted.

Makaylan dropped to the floor, unconscious.

Garrett tried 911 again. This time the operator acknowledged that there was a gas leak.

“They have shut the highway down because of it. They’re not letting anyone in, they can’t come evacuate y’all,” she said.

Garrett was afraid if they left the house, all three of them would pass out. She insisted on an ambulance. The dispatcher said one would meet them outside of town.



Gas victims Linda Garrett (right) and her granddaughter, Makaylan Burns, in Garrett's kitchen in Satartia in July.
Rory Doyle for HuffPost

Garrett and Lynett carried Makaylan out to the car. Garrett had a bad back and both adults were having trouble breathing, but they managed to get the teenager into the back seat, still unconscious.

Lynett drove and Garrett stayed on the phone with 911 as the operator told them the best route out of town. But after a few minutes, Garrett's breath "just cut out." "We ain't going to make it," she said, before she blacked out. Lynett drove to where they were supposed to meet the ambulance, but it didn't show up, and she had to drive to the hospital.

Back at her house, Thelma Brown ran outside to round up her 8- and 3-year-old grandchildren. She brought them into her bedroom, along with her 2-month-old grandson. The oldest, who has asthma but hadn't suffered an attack for some

gave some to the 3-year-old too, since she had been outside. Brown closed the windows and blocked air from coming in under the door with a wet towel.

Other relatives called, urging her to get out. But her pickup had a flat, and she was alone with three children. Her daughter was supposed to come get the kids after work, but called and told Brown that all the roads into the area were blocked off. Garrett told Brown what 911 had told her: that emergency workers were not coming into town to evacuate victims.

“I talked to the Lord. I said, ‘Lord, me and these kids going to bed,’” recalled Brown. “And I said, ‘We’re going to stay here until somebody comes and gets us out of here.’”

She waited for her son and the others to show up. She fell asleep.



Rory Doyle for HuffPost

At the same time, a group of friends were cooking crayfish and sipping beer at a fishing camp along the Yazoo River. It was getting dark when Hugh Martin noticed the rotten egg smell. Soon they were all wheezing and breathing hard. Martin's friend, Casey Sanders, collapsed onto the ground, then quickly came to.

Coughing and choking, everyone somehow made it to their vehicles. Martin jumped into his white pickup truck and drove up onto the levee that separates the town from the river. The glare of his headlights illuminated a green, misty fog. The suffocating feeling was nearly intolerable. "Only thing I been through worse than this was the gas chamber when I was in the Army training for Desert Storm," he said. "And that was CS gas." CS gas is a type of tear gas.

He called his elderly mother, Marguerite Vinson, who told him she was feeling dizzy.

"Got your shoes on, mama?" he asked, trying to keep the anxiety out of his voice. He told her to meet him in the carport of their home, not far from the fishing camp. After stopping once to throw up out of the truck window, he made it home.

"I saw mama standing there, holding her phone, and she was weak at the knees. And I just grabbed her and throwed her in the truck," said Martin. "Then I just took off and headed for the highway."

At the stop sign at Route 3 was a checkpoint, but he blew by it, heading north to the hospital in Yazoo City. His mother lay motionless on the passenger's seat: Her eyes were open, but she stared blankly ahead when he spoke to her.

At the hospital, he found others from the crayfish cook, including Casey Sanders, and learned that her teenage son, Nathan Weston Sanders, and his girlfriend were missing, after leaving the fishing camp minutes before the explosion.

Sanders had collapsed. She couldn't revive him and didn't know where they were. Now, Sanders' father and another man from the crayfish gathering were driving back into the fog to look for them.

An Improvised Response

Sheriff's Officer Terry Gann was at a grocery store, taking a break from a long day working a double homicide when he received an EMS alert about a motorist who had a seizure due to a "green fog" crossing Route 433 east of the town.

"My friend, she's laying on the ground, she's shaking, she's drooling out of the mouth"

0:00 / 2:51

Yazoo is Mississippi's biggest county at 923 square miles, but it's an economically disadvantaged one, with just 11 sheriff's officers who get called in for everything from tornadoes and floods to industrial accidents. Even though he is the county's only criminal investigator, Gann works the disasters too. At 7:32 p.m., he headed toward Satartia in his truck.

EMS advised responders that self-contained breathing apparatus was required to enter the "hot zone" inside the roadblocks, where the gas had settled. Gann didn't have SCBA with him, but he went in anyway.

had gone missing in the gas plume, not far from the ruptured pipe. The cloud was moving slowly northwest, so first Gann took the road over the levee to enter the village from the south to evacuate any remaining residents.



Terry Gann, chief investigator for the Yazoo County Sheriff's Department, with the truck he used to rescue gas victims in Satartia.
Rory Doyle for HuffPost

He did a round of checks on houses, banging on doors and peering through windows, but found no one. Around him he saw — and felt — the cloud. “It’s like I just ran a mile as fast as I could. My ears were popping. My face was burning like a sunburn.”

River, out of the cloud, to catch his breath and get the vehicle running, then returned to check more houses. Just outside of town, he found a young man and woman pacing the middle of an intersection.

“It was almost like something you’d see in a zombie movie. They were just walking in circles,” he said. “I kept telling ’em, ‘Y’all get in the truck.’ And they would just look at me with this blank look on their face. And the girl was holding a phone up to her head but she wasn’t saying nothing. … Finally I just yelled at ’em, I said, ‘Get in the truck or you’re gonna die!’”

Gann shoved the dazed teenagers into the back seat, not knowing it was Nathan Weston Sanders and his girlfriend.

After picking up a woman he found unresponsive in a stalled car, his engine began sputtering again, so he returned to the command post to meet the ambulance. By the time they got there, Gann himself could barely breathe and had to be given oxygen.

He did one last search of Satartia, then messaged dispatch, “Everyone evacuated” at 9 p.m. He radioed that he was heading for Perry Creek Road, which hadn’t yet been searched.

That worried Jack Willingham, director of Yazoo County Emergency Management Agency, since Gann had been breathing high levels of CO2 for nearly two hours and was panting audibly over the radio. His speech was often slurred and when it wasn’t, it didn’t always make sense. Willingham ordered Gann to leave the “hot zone” immediately and get medical attention.

But Gann, disoriented by the lack of oxygen, got lost and never made it to Perry Creek. With radio guidance, he met an ambulance that took him to a hospital in Yazoo City. After two hours of oxygen treatments, he went home, utterly spent.

'em, I said, 'Get in the truck or you're gonna die!'

By then, however, a three-man team of Vicksburg firefighters was on its way to Perry Creek Road.

They were driving a UTV, or utility task vehicle, a small ATV-like two-seater with an open cargo bed in back that held spare air bottles and tools. Jerry Briggs, fire coordinator for Warren County, squatted in the cargo area with Warren County 911 director Shane Garrard, while Lamar Frederick, a Vicksburg fire chief, drove. Each wore 60 pounds of fire protective clothing and gear, including SCBA.

After making their own fruitless search of the village, they decided that rather than return empty handed, they would enter the blast area via Perry Creek Road. The roar of the ruptured pipeline was deafening as they approached.

A half mile up Perry Creek Road, they saw a car with its lights on and windows up just as the UTV began stalling.

"We got victims," Frederick yelled above the roar.

Inside the small red Cadillac sedan were three men: DeEmmeris and Andrew Burns, and Victor Lewis. DeEmmeris Burns lay across the backseat in the fetal position. The other two were slumped against the windows, white foam coming out of their noses and mouths, their clothes stained with urine and excrement. The firemen thought they were too late.

The doors were stuck, so Briggs smashed the right rear window. The three were still breathing, though just barely. The rescuers shook them and tried sternum rubs, but got no reaction.



Warren County firefighter Jerry Briggs in July with the utility task vehicle he used during the February 2020 gas leak in Satartia.
Rory Doyle for HuffPost

Panting in exhaustion and sweating under all their gear, they managed to get all three out and cram them into the UTV.

They headed toward the south command post. After a few minutes of fresh air, the victims began to stir. Then they tried to stand up. They seemed about to fall off when a truck full of county deputies met up with the UTV, and one of the deputies bear-hugged the men into place until they met the ambulance.

The firemen had just a few minutes to breath fresh air and chug water before Willingham sent them to evacuate a group of mostly elderly residents just across the river. Willingham and the National Weather Service office in Jackson were tracking the plume as it headed northwest, and Willingham was determined to get ahead of it.

monitoring contractor, the Center for Toxicology and Environmental Health; the environmental remediation firm E3; an investigator for the federal Pipeline Hazardous Materials Safety Administration (PHMSA); and officials from the Mississippi's Emergency Management Agency and Department of Environmental Quality.

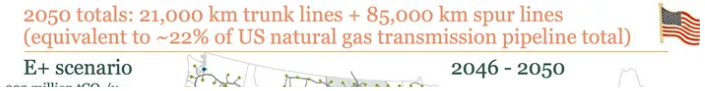
At 11:06 p.m., the Denbury team "observed no product coming from the failure location," according Denbury's report to PHMSA. The leak was officially declared over.

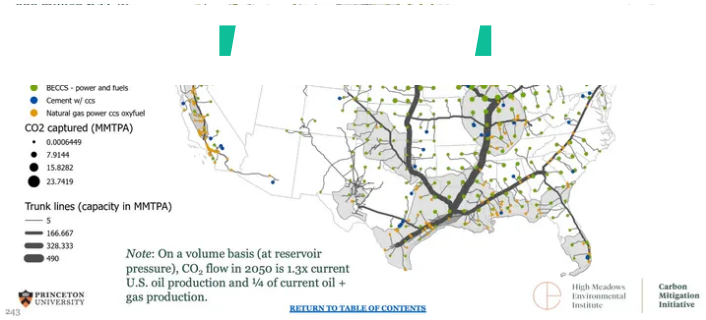
A Massive Buildout

Once the province of a few policy wonks and coal companies, shipping carbon dioxide and storing it underground has gotten much more mainstream attention in recent years amid a tsunami of conferences, draft legislation and interest groups.

The fossil fuel industry has gotten behind CCS as a technology that, it hopes, would allow continued production so long as the emissions are buried underground. But the immense network of pipelines needed to transport carbon dioxide to locations where it would be stored deep below ground weren't discussed publicly until recently, nor was how such a rapid, unprecedented pipeline buildout could be done.

A much-touted December 2020 Princeton University study — funded in part by the oil industry — calls for a 65,000-mile system by 2050, which means adding 60,000 miles to the current 5,000 miles of CO2 pipeline. The new system would be organized into a spider web of continent-spanning trunk lines as large as 4′ in diameter — twice the size of the Satartia pipeline — fed by a system of smaller spur lines.





Princeton Net-Zero America Report

But even 65,000 miles of pipeline could only move 15% of current U.S. greenhouse gas emissions. To have any effect on climate change "would entail CO2 pipeline capacity larger than the existing petroleum pipeline system," which totals 2.6 million miles, according to a 2020 study in Biophysical Economics and Sustainability.

Beginning with the Bush administration, the U.S. government has spent over $8 billion to promote carbon capture and storage (CCS). But almost all of the CO2 in current pipelines is used for enhanced oil recovery rather than being injected deep into the earth for secure geologic storage, and enhanced oil recovery produces more emissions than it sequesters. Almost none of today's CO2 is manmade, but comes from natural sources like the Jackson Dome.

Proposals like Princeton's would likely require extending CO2 pipelines into heavily populated areas, across mountains and other natural barriers. The cost of such an enormous system is driving some to suggest simply repurposing existing natural gas pipelines to move CO2.

But because CO2 is corrosive and will eat through the carbon steel used in petroleum pipelines if contaminated with even small amounts of water, CO2 pipelines have to be manufactured to a higher standard and the purity of the gas carefully monitored. And research shows that CO2 from a commonly used carbon capture technique is particularly likely to have water in it. CO2 pipelines also run at significantly higher pressures than natural gas pipelines, which in turn requires more energy-gobbling compressor stations along the line to keep the CO2 in a liquid state.

existing natural gas pipelines to move CO2. The American Petroleum Institute has also highlighted the risks.

Yet an influential white paper produced jointly by the Energy Futures Initiative, headed by former U.S. Energy Secretary Ernest Moniz, and the AFL-CIO proposes doing just that. “Repurposing the expansive U.S. network of existing oil and gas pipelines presents a ripe opportunity to lower costs for CO2 transport,” said the report.

Moniz was Biden’s energy adviser in his 2020 presidential campaign, and oversaw billions in spending on CCS in his time at the Department of Energy. He and his team are considered leading experts on both natural gas and carbon dioxide infrastructure. Yet the petroleum industry’s own longstanding warnings about mixing gas technology with carbon dioxide are nowhere to be found in a 79-page report or its 299 footnotes.

“So much of it is about cost cutting, finding ways to do things cheaper and where can you make compromises,” said Carroll Muffett, president of the Center for International Environmental Law and co-author of a highly critical report on CCS and pipelines.

Muffett noted that CO2 behaves differently from natural gas inside a pipeline — in ways that make a CO2 rupture uniquely dangerous.

“Because of the intense pressures involved, explosive decompression of a CO2 pipeline releases more gas, more quickly, than an equivalent explosion in a gas pipeline,” noted a report by CIEL and the Environmental Working Group, and “even a modest rupture can spread freezing CO2 over a wide area within seconds.”

A complicating factor in the Satartia accident was the presence of hydrogen sulfide. A Mississippi Emergency Management Agency email from the night of the accident said the leak contained an “unknown amount of pressurized CO2 with H2S.” CO2 is often contaminated with hydrogen sulfide, and Muffett points

health effects that can include damage to the nervous system, lungs, liver and heart.

Even CO2 by itself, however, can be quite lethal. On a summer day in 1986, a thick plume of CO2 from a volcanic lake in Cameroon killed 1,746 people. Birds dropped out of the sky and whole families died together in minutes.

Short of death, however, there is a wide range of CO2 inhalation effects, which include dizziness, headache, nausea, shortness of breath, increased heart rate, memory disturbances, lack of concentration, disorientation, convulsions, and unconsciousness — symptoms that closely track those of Satartia's gassing victims.

Unfortunately, few emergency rooms are familiar with the range of its effects.

A Scramble At The Hospital

When DeEmmeris Burns woke up, he was sitting in a chair near a nurse's station. He had no idea how he got to the hospital.

An IV was running down his arm, and his brother and cousin were in adjoining chairs. His lungs burned and his head ached. He was still in his soiled clothes.

"They didn't put us in rooms. I mean, it was just all bad," he remembered. "The nurses weren't prepared for this."

The hospitals told HuffPost that they responded appropriately under standard protocols for a mass toxic incident, but would not comment on specific cases.

At around 12:30 a.m., Sarah Belk, who had grown up with the Burns brothers, found the three sitting in chairs, wrapped in a single blanket. Belk had brought her own mother and daughter to the ER after they escaped from Sataria.

> ***realizing the extent of what was going on with these people," she said.***
>
> *Sarah Belk*

Andrew Burns asked where they were, and she told them they were at the hospital in Vicksburg, that their car stalled in the cloud of gas, and they'd been found unconscious. They were shivering "like they were in shock," Belk said.

She saw their stained clothes and the dried foam on their faces. All three were thirsty. No one was attending to them, and the nurses seemed dismissive and rude, Belk said.

"I felt that they were not realizing the extent of what was going on with these people," she said.

Belk's 16-year-old daughter, Ellie, had thrown up, and was still red-faced from the lack of air during her escape from Satartia. Belk's 57-year-old mother, who has COPD, was also struggling to breathe, and after more than an hour of gas exposure, her complexion "was gray." But Belk said she still struggled to get them oxygen or basic attention. The hospital seemed overwhelmed.

Belk let the three men borrow her phone to call their families.

"I'm like, 'What's going on?'" Berneva Lewis, Victor Lewis' mother, remembered. "'We're at the hospital.' That's all they could tell me on the phone. I'm like, 'What happened?' They're like, 'They said we were in gas.'"

Given how disoriented they were, Lewis was startled to get a call at 2 a.m. saying the men were being released. "It was ridiculous. They were out before I could even get to the hospital," she said.

father's home in Vicksburg. They were still in the same clothes they'd worn upon arrival.

Of some 49 gassing victims who went to the hospital, almost all were treated at Merit Health River Region in Vicksburg or Baptist Memorial Hospital in Yazoo City. But the victims say neither facility seemed prepared for how to deal with this kind of disaster. In response to questions from HuffPost, both hospitals acknowledged they based treatment on standard toxic event protocols, which included setting up unheated outdoor decontamination tents to undress and wash victims — despite temperatures in the low 40s that day.

Neither hospital said they'd received any special training in handling a CO2 pipeline incident. Medical records for four gassing victims treated at Baptist Memorial — and for six of those from Merit River Region, including the Burns brothers and Lewis — seem to reflect confusion about what they were exposed to.

"Asphyxiation by environmental toxic gas, accidental or unintentional initial encounter. CO2, H2S, chlorine gas exposure from ruptured gas line," reads the report for all four of the Baptist patients. Later the records cite "natural gas exposure."

"They [were] nowhere near ready for something like that to happen," Hugh Martin said. "They were understaffed, but they also didn't know what the hell they were dealing with."

For Denbury, An "Incident" Without Consequences

Denbury knew about the accident before anyone. At 7:07 p.m., a low pressure alarm at its Texas headquarters alerted the company that the pipeline was leaking, and the company closed the main operating valves for the Satartia section of the line at 7:15 p.m., according to Denbury's incident report to the federal Pipeline and Hazardous Materials Safety Administration (PHMSA).

responders, but both Fire Chief Durward Pettis and county Emergency Management Director Jack Willingham said nobody called them.

Denbury had no contact with them until Pettis called the company at about 7:45 p.m., according to the Yazoo County emergency dispatch log, and even then provided no guidance on the response or how to treat CO2 inhalation victims.

Without that guidance, 911 operators told callers there had been a natural gas pipeline rupture. But natural gas and CO2 are quite different. Natural gas is lighter than air, travels straight up, and is highly flammable. Exposure to CO2 mixed with hydrogen sulfide, on the other hand, can cause death from asphyxiation as well as lung damage. Residents of Sartaria were given no information about how to respond to such a mixture.

In the weeks that followed, Denbury also appears not to have disclosed the extent of the pipeline breach to investors.

“The affected pipeline segment was [isolated] within minutes of detection,” Denbury’s Senior Vice President of Operations David Sheppard said during a Feb. 25 quarterly earnings call. “And as a precaution, the area surrounding the leak site was evacuated, including residents of the small nearby town of Satartia. No injuries to local residents, our employees, our contractors were reported in association with the leak.”



LEFT: The CO2 pipeline rupture. RIGHT: Vehicles pass over the pipeline explosion site in Satartia in July.
Yazoo County Emergency Management Agency/Rory Doyle for HuffPost

To date, that is Denbury's most detailed public statement on the CO2 pipeline leak. Its filings with the Securities and Exchange Commission make no mention of a pipeline accident or leak, the evacuation, the injuries to residents, or any other details. Its 2021 annual report made two oblique references to the explosion, noting an oil production decline in 2020 at its Delhi, Louisiana, oil field "due to the lack of CO2 purchases between late-February and late-October 2020 as a result of the Delta-Tinsley CO2 pipeline being down for repair during that period" and "$4.3 million of costs associated with the Delta-Tinsley CO2 pipeline repair."

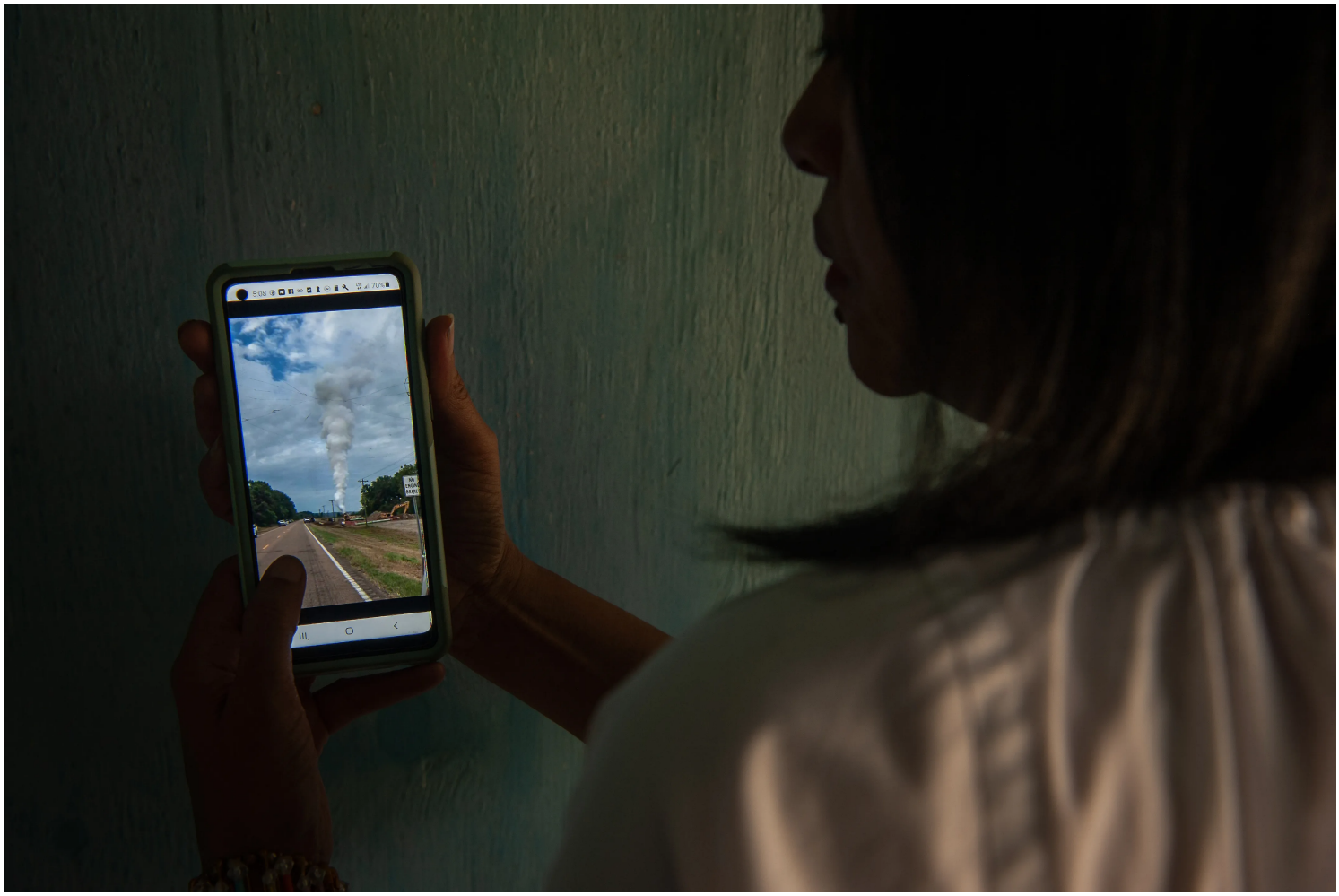
Denbury did disclose a total of 46 hospitalizations and 200 evacuees — the latter a little lower than the number reported by other sources — in its incident report to PHMSA.

Denbury also did not disclose that on Oct. 7, 2020, there was another accident while reconnecting the damaged pipeline section. While workers did a "controlled blow-down" to remove any remaining CO2 from the section, a valve "froze in the open position due to internal ice formation" and gas poured out, according to Denbury's report to the state Department of Environmental Quality. Multiple attempts to close it failed, and some residents had to be evacuated that night on short notice. But the second incident lasted longer — almost an entire

22 incident lasted four hours and released 31,407 barrels.

Why the pipeline initially ruptured also has yet to be determined. A PHMSA spokesman declined to comment on when its official report on the incident might be released.

Meanwhile, Denbury sent a section of the pipeline to a metallurgical lab for testing. Based on those findings and its contention that the pipeline was “code compliant,” it theorized in its report to PHMSA that soil movement caused by persistent heavy rains “induced axial stresses” that caused a rupture.



Berneva Lewis plays a video of an October 2020 gas leak in Satartia.
Rory Doyle for HuffPost.

evacuations along the Yazoo and Mississippi rivers. But Chad Jones, a plaintiff's lawyer representing gassing victims who is also a geologist, said flooding is common in the Delta, and should have been anticipated when the pipeline was built in 2007. Jones noted several other factors that should have been taken into account during construction as well: the soil in the area, called loess, is unstable and prone to shifting and mudslides, and building a pipeline through such soil requires special techniques because any rupture in that area would send the gas downhill into Satartia.

"They might claim an act of God," said Jones, "but I mean, we can prove that it wasn't."

Denbury Resources filed for bankruptcy five months after the incident, citing the pandemic crash in oil prices. It emerged from Chapter 11 in September 2020 after shedding $2.1 billion in debt and its old name. In March 2021, the newly restructured Denbury Inc. gave a presentation at the 26th Annual Credit Suisse Energy Summit recounting highlights of 2020, including "record levels of safety performance for the fourth consecutive year."

Among the new capital investments for 2021 that Denbury CEO Chris Kendall and other officials unveiled was a $7 million plan boosting CO2-based drilling operations in the Tinsley field — using the same pipeline that ruptured in 2020.

The Next Day

Officer Terry Gann got three hours of sleep before heading back to Satartia.

Abandoned vehicles were everywhere — doors ajar, many with their windows smashed from the rescue efforts. Gann had the keys to several, and rescuers set up a kind of lost and found on the side of the road.

Gann helped Denbury personnel, including technicians with gas measuring equipment, escort villagers back to their homes. The rotten egg odor was still heavy in the air.

technician's gas meter hit the red zone, and they had to leave until levels went down.

That evening, Satartia Mayor Kathy Nesbit, Pettis and several Denbury representatives presided over a standing-room-only meeting at First Baptist Church. Bruce Augustine, Denbury's operations manager, told the crowd that the company was "very happy that the air monitoring we've done shows that everyone can now return to their homes."

Denbury officials said they would be stationed at the town hall to deal with any problems or complaints, and that residents would be promptly reimbursed for medical bills. While there was some discussion of safety measures to prevent a repeat disaster, nothing definite was promised.

Nesbit, an intensive care nurse who had been working at River Region hospital the night before, tried to dispel fears of long-term health effects. "It is a natural chemical in our bodies," she said. "So it's not a poison that's going to infiltrate you and eventually kill you."

That was cold comfort to many survivors, some of whom noted pointedly that Nesbit hadn't been in town that night and didn't experience being inside the plume.

When it was over, Thelma Brown and Berneva Lewis thanked Vicksburg firefighters Jerry Briggs and Shane Garrard for saving their sons. "That was when they actually told us about the condition that the guys were in and how they were very near death and foaming at the mouth," Brown said.



Warren County firefighters Shane Garrard (left) and Lamar Frederick in Vicksburg, Mississippi, in July. They're next to the utility task vehicle they used during the February 2020 gas leak in Satartia.
Rory Doyle for HuffPost.

DeEmmeris and Andrew Burns and Victor Lewis were still in no shape to go to any meetings. After a sleepless night, more vomiting and severe headaches, they spent early Sunday on oxygen, being monitored and having bloodwork done at the University of Mississippi Medical Center in Jackson, the state's flagship teaching hospital. Even after that, Lewis told his mother, who is a nurse, that he still felt terrible.

She took all three to another doctor the next day, and tests revealed that their blood CO2 levels were still alarmingly high. The doctor said they would need to remain on oxygen until the numbers came down, and sent them to a pulmonologist.

medical bills quickly. Residents were asked to drop by Town Hall to discuss compensation for other losses, like pain and suffering. Those who accepted were paid on the spot, but waived their right to sue or discuss the settlement.

But many victims, some of whom say they are still sick, anxious and unable to fully return to their previous lives, weren't interested in a deal and decided to sue. The Burns brothers and Lewis hired Robert Gibbs, a well known lawyer from Jackson. Their suit will claim Denbury failed to properly maintain the pipeline or take necessary safety precautions to prevent exposure to hazardous gas, Gibbs said.

Another who decided to sue was Martin, whose occasional breathing difficulties from mild COPD have required much more frequent use of his inhaler since the February 2020 incident.

Medical records also show that months after the incident, his 78-year-old mother, who had no previous history of breathing difficulties, was using albuterol constantly, getting oxygen treatments, and had to be hospitalized for a week in March 2020 after he found her lying unresponsive in bed and having trouble breathing.

Marguerite Vinson was frustrated that not only was she not recovering, she seemed to be getting sicker.

"I can't think half-right! And I just wear out. Anything I try to do, it's hard to do if it requires exertion," she said.

Linda Garrett said Denbury asked to meet with her three weeks after the incident and offered her a package deal — $5,000 each for her, her daughter and granddaughter, which she refused. She said she heard one neighbor, who is white, had been offered $10,000, and that another white neighbor had been given $18,000 compensation for cows that miscarried after the incident.

"They value a cow more than they do a human," Garrett said.

Not long after the gassing, DeEmmeris Burns' phone rang. According to Burns, the voice on the other end identified himself as Denbury CEO Chris Kendall.

"He asked me 'How's everything going?'" said Burns. "I just told him I've got someone talking for me now."

"You Should've Told Us."

Over a year and a half after the gassing incident, the Burns brothers and Lewis still have not returned to work. They were under a doctor's care until February 2021, when they were taken off oxygen, said Gibbs. DeEmmeris Burns moved out of his mother's house because, he said, it's too painful for him to drive up Perry Creek Road.

Gibbs said his and some nine other law firms representing the Satartia CO2 plaintiffs have joined forces as the Denbury Litigation Group. While Gibbs represents only the three Perry Creek Road victims, some lawyers have as many as 60 or 70 clients. None has yet filed suit, awaiting the long-delayed Pipeline and Hazardous Materials Safety Administration report on the reasons for the accident.

Martin said he hopes a lawsuit will pry out all the facts about what happened that night and why.

"If there's this many malfunctions in that one section of pipeline, somebody was at fault, or they were passing inspections they shouldn't have passed," said Martin. "That's what we need to find out."

Nevertheless, opinions differ as to how or even whether Denbury should be held accountable. One reason may be an inherent reluctance to criticize the oil and gas industry, a source of scarce well-paid jobs as well as a statewide political power. Some are willing to consider the pipeline rupture "an act of God," though

of the disaster.



The sun sets on the village of Satartia alongside the Yazoo River in July.
Rory Doyle for HuffPost

Interestingly, only a few of the residents interviewed for this article had heard of carbon capture and sequestration — and none knew about plans for a greatly expanded CO2 pipeline network.

“That doesn’t make any sense,” said Martin. “Not when they can’t control what they’ve already got. I think there’s real basic questions that need to be answered

Linda Garrett said she still struggles with back pain from carrying Makaylan to the car that day. Makaylan's asthma, which had been in remission, is worse than ever, and both her daughter and granddaughter remain traumatized. She wants the company punished.

Denbury, she said, should have warned the town before there was an emergency.

"If you cared about us, you and the pipeline, you should have let us know," Garrett said. "But you didn't let us know nothing. You just telling us now. That doesn't seem right to me. Sometimes we have to be held accountable for the things that happen."

CORRECTIONS: *An earlier version of this article misidentified a person affected as Lynett Burns. The woman's name is Lynett Garrett. An earlier version of this article also misquoted Hugh Martin as saying his Army training for Desert Storm included "cyanide gas," rather than "CS gas."*

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Earthquake triggering and large-scale geologic storage of carbon dioxide

Mark D. Zoback[a,1] and Steven M. Gorelick[b]

Departments of [a]Geophysics and [b]Environmental Earth System Science, Stanford University, Stanford, CA 94305

Edited by Pamela A. Matson, Stanford University, Stanford, CA, and approved May 4, 2012 (received for review March 27, 2012)

Despite its enormous cost, large-scale carbon capture and storage (CCS) is considered a viable strategy for significantly reducing CO_2 emissions associated with coal-based electrical power generation and other industrial sources of CO_2 [Intergovernmental Panel on Climate Change (2005) IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change, eds Metz B, et al. (Cambridge Univ Press, Cambridge, UK); Szulczewski ML, et al. (2012) *Proc Natl Acad Sci USA* 109:5185–5189]. We argue here that there is a high probability that earthquakes will be triggered by injection of large volumes of CO_2 into the brittle rocks commonly found in continental interiors. Because even small- to moderate-sized earthquakes threaten the seal integrity of CO_2 repositories, in this context, large-scale CCS is a risky, and likely unsuccessful, strategy for significantly reducing greenhouse gas emissions.

carbon sequestration | climate change | triggered earthquakes

The combustion of coal for electrical power generation in the United States generates approximately 2.1 billion metric tons of CO_2 per year, ~36% of all US emissions. In 2011, China generated more than three times that much CO_2 by burning coal for electricity, which accounted for ~80% of its total emissions. (According to the Energy Information Agency of the US Department of Energy, total CO_2 emissions in China were 8.38 billion metric tonnes in 2011, with 6.95 billion tons from coal burning, nearly all of which is used electrical power generation.) From a global perspective, if large-scale carbon capture and storage (CCS) is to significantly contribute to reducing the accumulation of greenhouse gases, it must operate at a massive scale, on the order of 3.5 billion tons (1) of CO_2 per year, a volume roughly equivalent (2) to the ~27 billion barrels of oil currently produced annually around the world. (Under reservoir conditions, one billion tons of CO_2 occupies a volume of ~1.3 billion cubic meters, equivalent to 8.18 billion barrels. Thus, 3.5 billion tons of carbon dioxide would correspond to a volume of approximately 28.6 billion barrels. There are currently ~850,000 wells producing oil around the world.) Moreover, a leak rate from underground CO_2 storage reservoirs of less than 1% per thousand years is required for CCS to achieve the same climate benefits as renewable energy sources (3).

Before embarking on projects to inject enormous volumes of CO_2 at numerous sites around the world, it is important to note that over time periods of just a few decades, modern seismic networks have shown that earthquakes occur nearly everywhere in continental interiors. Fig. 1, *Upper* shows instrumentally recorded earthquakes in the central and eastern United States and southeastern Canada. Fig. 1, *Lower* shows instrumentally recorded intraplate earthquakes in south and east Asia (4). The seismicity catalogs are complete to magnitude (M) 3. The occurrence of these earthquakes means that nearly everywhere in continental interiors a subset of the preexisting faults in the crust is potentially active in the current stress field (5, 6). This is sometimes referred to as the *critically stressed* nature of the brittle crust (7). It should also be noted that despite the overall low rate of earthquake occurrence in continental interiors, some of the most devastating earthquakes in history occurred in these regions. In eastern China, the M 7.8, 1976 Tangshan earthquake, approximately 200 km east of Beijing, killed several hundred thousand people. In the central United States, three M 7+ earthquakes in 1811 and 1812 occurred in the New Madrid seismic zone in southeast Missouri.

Because of the critically stressed nature of the crust, fluid injection in deep wells can trigger earthquakes when the injection increases pore pressure in the vicinity of preexisting potentially active faults. The increased pore pressure reduces the frictional resistance to fault slip, allowing elastic energy already stored in the surrounding rocks to be released in earthquakes that would occur someday as the result of natural geologic processes (8). This effect was first documented in the 1960s in Denver, Colorado when injection into a 3-km-deep well at the nearby Rocky Mountain Arsenal triggered earthquakes (9). Soon thereafter it was shown experimentally (10) at the Rangely oil field in western Colorado that earthquakes could be turned on and off by varying the rate at which water was injected and thus modulating reservoir pressure. In 2011 alone, a number of small to moderate earthquakes in the United States seem to have been triggered by injection of wastewater (11). These include earthquakes near Guy, Arkansas that occurred in February and March, where the largest earthquake was M 4.7. In the Trinidad/Raton area near the border of Colorado and New Mexico, injection of produced water associated with coalbed methane production seems to have triggered a number of earthquakes, the largest being a M 5.3 event that occurred in August. Earthquakes seem to have been triggered by wastewater injection near Youngstown, Ohio on Christmas Eve and New Year's Eve, the largest of which was M 4.0. Although the risks associated with wastewater injection are minimal and can be reduced even further with proper planning (11), the situation would be far more problematic if similar-sized earthquakes were triggered in formations intended to sequester CO_2 for hundreds to thousands of years.

Deep borehole stress measurements confirm the critically stressed nature of the crust in continental interiors (12), in some cases at sites directly relevant to the feasibility of large-scale CCS. For example, deep borehole stress measurements at the Mountaineer coal-burning power plant on the Ohio River in West Virginia indicate a severe limitation on the rate at which CO_2 could be injected without the resulting pressure build-up initiating slip on preexisting faults (13). Because of the low permeability of the formations at depth, pore pressure increases would be expected to trigger slip on preexisting faults if CO_2 injection rates exceed approximately 1% of the 7 million tons of CO_2 emitted by the Mountaineer plant each year. Similarly, stress measurements at Teapot Dome, Wyoming, the US government-owned oil field where pilot CO_2

Author contributions: M.D.Z. and S.M.G. wrote the paper.

The authors declare no conflict of interest.

This article is a PNAS Direct Submission.

[1]To whom correspondence should be addressed. E-mail: zoback@stanford.edu.

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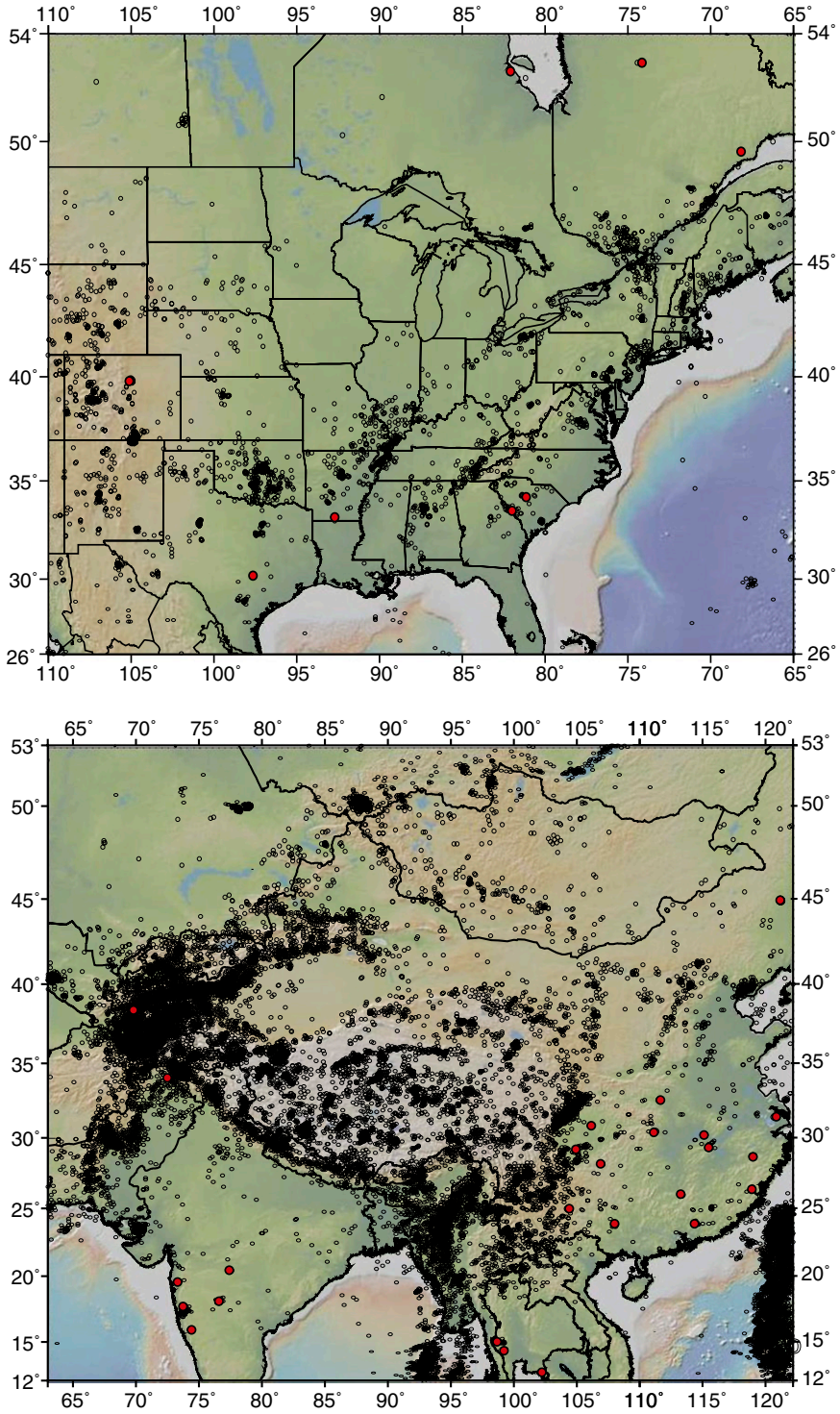


Fig. 1. *Upper*: Instrumentally recorded seismicity and damaging historical earthquakes in the central and eastern United States and southeastern Canada. Red dots indicate sites of reservoir-induced seismicity. *Lower*: Seismicity of south and east Asia and sites of reservoir-induced seismicity. Both data sets are available from the US Geological Survey (4).

injection projects have been considered, show that very small pressure buildups are capable of triggering slip on some preexisting faults (14).

Dam construction and water reservoir impoundment produce much smaller pore pressure changes at depth than are likely to occur with CO_2 sequestration, but many have triggered earthquakes at various sites around the world (15) (red dots in Fig. 1). Except for the much smaller pore pressure increases at depth, reservoir-triggered earthquakes are a good analog for the potential for seismicity to be triggered by CO_2 injection. Both activities cause pore pressure increases that act over large areas and are persistent for long periods. Three reservoir impoundments in eastern Canada (located in the ancient, stable core of the North American continent) triggered earthquakes as large as M 4.1 and M 5 at the two sites (Fig. 1), despite the fact that the pore pressure increases at depth were extremely small.

Triggered Earthquakes and Seal Integrity

Our principal concern is not that injection associated with CCS projects is likely to trigger large earthquakes; the problem is that even small to moderate earthquakes threaten the seal integrity of a CO_2 repository. In parts of the world with good construction practices, it is unusual for earthquakes smaller than approximately M 6 to cause significant human harm or property damage. Fig. 2 uses well-established seismological relationships to show how the magnitude of an earthquake is related to the size of the fault that slipped and the amount of fault slip that occurred (16). As shown, faults capable of producing M ~6 earthquakes are at least tens of kilometers in extent. (The fault size indicated along the abscissa is a lower bound of fault size as it refers to the size of the fault segment that slips in a given earthquake. The fault on which an earthquake occurs is larger than the part of the fault that slips in an individual event.) In most cases, such faults should be easily identified during geophysical site characterization studies and thus should be avoided at any site chosen for a CO_2 repository. (Faults in crystalline basement rocks might be difficult to recognize in geophysical data. We assume, however, that any site chosen as a potential CO_2 repository would be carefully selected, avoiding the possibility of pressure changes in the CO_2 repository from affecting faults in crystalline basement.) The problem is that site characterization studies can easily miss the much smaller faults associated with small to moderate earthquakes.

Although the ground shaking from small- to moderate-sized earthquakes is inconsequential, their impact on a CO_2 repository would not be. Most of the geologic formations to be used for long-term storage of CO_2 are likely to be at depths of approximately 2 km—deep enough for there to be adequate sealing formations to isolate the CO_2 from the biosphere but not so deep as to encounter formations with very low permeability. Given large volumes of CO_2 injected into selected formations for many decades, if a small to moderate earth-

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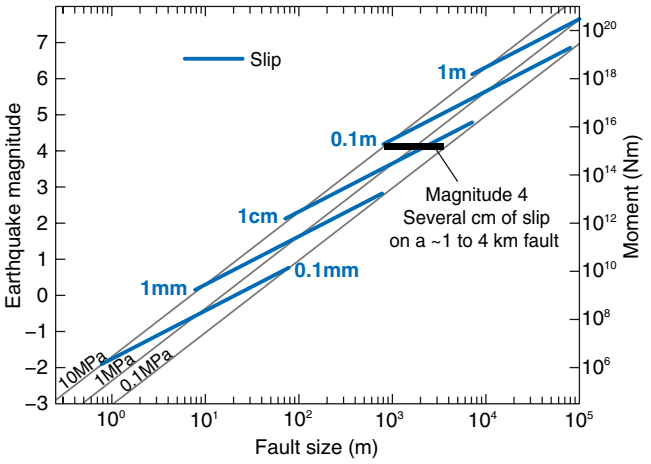


Fig. 2. Relationships among various scaling parameters for earthquakes. The larger the earthquake, the larger the fault and amount of slip, depending on the stress drop in a particular earthquake. Observational data indicate that earthquake stress drops range between 0.1 and 10 MPa.

quake were to be triggered in a geologic formation at approximately 2 km depth, it could jeopardize the seal integrity of the storage formation. For example, if a M ~4 earthquake were to be triggered by CO_2 sequestration (17)—an event that would be widely felt in a populated area but for which shaking would be unlikely to cause harm or damage—it would be associated with several centimeters of slip on a fault several kilometers in size. Because laboratory studies show that just a few millimeters of shear displacement are capable of enhancing fracture and joint permeability (18), several centimeters of slip would be capable of creating a permeable hydraulic pathway that could compromise the seal integrity of the CO_2 reservoir and potentially reach the near surface.

Safe Sequestration

It is important to emphasize that CCS can be valuable and useful for reducing greenhouse gas emissions in specific situations. A good example is the injection of CO_2 into the Utsira formation (19) at the Sleipner gas field in the North Sea, where a significant amount of CO_2 is coproduced with natural gas. After separating the CO_2 from the produced gas, approximately 1 million tons of CO_2 per year has been injected over the past 15 y without triggering seismicity. Assuming isolation from the near surface, injection into highly porous and permeable reservoirs that are laterally extensive would produce small increases in pressure in response to CO_2 injection. Moreover, weak, poorly cemented sandstones are expected to deform slowly in response to applied geologic forces. In such reservoirs, the stresses *relax* over time, and such formations are not prone to faulting (20). In this regard, the Utsira formation is ideal for CO_2 sequestration. It is isolated from vertical migration by impermeable shale formations, and it is highly porous, permeable, laterally extensive, and weakly cemented.

To contribute significantly to greenhouse gas emission reductions (2), roughly 3,500 sites similar to the Utsira formation would have to be found at convenient locations around the world, assuming comparable injection rates of approximately 1 million tons of CO_2 per year. In fact, it would take approximately 85 such sites coming on line each year to reach a goal of storing approximately 1 billion tons of CO_2 by midcentury. Clearly this is an extraordinarily difficult, if not impossible, task if only highly porous and permeable and weakly cemented formations are to be used.

Of course, rather than using potentially problematic geologic formations close to coal-burning power plants for sequestration (as illustrated by the Mountaineer case study cited above), relatively ideal formations for CO_2 storage could be sought on a regional basis to accommodate emissions from a number of plants. One example of this is the potential use of the Mt. Simon sandstone in the Illinois basin. The Mt. Simon is porous, permeable, and regionally extensive. However, models of injection of 100 million tons of CO_2 per year for 40 y predicts (21) increases in pore pressure of several megapascals over a region of ~40,000 km^2. The approximate area of significantly increased pore pressure resulting from injection is shown as the blue-shaded area in Fig. 3, essentially adjacent to the Wabash fault zone, where a series of moderate natural earthquakes occurred in the spring of 2008, the largest being M 5.2. Paleoseismic data indicate the occurrence of much larger nearby earthquakes (some greater than M ~7) in the recent geologic past (22). Importantly, the 100 million ton annual CO_2 injection rate used in the

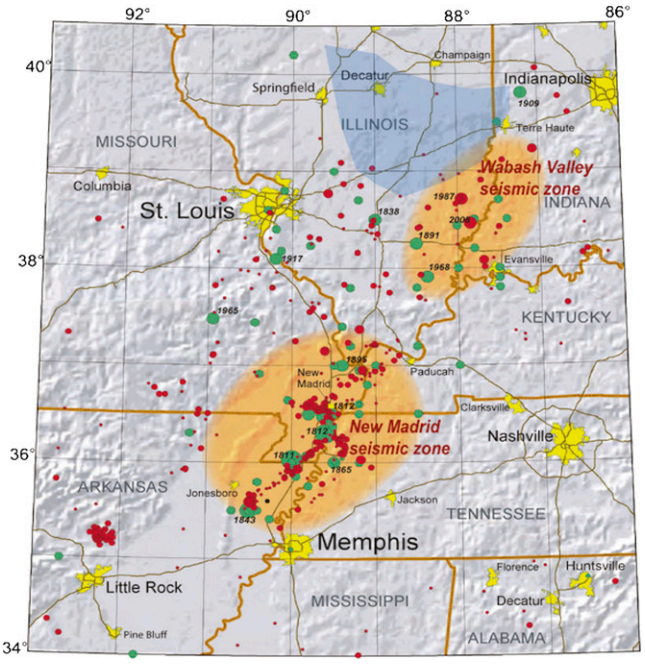


Fig. 3. Instrumentally recorded seismicity in the New Madrid and Wabash Valley seismic zones (modified from ref. 23). Red circles indicate earthquakes that occurred from 1974 to 2002 with magnitudes larger than 2.5 located using modern instruments. Green circles denote earthquakes that occurred before 1974. Larger earthquakes are represented by larger circles. The area shown in blue corresponds to the area where a pressure increase of several megapascals would result from injecting 100 million tons per year of CO_2 into the Mt. Simon sandstone in the Illinois Basin for 40 y (19).

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modeling only represents approximately one seventh of the CO_2 generated by the coal-burning power plants in the Ohio River Valley alone.

Because of the need to carefully monitor CO_2 repositories with observation wells, geophysical and geochemical monitoring systems, etc., it is likely that most sites will have to be located on land or very near shore. Otherwise, highly porous reservoirs located offshore, like those adjacent to salt domes along the US Gulf Coast, would be relatively ideal sites because salt formations are known to be excellent seals for hydrocarbons.

Depleted oil and gas reservoirs are potentially suitable for CO_2 storage for a variety of reasons—an infrastructure of wells and pipelines exist, and there is a great deal of geologic and subsurface property data available to characterize the subsurface from decades of study. In addition, from an earthquake-triggering perspective, depleted reservoirs are attractive because at the time injection of CO_2 might start, the pore pressure would be below the value that existed before petroleum production. Thus, there could be significant injection of CO_2 before pressures increase to preproduction values, thereby reducing the potential for triggering earthquakes.

There are a number of potential issues to consider before using depleted oil and gas reservoirs for CO_2 storage, the most important of which are capacity and geographic distribution. The reasons that there is such interest in using saline aquifers for CO_2 storage is that they are potentially well distributed with respect to likely sources of CO_2, and they could presumably accommodate the enormous volumes of CO_2 that need to be stored. If one were only to consider the United States, storing the 2.1 billion tons of CO_2 currently generated annually by coal-burning power plants in depleted oil and gas reservoirs would require injection of CO_2 at a rate of approximately 17 billion barrels per year; a rate equivalent to eight times current US annual oil production and more than four times US peak annual oil production that occurred in the early 1970s. In addition, it is important to make sure that production-related activities, such as water flooding during secondary recovery, did not compromise the seal capacity of the reservoirs. There also needs to be careful study of the wells in the depleted oil or gas field to make sure that poorly cemented well casings, especially in older wells, will not be pathways for release of stored CO_2 (23). Finally, there are likely to be complicated legal questions concerning ownership and liability that will need to be worked out on a case-by-case basis.

Although enhanced oil recovery (EOR) using CO_2 (in which CO_2 is injected to dissolve in oil and reduce its viscosity) would be a beneficial use of CO_2, it is important not to confuse this with CCS. In CCS the goal is to inject large quantities of CO_2 into available pore space and store it there for hundreds to thousands of years. When CO_2 is used for EOR, the CO_2 dissolved in the oil is separated and captured from produced oil and then reinjected. Thus, smaller volumes of CO_2 are used, and the long-term storage capacity of the reservoir is not an issue.

Many CCS research projects are currently underway around the world. Much of this work involves characterization and testing of potential storage formations and includes a number of small-scale pilot injection projects. Because the storage capacity/pressure build-up issue is critical to assess the potential for triggered seismicity, small-scale pilot injection projects do not reflect how pressures are likely to change (increase) once full-scale injection is implemented. Moreover, even though limitations on pressure build-up are among the many factors that are evaluated when potential formations are considered as sequestration sites, this is usually done in the context of not allowing pressures to exceed the pressure at which hydraulic fractures would be initiated in the storage formation or caprock. In the context of a critically stressed crust, slip on preexisting, unidentified faults could trigger small- to moderate-sized earthquakes at pressures far below that at which hydraulic fractures would form.

As mentioned above, sequences of small to moderate earthquakes were apparently induced by injection of waste water near Guy, Arkansas, Trinidad, Colorado, and Youngstown, Ohio in 2011 and on the Dallas-Ft. Worth airport, Texas. Although these earthquakes were widely felt, they caused no injury, and only the Trinidad earthquake resulted in any significant damage. However, had similar earthquakes been triggered at sites where CO_2 was being injected, the impacts would have raised pressing and important questions: Had the seal been breached? Was it still safe to leave previously injected CO_2 in place?

In summary, multiple lines of evidence indicate that preexisting faults found in brittle rocks almost everywhere in the earth's crust are subject to failure, often in response to very small increases in pore pressure. In light of the risk posed to a CO_2 repository by even small- to moderate-sized earthquakes, formations suitable for large-scale injection of CO_2 must be carefully chosen. In addition to being well sealed by impermeable overlaying strata, they should also be weakly cemented (so as not to fail through brittle faulting) and porous, permeable, and laterally extensive to accommodate large volumes of CO_2 with minimal pressure increases. Thus, the issue is not whether CO_2 can be safely stored at a given site; the issue is whether the capacity exists for sufficient volumes of CO_2 to be stored geologically for it to have the desired beneficial effect on climate change. In this context, it must be recognized that large-scale CCS will be an extremely expensive and risky strategy for achieving significant reductions in greenhouse gas emissions.

ACKNOWLEDGMENTS. We thank Owen Hurd and Randi Walters for their help in preparation of the figures, and Mary Lou Zoback, Greg Beroza, Doug Arent, Sally Benson, Franklin Orr, John Bredehoeft, and Larry Goulder for their helpful comments.

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California 95691
(916) 373-3710
nahc@nahc.ca.gov
NAHC.ca.gov

June 13, 2023

Cindi Hoover
Kern County Planning and Natural Resources Department
2700 M St, Ste. 100
Bakersfield, CA 93301

Re: 2023060293, CarbonFrontier CCS Project by Aera Energy, LLC, Kern County

Dear Ms. Hoover:

The Native American Heritage Commission (NAHC) has received the Notice of Preparation (NOP), Draft Environmental Impact Report (DEIR) or Early Consultation for the project referenced above. The California Environmental Quality Act (CEQA) (Pub. Resources Code §21000 et seq.), specifically Public Resources Code §21084.1, states that a project that may cause a substantial adverse change in the significance of a historical resource, is a project that may have a significant effect on the environment. (Pub. Resources Code § 21084.1; Cal. Code Regs., tit.14, §15064.5 (b) (CEQA Guidelines §15064.5 (b)). If there is substantial evidence, in light of the whole record before a lead agency, that a project may have a significant effect on the environment, an Environmental Impact Report (EIR) shall be prepared. (Pub. Resources Code §21080 (d); Cal. Code Regs., tit. 14, § 5064 subd.(a)(1) (CEQA Guidelines §15064 (a)(1)). In order to determine whether a project will cause a substantial adverse change in the significance of a historical resource, a lead agency will need to determine whether there are historical resources within the area of potential effect (APE).

CEQA was amended significantly in 2014. Assembly Bill 52 (Gatto, Chapter 532, Statutes of 2014) (AB 52) amended CEQA to create a separate category of cultural resources, "tribal cultural resources" (Pub. Resources Code §21074) and provides that a project with an effect that may cause a substantial adverse change in the significance of a tribal cultural resource is a project that may have a significant effect on the environment. (Pub. Resources Code §21084.2). Public agencies shall, when feasible, avoid damaging effects to any tribal cultural resource. (Pub. Resources Code §21084.3 (a)). **AB 52 applies to any project for which a notice of preparation, a notice of negative declaration, or a mitigated negative declaration is filed on or after July 1, 2015.** If your project involves the adoption of or amendment to a general plan or a specific plan, or the designation or proposed designation of open space, on or after March 1, 2005, it may also be subject to Senate Bill 18 (Burton, Chapter 905, Statutes of 2004) (SB 18). **Both SB 18 and AB 52 have tribal consultation requirements**. If your project is also subject to the federal National Environmental Policy Act (42 U.S.C. § 4321 et seq.) (NEPA), the tribal consultation requirements of Section 106 of the National Historic Preservation Act of 1966 (154 U.S.C. 300101, 36 C.F.R. §800 et seq.) may also apply.

The NAHC recommends consultation with California Native American tribes that are traditionally and culturally affiliated with the geographic area of your proposed project as early as possible in order to avoid inadvertent discoveries of Native American human remains and best protect tribal cultural resources. Below is a brief summary of portions of AB 52 and SB 18 as well as the NAHC's recommendations for conducting cultural resources assessments.

Consult your legal counsel about compliance with AB 52 and SB 18 as well as compliance with any other applicable laws.

AB 52

AB 52 has added to CEQA the additional requirements listed below, along with many other requirements:

1. Fourteen Day Period to Provide Notice of Completion of an Application/Decision to Undertake a Project: Within fourteen (14) days of determining that an application for a project is complete or of a decision by a public agency to undertake a project, a lead agency shall provide formal notification to a designated contact of, or tribal representative of, traditionally and culturally affiliated California Native American tribes that have requested notice, to be accomplished by at least one written notice that includes:

- **a.** A brief description of the project.
- **b.** The lead agency contact information.
- **c.** Notification that the California Native American tribe has 30 days to request consultation. (Pub. Resources Code §21080.3.1 (d)).
- **d.** A "California Native American tribe" is defined as a Native American tribe located in California that is on the contact list maintained by the NAHC for the purposes of Chapter 905 of Statutes of 2004 (SB 18). (Pub. Resources Code §21073).

2. Begin Consultation Within 30 Days of Receiving a Tribe's Request for Consultation and Before Releasing a Negative Declaration, Mitigated Negative Declaration, or Environmental Impact Report: A lead agency shall begin the consultation process within 30 days of receiving a request for consultation from a California Native American tribe that is traditionally and culturally affiliated with the geographic area of the proposed project. (Pub. Resources Code §21080.3.1, subds. (d) and (e)) and prior to the release of a negative declaration, mitigated negative declaration or Environmental Impact Report. (Pub. Resources Code §21080.3.1(b)).

- **a.** For purposes of AB 52, "consultation shall have the same meaning as provided in Gov. Code §65352.4 (SB 18). (Pub. Resources Code §21080.3.1 (b)).

3. Mandatory Topics of Consultation If Requested by a Tribe: The following topics of consultation, if a tribe requests to discuss them, are mandatory topics of consultation:

- **a.** Alternatives to the project.
- **b.** Recommended mitigation measures.
- **c.** Significant effects. (Pub. Resources Code §21080.3.2 (a)).

4. Discretionary Topics of Consultation: The following topics are discretionary topics of consultation:

- **a.** Type of environmental review necessary.
- **b.** Significance of the tribal cultural resources.
- **c.** Significance of the project's impacts on tribal cultural resources.
- **d.** If necessary, project alternatives or appropriate measures for preservation or mitigation that the tribe may recommend to the lead agency. (Pub. Resources Code §21080.3.2 (a)).

5. Confidentiality of Information Submitted by a Tribe During the Environmental Review Process: With some exceptions, any information, including but not limited to, the location, description, and use of tribal cultural resources submitted by a California Native American tribe during the environmental review process shall not be included in the environmental document or otherwise disclosed by the lead agency or any other public agency to the public, consistent with Government Code §6254 (r) and §6254.10. Any information submitted by a California Native American tribe during the consultation or environmental review process shall be published in a confidential appendix to the environmental document unless the tribe that provided the information consents, in writing, to the disclosure of some or all of the information to the public. (Pub. Resources Code §21082.3 (c)(1)).

6. Discussion of Impacts to Tribal Cultural Resources in the Environmental Document: If a project may have a significant impact on a tribal cultural resource, the lead agency's environmental document shall discuss both of the following:

- **a.** Whether the proposed project has a significant impact on an identified tribal cultural resource.
- **b.** Whether feasible alternatives or mitigation measures, including those measures that may be agreed to pursuant to Public Resources Code §21082.3, subdivision (a), avoid or substantially lessen the impact on the identified tribal cultural resource. (Pub. Resources Code §21082.3 (b)).

7. Conclusion of Consultation: Consultation with a tribe shall be considered concluded when either of the following occurs:

a. The parties agree to measures to mitigate or avoid a significant effect, if a significant effect exists, on a tribal cultural resource; or

b. A party, acting in good faith and after reasonable effort, concludes that mutual agreement cannot be reached. (Pub. Resources Code §21080.3.2 (b)).

8. Recommending Mitigation Measures Agreed Upon in Consultation in the Environmental Document: Any mitigation measures agreed upon in the consultation conducted pursuant to Public Resources Code §21080.3.2 shall be recommended for inclusion in the environmental document and in an adopted mitigation monitoring and reporting program, if determined to avoid or lessen the impact pursuant to Public Resources Code §21082.3, subdivision (b), paragraph 2, and shall be fully enforceable. (Pub. Resources Code §21082.3 (a)).

9. Required Consideration of Feasible Mitigation: If mitigation measures recommended by the staff of the lead agency as a result of the consultation process are not included in the environmental document or if there are no agreed upon mitigation measures at the conclusion of consultation, or if consultation does not occur, and if substantial evidence demonstrates that a project will cause a significant effect to a tribal cultural resource, the lead agency shall consider feasible mitigation pursuant to Public Resources Code §21084.3 (b). (Pub. Resources Code §21082.3 (e)).

10. Examples of Mitigation Measures That, If Feasible, May Be Considered to Avoid or Minimize Significant Adverse Impacts to Tribal Cultural Resources:

a. Avoidance and preservation of the resources in place, including, but not limited to:

i. Planning and construction to avoid the resources and protect the cultural and natural context.

ii. Planning greenspace, parks, or other open space, to incorporate the resources with culturally appropriate protection and management criteria.

b. Treating the resource with culturally appropriate dignity, taking into account the tribal cultural values and meaning of the resource, including, but not limited to, the following:

i. Protecting the cultural character and integrity of the resource.

ii. Protecting the traditional use of the resource.

iii. Protecting the confidentiality of the resource.

c. Permanent conservation easements or other interests in real property, with culturally appropriate management criteria for the purposes of preserving or utilizing the resources or places.

d. Protecting the resource. (Pub. Resource Code §21084.3 (b)).

e. Please note that a federally recognized California Native American tribe or a non-federally recognized California Native American tribe that is on the contact list maintained by the NAHC to protect a California prehistoric, archaeological, cultural, spiritual, or ceremonial place may acquire and hold conservation easements if the conservation easement is voluntarily conveyed. (Civ. Code §815.3 (c)).

f. Please note that it is the policy of the state that Native American remains and associated grave artifacts shall be repatriated. (Pub. Resources Code §5097.991).

11. Prerequisites for Certifying an Environmental Impact Report or Adopting a Mitigated Negative Declaration or Negative Declaration with a Significant Impact on an Identified Tribal Cultural Resource: An Environmental Impact Report may not be certified, nor may a mitigated negative declaration or a negative declaration be adopted unless one of the following occurs:

a. The consultation process between the tribes and the lead agency has occurred as provided in Public Resources Code §21080.3.1 and §21080.3.2 and concluded pursuant to Public Resources Code §21080.3.2.

b. The tribe that requested consultation failed to provide comments to the lead agency or otherwise failed to engage in the consultation process.

c. The lead agency provided notice of the project to the tribe in compliance with Public Resources Code §21080.3.1 (d) and the tribe failed to request consultation within 30 days. (Pub. Resources Code §21082.3 (d)).

The NAHC's PowerPoint presentation titled, "Tribal Consultation Under AB 52: Requirements and Best Practices" may be found online at: http://nahc.ca.gov/wp-content/uploads/2015/10/AB52TribalConsultation_CalEPAPDF.pdf

SB 18

SB 18 applies to local governments and requires local governments to contact, provide notice to, refer plans to, and consult with tribes prior to the adoption or amendment of a general plan or a specific plan, or the designation of open space. (Gov. Code §65352.3). Local governments should consult the Governor's Office of Planning and Research's "Tribal Consultation Guidelines," which can be found online at: https://www.opr.ca.gov/docs/09_14_05_Updated_Guidelines_922.pdf.

Some of SB 18's provisions include:

1. Tribal Consultation: If a local government considers a proposal to adopt or amend a general plan or a specific plan, or to designate open space it is required to contact the appropriate tribes identified by the NAHC by requesting a "Tribal Consultation List." If a tribe, once contacted, requests consultation the local government must consult with the tribe on the plan proposal. **A tribe has 90 days from the date of receipt of notification to request consultation unless a shorter timeframe has been agreed to by the tribe.** (Gov. Code §65352.3 (a)(2)).

2. No Statutory Time Limit on SB 18 Tribal Consultation. There is no statutory time limit on SB 18 tribal consultation.

3. Confidentiality: Consistent with the guidelines developed and adopted by the Office of Planning and Research pursuant to Gov. Code §65040.2, the city or county shall protect the confidentiality of the information concerning the specific identity, location, character, and use of places, features and objects described in Public Resources Code §5097.9 and §5097.993 that are within the city's or county's jurisdiction. (Gov. Code §65352.3 (b)).

4. Conclusion of SB 18 Tribal Consultation: Consultation should be concluded at the point in which:

- **a.** The parties to the consultation come to a mutual agreement concerning the appropriate measures for preservation or mitigation; or
- **b.** Either the local government or the tribe, acting in good faith and after reasonable effort, concludes that mutual agreement cannot be reached concerning the appropriate measures of preservation or mitigation. (Tribal Consultation Guidelines, Governor's Office of Planning and Research (2005) at p. 18).

Agencies should be aware that neither AB 52 nor SB 18 precludes agencies from initiating tribal consultation with tribes that are traditionally and culturally affiliated with their jurisdictions before the timeframes provided in AB 52 and SB 18. For that reason, we urge you to continue to request Native American Tribal Contact Lists and "Sacred Lands File" searches from the NAHC. The request forms can be found online at: http://nahc.ca.gov/resources/forms/.

NAHC Recommendations for Cultural Resources Assessments

To adequately assess the existence and significance of tribal cultural resources and plan for avoidance, preservation in place, or barring both, mitigation of project-related impacts to tribal cultural resources, the NAHC recommends the following actions:

1. Contact the appropriate regional California Historical Research Information System (CHRIS) Center (https://ohp.parks.ca.gov/?page_id=30331) for an archaeological records search. The records search will determine:

- **a.** If part or all of the APE has been previously surveyed for cultural resources.
- **b.** If any known cultural resources have already been recorded on or adjacent to the APE.
- **c.** If the probability is low, moderate, or high that cultural resources are located in the APE.
- **d.** If a survey is required to determine whether previously unrecorded cultural resources are present.

2. If an archaeological inventory survey is required, the final stage is the preparation of a professional report detailing the findings and recommendations of the records search and field survey.

- **a.** The final report containing site forms, site significance, and mitigation measures should be submitted immediately to the planning department. All information regarding site locations, Native American human remains, and associated funerary objects should be in a separate confidential addendum and not be made available for public disclosure.
- **b.** The final written report should be submitted within 3 months after work has been completed to the appropriate regional CHRIS center.

3. Contact the NAHC for:

a. A Sacred Lands File search. Remember that tribes do not always record their sacred sites in the Sacred Lands File, nor are they required to do so. A Sacred Lands File search is not a substitute for consultation with tribes that are traditionally and culturally affiliated with the geographic area of the project's APE.

b. A Native American Tribal Consultation List of appropriate tribes for consultation concerning the project site and to assist in planning for avoidance, preservation in place, or, failing both, mitigation measures.

4. Remember that the lack of surface evidence of archaeological resources (including tribal cultural resources) does not preclude their subsurface existence.

a. Lead agencies should include in their mitigation and monitoring reporting program plan provisions for the identification and evaluation of inadvertently discovered archaeological resources per Cal. Code Regs., tit. 14, §15064.5(f) (CEQA Guidelines §15064.5(f)). In areas of identified archaeological sensitivity, a certified archaeologist and a culturally affiliated Native American with knowledge of cultural resources should monitor all ground-disturbing activities.

b. Lead agencies should include in their mitigation and monitoring reporting program plans provisions for the disposition of recovered cultural items that are not burial associated in consultation with culturally affiliated Native Americans.

c. Lead agencies should include in their mitigation and monitoring reporting program plans provisions for the treatment and disposition of inadvertently discovered Native American human remains. Health and Safety Code §7050.5, Public Resources Code §5097.98, and Cal. Code Regs., tit. 14, §15064.5, subdivisions (d) and (e) (CEQA Guidelines §15064.5, subds. (d) and (e)) address the processes to be followed in the event of an inadvertent discovery of any Native American human remains and associated grave goods in a location other than a dedicated cemetery.

If you have any questions or need additional information, please contact me at my email address: Cameron.Vela@nahc.ca.gov

Sincerely,

Cameron Vela

Cameron Vela
Cultural Resources Analyst

cc: State Clearinghouse

Office Memorandum

KERN COUNTY

To: Planning and Natural Resources Department
Cindi Hoover

Date: June 14, 2023

From: Public Works Department
Floodplain Management Section
Kevin Hamilton, by Brian Blase

Phone: (661) 862-5098
Email: BlaseB@kerncounty.com

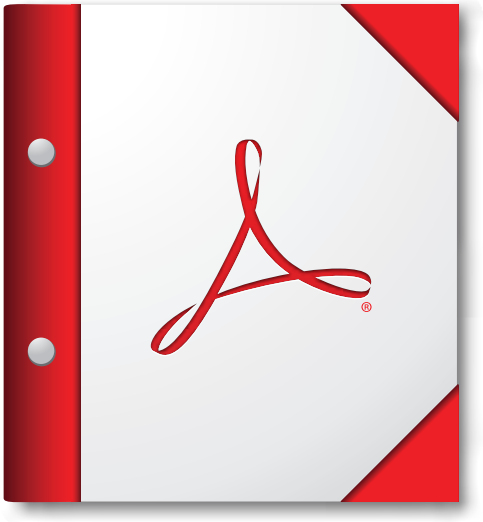
Subject: Preparation of an Environmental Impact Report
CarbonFrontier Carbon Capture Sequestration Project

Our section has reviewed the attached subject documents and has the following comments:

The subject property is subject to flooding.

Therefore, this section recommends the following be included as Conditions of Approval for this project:

Associated flood hazard requirements will need to be incorporated into the design of this project per the Kern County Floodplain Management Ordinance.



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State of California – Natural Resources Agency
DEPARTMENT OF FISH AND WILDLIFE
Central Region
1234 East Shaw Avenue
Fresno, California 93710
(559) 243-4005
www.wildlife.ca.gov

GAVIN NEWSOM, Governor
CHARLTON H. BONHAM, Director

GOVERNOR'S OFFICE OF PLANNING AND RESEARCH
Jul 06 2023
STATE OF CALIFORNIA

July 6, 2023

Cindi Hoover
Kern County Planning and Natural Resources Department
2700 M Street, Suite 100
Bakersfield, California 93301
HooverC@kerncounty.com

Subject: Carbon Frontier Carbon Capture and Sequestration Project (Project)
Notice of Preparation (NOP)
State Clearinghouse No. 2023060293

Dear Cindi Hoover:

The California Department of Fish and Wildlife (CDFW) received a NOP from the Kern County Planning and Natural Resources Department for the above-referenced Project pursuant to the California Environmental Quality Act (CEQA) and CEQA Guidelines.[1]

Thank you for the opportunity to provide comments and recommendations regarding those activities involved in the Project that may affect California fish and wildlife. Likewise, CDFW appreciates the opportunity to provide comments regarding those aspects of the Project that CDFW, by law, may be required to carry out or approve through the exercise of its own regulatory authority under Fish and Game Code.

CDFW ROLE

CDFW is California's **Trustee Agency** for fish and wildlife resources and holds those resources in trust by statute for all the people of the State (Fish & G. Code, §§ 711.7, subd. (a) & 1802; Pub. Resources Code, § 21070; CEQA Guidelines § 15386, subd. (a)). CDFW, in its trustee capacity, has jurisdiction over the conservation, protection, and management of fish, wildlife, native plants, and habitat necessary for biologically sustainable populations of those species (*Id*., § 1802). Similarly, for purposes of CEQA, CDFW is charged by law to provide, as available, biological expertise during public agency environmental review efforts, focusing specifically on

[1] CEQA is codified in the California Public Resources Code in section 21000 et seq. The "CEQA Guidelines" are found in Title 14 of the California Code of Regulations, commencing with section 15000.

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projects and related activities that have the potential to adversely affect fish and wildlife resources.

CDFW is also submitting comments as a **Responsible Agency** under CEQA (Pub. Resources Code, § 21069; CEQA Guidelines, § 15381). CDFW expects that it may need to exercise regulatory authority as provided by the Fish and Game Code. As proposed, for example, the Project may be subject to CDFW's lake and streambed alteration regulatory authority (Fish & G. Code, § 1600 et seq.). Likewise, to the extent implementation of the Project as proposed may result in "take" as defined by State law of any species protected under the California Endangered Species Act (CESA) (Fish & G. Code, § 2050 et seq.), related authorization as provided by the Fish and Game Code will be required.

Fully Protected Species: CDFW has jurisdiction over species of birds, mammals, amphibians, reptiles, and fish designated by statute as "fully protected" pursuant to Fish and Game Code sections 3511, 4700, 5050, and 5515. Take of any fully protected species is prohibited and CDFW cannot authorize their incidental take except as specifically provided for in Fish and Game Code; none of those specific exceptions are applicable to this project.

Nesting Birds: CDFW has jurisdiction over actions with potential to result in the disturbance or destruction of active nest sites or the unauthorized take of birds. Fish and Game Code sections that protect birds, their eggs and nests include sections 3503 (regarding unlawful take, possession or needless destruction of the nest or eggs of any bird), 3503.5 (regarding the take, possession or destruction of any birds-of-prey or their nests or eggs), and 3513 (regarding unlawful take of any migratory nongame bird).

Unlisted Species: Species of plants and animals need not be officially listed as Endangered, Rare, or Threatened (E, R, or T) on any State or federal list to be considered E, R, or T under CEQA. If a species can be shown to meet the criteria for E, R, or T, as specified in the CEQA Guidelines section 15380, CDFW recommends it be fully considered in the environmental analysis for the Project.

PROJECT DESCRIPTION SUMMARY

Proponent: Aera Energy, LLC

Objective: Aera Energy, LLC proposes the construction and operation of a carbon capture and storage (CSS) facility over portions of the existing and contiguous South Belridge and North Belridge oil fields near the community of Lost Hills in western Kern County. In the NOP, Kern County Planning and Natural Resources Department indicates that the CCS facility would involve the construction of appurtenant structures

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for the capture, transport, and subsurface injection (geologic sequestration) of carbon dioxide (CO_2). Once the Project is implemented, CO_2 would be captured at newly constructed facilities within the South Belridge oil field and transported in newly constructed pipelines to existing abandoned oil wells in the North Belridge oil field. These wells will be retrofitted to function as injection wells and used to inject the captured CO_2 into the depleted underground oil- and gas-bearing geologic formation where it will be permanently sequestered.

The Kern County Planning and Natural Resources Department will prepare an Environmental Impact Report (EIR) for the Project. The NOP lacks detailed information with regard to the actual footprint of the Project (Project Site) within the oil fields, and does not address ground disturbance, staging, laydown, or other specific Project-related activities which could threaten biological resources and result in significant environmental impacts within the Project Site. CDFW expects these details will be provided in the EIR. CDFW also expects additional detail will be provided in the EIR addressing:

- the need for nightwork during construction or operations/maintenance of the facilities;
- construction of the pipeline (aboveground vs underground, support of aboveground sections);
- the phase of the CO_2 transported through the pipeline (gaseous or liquid); and
- potential catastrophic events (and emergency responses to those events) which could occur along the pipeline, at the capture facilities, and at the injection facilities over the life of the Project.

Location: The Project Site exists within the administrative boundaries of the existing South Belridge and North Belridge oil fields, which adjoin each other (one immediately north of the other) and are generally west of State Route 33 and north and south of Lerdo Highway. The oil fields containing the Project Site are approximately seven miles southwest of the community of Lost Hills and approximately 30 miles northwest of the city of Bakersfield in Kern County, California.

Timeframe: n/a

COMMENTS AND RECOMMENDATIONS

Special-Status Species: Special-status species are known to exist in the vicinity of the Project Site, there is the potential for the Project to impact State and federally listed species. Records from the California Natural Diversity Database (CNDDB) show that the following special-status species, including State and federally listed species (CDFW 2023) could be impacted: the State threatened and federally endangered San Joaquin kit fox (*Vulpes macrotis mutica*); the State and federally endangered and State fully

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protected blunt-nosed leopard lizard (*Gamelia sila*); the State and federally endangered and California Rare Plant Ranked (CRPR) 1B.1 California jewelflower (*Caulanthus californicus*); the State and federally endangered giant kangaroo rat (*Dipodomys ingens*), Tipton kangaroo rat (*Dipodomys nitratoides nitratoides*); the State threatened San Joaquin antelope squirrel (*Ammospermophilus nelsoni*), tricolored blackbird (*Agelaius tricolor*), and Swainson's hawk (*Buteo swainsoni*); the federally endangered and State species of special concern Buena Vista Lake ornate shrew (*Sorex ornatus relictus*); the federally endangered and CRPR 1B.2 San Joaquin woollythreads (*Monolopia congdonii*) and Kern mallow (*Eremalche parrye ssp. kernensis*); the candidates for State listing Temblor legless lizard (*Anniella alexanderae*) and Crotch bumble bee (*Bombus crotchii*); the State species of special concern burrowing owl (*Athene cunicularia*), short-nosed kangaroo rat (*Dipodomys nitratoides brevinasus*), Tulare grasshopper mouse (*Onychomys torridus tularensis*), western spadefoot (*Spea hammondii*), American badger (*Taxidea taxus*), San Joaquin coachwhip (*Masticophis flagellum ruddocki*), and Le Conte's thrasher (*Toxostoma lecontei*); and the CRPR 1B.1, 1B.2 and 4.2 California alkali grass (*Puccinellia simplex*), Coulter's goldfields (*Lasthenia glabrata ssp. coulteri*), heartscale (*Atriplex cordulata var. cordulata*), Lost Hills crownscale (*Atriplex coronata var. vallicola*), recurved larkspur (*Delphinium recurvatum*), showy golden madia (*Madia radiata*), and Hoover's eriastrum (*Eriastrum hooveri*).

CDFW recommends that a habitat assessment be conducted at and in the vicinity of the Project Site for the aforementioned plant and animal species. The assessment should be conducted by a qualified biologist knowledgeable with the species and any potentially suitable habitat identified should be surveyed by a qualified biologist for the potential presence of these species as part of the biological technical studies conducted in support of the EIR. If the surveys reveal the aforementioned listed and candidate species occur at and/or near the Project Site, the EIR should include either measures to avoid take of those species, or the Project proponent's commitment to obtaining incidental take authorization under Section 2081 of Fish and Game Code, as appropriate, if avoidance will be unfeasible. Similarly, if the surveys reveal the aforementioned unlisted species, the EIR should include a commitment by the Project proponent to consult with CDFW, prior to commencing the Project, to identify and implement appropriate measures to avoid or minimize impacts to those species. It should be noted that blunt-nosed leopard lizard is State fully protected, therefore, no "take", incidental or otherwise, can be authorized by CDFW; complete avoidance of this species is required to comply with State law.

CDFW recommends that the surveys for blunt-nosed leopard lizard, San Joaquin kit fox, tricolored blackbird, Swainson's hawk, and burrowing owl be conducted in accordance with the species-specific protocols which can be found here:

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https://wildlife.ca.gov/Conservation/Survey-Protocols. CDFW recommends that the surveys for the aforementioned special status and CRPR plants be surveyed for by a qualified botanist following the "Protocols for Surveying and Evaluating Impacts to Special Status Native Plant Populations and Sensitive Natural Communities" which can also be found at: https://wildlife.ca.gov/Conservation/Survey-Protocols.This protocol, which is intended to maximize detectability, includes identification of reference populations to facilitate the likelihood of field investigations occurring during the appropriate floristic period. In the absence of protocol-level surveys being performed, additional surveys may be necessary. If take could occur as a result of Project-related activities, consultation with CDFW may be warranted.

Nesting birds: CDFW recommends that Project ground-disturbing activities occur during the bird non-nesting season; however, if ground-disturbing or vegetation-disturbing activities must occur during the nesting season (February 1st through September 15th), the Project applicant is responsible for ensuring that implementation of the Project does not result in violation of the Migratory Bird Treaty Act or relevant Fish and Game Codes as referenced above.

To evaluate Project-related impacts on nesting birds, CDFW recommends that a general habitat assessment for nesting birds be conducted as part of the biological technical studies conducted in support of the EIR. Depending on the results of that assessment, CDFW further recommends that the EIR for this Project include that a qualified biologist conduct a pre-construction survey for active nests no more than 10 days prior to the start of ground- or vegetation-disturbance to maximize the probability that nests that could potentially be impacted are detected. CDFW also recommends that surveys cover a sufficient area around the Project Site to identify nests and determine their status. A sufficient area means any area potentially affected, either directly or indirectly, by the Project. In addition to direct impacts (i.e. nest destruction), noise, vibration, and movement of workers or equipment could also affect nests. CDFW recommends that a qualified biologist establish a behavioral baseline of all identified nests. Once Project activities begin, CDFW recommends having a qualified biologist continuously monitor nests to detect behavioral changes resulting from the Project. If behavioral changes occur, CDFW recommends halting the work causing that change and consulting with CDFW for additional avoidance and minimization measures.

If continuous monitoring of identified nests by a qualified biologist is not feasible, CDFW recommends the EIR include a minimum no-disturbance buffer of 250 feet around active nests of non-listed bird species and a 500-foot no-disturbance buffer around active nests of non-listed raptors. These buffers are advised to remain in place until the breeding season has ended or until a qualified biologist has determined that the birds have fledged and are no longer reliant upon the nest or on-site parental care for survival. Variance from these no-disturbance buffers is possible when there is a

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compelling biological or ecological reason to do so, such as when the Project Site would be concealed from a nest site by topography. CDFW recommends that a qualified biologist advise and support any variance from these buffers and notify CDFW in advance of implementing a variance.

CNDDB: Please note that the CNDDB is populated by and records voluntary submissions of species detections. As a result, species may be present in locations not depicted in the CNDDB but where there is suitable habitat and features capable of supporting species. A lack of an occurrence record in the CNDDB does not mean a species is not present. In order to adequately assess any potential Project-related impacts to biological resources, surveys conducted by a qualified biologist during the appropriate survey period(s) and using the appropriate protocol survey methodology are warranted in order to determine whether or not any special status species are present at or near the Project Site.

Project Alternatives Analysis: CDFW recommends that the information and results obtained from the biological technical surveys, studies, and analysis conducted in support of the project's CEQA document be used to develop and modify the Project's alternatives to avoid and minimize impacts to biological resources to the maximum extent possible. When efforts to avoid and minimize have been exhausted, remaining impacts to sensitive biological resources may need to be mitigated to reduce impacts to a less than significant level, if feasible.

Cumulative Impacts: CDFW recommends that a cumulative impact analysis be conducted for all biological resources that will either be significantly or potentially significantly impacted by implementation of the Project, including those whose impacts are determined to be less than significant with mitigation incorporated or for those resources that are rare or in poor or declining health and will be impacted by the project, even if those impacts are relatively small (i.e. less than significant). CDFW recommends cumulative impacts be analyzed using an acceptable methodology to evaluate the impacts of past, present, and reasonably foreseeable future projects on resources and be focused specifically on the resource, not the Project. An appropriate resource study area identified and utilized for this analysis is advised. CDFW staff is available for consultation in support of cumulative impacts analyses as a trustee and responsible agency under CEQA.

Lake and Stream Alteration: The Project may be subject to CDFW's regulatory authority pursuant to Fish and Game Code section 1600 et seq. Fish and Game Code section 1602 requires the Project proponent notify CDFW prior to commencing any activity that may (a) substantially divert or obstruct the natural flow of any river, stream, or lake; (b) substantially change or use any material from the bed, bank, or channel of any river, stream, or lake; or (c) deposit debris, waste or other materials that could pass

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into any river, stream, or lake. “Any river, stream, or lake” includes those that are ephemeral or intermittent as well as those that are perennial in nature. The EIR should address the potential Project-related impacts to all streams at and near the Project Site. For additional information on notification requirements, please contact our staff in the LSA Program at (559) 243-4593, or R4LSA@wildlife.ca.gov.

Federally Listed Species: CDFW recommends consulting with the USFWS on potential impacts to federally listed species including, but not limited to the aforementioned San Joaquin kit fox, blunt-nosed leopard lizard, California jewelflower, giant kangaroo rat, Tipton kangaroo rat, Buena Vista Lake ornate shrew, San Joaquin woollythreads, and Kern mallow. Take under the Federal Endangered Species Act (FESA) is more broadly defined than CESA; take under FESA also includes significant habitat modification or degradation that could result in death or injury to a listed species by interfering with essential behavioral patterns such as breeding, foraging, or nesting. Consultation with the USFWS in order to comply with FESA is advised well in advance of any ground disturbing activities.

CDFW is available to meet with you ahead of draft EIR preparation to discuss potential impacts and possible mitigation measures for some or all of the resources that may be analyzed in the EIR. If you have any questions, please contact Steven Hulbert, Senior Environmental Scientist Specialist, at the address provided on this letterhead, by telephone at (559) 575-6415, or by electronic mail at Steven.Hulbert@wildlife.ca.gov.

Sincerely,

DocuSigned by:
Krista Tomlinson
12950B95267A4F5...

FOR Julie A. Vance
Regional Manager

ec: United States Fish and Wildlife Service
Patricia Cole; patricia_cole@fws.gov

CDFW LSA/1600; R4LSA@wildlife.ca.gov

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REFERENCES CITED

California Department of Fish and Wildlife. 2023. Biogeographic Information and Observation System (BIOS). https://www.wildlife.ca.gov/Data/BIOS. Accessed June 27, 2023.

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State of California – Natural Resources Agency
DEPARTMENT OF FISH AND WILDLIFE
Central Region
1234 East Shaw Avenue
Fresno, California 93710
(559) 243-4005
www.wildlife.ca.gov

GAVIN NEWSOM, Governor
CHARLTON H. BONHAM, Director

GOVERNOR'S OFFICE OF PLANNING AND RESEARCH
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Cindi Hoover
Kern County Planning and Natural Resources Department
2700 M Street, Suite 100
Bakersfield, California 93301
HooverC@kerncounty.com

Subject: Carbon Frontier Carbon Capture and Sequestration Project (Project)
Notice of Preparation (NOP)
State Clearinghouse No. 2023060293

Dear Cindi Hoover:

The California Department of Fish and Wildlife (CDFW) received a NOP from the Kern County Planning and Natural Resources Department for the above-referenced Project pursuant to the California Environmental Quality Act (CEQA) and CEQA Guidelines.[1]

Thank you for the opportunity to provide comments and recommendations regarding those activities involved in the Project that may affect California fish and wildlife. Likewise, CDFW appreciates the opportunity to provide comments regarding those aspects of the Project that CDFW, by law, may be required to carry out or approve through the exercise of its own regulatory authority under Fish and Game Code.

CDFW ROLE

CDFW is California's **Trustee Agency** for fish and wildlife resources and holds those resources in trust by statute for all the people of the State (Fish & G. Code, §§ 711.7, subd. (a) & 1802; Pub. Resources Code, § 21070; CEQA Guidelines § 15386, subd. (a)). CDFW, in its trustee capacity, has jurisdiction over the conservation, protection, and management of fish, wildlife, native plants, and habitat necessary for biologically sustainable populations of those species (*Id*., § 1802). Similarly, for purposes of CEQA, CDFW is charged by law to provide, as available, biological expertise during public agency environmental review efforts, focusing specifically on

[1] CEQA is codified in the California Public Resources Code in section 21000 et seq. The "CEQA Guidelines" are found in Title 14 of the California Code of Regulations, commencing with section 15000.

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projects and related activities that have the potential to adversely affect fish and wildlife resources.

CDFW is also submitting comments as a **Responsible Agency** under CEQA (Pub. Resources Code, § 21069; CEQA Guidelines, § 15381). CDFW expects that it may need to exercise regulatory authority as provided by the Fish and Game Code. As proposed, for example, the Project may be subject to CDFW's lake and streambed alteration regulatory authority (Fish & G. Code, § 1600 et seq.). Likewise, to the extent implementation of the Project as proposed may result in "take" as defined by State law of any species protected under the California Endangered Species Act (CESA) (Fish & G. Code, § 2050 et seq.), related authorization as provided by the Fish and Game Code will be required.

Fully Protected Species: CDFW has jurisdiction over species of birds, mammals, amphibians, reptiles, and fish designated by statute as "fully protected" pursuant to Fish and Game Code sections 3511, 4700, 5050, and 5515. Take of any fully protected species is prohibited and CDFW cannot authorize their incidental take except as specifically provided for in Fish and Game Code; none of those specific exceptions are applicable to this project.

Nesting Birds: CDFW has jurisdiction over actions with potential to result in the disturbance or destruction of active nest sites or the unauthorized take of birds. Fish and Game Code sections that protect birds, their eggs and nests include sections 3503 (regarding unlawful take, possession or needless destruction of the nest or eggs of any bird), 3503.5 (regarding the take, possession or destruction of any birds-of-prey or their nests or eggs), and 3513 (regarding unlawful take of any migratory nongame bird).

Unlisted Species: Species of plants and animals need not be officially listed as Endangered, Rare, or Threatened (E, R, or T) on any State or federal list to be considered E, R, or T under CEQA. If a species can be shown to meet the criteria for E, R, or T, as specified in the CEQA Guidelines section 15380, CDFW recommends it be fully considered in the environmental analysis for the Project.

PROJECT DESCRIPTION SUMMARY

Proponent: Aera Energy, LLC

Objective: Aera Energy, LLC proposes the construction and operation of a carbon capture and storage (CSS) facility over portions of the existing and contiguous South Belridge and North Belridge oil fields near the community of Lost Hills in western Kern County. In the NOP, Kern County Planning and Natural Resources Department indicates that the CCS facility would involve the construction of appurtenant structures

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for the capture, transport, and subsurface injection (geologic sequestration) of carbon dioxide (CO_2). Once the Project is implemented, CO_2 would be captured at newly constructed facilities within the South Belridge oil field and transported in newly constructed pipelines to existing abandoned oil wells in the North Belridge oil field. These wells will be retrofitted to function as injection wells and used to inject the captured CO_2 into the depleted underground oil- and gas-bearing geologic formation where it will be permanently sequestered.

The Kern County Planning and Natural Resources Department will prepare an Environmental Impact Report (EIR) for the Project. The NOP lacks detailed information with regard to the actual footprint of the Project (Project Site) within the oil fields, and does not address ground disturbance, staging, laydown, or other specific Project-related activities which could threaten biological resources and result in significant environmental impacts within the Project Site. CDFW expects these details will be provided in the EIR. CDFW also expects additional detail will be provided in the EIR addressing:

- the need for nightwork during construction or operations/maintenance of the facilities;
- construction of the pipeline (aboveground vs underground, support of aboveground sections);
- the phase of the CO_2 transported through the pipeline (gaseous or liquid); and
- potential catastrophic events (and emergency responses to those events) which could occur along the pipeline, at the capture facilities, and at the injection facilities over the life of the Project.

Location: The Project Site exists within the administrative boundaries of the existing South Belridge and North Belridge oil fields, which adjoin each other (one immediately north of the other) and are generally west of State Route 33 and north and south of Lerdo Highway. The oil fields containing the Project Site are approximately seven miles southwest of the community of Lost Hills and approximately 30 miles northwest of the city of Bakersfield in Kern County, California.

Timeframe: n/a

COMMENTS AND RECOMMENDATIONS

Special-Status Species: Special-status species are known to exist in the vicinity of the Project Site, there is the potential for the Project to impact State and federally listed species. Records from the California Natural Diversity Database (CNDDB) show that the following special-status species, including State and federally listed species (CDFW 2023) could be impacted: the State threatened and federally endangered San Joaquin kit fox (*Vulpes macrotis mutica*); the State and federally endangered and State fully

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protected blunt-nosed leopard lizard (*Gamelia sila*); the State and federally endangered and California Rare Plant Ranked (CRPR) 1B.1 California jewelflower (*Caulanthus californicus*); the State and federally endangered giant kangaroo rat (*Dipodomys ingens*), Tipton kangaroo rat (*Dipodomys nitratoides nitratoides*); the State threatened San Joaquin antelope squirrel (*Ammospermophilus nelsoni*), tricolored blackbird (*Agelaius tricolor*), and Swainson's hawk (*Buteo swainsoni*); the federally endangered and State species of special concern Buena Vista Lake ornate shrew (*Sorex ornatus relictus*); the federally endangered and CRPR 1B.2 San Joaquin woollythreads (*Monolopia congdonii*) and Kern mallow (*Eremalche parrye ssp. kernensis*); the candidates for State listing Temblor legless lizard (*Anniella alexanderae*) and Crotch bumble bee (*Bombus crotchii*); the State species of special concern burrowing owl (*Athene cunicularia*), short-nosed kangaroo rat (*Dipodomys nitratoides brevinasus*), Tulare grasshopper mouse (*Onychomys torridus tularensis*), western spadefoot (*Spea hammondii*), American badger (*Taxidea taxus*), San Joaquin coachwhip (*Masticophis flagellum ruddocki*), and Le Conte's thrasher (*Toxostoma lecontei*); and the CRPR 1B.1, 1B.2 and 4.2 California alkali grass (*Puccinellia simplex*), Coulter's goldfields (*Lasthenia glabrata ssp. coulteri*), heartscale (*Atriplex cordulata var. cordulata*), Lost Hills crownscale (*Atriplex coronata var. vallicola*), recurved larkspur (*Delphinium recurvatum*), showy golden madia (*Madia radiata*), and Hoover's eriastrum (*Eriastrum hooveri*).

CDFW recommends that a habitat assessment be conducted at and in the vicinity of the Project Site for the aforementioned plant and animal species. The assessment should be conducted by a qualified biologist knowledgeable with the species and any potentially suitable habitat identified should be surveyed by a qualified biologist for the potential presence of these species as part of the biological technical studies conducted in support of the EIR. If the surveys reveal the aforementioned listed and candidate species occur at and/or near the Project Site, the EIR should include either measures to avoid take of those species, or the Project proponent's commitment to obtaining incidental take authorization under Section 2081 of Fish and Game Code, as appropriate, if avoidance will be unfeasible. Similarly, if the surveys reveal the aforementioned unlisted species, the EIR should include a commitment by the Project proponent to consult with CDFW, prior to commencing the Project, to identify and implement appropriate measures to avoid or minimize impacts to those species. It should be noted that blunt-nosed leopard lizard is State fully protected, therefore, no "take", incidental or otherwise, can be authorized by CDFW; complete avoidance of this species is required to comply with State law.

CDFW recommends that the surveys for blunt-nosed leopard lizard, San Joaquin kit fox, tricolored blackbird, Swainson's hawk, and burrowing owl be conducted in accordance with the species-specific protocols which can be found here:

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https://wildlife.ca.gov/Conservation/Survey-Protocols. CDFW recommends that the surveys for the aforementioned special status and CRPR plants be surveyed for by a qualified botanist following the "Protocols for Surveying and Evaluating Impacts to Special Status Native Plant Populations and Sensitive Natural Communities" which can also be found at: https://wildlife.ca.gov/Conservation/Survey-Protocols.This protocol, which is intended to maximize detectability, includes identification of reference populations to facilitate the likelihood of field investigations occurring during the appropriate floristic period. In the absence of protocol-level surveys being performed, additional surveys may be necessary. If take could occur as a result of Project-related activities, consultation with CDFW may be warranted.

Nesting birds: CDFW recommends that Project ground-disturbing activities occur during the bird non-nesting season; however, if ground-disturbing or vegetation-disturbing activities must occur during the nesting season (February 1st through September 15th), the Project applicant is responsible for ensuring that implementation of the Project does not result in violation of the Migratory Bird Treaty Act or relevant Fish and Game Codes as referenced above.

To evaluate Project-related impacts on nesting birds, CDFW recommends that a general habitat assessment for nesting birds be conducted as part of the biological technical studies conducted in support of the EIR. Depending on the results of that assessment, CDFW further recommends that the EIR for this Project include that a qualified biologist conduct a pre-construction survey for active nests no more than 10 days prior to the start of ground- or vegetation-disturbance to maximize the probability that nests that could potentially be impacted are detected. CDFW also recommends that surveys cover a sufficient area around the Project Site to identify nests and determine their status. A sufficient area means any area potentially affected, either directly or indirectly, by the Project. In addition to direct impacts (i.e. nest destruction), noise, vibration, and movement of workers or equipment could also affect nests. CDFW recommends that a qualified biologist establish a behavioral baseline of all identified nests. Once Project activities begin, CDFW recommends having a qualified biologist continuously monitor nests to detect behavioral changes resulting from the Project. If behavioral changes occur, CDFW recommends halting the work causing that change and consulting with CDFW for additional avoidance and minimization measures.

If continuous monitoring of identified nests by a qualified biologist is not feasible, CDFW recommends the EIR include a minimum no-disturbance buffer of 250 feet around active nests of non-listed bird species and a 500-foot no-disturbance buffer around active nests of non-listed raptors. These buffers are advised to remain in place until the breeding season has ended or until a qualified biologist has determined that the birds have fledged and are no longer reliant upon the nest or on-site parental care for survival. Variance from these no-disturbance buffers is possible when there is a

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compelling biological or ecological reason to do so, such as when the Project Site would be concealed from a nest site by topography. CDFW recommends that a qualified biologist advise and support any variance from these buffers and notify CDFW in advance of implementing a variance.

CNDDB: Please note that the CNDDB is populated by and records voluntary submissions of species detections. As a result, species may be present in locations not depicted in the CNDDB but where there is suitable habitat and features capable of supporting species. A lack of an occurrence record in the CNDDB does not mean a species is not present. In order to adequately assess any potential Project-related impacts to biological resources, surveys conducted by a qualified biologist during the appropriate survey period(s) and using the appropriate protocol survey methodology are warranted in order to determine whether or not any special status species are present at or near the Project Site.

Project Alternatives Analysis: CDFW recommends that the information and results obtained from the biological technical surveys, studies, and analysis conducted in support of the project's CEQA document be used to develop and modify the Project's alternatives to avoid and minimize impacts to biological resources to the maximum extent possible. When efforts to avoid and minimize have been exhausted, remaining impacts to sensitive biological resources may need to be mitigated to reduce impacts to a less than significant level, if feasible.

Cumulative Impacts: CDFW recommends that a cumulative impact analysis be conducted for all biological resources that will either be significantly or potentially significantly impacted by implementation of the Project, including those whose impacts are determined to be less than significant with mitigation incorporated or for those resources that are rare or in poor or declining health and will be impacted by the project, even if those impacts are relatively small (i.e. less than significant). CDFW recommends cumulative impacts be analyzed using an acceptable methodology to evaluate the impacts of past, present, and reasonably foreseeable future projects on resources and be focused specifically on the resource, not the Project. An appropriate resource study area identified and utilized for this analysis is advised. CDFW staff is available for consultation in support of cumulative impacts analyses as a trustee and responsible agency under CEQA.

Lake and Stream Alteration: The Project may be subject to CDFW's regulatory authority pursuant to Fish and Game Code section 1600 et seq. Fish and Game Code section 1602 requires the Project proponent notify CDFW prior to commencing any activity that may (a) substantially divert or obstruct the natural flow of any river, stream, or lake; (b) substantially change or use any material from the bed, bank, or channel of any river, stream, or lake; or (c) deposit debris, waste or other materials that could pass

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into any river, stream, or lake. “Any river, stream, or lake” includes those that are ephemeral or intermittent as well as those that are perennial in nature. The EIR should address the potential Project-related impacts to all streams at and near the Project Site. For additional information on notification requirements, please contact our staff in the LSA Program at (559) 243-4593, or R4LSA@wildlife.ca.gov.

Federally Listed Species: CDFW recommends consulting with the USFWS on potential impacts to federally listed species including, but not limited to the aforementioned San Joaquin kit fox, blunt-nosed leopard lizard, California jewelflower, giant kangaroo rat, Tipton kangaroo rat, Buena Vista Lake ornate shrew, San Joaquin woollythreads, and Kern mallow. Take under the Federal Endangered Species Act (FESA) is more broadly defined than CESA; take under FESA also includes significant habitat modification or degradation that could result in death or injury to a listed species by interfering with essential behavioral patterns such as breeding, foraging, or nesting. Consultation with the USFWS in order to comply with FESA is advised well in advance of any ground disturbing activities.

CDFW is available to meet with you ahead of draft EIR preparation to discuss potential impacts and possible mitigation measures for some or all of the resources that may be analyzed in the EIR. If you have any questions, please contact Steven Hulbert, Senior Environmental Scientist Specialist, at the address provided on this letterhead, by telephone at (559) 575-6415, or by electronic mail at Steven.Hulbert@wildlife.ca.gov.

Sincerely,

DocuSigned by:
Krista Tomlinson
12950B95267A4F5...

FOR Julie A. Vance
Regional Manager

ec: United States Fish and Wildlife Service
Patricia Cole; patricia_cole@fws.gov

CDFW LSA/1600; R4LSA@wildlife.ca.gov

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REFERENCES CITED

California Department of Fish and Wildlife. 2023. Biogeographic Information and Observation System (BIOS). https://www.wildlife.ca.gov/Data/BIOS. Accessed June 27, 2023.

From:	Medrano, Victor@DOC
To:	loreleo@kerncounty.com
Cc:	Cookey-Gam, David@DOC; Oladimeji, Olu@DOC; CalGEMCentralEnvironmental@DOC; OPR State Clearinghouse; OLRA@DOC; Perez, Jan@DOC
Subject:	CalGEM comments on CarbonFrontier Carbon Capture and Sequestration by Aera Energy, LLC project, SCH # 2023060293
Date:	Monday, July 10, 2023 10:27:31 AM
Attachments:	image001.png image002.png image003.png image004.png image005.png

Governor's Office of Planning & Research

Jul 10 2023

STATE CLEARINGHOUSE

Good morning Ms. Oviatt,

Please see below comments from the California Geologic Energy Management Division (CalGEM) regarding the **CarbonFrontier Carbon Capture and Sequestration by Aera Energy, LLC; SCH # 2023060293** project.

PROJECT DESCRIPTION:
The project proponent is proposing to construct and operate a CCS project within the North and South Belridge oilfields.

COMMENTS:
The parcels are located within the North and South Belridge administrative boundaries, and it is an active oil and gas field. As listed in section 1.5 "Proposed Discretionary Actions/Required Approvals" of the Notice of Preparation Draft Environmental Impact Report (EIR), the applicant shall obtain permits/approvals from the respective agencies as required.

The applicant shall file proper permitting with CalGEM for any required oil and gas operations.

Sincerely,

Victor D. Medrano
Associate Oil and Gas Engineer | Central District

California Department of Conservation
Geologic Energy Management Division
11000 River Run Blvd.
Bakersfield, CA 93311
T: (661) 322-4031 | C: (661) 201-8607
E: Victor.Medrano@conservation.ca.gov
W: https://www.conservation.ca.gov/calgem

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July 10, 2023

To: Lorelei Oviatt, Director
Planning and Natural Resources Department
Cindi Hoover AICP, Division Chief

From: Jeremy M. Brock, County Surveyor
By: Andres Arias, Engineering Support Supervisor Phone: 28959

Subject: Notice of Preparation of an Environmental Impact Report – CarbonFrontier Carbon Capture Sequestration Project by Aera Energy, LLC. (PP23402).

I have reviewed the above noted project Notice of Preparation of EIR and recommend the following conditions be placed on the Conditional Use Permits:

1. Prior to issuance of a building or grading permit: All survey monuments shall be tied out by a Licensed Land Surveyor. A corner record for each monument or record of survey shall be submitted to the County Surveyor for review and processing, per Section 8771 of the Professional Land Surveyor's (PLS) Act.

2. Prior to Final Inspection: All survey monuments that were destroyed during construction shall be re-set or have a suitable witness corner set. A post construction corner record for each monument re-set or a record of survey shall be submitted to the County Surveyor for processing, per Section 8771 of the Professional Land Surveyor's Act.

3. Upon completion of project: All survey monuments shall be accessible by a Licensed Land Surveyor or their representatives, with prior notice, per Section 8774 of the PLS Act and Civil Code 846.5 (a).

Thank you for the opportunity to review and comment on this project. Should you have any questions please contact me.

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

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[illegible]
[illegible] [illegible] [illegible]
2700 "M" Street, Suite 100
[illegible]

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[illegible]

[illegible]

1) [illegible]

[illegible]

The District's initial review of the Project concludes that emissions resulting from [illegible] as identified in the District's [illegible]

Samir Sheikh
Executive Director/Air Pollution Control Officer

Northern Region
4800 Enterprise Way
Modesto, CA 95356-8718
Tel: (209) 557-6400 FAX: (209) 557-6475

Central Region (Main Office)
1990 E. Gettysburg Avenue
Fresno, CA 93726-0244
Tel: (559) 230-6000 FAX: (559) 230-6061

Southern Region
34946 Flyover Court
Bakersfield, CA 93308-9725
Tel: (661) 392-5500 FAX: (661) 392-5585

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conducted for the Project's construction and operational emissions.

1a) Construction Emissions

1b) Operational Emissions

sources should be analyzed separately. For reference, the District's

Recommended Mitigation Measure

1c) Project Trip Generation and VMT Trace

County's

1d) Recommended Model for Air Quality Emissions

2) Health Risk Screening Assessment

[illegible] a health risk screening assessment is required for an application if the District concludes that the emissions unit [illegible] a risk management review pursuant to District Rule 2520, Federally Mandated Operating Permits, Section 6.3.2. The District's risk management policy for permitting new and modified sources [illegible] specifies that permitting actions for units exempted from BACT requirements due to low emissions [illegible] a health risk screening assessment to demonstrate that the unit's impact is less than the District's risk management policy thresholds.

[illegible] determine if the proposed emissions increase from this project will require a health risk assessment, the applicant submitted a health risk screening assessment [illegible] the District's Risk Management Policy for Permitting New and Modified Sources. The District reviewed the assessment and performed its own risk screening analysis using the District's HRSA Tool, which is based on the California Air Pollution Control Officers Association (CAPCOA) Hot Spots Analysis and Reporting Program (HARP) risk assessment guidance. The District's analysis is based on the annual emissions and the stack parameters listed in the application. The analysis was performed to determine the incremental cancer risk, chronic hazard index, and acute hazard index associated with the proposed project. The District's analysis determined that the cancer risk is less than one in one million (1.0), the chronic hazard index is less than 1.0, and the acute hazard index is less than 1.0. Therefore, the project is not required to perform a more refined health risk assessment.

[illegible] Prioritization and Risk Management Policy Analysis
A "Prioritization" is the recommended method for a conservative screening [illegible] determine risks associated with [illegible] [illegible] prioritization is based on the California Air Pollution Control Officers Association's (CAPCOA) methodology.

[illegible] District's analysis is based on [illegible] emissions and [illegible] parameters listed in the application. The analysis was performed to determine the [illegible] cancer risk, chronic hazard index, and acute hazard index associated with the proposed project. The District's analysis determined that the cancer risk is less than one in one million (1.0), the chronic hazard index is less than 1.0, and the acute hazard index is less than 1.0. Therefore, the project is not required to perform a more refined health risk assessment.

[illegible] Risk Management Policy Analysis
[illegible] the [illegible] [illegible] [illegible]

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4) Voluntary Emission Reduction Agreement

Criteria pollutant emissions may result in emissions exceeding the District's significance thresholds. Therefore, unless the Project Specific Determination demonstrates that the Project's emissions are less than the District's significance thresholds, the Lead Agency should require the applicant to enter into a VERA with the District. In this VERA, the project proponent agrees to mitigate project emissions by providing funds for the District's incentives programs. The funds are used to reduce emissions by the amount specified in the project's Specific Determination. The project proponent should provide a copy of the executed VERA to the Lead Agency and the District prior to issuance of the first discretionary approval. Upon payment of the VERA fee, the project proponent will not be responsible for implementing the emission reduction measures. The District will use the fee to implement emission reduction projects within two years of receiving the payment. In the event the District is unable to secure sufficient emission reductions, the project proponent may be required to implement on-site measures or pay an in-lieu fee.

The VERA is a mitigation measure by which a project proponent provides pre-project funding to the District that results in the reduction of emissions sufficient to offset the project's emissions. The project proponent should not commence construction activities until the VERA has been executed and the first discretionary approval has been issued. Information about how to enter into a VERA with the District may be obtained by contacting the District's Fresno office. The VERA must be executed before the project can be relied upon to mitigate air quality impacts.

5) Applicability and Timing of Voluntary Emission Reduction Agreements

The Lead Agency should contact the District to determine if a VERA is appropriate for a project. If a project proponent and the Lead Agency choose to enter into a VERA, the project proponent should submit an application to the District's Fresno office. The District will then prepare the VERA and forward it to the project proponent. The project proponent should execute the VERA and return it to the District. The District will then execute the VERA and return a fully executed copy to the project proponent and the Lead Agency.

6) District Rule and Regulation

The District's rules and regulations may require a project to implement measures to reduce emissions. Prior to the issuance of a project's first discretionary approval, the District will review the project to determine which District rules and regulations may apply to the project. The District's

r[illegible] [illegible] District's r[illegible] [illegible] [illegible] [

6c) Other District Rule and Regulation

Prior to operation, the project may be subject to the following District Rules: Regulation II (Permit Requirements), Rule 2201 (New and Modified Stationary Source Review Rule), Rule 4002 (National Emission Standards for Hazardous Air Pollutants), Rule 4101 (Visible Emissions), Rule 4102 (Nuisance), Rule 4601 (Architectural Coatings), Rule 4641 (Cutback, Slow Cure, and Emulsified Asphalt, Paving and Maintenance Operations), Rule 4702 (Internal Combustion Engines), Rule 4901 (Wood Burning Fireplaces and Wood Burning Heaters), Rule 4905 (Natural Gas-Fired, Fan-Type Central Furnaces), Rule 5550 (Indirect Source Review), Rule 5530 (Fugitive PM10 Prohibitions), and Rule 9510 (Indirect Source Review Fee).

7) District Comment Letter

The District recommends that a copy of the District's comments be provided to the project proponent.

If you have questions or require further information, please contact Mr. Mark Montelongo by e-mail at mark.montelongo@valleyair.org or by phone at (559) 230-5860.

Sincerely,

Brian Clements
Director of Permit Services



For Mark Montelongo
Program Manager

California Department of Transportation

DISTRICT 6 OFFICE
1352 WEST OLIVE AVENUE |P.O. BOX 12616 |FRESNO, CA 93778-2616
(559) 840-6066 | FAX (559) 488-4195 | TTY 711
www.dot.ca.gov

July 25, 2023

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DRAFT EIR
CARBONFRONTIER
GTS: 02291

SENT VIA EMAIL

Ms. Cindi Hoover – Division Chief
Kern County Planning and Natural Resources Department
2700 M Street
Bakersfield, CA 93301

Dear Ms. Hoover:

Thank you for the opportunity to review the Notice of Preparation for the Draft Environmental Impact Report proposing to build a Carbon Capture Sequestration Facility (Project). The Project site is comprised of 47 privately owned parcels and 2 provisional parcels located west of State Route (SR) 33, approximately 7 miles southwest of the Community of Lost Hills, in the County of Kern.

Per the site plan, the primary access to the Project site would be from Oasis Road (a private road), accessed from 7th Standard Road, west of SR 33. Oasis Road is connected to a network of existing dirt roads inside a field. New internal access roads may be constructed, but these roads will likely be compacted dirt roads.

Caltrans provides the following comments consistent with the State's smart mobility goals that support a vibrant economy and sustainable communities:

- A transportation impact study scoping meeting with Caltrans District 6 staff to discuss the most appropriate methodology for this analysis is recommended. Prior to the scoping meeting, a detailed operational statement should be submitted for review. This should include the nature of operations, hours of operation, number of expected AM and PM peak hour vehicle trips, and truck percentage. Please also provide information about future expansion phases of the project, if any, as this will allow for a more accurate assessment of the trips generated by the development. Once this information is provided, we will be able to complete our review and determine if a Traffic Impact Study (TIS) or other mitigation is required.

- Vicinity maps, regional location maps, and a site plan clearly showing project access in relation to nearby roadways and key destinations, ingress, and egress for all project components should be clearly identified. Please identify the State right-of-way (ROW). Project driveways, the State Highway System, local roads, intersections, interchanges, pedestrian and bicycle routes, car/bike parking, transit routes, and facilities should be mapped.

- Evidence indicates the project has the potential to impact additional environmental resources along SR 33. Caltrans analysis is an attempt to help the lead agency avoid any potential delays to the Project' encroachment permit process. The EIR should identify, evaluate, and propose mitigation for potential impacts to the SHS, including the entire width of the State right-of-way. To avoid delays to the encroachment permit process, a thorough environmental analysis will be required for the proposed mitigation of impacts to the SHS and should be included in the environmental document.

- As a point of information, any work completed in the State's right-of-way will require a Caltrans encroachment permit. An encroachment permit must be obtained for all proposed activities for placement of encroachments within, under, or over the State highway rights-of-way. Activity and work planned in the State right-of-way shall be performed to State standards and specifications, at no cost to the State. Engineering plans, calculations, specifications, and reports (documents) shall be stamped and signed by a licensed Engineer or Architect. Engineering documents for encroachment permit activity and work in the State right-of-way may be submitted using English Units. The Permit Department and the Environmental Planning Branch will review and approve the activity and work in the State right-of-way before an encroachment permit is issued. The Streets and Highways Code Section 670 provides Caltrans discretionary approval authority for projects that encroach on the State Highway System. Encroachment permits will be issued in accordance with Streets and Highway Codes, Section 671.5, "Time Limitations." Encroachment permits do not run with the land. A change of ownership requires a new permit application. Only the legal property owner or his/her authorized agent can pursue obtaining an encroachment permit.

- Prior to an encroachment permit application submittal, the project proponent is required to schedule a "Pre-Submittal" meeting with District 6 Encroachment Permit Office. To schedule this meeting, please call the Caltrans Encroachment Permit Office - District 6: 1352 W. Olive, Fresno, CA 93778, at (559) 383-5047 or (559) 383-5235.

- Please review the permit application - required document checklist at: https://forms.dot.ca.gov/v2Forms/servlet/FormRenderer?frmid=TR0402&distpath=MAOTO&brapath=PERM.

- Please also review the permit application - processing checklist at: https://dot.ca.gov/programs/traffic-operations/ep, and at, https://dot.ca.gov/-/media/dot-media/programs/traffic-operations/documents/encroachment-permits/tr-0416-a11y.pdf.

If you have any other questions, please contact Scott Lau at (559) 981-7341 or scott.lau@dot.ca.gov.

Sincerely,

Lorena Mendibles

LORENA MENDIBLES, Chief
Transportation Planning – South

A.3 Scoping Meeting Agenda

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AGENDA

KERN COUNTY PLANNING & NATURAL RESOURCES DEPARTMENT

Scoping Meeting

Kern County Public Services Building
2700 "M" Street, Public Meeting Room 1-A
Bakersfield, California 93301

June 23, 2023 – 1:30 p.m.

Pursuant to revised Section 21083.9 of the Public Resources Code, California Environmental Quality Act, effective January 1, 2002, this scoping meeting is being held to receive agency comments on the preparation of the Environmental Impact Reports (EIR) on certain projects. The process of determining the scope, focus, and content of the EIR is known as "scoping." Scoping helps to identify the range of actions, alternatives, environmental effects, methods of assessment, and mitigation measures to be analyzed in depth, and eliminate issues from the detailed study that are not important to the decision at hand. This is not a public hearing; however, the public may be present and offer comments. If you attend as a member of the public to address an item on the agenda, please let the chairperson know when discussion begins on that item. Each project will be presented by staff followed by an opportunity for comments for the record.

A. INTRODUCTION: Staff and meeting format

B. NEW CASES:

EIR – Notice of Preparation
CarbonFrontier Carbon Capture and Sequestration Project by Aera Energy, LLC (PP23402)
ZCC 4, Map 51; ZCC 3, Map 74; ZCC 4, Map 75; CUP 9, Map 51
CUP 7, Map 74; CUP 7, Map 75; CUP 9, Map 96

C. ADJOURNMENT:

AMERICANS WITH DISABILITIES ACT
(Government Code Section 54953.2)

Disabled individuals who need special assistance to attend or participate in the scoping meeting may request assistance at the Kern County Planning Department or by calling Alyssa Torres at (661) 862-8615. Every effort will be made to reasonably accommodate individuals with disabilities by making meeting materials available in alternative formats. Requests for assistance should be made five (5) working days in advance whenever possible.

Posted: June 20, 2023
KTA

SUBMIT WRITTEN COMMENTS ON THE NOP BY July 10, 2023 AT 5:00 PM

Mail to:
Kern County Planning and Natural Resources Department
Attn: Cindi Hoover
2700 "M" Street, Suite 100
Bakersfield, CA 93301
Phone: (661) 862-8629, **Email:** HooverC@kerncounty.com

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A.4 Summary of Proceedings: NOP Scoping Meeting

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SUMMARY OF PROCEEDINGS

KERN COUNTY AGENCY SCOPING MEETING

Kern County Planning and Natural Resources Department
2700 M Street, Suite 100
Bakersfield, California

Conference Room 1A

Date June 23, 2022

STAFF ATTENDANCE:
Cindi Hoover, Division Chief
Keith Alvidrez, Planner I

The meeting convened at 1:30 p.m. with introductions from Staff that were in attendance and outlining the purpose of the scoping meeting. Items were then discussed in order as identified on the agenda.

NOTICE OF PREPARATION PROJECT:

Environmental Impact Report – Notice of Preparation:
Belridge Carbon Capture Sequestration Project by Aera Energy, LLC (PP23402)

Twelve (12) members of the public were present. No public comments were presented.

Public testimony closed at approximately 1:41 p.m.

Notes prepared by
Keith Alvidrez, Planner I

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Appendix B
Air Quality and Greenhouse Gas Emissions Technical Documentation

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B.1 Air Quality Impacts Analysis

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AIR QUALITY IMPACT ANALYSIS

CarbonFrontier Project
Aera Energy LLC.

Kern County, CA

Prepared By:

TRINITY CONSULTANTS
4900 California Avenue, Suite 420A
Bakersfield, CA 93309
661-282-2200

December 2023

Project 210505.0198

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1. EXECUTIVE SUMMARY

Trinity Consultants has completed an Air Quality Impact Analysis (AQIA) for the proposed CarbonFrontier Project (Project) by Aera Energy LLC. (Aera Energy). The Project would be located within the Central Valley portion of western Kern County. The South Belridge and North Belridge oil fields are contiguous and located approximately six miles southwest of the community of Lost Hills and west of State Route (SR) 33. Together, the two Belridge oil fields cover an area of approximately 13 miles long and three miles wide. Aera Energy is the primary operator within both oil fields. The main entrance to the South Belridge Oil Field is located at the private Oasis Road along Seventh Standard Road west of SR 33.

The Project site is comprised of forty-six (46) privately owned parcels, within the administrative boundaries of the North and South Belridge oil fields. The North and South Belridge oil fields are contiguous and located west of Highway 33, approximately seven miles southwest of the community of Lost Hills.

The proposed carbon capture and sequestration (CCS) Project would capture carbon dioxide (CO_2) from existing produced gas streams (pre-combustion) and emissions from existing stationary sources (post-combustion) within the South Belridge Oil Field and transport the CO_2 through a pipeline to the North Belridge Oil Field for injection at dedicated Underground Injection Control (UIC) Class VI injection wells. The proposed underground CO_2 sequestration field, approximately 2,636 acres in size (maximum modeled CO_2 plume area), would be located within the North Belridge Oil Field with surface and mineral rights held by Aera Energy and other private owners. Oil and gas production activities would cease within the underground geologic formation where CO_2 would be stored, prior to commencement of the Project.

It is anticipated that the proposed Project would capture and sequester up to 1.6 million metric tons of CO_2 per year beginning in 2027 and contribute to California's goal of carbon net-neutrality by 2045 (Governor's Executive Order B-55-18) by reducing industrial CO_2 emissions.

The proposed Project's construction would include the following criteria pollutant emissions: reactive organic gases (ROG), carbon monoxide (CO), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), and suspended particulate matter (PM_{10} and $PM_{2.5}$). Project operations would generate air pollutant emissions from mobile sources, energy sources, and area sources. Project construction and operational activities would also generate greenhouse gas (GHG) emissions. Criteria and GHG emissions were estimated using the California Emissions Estimator Model (CalEEMod) Version 2022.1.1.13 (California Air Pollution Control Officers Association (CAPCOA) 2022), which is the most current version of the model approved for use by the San Joaquin Valley Air Pollution Control District (SJVAPCD), AP-42 emission factors, manufacture emission guarantees, and Tanks ESP.

Table 4-3 **through 4-8** present the Project's construction emissions, baseline operational mobile source emissions, operational mobile source emissions increase, baseline operational stationary source emissions, operational stationary source emission increase and total emissions from oil and gas operations from wells on a per well basis. As discussed in Section 4.11, the Project will reduce the overall GHG emissions impact to air quality. SJVAPCD uses a single threshold for determination of significance for both project specific and cumulative impacts. Section 5.0 discusses both a qualitative and quantitative evaluation of the cumulative impacts that the Project's contribution would pose.

2. INTRODUCTION

2.1 Purpose

This AQIA was prepared pursuant to the SJVAPCD Guidance for Assessing and Mitigating Air Quality Impacts (GAMAQI) (SJVAPCD 2015), the Kern County Planning and Community Development Department's (KCPD) Air Quality Preparation Guidelines (KCPD 2006), and the California Environmental Quality Act (CEQA) Statute and Guidelines (CEQA 2023).

2.2 General Project Description

Aera Energy is proposing the CarbonFrontier Project to capture CO_2 from existing produced gas streams (pre-combustion) and emissions from existing stationary sources (post-combustion) within the South Belridge Oil Field and transport the CO_2 through pipelines to the North Belridge Oil Field for injection at dedicated Class VI injection wells. The proposed Project includes a request to the Kern County Planning and Natural Resources Department for approval of a Zoning Change and CUP and any other required approvals, if any, for the construction and operation of the proposed Project, as follows:

Aera Energy proposes to capture and sequester approximately 1.6 million metric tons per year within the 64 Zone reservoir of the North Belridge Oil Field over a period of approximately 20 years[1]. The project would be sized to accept CO_2 from additional sources, totaling 3.3 million metric tons per year. The proposed CO_2 related facilities, pipelines, Class VI injection wells and associated CO_2 monitoring wells would be located within the CUP boundary.

The proposed Project includes the following components:

- **CO_2 Capture Facilities.** One pre-combustion capture facility and three post-combustion capture facilities.
- **Pipelines.** An approximately 10-mile main CO_2 pipeline, CO_2 distribution lines to each injection well, and produced gas, water, and steam pipelines.
- **Wells.** Development/Conversion and operation of up to nine CO_2 injection wells, and up to eight monitoring wells. Up to 55 existing oil wells would be plugged and abandoned within the North Belridge Oil Field, and up to 40 additional wells, previously abandoned within the North Belridge Oil Field, would be re-abandoned to meet current state and federal plugging requirements. Further, 21 production wells would be plugged and abandoned within the proposed capture facility areas in South Belridge,
- **Access Roads.** Maintenance, repair, and improvement of existing field access roads.
- **Water Systems.** Construction of water treatment facilities at each of the CO_2 capture facilities.
- **Electrical Transmission.** Construction of approximately 6,840 feet of 115 kV overhead transmission lines from the existing Aera Energy-owned electrical supply grid to two new electrical

[1] Note, the operational life of the proposed Project will be controlled by the sequestration reservoir's storage capacity (currently undergoing review) and volume of CO_2 captured per year which will fluctuate.

substations located adjacent to the CO_2 capture facilities. Also, two existing PG&E electrical substations may require upgrades at full Project build-out.

- **Networks.** Electrical power distribution, and supervisory control and data acquisition (SCADA) networks.

The surrounding area, as shown in **Figure 2-1**, is comprised of oil and gas exploration and production, grazing, and agricultural lands. The Project site is located within the Central Valley portion of western Kern County. The South Belridge and North Belridge oil fields are contiguous and located approximately six miles southwest of the community of Lost Hills and west of State Route (SR) 33. Together, the two Belridge oil fields cover an area of approximately 13 miles long and three miles wide. Aera Energy is the primary operator within both oil fields. The main entrance to the South Belridge Oil Field is located at the private Oasis Road along Seventh Standard Road west of SR 33.

The Project is proposed to be implemented in phases to maximize efficiency and help moderate construction activity levels. Most of the processing facility construction would occur over a three-year time period, expected to start in 2025 after the applicable permits are issued.

CO_2 capture facility and infrastructure construction would occur for approximately three years, starting with the Pre-C facility construction at the Gas Plant in section 32 (GP 32). Sequential construction would occur for construction of the Post-C facilities located at the section 32 cogeneration facility (COGEN 32) and the two Steam Generation Stations (SGSs). Injection well pad construction, drilling and plugging and abandonment activities, and pipeline construction activities would begin concurrently with the start of facility construction. Installation of CO_2 distribution pipelines, installation of intra-field electrical distribution, and well hookups would occur throughout the three-year period.

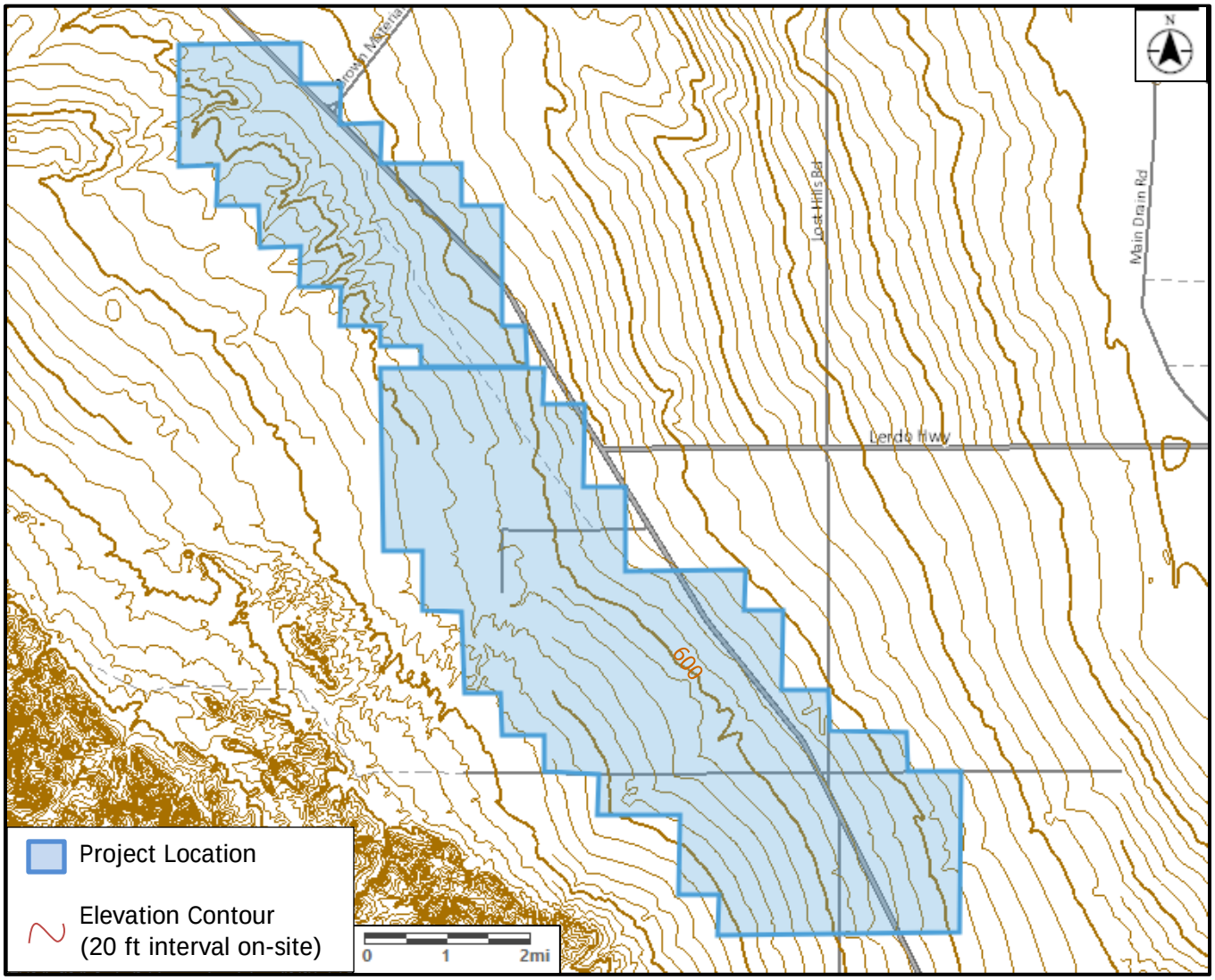
Figure 2-1. Regional and Project Location



Source: Stantec 2023

Figure 2-2 depicts the Project site's topography based on Kern County's Interactive County Map (Kern 2023). The Project site's elevation varies from 460 to 760 feet above mean sea level.

Figure 2-2. Project Site Topography



3. SETTING

Protection of the public health is maintained through the attainment and maintenance of ambient air quality standards for various atmospheric compounds and the enforcement of emissions limits for individual stationary sources. The Federal Clean Air Act requires that the U.S. Environmental Protection Agency (EPA) establish National Ambient Air Quality Standards (NAAQS) to protect the health, safety, and welfare of the public. NAAQS have been established for ozone (O_3), CO, NO_2, SO_2, PM_{10} and $PM_{2.5}$, and lead (Pb). California has also adopted ambient air quality standards (CAAQS) for these "criteria" air pollutants. CAAQS are more stringent than the corresponding NAAQS and include standards for hydrogen sulfide (H_2S), vinyl chloride (chloroethene), and visibility reducing particles. The U.S. Clean Air Act Amendments of 1977 required each state to identify areas that were in non-attainment of the NAAQS and to develop State Implementation Plans (SIP's) containing strategies to bring these non-attainment areas into compliance. NAAQS and CAAQS designation/classification for Kern County are presented in **Section 3.1** below.

Responsibility for regulation of air quality in California lies with the California Air Resources Board (CARB) and the 35 local air districts with oversight responsibility held by the EPA. CARB is responsible for regulating mobile source emissions, establishing CAAQS, conducting research, managing regulation development, and providing oversight and coordination of the activities of the 35 air districts. The air districts are primarily responsible for regulating stationary source emissions and monitoring ambient pollutant concentrations. CARB also determines whether air basins, or portions thereof, are “unclassified,” in “attainment” or in “non-attainment” for the NAAQS and CAAQS relying on statewide air quality monitoring data.

3.1 Air Quality Standards

The Project area is located within Kern County’s portion of the San Joaquin Valley Air Basin (SJVAB or Basin). Kern County is included among the eight counties that comprise the SJVAPCD. The SJVAPCD acts as the regulatory agency for air pollution control in the Basin and is the local agency empowered to regulate air pollutant emissions for the Project area. **Table 3-1** provides the NAAQS and CAAQS.

Table 3-1. Federal & California Air Quality Standards

Pollutant	Averaging Time	NAAQS	CAAQS
		Concentration	
O_3	8-hour	0.070 ppm (137 µg/m^3)[a]	0.070 ppm (137 µg/m^3)
	1-hour		0.09 ppm (180 µg/m^3)
CO	8-hour	9 ppm (10 µg/m^3)	9 ppm (10 µg/m^3)
	1-hour	35 ppm (40 µg/m^3)	20 ppm (23 µg/m^3)
NO_2	Annual Average	53 ppb (100 µg/m^3)	0.030 ppm (57 µg/m^3)
	1-Hour	100 ppb (188.68 µg/m^3)	0.18 ppm (339 µg/m^3)
SO_2	3-Hour	0.5 ppm (1,300 µg/m^3)	
	24 Hour	0.14 ppm (365 µg/m^3)	0.04 ppm (105 µg/m^3)
	1-Hour	75 ppb (196 µg/m^3)	0.25 ppm (655 µg/m^3)
Particulate Matter (PM_{10})	Annual Arithmetic Mean		20 µg/m^3
	24-Hour	150 µg/m^3	50 µg/m^3
Fine Particulate Matter ($PM_{2.5}$)	Annual Arithmetic Mean	12 µg/m^3	12 µg/m^3
	24-Hour	35 µg/m^3	
Sulfates	24-Hour		25 µg/m^3
Pb[d]	Rolling Three-Month Average	0.15 µg/m^3	
	30 Day Average		1.5 µg/m^3
H_2S	1-Hour		0.03 ppm (42 µg/m^3)
Vinyl Chloride (chloroethene)	24-Hour		0.010 ppm (26 µg/m^3)
Visibility Reducing particles	8 Hour (1000 to 1800 PST)		[b]

ppm = parts per million
ppb = parts per billion
mg/m^3 = milligrams per cubic meter
µg/m^3 = micrograms per cubic meter

Source: CARB 2016

a. On October 1, 2015, the national 8-hour ozone primary and secondary standards were lowered from 0.075 to 0.070 ppm

b. In 1989, CARB converted both the general statewide 10-mile visibility standards and the Lake Tahoe 30-mile visibility standard to instrumental equivalents, which are “extinction of 0.23 per kilometer” and “extinction of 0.07 per kilometer” for the statewide and Lake Tahoe Air Basin standards, respectively.

Under the provisions of the U.S. Clean Air Act, the Kern County portion of the SJVAB has been classified as nonattainment/extreme, nonattainment/severe, nonattainment, attainment/unclassified, attainment, or unclassified under the established NAAQS and CAAQS for various criteria pollutants. **Table 3-2** provides the SJVAB's designation and classification based on the various criteria pollutants under both NAAQS and CAAQS.

Table 3-2. SJVAB Attainment Status

Pollutant	NAAQS[a]	CAAQS[b]
O_3, 1-hour	No Federal Standard[f]	Nonattainment/Severe
O_3, 8-hour	Nonattainment/Extreme[e]	Nonattainment
PM_{10}	Attainment[c]	Nonattainment
$PM_{2.5}$	Nonattainment[d]	Nonattainment
CO	Attainment/Unclassified	Attainment/Unclassified
NO_2	Attainment/Unclassified	Attainment
SO_2	Attainment/Unclassified	Attainment
Pb (Particulate)	No Designation/Classification	Attainment
H_2S	No Federal Standard	Unclassified
Sulfates	No Federal Standard	Attainment
Visibility Reducing Particulates	No Federal Standard	Unclassified
Vinyl Chloride	No Federal Standard	Attainment

Source: SJVAPCD 2022a

Note:

a. See 40 CFR Part 81

b. See CCR Title 17 Sections 60200-60210

c. On September 25, 2008, EPA redesignated the San Joaquin Valley to attainment for the PM_{10} National Ambient Air Quality Standard (NAAQS) and approved the PM_{10} Maintenance Plan.

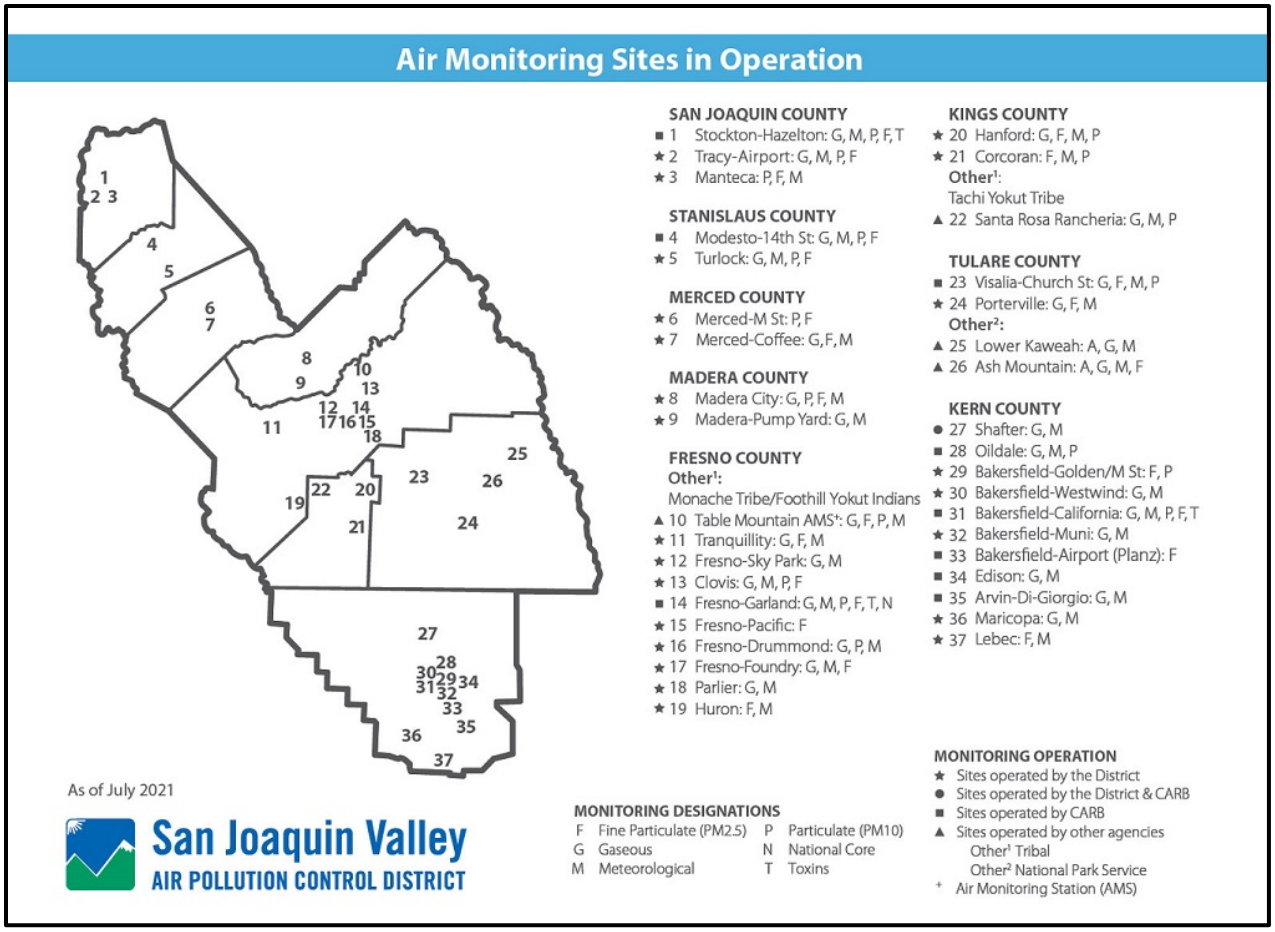
d. The Valley is designated nonattainment for the 1997 $PM_{2.5}$ NAAQS. EPA designated the Valley as nonattainment for the 2006 $PM_{2.5}$ NAAQS on November 13, 2009 (effective December 14, 2009).

e. Though the Valley was initially classified as serious nonattainment for the 1997 8-hour O_3 standard, EPA approved Valley reclassification to extreme nonattainment in the Federal Register on May 5, 2010 (effective June 4, 2010).

f. Effective June 15, 2005, the EPA revoked the federal 1-hour O_3 standard, including associated designations and classifications. EPA had previously classified the SJVAB as extreme nonattainment for this standard. EPA approved the 2004 Extreme Ozone Attainment Demonstration Plan on March 8, 2010 (effective April 7, 2010). Many applicable requirements for extreme 1-hour O3 nonattainment areas continue to apply to the SJVAB.

The SJVAPCD, along with CARB, operates an air quality monitoring network that provides information on average concentrations of those pollutants for which Federal or State agencies have established NAAQS and CAAQS, respectively. The monitoring stations in the San Joaquin Valley are depicted in **Figure 3-1**.

Figure 3-1. SJVAPCD Monitoring Network



Source: SJVAPCD 2022b

3.2 Existing Air Quality

For the purposes of background data and this air quality analysis, this analysis relied on data collected in the last three years for the CARB monitoring stations that are located in the closest proximity to the project site. **Table 3-3** provides the background concentrations for O_3, particulate matter of 10 microns (PM_{10}), particulate matter of less than 2.5 microns ($PM_{2.5}$), CO, NO_2, SO_2, and Pb. Information is provided for the Bakersfield – 5558 California Avenue, Bakersfield – 410 E. Planz Road, Bakersfield – Golden State Highway Oildale – 3311 Manor Street, Maricopa – Stanislaus Street, and Shafter – Walker Street monitoring stations for 2019 through 2021. No data is available for H_2S, Vinyl Chloride or other toxic air contaminants in Kern County.

Table 3-3. Existing Air Quality Monitoring Data in Project Area

Pollutant and Monitoring Station Location	Maximum Concentration			Days Exceeding Standard		
	2019	2020	2021	2019	2020	2021
O_3 – 1-hour CAAQS (0.09 ppm)						
Bakersfield - 5558 California Ave	0.097	0.110	0.090	2	3	0
Oildale - 3311 Manor Street	0.099	0.109	0.107	1	3	6
Maricopa – Stanislaus Street	0.086	0.122	0.083	0	7	0
O_3 – 8-hour CAAQS (0.070 ppm)						
Bakersfield - 5558 California Ave	0.088	0.098	0.081	28	25	11
Oildale - 3311 Manor Street	0.087	0.096	0.095	20	24	46
Maricopa – Stanislaus Street	0.080	0.096	0.077	45	40	11
O_3 – 8-hour NAAQS (0.070 ppm)						
Bakersfield - 5558 California Ave	0.088	0.098	0.080	24	25	11
Oildale - 3311 Manor Street	0.086	0.096	0.095	16	23	43
Maricopa – Stanislaus Street	0.080	0.095	0.077	41	38	10
PM_{10} – 24-hour CAAQS (50 µg/m^3)						
Bakersfield - 5558 California Ave	125.9	196.8	439.3	17	18	124
Oildale - 3311 Manor Street	392.1	277.3	423.0	118	123	129
PM_{10} – 24-hour NAAQS (150 µg/m^3)						
Bakersfield - 5558 California Ave	116.3	193.8	437.5	0	1	3
Oildale - 3311 Manor Street	389.3	517.2	421.4	8	15	2
$PM_{2.5}$ - 24-hour NAAQS (35 µg/m^3)						
Bakersfield - 5558 California Ave	59.1	150.7	72.3	12	44	40
Bakersfield – Golden State Highway	66.1	150.2	78.5	4	10	43
Bakersfield – 410 E Planz Road	83.7	158.6	70.5	3	17	17
CO - 8-Hour CAAQS & NAAQS (9.0 ppm)						
No data collected	*	*	*	*	*	*
NO_2 - 1-Hour CAAQS (0.18 ppm)						
Bakersfield - 5558 California Ave	0.067	0.050	0.057	0	0	0
Shafter - Walker Street	0.049	0.040	0.047	0	0	0
NO_2 - 1-Hour NAAQS (0.10 ppm)						
Bakersfield - 5558 California Ave	0.0671	0.0504	0.0572	0	0	0
Shafter - Walker Street	0.0493	0.0409	0.0478	0	0	0
SO_2 – 24-hour Concentration - CAAQS (0.04 ppm) & NAAQS (0.14 ppm)						
No data collected	*	*	*	*	*	*
Pb - Maximum 30-Day Concentration CAAQS (1500 ng/m^3)						
Bakersfield - 5558 California Ave	8.5	5.7	9.9	*	*	*

Source: CARB 2022a
Notes: ppm= parts per million
* There was insufficient (or no) data available to determine the value.

The following is a description of criteria air pollutants, typical sources and health effects and the recently documented pollutant levels in the project vicinity.

3.2.1 Ozone (O_3)

The most severe air quality problem in the San Joaquin Valley is high concentrations of O_3. High levels of O_3 cause eye irritation and can impair respiratory functions. High levels of O_3 can also affect plants and materials. Grapes, lettuce, spinach and many types of garden flowers and shrubs are particularly vulnerable to O_3 damage. O_3 is not emitted directly into the atmosphere but is a secondary pollutant produced through photochemical reactions involving hydrocarbons and nitrogen oxides (NOx). Significant O_3 generation requires about one to three hours in a stable atmosphere with strong sunlight. For this reason, the months of April through October comprise the "ozone season." O_3 is a regional pollutant because O_3 precursors are transported and diffused by wind concurrently with the reaction process. The data contained in **Table 3-3** shows that the Bakersfield, Oildale and Maricopa areas exceeded the 1-hour average ambient O_3 CAAQS and the 8-hour average ambient O_3 NAAQS and CAAQS during the 2019 through 2021 period.

3.2.2 Suspended Particulate Matter (PM_{10} and $PM_{2.5}$)

Both State and Federal particulate standards now apply to particulates under 10 microns (PM_{10}) rather than to total suspended particulate (TSP), which includes particulates up to 30 microns in diameter. Continuing studies have shown that the smaller-diameter fraction of TSP represents the greatest health hazard posed by the pollutant; therefore, EPA has recently established NAAQS for $PM_{2.5}$. The project area is classified as attainment for PM_{10} and non-attainment for particulates under 2.5 microns ($PM_{2.5}$) for NAAQS.

Particulate matter consists of particles in the atmosphere resulting from many kinds of dust and fume-producing industrial and agricultural operations, from combustion, and from atmospheric photochemical reactions. Natural activities also increase the level of particulates in the atmosphere; wind-raised dust and ocean spray are two sources of naturally occurring particulates. The largest sources of PM_{10} and $PM_{2.5}$ in Kern County are vehicle movement over paved and unpaved roads, demolition and construction activities, farming operations, and unplanned fires. PM_{10} and $PM_{2.5}$ are considered regional pollutants with elevated levels typically occurring over a wide geographic area. Concentrations tend to be highest in the winter, during periods of high atmospheric stability and low wind speed. In the respiratory tract, very small particles of certain substances may produce injury by themselves or may contain absorbed gases that are injurious. Particulates of aerosol size suspended in the air can both scatter and absorb sunlight, producing haze and reducing visibility. They can also cause a wide range of damage to materials.

Table 3-3 shows that PM_{10} levels regularly exceeded the CAAQS but not the NAAQS at two monitoring stations over the three-year period of 2019 through 2021. **Table 3-3** shows that $PM_{2.5}$ NAAQS were exceeded from 2019 through 2021. Similar levels can be expected to occur in the vicinity of the Project site.

3.2.3 Carbon Monoxide (CO)

Ambient CO concentrations normally correspond closely to the spatial and temporal distributions of vehicular traffic. Relatively high concentrations of CO would be expected along heavily traveled roads and near busy intersections. Wind speed and atmospheric mixing also influence CO concentrations; however, under inversion conditions prevalent in the San Joaquin Valley, CO concentrations may be more uniformly distributed over a broad area.

Internal combustion engines, principally in vehicles, produce CO due to incomplete fuel combustion. Various industrial processes also produce CO emissions through incomplete combustion. Gasoline-powered motor vehicles are typically the major source of this contaminant. CO does not irritate the respiratory tract but passes

through the lungs directly into the blood stream, and by interfering with the transfer of fresh oxygen to the blood, deprives sensitive tissues of oxygen, thereby aggravating cardiovascular disease, causing fatigue, headaches, and dizziness. CO is not known to have adverse effects on vegetation, visibility, or materials.

Table 3-3 reports no CO data is available for the three-year period from 2019 through 2021; historically Bakersfield area data for CO has been below the CAAQS and NAAQS.

3.2.4 Nitrogen Dioxide (NO_2) and Hydrocarbons

Kern County has been designated as an attainment area for the NAAQS for NO_2. NO_2 is the "whiskey brown" colored gas readily visible during periods of heavy air pollution. Mobile sources and oil and gas production account for nearly all of the County's NOx emissions, most of which is emitted as NO_2. Combustion in motor vehicle engines, power plants, refineries and other industrial operations are the primary sources in the region. Railroads and aircraft are other potentially significant sources of combustion air contaminants. Oxides of nitrogen are direct participants in photochemical smog reactions. The emitted compound, nitric oxide, combines with oxygen in the atmosphere in the presence of hydrocarbons and sunlight to form NO_2 and O_3. NO_2, the most significant of these pollutants, can color the atmosphere at concentrations as low as 0.5 ppm on days of 10-mile visibility. NOx is an important air pollutant in the region because it is a primary receptor of ultraviolet light, which initiates the reactions producing photochemical smog. It also reacts in the air to form nitrate particulates.

Motor vehicles are the major source of reactive hydrocarbons in the basin. Other sources include evaporation of organic solvents and petroleum production and refining operations. Certain hydrocarbons can damage plants by inhibiting growth and by causing flowers and leaves to fall. Levels of hydrocarbons currently measured in urban areas are not known to cause adverse effects in humans. However, certain members of this contaminant group are important components in the reactions, which produce photochemical oxidants.

Table 3-3 shows that the Shafter area exceeded the 1-hour average ambient NO_2 NAAQS and CAAQS for the 2019 through 2021 period. Hydrocarbons are not currently monitored.

3.2.5 Sulfur Dioxide (SO_2)

Kern County has been designated as an attainment area for the NAAQS for SO_2. SO_2 is the primary combustion product of sulfur, or sulfur containing fuels. Fuel combustion is the major source of this pollutant, while chemical plants, sulfur recovery plants, and metal processing facilities are minor contributors. Gaseous fuels (natural gas, propane, etc.) typically have lower percentages of sulfur containing compounds than liquid fuels such as diesel or crude oil. SO_2 levels are generally higher in the winter months. Decreasing levels of SO_2 in the atmosphere reflect the use of natural gas in power plants and boilers.

At high concentrations, SO_2 irritates the upper respiratory tract. At lower concentrations, when respirated in combination with particulates, SO_2 can result in greater harm by injuring lung tissues. Sulfur oxides (SOx), in combination with moisture and oxygen, results in the formation of sulfuric acid, which can yellow the leaves of plants, dissolve marble, and oxidize iron and steel. SOx can also react to produce sulfates that reduce visibility and sunlight.

Table 3-3 shows no data has been reported over the three-year period in Kern County.

3.2.6 Lead (Pb) and Suspended Sulfate

Ambient Pb levels have dropped dramatically due to the increase in the percentage of motor vehicles that run exclusively on unleaded fuel. Ambient Pb levels in Elk Hills are well below the ambient standard and are

expected to continue to decline; the data reported in **Table 3-3** only shows the highest concentration as the number of days exceeding standards are not reported. Suspended sulfate levels have stabilized to the point where no excesses of the State standard are expected in any given year.

3.3 Climate

The most significant single control on the weather pattern of the San Joaquin Valley is the semi-permanent subtropical high-pressure cell, referred to as the "Pacific High." During the summer, the Pacific High is positioned off the coast of northern California, diverting ocean-derived storms to the north. Hence, the summer months are virtually rainless. During the winter, the Pacific High moves southward allowing storms to pass through the San Joaquin Valley. Almost all of the precipitation expected during a given year occurs from December through April. During the summer, the predominant surface winds are out of the northwest. Air enters the Valley through the Carquinez strait and flows toward the Tehachapi Mountains. This up-valley (northwesterly) wind flow is interrupted in early fall by the emergence of nocturnal, down-valley (southeasterly) winds which become progressively more predominant as winter approaches. Wind speeds are generally highest during the spring and lightest in fall and winter. The relatively cool air flowing through the Carquinez strait is warmed on its journey south through the Valley. On reaching the southern end of the Valley, the average high temperature during the summer is nearly 100 degrees Fahrenheit (°F). Relative humidity during the summer is quite low, causing large diurnal temperature variations. Temperatures during the summer often drop into the upper 60s. In winter, the average high temperatures reach the mid-50s and the average low drops to the mid-30s. In addition, another high-pressure cell, known as the "Great Basin High," develops east of the Sierra Nevada Mountain Range during winter. When this cell is weak, a layer of cool, damp air becomes trapped in the basin and extensive fog results. During inversions, vertical dispersion is restricted, and pollutant emissions are trapped beneath the inversion and pushed against the mountains, adversely affecting regional air quality. Surface-based inversions, while shallow and typically short-lived, are present most mornings. Elevated inversions, while less frequent than ground-based inversions, are typically longer lasting and create more severe air stagnation problems. The winter season characteristically has the poorest conditions for vertical mixing of the entire year.

Meteorological data for various monitoring stations is maintained by the Western Regional Climate Center. Meteorological data for the Project site is expected to be similar to the data recorded at the Buttonwillow monitoring station. This data is provided in **Table 3-4**, which contains average precipitation data recorded at the Buttonwillow monitoring station. Over the 115-year period from January of 1901 through June of 2016 (the most recent data available), the average annual precipitation was 5.64 inches.

Table 3-4. Buttonwillow Weather Data

Period of Record Monthly Climate Summary for the Period 01/05/1901 to 6/10/2016													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Avg. Maximum Temp (F)	56.4	63.2	69.1	76.0	84.7	92.4	98.4	96.7	91.7	81.4	67.4	57.2	77.9
Avg. Minimum Temp (F)	35.2	39.0	43.0	47.2	54.1	60.1	65.3	63.3	57.9	48.8	39.2	34.5	49.0
Average Total Precipitation (in.)	1.06	1.07	0.97	0.55	0.21	0.05	0.02	0.02	0.12	0.27	0.55	0.75	5.64
Average Snowfall (in.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Average Snow Depth (in.)	0	0	0	0	0	0	0	0	0	0	0	0	0
Percent of possible observations for period of record: Max. Temp.: 99.1% Min. Temp.: 99.1% Precipitation: 98.8% Snowfall: 99.2% Snow Depth: 99.2%													
Source: Western Regional Climate Center, 2023.													

3.4 Climate Change and Greenhouse Gases

3.4.1 Global Climate Change

"Global climate change" refers to change in average meteorological conditions on the earth with respect to temperature, precipitation, and storms, lasting for decades or longer. The term "global climate change" is often used interchangeably with the term "global warming," but "global climate change" is preferred by some scientists and policy makers to "global warming" because it helps convey the notion that in addition to rising temperatures, other changes in global climate may occur. Climate change may result from the following influences:

- Natural factors, such as changes in the sun's intensity or slow changes in the Earth's orbit around the sun;
- Natural processes within the climate system (e.g., changes in ocean circulation); and/or
- Human activities that change the atmosphere's composition (e.g., through burning fossil fuels) and the land surface (e.g., deforestation, reforestation, urbanization, and desertification).

As determined from worldwide meteorological measurements between 1990 and 2005, the primary observed effect of global climate change has been a rise in the average global tropospheric temperature of 0.36 degree Fahrenheit (°F) per decade. Climate change modeling shows that further warming could occur, which could induce additional changes in the global climate system during the current century. Changes to the global climate system, ecosystems, and the environment of California could include higher sea levels, drier or wetter weather, changes in ocean salinity, changes in wind patterns or more energetic aspects of extreme weather (e.g., droughts, heavy precipitation, heat waves, extreme cold, and increased intensity of tropical cyclones). Specific effects from climate change in California may include a decline in the Sierra Nevada snowpack, erosion of California's coastline, and seawater intrusion in the Sacramento-San Joaquin River Delta.

Human activities, including fossil fuel combustion and land use changes, release carbon dioxide (CO_2) and other compounds cumulatively termed greenhouse gases (GHGs). GHGs are effective at trapping radiation that would otherwise escape the atmosphere. This trapped radiation warms the atmosphere, the oceans, and the earth's surface (USGCRP, 2014). Many scientists believe "most of the warming observed over the last 50 years is attributable to human activities" (IPCC, 2017). The increased amount of CO_2 and other GHGs in the atmosphere is the alleged primary result of human-induced warming.

GHGs are present in the atmosphere naturally, released by natural sources, or formed from secondary reactions taking place in the atmosphere. They include CO_2, methane (CH_4), nitrous oxide (N_2O), and O_3. In the last 200 years, substantial quantities of GHGs have been released into the atmosphere, primarily from fossil fuel combustion. These human-induced emissions are increasing GHG concentrations in the atmosphere, therefore enhancing the natural greenhouse effect. The GHGs resulting from human activity are believed to be causing global climate change. While human-made GHGs include CO_2, CH_4, and N_2O, some (like chlorofluorocarbons [CFCs]) are completely new to the atmosphere. GHGs vary considerably in terms of Global Warming Potential (GWP), the comparative ability of each GHG to trap heat in the atmosphere. The GWP is based on several factors, including the relative effectiveness of a gas to absorb infrared radiation and the length of time that the gas remains in the atmosphere ("atmospheric lifetime"). The GWP of each gas is measured relative to CO_2, the most abundant GHG. The definition of GWP for a particular GHG is the ratio of heat trapped by one unit mass of the GHG to the ratio of heat trapped by one unit mass of CO_2 over a specified time period. GHG emissions are typically measured in terms of pounds or tons of "CO_2 equivalents" (CO_2e).

Methane is produced when organic matter decomposes in environments lacking sufficient oxygen. Natural sources of CH_4 production include wetlands, termites, and oceans. Human activity accounts for the majority of the approximately 500 million metric tons of CH_4 emitted annually. These anthropogenic sources include the mining and burning of fossil fuels; digestive processes in ruminant livestock such as cattle; rice cultivation; and the decomposition of waste in landfills. The major removal process for atmospheric CH_4, the chemical breakdown in the atmosphere, cannot keep pace with source emissions; therefore, CH_4 concentrations in the atmosphere are rising.

Worldwide emissions of GHGs in 2008 were 30.1 billion metric tons of CO_2e and have increased considerably since that time (United Nations, 2011). It is important to note that the global emissions inventory data are not all from the same year and may vary depending on the source of the data (U.S. EPA, 2019). Emissions from the top five emitting countries and the European Union accounted for approximately 70% of total global GHG emissions in 2014. The United States was the number two producer of GHG emissions behind China. The primary GHG emitted by human activities was CO_2, representing approximately 76% of total global GHG emissions (U.S. EPA, 2019).

In 2017, the United States emitted approximately 6.5 million metric tons of CO_2e. Of the six major sectors nationwide (electric power industry, transportation, industry, agriculture, commercial, and residential), the electric power industry and transportation sectors combined account for approximately 57% of the GHG emissions; the majority of the electrical power industry and all of the transportation emissions are generated from direct fossil fuel combustion. Between 1990 and 2017, total United States GHG emissions rose approximately 1.3% (U.S. EPA, 2019).

Worldwide, energy-related CO_2 emissions are expected to increase at an average rate of 0.6% annually between 2018 and 2050, compared with the average growth rate of 1.8% per year from 1990 to 2018. Much of the increase in these emissions is expected to occur in the developing world where emerging economies, such as China and India, fuel economic development with fossil fuel energy. Developing countries' emissions are expected to grow above the world average at a rate of approximately 1% annually between 2018 and 2050 and surpass emissions of industrialized countries by 2025 (U.S. EIA, 2019).

CARB is responsible for developing and maintaining the California GHG emissions inventory. This inventory estimates the amount of GHGs emitted into and removed from the atmosphere by human activities within the state of California and supports the Assembly Bill (AB) 32 Climate Change Program. CARB's current GHG emission inventory covers the years 2000 through 2017 and is based on fuel use, equipment activity, industrial processes, and other relevant data (e.g., housing, landfill activity, and agricultural lands).

In 2017, emissions from statewide emitting activities were 424 million metric tons of CO_2 equivalent (MMT CO_2e), which is 5 MMT CO_2e lower than 2016 levels. 2017 emissions have decreased by 14% since peak levels in 2004 and are 7 MMT CO_2e below the 1990 emissions level and the State's 2020 GHG limit. Per capita GHG emissions in California have dropped from a 2001 peak of 14.1 tonnes per person to 10.7 tonnes per person in 2017, a 24% decrease (CARB 2019).

CARB estimates that transportation was the source of approximately 40% of California's GHG emissions in 2017, followed by electricity generation at 15%. Other sources of GHG emissions were industrial sources at 21%, residential plus commercial activities at 10%, and agriculture at 8% (CARB 2019).

CARB has projected the estimated statewide GHG emissions for the year 2020, which represent the emissions that would be expected to occur with reductions anticipated from Pavley I and the Renewables Electricity Standard (30 MMT CO_2e total), will be 509 MMT of CO_2e (CARB, 2014). GHG emissions from the transportation and electricity sectors as a whole are expected to increase at approximately 36% and 20% of total CO_2e emissions, respectively, as compared to 2009. The industrial sector consists of large stationary sources of GHG emissions and the percentage of the total 2020 emissions is projected to be 18% of total CO_2e emissions. The remaining sources of GHG emissions in 2020 are high global warming potential gases at 6%, residential and commercial activities at 10%, agriculture at 7%, and recycling and waste at 2%.

3.4.2 Effects of Global Climate Change

Changes in the global climate are assessed using historical records of temperature changes that have occurred in the past. Climate change scientists use this temperature data to extrapolate a level of statistical significance specifically focusing on temperature records from the last 150 years (the Industrial Age) that differ from past climate changes in rate and magnitude.

The Intergovernmental Panel on Climate Change (IPCC) constructed several emission trajectories of GHGs needed to stabilize global temperatures and climate change impacts. In its Fifth Assessment Report, the IPCC predicted that the global mean temperature change from 1990 to 2100 could range from 1.1 degree Celsius (°C) to 6.4 °C (8 to 10.4 °Fahrenheit) (IPCC, 2013). Global average temperatures and sea levels are expected to rise under all scenarios (IPCC, 2014). The IPCC concluded that global climate change was largely the result of human activity, mainly the burning of fossil fuels. However, scientific literature is not consistent regarding many of the aspects of climate change, the actual temperature changes during the 20th century, and contributions from human versus non-human activities.

Effects from global climate change may arise from temperature increases, climate sensitive diseases, extreme weather events, and degradation of air quality. There may be direct temperature effects through increases in average temperature leading to more extreme heat waves and less extreme cold spells. Those living in warmer climates are likely to experience more stress and heat-related problems. Heat-related problems include heat rash and heat stroke, drought, etc. In addition, climate-sensitive diseases may increase, such as those spread by mosquitoes and other disease-carrying insects. Such diseases include malaria, dengue fever, yellow fever, and encephalitis. Extreme events such as flooding and hurricanes can displace people and agriculture. Global warming may also contribute to air quality problems from increased frequency of smog and particulate air pollution.

According to the 2006 California Climate Action Team (CAT) Report, several climate change effects can be expected in California over the course of the next century (CalEPA, 2006). These are based on trends established by the IPCC and are summarized below.

- A diminishing Sierra snowpack declining by 70% to 90%, threatening the state's water supply.

- A rise in sea levels, resulting in the displacement of coastal businesses and residences. During the past century, sea levels along California's coast have risen about seven inches. If emissions continue unabated and temperatures rise into the higher anticipated warming range, sea level is expected to rise an additional 22 to 35 inches by the end of the century. Sea level rises of this magnitude would inundate coastal areas with salt water, accelerate coastal erosion, threaten vital levees and inland water systems, and disrupt wetlands and natural habitats. (Note: This condition would not affect the proposed Project area, as it is a significant distance away from coastal areas.)
- An increase in temperature and extreme weather events. Climate change is expected to lead to increases in the frequency, intensity, and duration of extreme heat events and heat waves in California. More heat waves can exacerbate chronic disease or heat-related illness.
- Increased risk of large wildfires if rain increases as temperatures rise. Wildfires in the grasslands and chaparral ecosystems of southern California are estimated to increase by approximately 30% toward the end of the 21st century because more winter rain will stimulate the growth of more plant fuel available to burn in the fall. In contrast, a hotter, drier climate could promote up to 90% more northern California fires by the end of the century by drying out and increasing the flammability of forest vegetation.
- Increasing temperatures from 8 to 10.4 °F under the higher emission scenarios, leading to a 25% to 35% increase in the number of days that ozone pollution levels are exceeded in most urban areas (see below).
- Increased vulnerability of forests due to forest fires, pest infestation, and increased temperatures.
- Reductions in the quality and quantity of certain agricultural products. The crops and products likely to be adversely affected include wine grapes, fruit, nuts, and milk.
- Exacerbation of air quality problems. If temperatures rise to the medium warming range, there could be 75 to 85% more days with weather conducive to ozone formation in Los Angeles and the San Joaquin Valley, relative to today's conditions. This is more than twice the increase expected if rising temperatures remain in the lower warming range. This increase in air quality problems could result in an increase in asthma and other health-related problems.
- A decrease in the health and productivity of California's forests. Climate change can cause an increase in wildfires, an enhanced insect population, and establishment of non-native species.
- Increased electricity demand, particularly in the hot summer months.
- Increased ground-level ozone formation due to higher reaction rates of ozone precursors.

3.4.3 Global Climate Change Regulatory Issues

In 1988, the United Nations established the Intergovernmental Panel on Climate Change to evaluate the impacts of global warming and to develop strategies that nations could implement to curtail global climate change. In 1992, the United Nations Framework Convention on Climate Change established an agreement with the goal of controlling GHG emissions, including methane. As a result, the Climate Change Action Plan was developed to address the reduction of GHGs in the United States. The plan consists of more than 50 voluntary programs. Additionally, the Montreal Protocol was originally signed in 1987 and substantially amended in 1990 and 1992. The Montreal Protocol stipulates that the production and consumption of compounds that deplete O_3 in the stratosphere (chlorofluorocarbons [CFCs], halons, carbon tetrachloride, and methyl chloroform) were phased out by 2000 (methyl chloroform was phased out by 2005).

On September 27, 2006, Assembly Bill 32 (AB32), the California Global Warming Solutions Act of 2006 (the Act) was enacted by the State of California. The legislature stated, "Global warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California." The Act caps California's GHG emissions at 1990 levels by 2020. The Act defines GHG emissions as all of the following gases: carbon dioxide (CO_2), methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. This agreement represents the first enforceable statewide program in the U.S. to cap all GHG emissions from major industries that includes penalties for non-compliance. While acknowledging that national

and international actions will be necessary to fully address the issue of global warming, AB32 lays out a program to inventory and reduce GHG emissions in California and from power generation facilities located outside the state that serve California residents and businesses.

AB32 charges CARB with responsibility to monitor and regulate sources of GHG emissions in order to reduce those emissions. CARB has adopted a list of discrete early action measures that can be implemented to reduce GHG emissions. CARB has defined the 1990 baseline emissions for California and has adopted that baseline as the 2020 statewide emissions cap. CARB is conducting rulemaking for reducing GHG emissions to achieve the emissions cap by 2020. In designing emission reduction measures, CARB must aim to minimize costs, maximize benefits, improve, and modernize California's energy infrastructure, maintain electric system reliability, maximize additional environmental and economic co-benefits for California, and complement the state's efforts to improve air quality.

Subsequent legislation by the California legislature has included Senate Bill (SB) 32, which expanded upon AB32 to reduce GHG emissions to 40% below the 1990 levels by 2030; AB197 which increased the legislative oversight of the CARB by adding two legislatively appointed non-voting members to the CARB Board and provided additional protection to disadvantaged communities; SB350, which increased California's renewable energy electricity procurement goal and SB100, which established a landmark policy requiring renewable energy and zero-carbon resources to supply 100 percent of electrical retail sales to end use customers and 100 percent of electricity procured to serve state agencies by 2045.

Global warming and climate change have received substantial public attention for more than 20 years. For example, the United States Global Change Research Program was established by the Global Change Research Act of 1990 to enhance the understanding of natural and human-induced changes in the Earth's global environmental system, to monitor, understand, and predict global change, and to provide a sound scientific basis for national and international decision-making. Even so, the analytical tools have not been developed to determine the effect on worldwide global warming from a particular increase in GHG emissions, or the resulting effects on climate change in a particular locale. The scientific tools needed to evaluate the impacts that a specific project may have on the environment are even farther in the future.

The California Supreme Court's CEQA decision on the Newhall Ranch development case, Center for Biological v. California Department of Fish and Wildlife (November 30, 2015, Case No. 217763), determined that the project's Environmental Impact Report (EIR) did not substantiate the conclusion that the GHG cumulative impacts would be less than significant. The EIR determined that the Newhall Ranch development project would reduce GHG emissions by 31 percent from business as usual (BAU). This reduction was compared to California's target of reducing GHG emissions statewide by 29 percent from business as usual. The Court determined that "the EIR's deficiency stems from taking a quantitative comparison method developed by the Scoping Plan as a measure of the greenhouse gas reduction effort required by the state as a whole, and attempting to use that method, without adjustments, for a purpose very different from its original design." In the Court's final ruling it offered suggestions that were deemed appropriate use of the BAU methodology:

1. Lead agencies can use the comparison to BAU methodology if they determine what reduction a particular project must achieve in order to comply with statewide goals,
2. Project design features that comply with regulations to reduce emissions may demonstrate that those components of emissions are less than significant, and
3. Lead agencies could also demonstrate compliance with locally adopted climate plans or could apply specific numerical thresholds developed by some local agencies.

Kern County, the Lead CEQA agency for this Project, has not developed specific thresholds for GHGs. As discussed in **Section 4.1**, the SJVAPCD, a CEQA Trustee Agency for this Project, has developed thresholds

to determine significance of a proposed project – either implement Best Performance Standards or achieve a 29% reduction from BAU (a specific numerical threshold). However, the SJVAPCD has established their BAU and baseline emissions based on the years 2002-2004 and 2020, respectively. The 2020 projected baseline has passed, and at this time, no new guidance has been approved for determining BAU and projected baseline for the next target year. Therefore, the 29% reduction from BAU cannot be applied to the subject Project in order to determine significance. Additionally, a Best Performance Standards threshold has not been established. For this Project, however, there will be a net benefit for GHG emissions. Therefore, the GHG analysis for this Project follows the suggestions from the Court's ruling on the Newhall Ranch development project in order to determine significance using the Project's design features.

4. IMPACT ASSESSMENT

4.1 Significance Criteria

To determine whether a proposed Project could create a potential CEQA impact, local, State, and Federal agencies have developed various means by which a project's impacts may be measured and evaluated. Such means can generally be categorized as follows:

- Thresholds of significance adopted by air quality agencies to guide lead agencies in their evaluation of air quality impacts under the CEQA.
- Regulations established by air districts, CARB and EPA for the evaluation of stationary sources when applying for Authorities to Construct, Permits to Operate and other permit program requirements (e.g., New Source Review).
- Thresholds utilized to determine if a project would cause or contribute significantly to violations of the ambient air quality standards or other concentration-based limits.
- Regulations applied in areas where severe air quality problems exist.

Summary tables of these emission-based and concentration-based thresholds of significance for each pollutant are provided below along with a discussion of their applicability.

4.1.1 Thresholds Adopted for the Evaluation of Air Quality Impacts under CEQA

In order to maintain consistency with CEQA, the SJVAPCD (2015) adopted guidelines to assist applicants in complying with the various requirements. According to the SJVAPCD's GAMAQI, a project would have potentially significant air quality impacts when the project:

- Creates a conflict with or obstructs implementation of the applicable air quality plan;
- Causes a violation of any air quality standard or generates substantial contribution towards exceeding an existing or projected air quality standard;
- Results in a cumulatively considerable net increase of any criteria pollutant for which the project region is designated non-attainment under a NAAQS and CAAQS (including emissions which exceed quantitative thresholds for O_3 precursors);
- Exposes sensitive receptors to substantial pollutant concentrations; or
- Creates objectionable odors that affect a substantial number of people.

The SJVAPCD GAMAQI thresholds are designed to implement the general criteria for air quality emissions as required in the CEQA Guidelines, Appendix G, Paragraph III (Title 14 of the California Code of Regulations §15064.7) and CEQA (California Public Resources Code Sections 21000 et. al). SJVAPCD's specific CEQA air quality thresholds are presented in **Table 4-1**.

Table 4-1. SJVAPCD CEQA Thresholds of Significance

Criteria Pollutant	Significance Level	
	Construction	Operational
CO	100 tons/yr	100 tons/yr
NOx	10 tons/yr	10 tons/yr
ROG	10 tons/yr	10 tons/yr
SOx	27 tons/yr	27 tons/yr
PM_{10}	15 tons/yr	15 tons/yr
$PM_{2.5}$	15 tons/yr	15 tons/yr
Source: SJVAPCD 2015		

4.1.2 Thresholds for Ambient Air Quality Impacts

CEQA Guidelines – Appendix G (Environmental Checklist) states that a project that would "violate any air quality standard or contribute substantially to an existing or projected air quality violation" would be considered to create significant impacts on air quality. Therefore, an AQIA should determine whether the emissions from a project would cause or contribute significantly to violations of the NAAQS or CAAQS (presented above in **Table 3-1**) when added to existing ambient concentrations.

The EPA has established the Federal Prevention of Significant Deterioration (PSD) program to determine what comprises "significant impact levels" (SIL) to NAAQS attainment areas. A project's impacts are considered less than significant if emissions are below PSD SIL for a particular pollutant. When a SIL is exceeded, an additional "increment analysis" is required. As the Project would include modification to a stationary source under new source review (NSR), it would be subject to either PSD or NSR review. The PSD SIL thresholds are used with ambient air quality modeling for a CEQA project to address whether the Project would "violate any air quality standard or contribute substantially to an existing or projected air quality violation." Ambient air quality emissions estimates below the PSD SIL thresholds would result in less than significant ambient air quality impacts for both a project and cumulative CEQA impact analysis. The SJVAB is classified as non-attainment for the O_3 NAAQS and, as such, is subject to "non-attainment new source review". PSD SILs and increments are more stringent than the CAAQS or NAAQS and represent the most stringent thresholds of significance.

4.1.3 Thresholds for Hazardous Air Pollutants

The SJVAPCD's GAMAQI states, "From a health risk perspective there are basically two types of land use projects that have the potential to cause long-term public health risk impacts:

- Type A Projects: Land use projects that will place new toxic sources in the vicinity of existing receptors, and
- Type B Projects: Land use projects that will place new receptors in the vicinity of existing toxics sources" (SJVAPCD 2015).

Since, the Project is a Type A project a health risk analysis will be required. **Table 4-2**Table 4-2 presents the thresholds of significance used with toxic air contaminants when evaluating hazardous air pollutants (HAPs).

Table 4-2. Measures of Significance - Toxic Air Contaminants

Agency	Level	Description
Significance Thresholds Adopted for the Evaluation of Impacts Under CEQA		
SJVAPCD	Carcinogens	Maximally Exposed Individual risk **equals or exceeds** 20 in one million.
	Non-Carcinogens	**Acute**: Hazard Index **equals or exceeds** 1 for the Maximally Exposed Individual.
		Chronic: Hazard Index **equals or exceeds** 1 for the Maximally Exposed Individual.
Source: SJVAPCD 2015		

4.1.4 Cumulative Impacts Threshold of Significance

Attachment A of Kern County's Guidelines for Preparing an Air Quality Assessment for Use in Environmental Impact Reports states "the following threshold are defined for purposes of determining cumulative effects as the baseline for "considerable". "Projects in the San Joaquin Valley Air Pollution Control District...will be subject to the following significance thresholds". The thresholds outlined in the guidelines mirror the individual project

significance thresholds of 15 tons per year for PM_{10} and 10 tons per year for NO_X and ROG. Therefore, owing to the inherently cumulative nature of air quality impacts, the threshold for whether a project would make a cumulatively considerable contribution to a significant cumulative impact is simply whether the project would exceed project-level thresholds.

4.1.5 Global Climate Change Thresholds of Significance

On December 17, 2009, SJVAPCD adopted Guidance for Valley Land-use Agencies in Addressing GHG Emission Impacts for New Projects under CEQA (SJVAPCD 2009); which outlined the SJVAPCD's methodology for assessing a project's significance for GHGs under CEQA. The following criteria was outlined in the document to determine whether a project could have a significant impact:

- Projects determined to be exempt from the requirements of CEQA would be determined to have a less than significant individual and cumulative impact for GHG emissions and would not require further environmental review, including analysis of project specific GHG emissions. Projects exempt under CEQA would be evaluated consistent with established rules and regulations governing project approval and would not be required to implement Best Performance Standards (BPS).
- Projects complying with an approved GHG emission reduction plan or GHG mitigation program which avoids or substantially reduces GHG emissions within the geographic area in which the project is located would be determined to have a less than significant individual and cumulative impact for GHG emissions. Such plans or programs must be specified in law or approved by the lead agency with jurisdiction over the affected resource and supported by a CEQA compliant environmental review document adopted by the lead agency. Projects complying with an approved GHG emission reduction plan or GHG mitigation program would not be required to implement BPS.
- Projects implementing Best Performance Standards would not require quantification of project specific GHG emissions. Consistent with CEQA Guidelines, such projects would be determined to have a less than significant individual and cumulative impact for GHG emissions.
- Projects not implementing Best Performance Standards would require quantification of project specific GHG emissions and demonstration that project specific GHG emissions would be reduced or mitigated by at least 29%, compared to Business-as-Usual (BAU), including GHG emission reductions achieved since the 2002-2004 baseline period. Projects achieving at least a 29% GHG emission reduction compared to BAU would be determined to have a less than significant individual and cumulative impact for GHG.
- Notwithstanding any of the above provisions, projects requiring preparation of an Environmental Impact Report for any other reason would require quantification of project specific GHG emissions. Projects implementing BPS or achieving at least a 29% GHG emission reduction compared to BAU would be determined to have a less than significant individual and cumulative impact for GHG.

4.2 Project Related Emissions

This document was prepared pursuant to the SJVAPCD's GAMAQI. The GAMAQI identifies separate thresholds for a project's short-term (construction) and long-term (operational) emissions.

Project emissions were estimated for the following project development stages:

- Short-term (Construction and Demolition) – Construction emissions of the proposed Project were estimated in CalEEMod based on estimated construction schedule, equipment and manpower provided by Aera Energy.
- Long-term (Operations) – Long term emissions were also estimated in CalEEMod, EMFAC2021, TanksESP, AP-42 Emission Factors, manufacturer guaranteed emission factors, and San Joaquin Valley Air Pollution Control District Permit to Operate Emission Factors.

4.2.1 Short-Term Emissions

The CalEEMod equipment list was updated to reflect the list of proposed construction equipment that was provided by Aera Energy. Applying model defaults as well as a conservative analysis approach, construction emissions were estimated according to the supplied construction schedule starting in 2025. Anticipated construction equipment and schedules can be found in **Appendix B**. The dates entered into the CalEEMod program may not represent the actual dates the equipment will operate; however, the total construction time is accurate, and therefore, all estimated emission totals are conservative and reflect a reasonable and legally sufficient estimate of potential impacts. All construction equipment activity assumption levels were based on the specified CalEEMod default values for equipment horsepower, load factors and hours per day.

CO_2 capture facility and infrastructure construction would occur over a period of approximately three years, starting with the Pre-C facility construction at GP 32. Sequential construction would occur for construction of the Post-C facilities located at COGEN 32 and the two SGSs. Injection well pad construction, drilling and plugging and abandonment activities, and pipeline construction activities would begin concurrently with the start of facility construction. Installation of CO_2 distribution pipelines, intra-field electrical distribution, and well hookups would occur throughout the three-year period.

Demolition

The proposed CO_2 capture facility areas currently contain piping and other idle equipment that would be removed, and wells that would be permanently abandoned, prior to construction of the proposed facilities. There is some debris from former operations, such as broken concrete, in scattered locations throughout the Project site. Debris would be reused or recycled to the extent feasible. Five shipping pumps, two water tanks, two electrical transformers, a water heater, an electrical panel, and one moisture separator would be removed or demolished on the land north of GP 32; all equipment is out of service. Demolition of various oil production facilities (old pipelines) and equipment (a production header) would occur on approximately nine acres of land around SGS 2868. Miscellaneous rubble piles would also be cleared. Demolition of various oil production facilities (including old foundations and pipelines) and equipment would occur on approximately 16 acres of land in areas around SGS 2972.

The proposed CO_2 capture facility areas also contain abandoned structures that would be demolished prior to construction of the proposed facilities. Demolition of a sulfur treatment facility, maintenance shed, old equipment yard, and a building would occur on approximately 1.5 acres of land at GP 32. The to-be-demolished building holds a former Control Room, Lab, Conference Room, and associated offices. The old equipment yard currently stores three gas compressors and five cylindrical gas tanks, which would be relocated prior to demolition. One storage building would be demolished on the land northeast of GP 32.

Grading

The Project would require minor grading of the proposed CO_2 capture facility sites, totaling approximately 40 acres, most of which is previously disturbed area. The Project would maximize the use of existing roads, well pads, and cleared areas wherever possible. Proposed cut and fill volumes are approximately 203,000, cubic yards total. Well pads would be approximately 145 feet by 280 feet in area. Each well pad would be cleared of vegetation and leveled to prepare it for well drilling. Excess soils would be transported to a designated fill location within the Project site for re-use as fill material or moved off-site to an appropriate soils disposal or reuse facility.

Additional ground disturbance would occur for construction of the utilities component of the Project, as a result for the water pipelines and overhead power lines. The estimated disturbance from the Project pipelines

would be minimized as most would be located aboveground, placed on existing and new pipe supports and along existing pipeline corridors. The estimated ground disturbance for the 115 kV and 12 kV power lines would be approximately 2.1 acres.

Well Pads and Roadways

Well locations have been carefully selected to minimize disturbance by reusing existing well pads, where feasible, and to allow for the permanent CO_2 sequestration within the dedicated zone. Well pads have been designed to minimize the amount of surface disturbance while meeting the technical constraints of drilling and operating the wells. Areas within the designated well pad area would be cleared of all vegetation and other deleterious material utilizing heavy equipment. The proposed wells would be constructed on existing well pads; however, these pads may need to be cleared of encroaching vegetation or enlarged to meet Project requirements. Earthwork would be completed utilizing conventional equipment (e.g., dozers, loaders, scrapers, motor graders, excavators, sheep's foot compactors, smooth drum rollers, water trucks. etc.). Well pad prep emissions are captured under the total emissions of all oil and gas activities on a per well basis calculated in Section 4.2.3 below and therefore not calculated in this section.

Drilling

Drilling rigs would operate 24 hours per day while drilling, and depending on the type of well, would operate consecutively for up to 14 days at each location. The specific rig has not been determined at this time, but the rig will be the equivalent to Kenai #18.

Kenai #18 is 279 feet long and 145 feet wide with a footprint of approximately 33,500 square feet. The rig has a 121-foot-tall mast which sits on the drill rig floor. However, Kenai #18 has a 750,000-pound static hook load capacity, which exceeds Aera Energy's standard currently used for drilling in the San Joaquin Valley.

Since a larger rig footprint may be required as the Project develops, Aera Energy is planning to utilize the larger rig (Kenai #18 or equivalent). Additional drilling equipment for either rig would include the following: fluid handling equipment, waste storage containers, four generators, mud handling system, blow out prevention equipment, spill prevention equipment, hydrogen sulfide detection equipment, three mud pumps, cuttings bin, catwalk, trailer (also referred to as "doghouse") and others. Note, the equipment listed is for a typical drilling operation, the exact equipment list and layout may vary depending on the specific well to be drilled. Well drilling emissions are captured under the total emissions of all oil and gas activities on a per well basis calculated in Section 4.2.3 below and therefore not calculated in this section.

Facilities Construction

The following outlines construction procedures associated with grading and installation of the processing facilities in consecutive order:

- *Staging*. Material and equipment would be gathered on-site;
- *Inspection*. Material and equipment would be inspected for quality assurance. Construction equipment would be verified to meet applicable environmental regulations. Equipment operators and field workers would be verified to possess the proper qualifications;
- *Civil*. Soil would be graded and excavated. Concrete equipment foundations, pipe supports, pads and containment would be poured;

- *Equipment*. Major vessels and equipment would be set on foundations;
- *Supports*. Pipe supports would be installed;
- *Plant Piping*. Piping, valves, and instrumentation would be installed between equipment and vessels. Welds would be radiographed and connections strength tested;
- *Electrical.* Electrical panels, conduit, and power wiring would be installed;
- *Instrumentation*. Instrumentation signal wiring and tubing would be installed. Terminations would be made at the instrumentation and connections would be tested;
- *Corrosion Control*. Piping and non-galvanized structural steel would either be insulated or primed and painted. Buried steel piping would be coated or wrapped with protective coatings. Cathodic protection may be used in certain areas to protect buried steel piping from external corrosion. Insulating kits would be used to protect buried steel piping from external corrosion. Insulating kits would be used to isolate above-ground from buried piping;
- *Start-Up Preparation*. All valves and instrumentation would be put in normal operating positions/modes for start-up. All safety devices would be checked for proper operation;
- *Personnel Training*. Operators, mechanics, and instrument mechanics would be trained to operate and maintain the facilities;
- *Start-Up*. Plant would be started and tested for proper operation. Any problems or issues would be resolved; and
- *Operation.* Normal operation would commence.

Main Pipeline Construction

Construction and installation of the CO_2 pipeline would be primarily aboveground, resting either on existing pipe supports or new supports. At designated internal road crossings, the pipeline would be installed by conventional trenching.

The sequence of construction activities for the CO_2 pipeline component of the Project is summarized below. Construction of the CO_2 pipeline is scheduled to take approximately six months.

- *Mobilization and Staging.* Prior to construction, the contractor would mobilize the site and establish staging areas for materials and equipment storage. Construction equipment would be staged along the route and would progress with the pipe installation.
- *Surveying, Staking and Flagging.* The centerline would be marked at line-of-sight intervals, at points of intersection (including offset stakes marking the edges of the right-of-way, and at all known underground facilities. In addition, any environmentally sensitive areas (i.e., biological, cultural, and/or hydrological resources) would be clearly marked.
- *Clearing and Grading.* The majority of the temporary construction easement occurs along the previously disturbed pipeline corridors. Where necessary, existing vegetation would be cleared and

the ground within the construction right-of-way would be graded and smooth to provide safe and efficient operation of construction equipment.

- *Hauling and Stringing.* The pipe would be hauled by truck to one of the staging areas where it would be offloaded by cranes and loaded onto stringing trucks to be delivered to the construction right-of-way.

- *Pipe Supports.* Pipe supports would be constructed at approximately 20-foot to 30-foot intervals along the pipeline, as needed. A truck-mounted drill would be used to auger a 24-inch to 36-inch diameter hole approximately six to eight feet deep. The pre-fabricated steel, or alternate, pipe support would be set into the hole and the hole would then be filled with concrete.

- *Trenching.* The typical trench would be approximately five feet deep and between two and five feet wide. Excavated soils may be preserved and used as backfill materials at the site of origin. Spoil piles would be placed along the trench in areas where a temporary construction easement is available. Materials deemed unsuitable for backfill would be disposed of off-site and/or transported to Aera Energy's Belridge road-mix facility for re-use in accordance with all applicable regulations.

- *Jack-and-Bore.* Jack-and-bore tunneling would be utilized at road crossings, where required. This methodology is used for horizontal pipeline construction and entails the excavation of pits on either side of the crossing and use of a boring machine with a cutting 'head', auger, and casing. The auger and casing are pushed behind the 'head' as it cuts through the ground. The auger carries the debris back to the pit as the head cuts. Jack-and-bore horizontal tunneling is anticipated to take approximately 10 days to complete at each location. Additional locations may be added based on circumstances that are unknown at this time, such as utility conflicts or requirements imposed by the County or Caltrans. Typical horizontal bores are 10 feet deep and require entry pits of approximately 15 feet by 40 feet and receiving pits of approximately 10 feet by 15 feet. In any location where Jack and Bore is used, there is only one entry pit and one exit pit.

- *Pipe Placement, Welding and Coating.* New pipeline segments would be inspected to locate and repair any faults or voids in the pipeline coating prior to being lowered into the trench. In areas where the pipe is joined within the ditch, "bell holes" would be dug at each pipe joint to facilitate access for welding and joint coating application. These welds would typically be made in the ditch, with the pipe at its final elevation and alignment. Welding and Coating would apply to all areas throughout the Project.

- *Weld Inspection.* All welds would be inspected in accordance with state and federal welding requirements. When inspected radiographically, all radiographs would be recorded and interpreted for acceptability in accordance with American Petroleum Institute 1104. All rejected welds would be repaired or replaced as necessary and re-radiographed. The inspection reports would be kept for the life of the pipeline.

- *Line Lowering, Backfill and Compaction.* For conventional open trench segments, the welded pipe segments or individual pipe lengths would be lifted and lowered into the trench by side boom tractors. The native material excavated from the pipeline trench would either be reused as backfill, transported to Aera Energy's Belridge road-mix facility, or would be hauled and disposed off-site to at an approved landfill facility. Required backfill material would be compacted with compaction rollers and/or hydraulic tampers and undergo compaction testing to ensure that all trench locations

are compacted in accordance with standard engineering practices and permit requirements. All trenches would either be fenced, backfilled, or covered with steel plates at the end of each workday.

- *Aboveground Equipment Installation.* The majority of aboveground equipment would be pre-fabricated at a staging area and then transported to the respective locations for final assembly and tie-in to the pipeline facilities. Valve and meter set assembly locations would be either paved or graveled.

- *Hydrostatic Testing.* In accordance with the applicable codes and regulations, the pipeline would undergo hydrostatic testing prior to operation by pumping water into the test sections, pressurized to design-test pressure, and maintained that pressure for a minimum amount of time to identify defects in construction. Water to be used for hydrotest will be from local water systems. Discharged water will be stored into temporary tanks and held for testing. After results of the samples are analyzed, the water may be used for dust control at the project site or used for additional testing on other pipeline segments. The Storm Water Protection and Prevention Plan prepared by Aera Energy would also include Best Management Practices in case the hydrotest is not successful initially.

- *Pigging.* Pipeline pigs are devices that are inserted into and travel throughout the length of a pipeline driven by a product flow to perform functions, such as cleaning or dewatering and provide information on the condition of the line, as well as the extent and location of any problems. After the pipeline has been hydrostatically tested and dewatered, the contractor would run several utility pigs of various types to remove as much water as possible and any remaining small debris from within the pipeline.

- *Cleanup and Restoration.* All construction material and debris would be removed and disposed of at appropriate landfills or recycled. Clean up and restoration would be ongoing throughout the project and when an active site is completed, the area shall be restored to surface grade. In upland areas, the right-of-way would be regraded to its approximate pre-construction contour and stabilized or restored to pre-construction conditions, in compliance with all relevant permits. All staging areas and temporary extra workspaces would be recontoured to pre-construction conditions and would be stabilized or restored in accordance with all relevant permits. All asphalt repairs would be made in accordance with the current County requirements. As a final step, the route within unpaved portions of the roadway shoulder or private right-of-way would be marked with approximately five-foot-high pipeline markers placed in accordance with PHMSA standards.

- *Operations and Maintenance.* Maintenance of pipeline and auxiliary facilities would continue to be performed as required by state and federal requirements.

Intra-Field Pipelines

The field gathering and distribution system would be designed to locate pipeline corridors primarily along existing pipeline corridors on raised pipe supports to minimize external corrosion. The sequence of general construction procedures associated with the installation of intra-field pipelines would be similar to the CO_2 pipeline construction described above and would follow the process listed below:

- Mobilization and Staging;

- Surveying, Staking and Flagging;

- Clearing and Grading;
- Hauling and Stringing;
- Pipe Placement, Welding, Inspection, and Coating; and
- Pipeline Installation and Testing.

Intra-Field Electrical Distribution

The intra-field electrical distribution system would be constructed concurrently with injection well drilling, re-purposing, and CO_2 capture facility construction. Once poles are erected, the conductor would be strung from conductor pull and tension sites at the end of the power line interconnection alignment moving from one pole to the next. Each conductor would be pulled into place at a pre-calculated sag and then tension-clamped to the end of each insulator. The sheaves and vibration dampers and accessories would be removed once installation is complete.

Transmission Power Line Construction

Aera Energy would construct, operate, and maintain approximately 1.26-miles of new 115-kV transmission lines to the Aera Energy-owned substations located at the Project site. The estimated permanent disturbance of the 115 kV electrical interconnection would be two acres with four acres of temporary disturbance. To support the major construction efforts, electrical connections are anticipated to be in place prior to significant field activities. Additional improvements to off-site PG&E substations may also be necessary; however, those potential improvements have not been specified at this time.

Primary access to the power line interconnection sites would be using existing access roads. Construction of the power line interconnection would be completed by the designated contractor. The new wood poles would require approximately six to eight feet of embedment. Construction would involve temporary ground disturbance around each new power pole location (approximately a 50-foot radius) as well as temporary ground disturbance associated with access to each pole location (approximately a 15-foot-wide access route). All new poles and access thereto would be located within existing oil field production areas or along a dirt road. Pole work areas would likely be located approximately every 400 feet for 115kV lines, and 200 feet for 12kV lines. Where final design allows, power pole work areas would overlap. Final design would determine final power pole locations. Temporary staging and lay down areas may also be needed for the construction of the interconnection facilities but would primarily use existing disturbed/developed areas.

Substations. Two new substations will be constructed near the proposed CO_2 capture facilities. Each substation would require approximately 1 acre.

Power Line Removal/Construction. The 6,840 feet of new 115 kV power lines would be supported by up to approximately 17 wooden poles. The approximately 13,000 feet of new 12kV overhead distribution power lines would be supported by 65 wooden poles. The wooden poles would be embedded approximately six feet deep.

Pole installation would consist of the following basic steps:

- Deliver new pole at pole site;
- Auger new hole using line truck attachment or hand dig if the line truck cannot access the site;

- Backfill around the pole;
- Install bottom section by line truck, crane;
- Install top section by line truck, crane; and
- Install switches where necessary. There may be several SCADA-operable or other switches at the point of interconnection and elsewhere.

Once poles are erected, conductor would be strung from conductor pull and tension sites at the end of the power line interconnection alignment. The average distance is 4,000 feet between pull and tension sites. Each conductor would be pulled into place at a pre-calculated sag and then tension-clamped to the end of each insulator. The sheaves and vibration dampers and accessories would be removed once installation is complete.

Transmission Power Line construction and substation improvements are anticipated to take approximately six months.

SJVAPCD's required construction site measures for all projects were also applied:

- Water exposed areas 3 times per day; and
- Reduce vehicle speed to less than 15 miles per hour.

Table 4-3 presents the Project's short-term emissions based on the anticipated construction period.

Table 4-3. Short-Term Project Emissions

Emissions Source	Pollutant (tons/year)					
	ROG	NO_X	CO	SO_2	PM_{10}	$PM_{2.5}$
Year 2025 - Total	**6.75**	**50.41**	**45.99**	**0.09**	**4.14**	**3.03**
On-Site Roads	*0.09*	*0.30*	*0.22*	*0.00*	*0.01*	*0.01*
Facilities Pad Grading - GP32	*0.06*	*0.56*	*0.47*	*0.00*	*0.07*	*0.04*
Facilities Pad Grading - 32 Cogen	*0.06*	*0.56*	*0.47*	*0.00*	*0.07*	*0.04*
Facilities Pad Grading - SGS2868	*0.06*	*0.56*	*0.47*	*0.00*	*0.07*	*0.04*
Facilities Pad Grading – SGS2972	*0.06*	*0.56*	*0.47*	*0.00*	*0.07*	*0.04*
GP32 - CO2 Capture Facility	*1.18*	*8.36*	*7.41*	*0.01*	*0.72*	*0.53*
32 Cogen - CO2 Capture Facility	*1.97*	*13.91*	*12.34*	*0.02*	*1.20*	*0.88*
SGS2868 - CO2 Capture Facility	*0.67*	*4.74*	*4.21*	*0.01*	*0.41*	*0.30*
Compressor Station Construction	*0.29*	*2.00*	*1.78*	*0.00*	*0.16*	*0.12*
CO2 Main Pipeline	*0.91*	*7.50*	*7.02*	*0.01*	*0.53*	*0.40*
Distribution Pipelines	*0.62*	*4.78*	*4.87*	*0.01*	*0.38*	*0.29*
Elec Transmission Lines	*0.11*	*1.05*	*0.74*	*0.00*	*0.05*	*0.04*
Onsite Electrical Substations	*0.17*	*1.53*	*1.54*	*0.00*	*0.11*	*0.08*
Water Pipelines	*0.16*	*1.29*	*1.28*	*0.00*	*0.10*	*0.07*
Tulare CVR Gas Pipeline	*0.11*	*0.89*	*0.88*	*0.00*	*0.07*	*0.05*
Steam Pipelines	*0.16*	*1.31*	*1.29*	*0.00*	*0.10*	*0.07*
Demolition	*0.06*	*0.52*	*0.54*	*0.00*	*0.03*	*0.02*
Year 2026 - Total	**9.37**	**66.94**	**59.54**	**0.12**	**5.75**	**4.20**
Facilities Pad Grading - SGS2972	*0.06*	*0.56*	*0.47*	*0.00*	*0.07*	*0.04*
GP32 - CO2 Capture Facility	*2.30*	*16.24*	*14.41*	*0.03*	*1.41*	*1.03*
32 Cogen - CO2 Capture Facility	*2.30*	*16.24*	*14.41*	*0.03*	*1.41*	*1.03*
SGS2868 - CO2 Capture Facility	*2.30*	*16.24*	*14.41*	*0.03*	*1.41*	*1.03*
SGS2972 - CO2 Capture Facility	*1.86*	*13.13*	*11.64*	*0.02*	*1.14*	*0.83*
CO2 Main Pipeline	*0.44*	*3.51*	*3.43*	*0.01*	*0.25*	*0.19*
Intra-Field Electrical Distribution	*0.11*	*1.03*	*0.78*	*0.00*	*0.05*	*0.04*
Year 2027 - Total	**4.89**	**34.44**	**30.44**	**0.06**	**3.03**	**2.18**
GP32 - CO2 Capture Facility	*0.95*	*6.73*	*5.95*	*0.01*	*0.59*	*0.43*
32 Cogen - CO2 Capture Facility	*0.18*	*1.28*	*1.13*	*0.00*	*0.11*	*0.08*
SGS2868 - CO2 Capture Facility	*1.46*	*10.27*	*9.08*	*0.02*	*0.90*	*0.65*
SGS2972 - CO2 Capture Facility	*2.29*	*16.16*	*14.28*	*0.03*	*1.42*	*1.02*
Year 2028 - Total	**0.21**	**1.58**	**1.57**	**0.00**	**0.14**	**0.09**
SGS2972 - CO2 Capture Facility	*0.21*	*1.58*	*1.57*	*0.00*	*0.14*	*0.09*

Source: Trinity Consultants 2023

4.2.2 Long-Term Operations Emissions

Long-term emissions are caused by operational mobile, area, and energy sources. Long-term emissions would consist of the following components:

4.2.2.1 Fugitive Dust Emissions

Operation of the Project site at full build-out is not expected to present a substantial source of fugitive dust (PM_{10}) emissions. The main source of PM_{10} emissions would be from vehicular traffic associated with the Project site.

PM_{10}, on its own as well as in combination with other pollutants, creates a health hazard. The SJVAPCD's Regulation VIII establishes required controls to reduce and minimizing fugitive dust emissions. The following SJVAPCD Rules and Regulations apply to the proposed Project (and all projects):

- Rule 4102 - Nuisance
- Regulation VIII – Fugitive PM10 Prohibitions
  - Rule 8011 - General Requirements
  - Rule 8021 - Construction, Demolition, Excavation, Extraction, and Other Earthmoving Activities
  - Rule 8041 - Carryout and Trackout
  - Rule 8051 - Open Areas

The Project would comply with applicable SJVAPCD Rules and Regulations, the local zoning codes, and additional emissions reduction measures recommended later in this analysis, in Section 7, Mitigation and Other Recommended Measures.

4.2.2.2 Mobile Source Exhaust Emissions

Project-related transportation activities from employees and various other oil and gas operations would generate mobile source ROG, NOx, SOx, CO, PM_{10}, and $PM_{2.5}$ exhaust emissions. Exhaust emissions would vary substantially from day to day but would average out over the course of an operational year. The Traffic Impact Study (Stantec 2023) analyzed the potential for operational vehicular traffic from the operations and maintenance of the compression and pumping facility. The traffic study estimated 25 average daily trips (ADT) from worker vehicles.

Operational Mobile Source Assumptions:

- Baseline has 25 dedicated workers making 50 ADTs per day.
- Project includes an additional 10 workers making 25 ADTs (per traffic study).
- 50-mile trip distance.
- EMFAC2021 v1.0.2 was used to estimate mobile source emission.
  - County: Kern
  - Calendar Year: Baseline 2022, Post-Project 2026
  - Season: Annual
  - Vehicle Category: EMFAC202x (LDA, LDT1 and LDT2)
  - Model Year: Aggregate
  - Speed: Aggregate
  - Fuel: Gasoline

Table 4-4. Baseline Mobile Source (Operational) Exhaust Emissions

Emissions Source	Pollutant (tons/year)					
	ROG	NOX	CO	SOX	PM_{10}	$PM_{2.5}$
Baseline Mobile Emissions	0.025	0.127	1.434	0.003	0.017	0.017
Source: Trinity Consultants 2023						

Table 4-5. Mobile Source (Operational) Exhaust Emissions Increase

Emissions Source	Pollutant (tons/year)					
	ROG	NOX	CO	SOX	PM_{10}	$PM_{2.5}$
Project Mobile Emissions Increase	0.008	0.040	0.515	0.002	0.008	0.003
Source: Trinity Consultants 2023						

4.2.2.3 Stationary Source Emissions

Proposed CO_2 capture facilities include the separation, dehydration, compression, and cooling of CO_2 from both pre-combustion (Pre-C) produced gas stream and from post-combustion (Post-C) flue gas. A general discussion of each facility is presented below.

Pre-Combustion

The Pre-C carbon capture facility would treat produced gas from the Diatomite and Tulare formations. Gas produced from the Tulare Formation is not currently processed at Gas Plant 32. To capture CO_2 from this gas stream, a combination of new and existing pipelines will be used to deliver the Tulare gas stream to the Pre-C capture facility located at GP 32. Two transport route alternatives are described below.

Del Sur to GP 32 Line. Gas produced from the Tulare Formation via existing oil wells within South Belridge would be transported, via an existing 16-inch diameter 3.3-mile long pipeline operating at approximately 150 pounds per square inch gauge. It is known as the Wet Gas Del Sur pipeline to GP 32. The Tulare gas stream would need to go through the Del Sur Compressor Station to increase pressure before being transported to GP 32, which would require a "jumper" pipeline to be constructed. The new jumper pipeline would be approximately 200 feet long. One existing idle compressor at the Del Sur Compressor Station would be put back in service to accommodate the Tulare gas. The Del Sur compressors would also be upgraded with new materials/trim for corrosion resistance.

Tulare CVR to GP 32 Pipeline. Alternatively, gas produced from the Tulare Formation via existing oil wells within South Belridge will be transported via a new 12- to 16-inch diameter 3.5-mile pipeline constructed primarily aboveground from the SOX 2-3 facility east of SR 33 to the SOX 3-2 facility, then to GP 32. The proposed pipeline will be constructed aboveground on pipe supports over most of its length. The pipeline will cross SR 33 and Seventh Standard Road using horizontal boring techniques. Alternatively, the produced gas may be commingled in existing gas pipelines along the pipeline route.

GP 32. The Tulare gas stream would first be treated to remove sulfur through one of two alternative methods: 1) treatment at the existing SOX Plants 3-2 and 2-3 or 2) the gas would be treated at the existing SOX Plant within the GP 32. CO_2 would be removed from the combined produced gas stream (Tulare and Diatomite production) using a physical solvent or traditional amine absorption process or equivalent. Aera Energy has not yet selected a specific amine solution vendor. The facility will include three steel towers of varying height, but none taller than 120-feet in height and between 2 to 12 feet in diameter. Supporting this facility will be several heat exchangers, transfer pumps, compressors, and storage area for make-up chemicals. Additionally, a 1.45 mile aboveground gas pipeline between GP 32 and SGS 2868 has been included in the project to consolidate produced gas use at the SGS 2972 and SGS 2868 capture facilities.

Post-Combustion

Post-C facilities would be constructed at three existing facilities within the South Belridge Oil Field: COGEN 32, SGS 2868, and SGS 2972. Flue gas from each Post-C source would be ducted to dedicated CO_2 capture

facilities. CO_2 would be captured using an amine absorption process or equivalent process. The concentrated CO_2 would then be compressed, dehydrated, and stripped of oxygen.

Similar to Pre-C facility, each Post-C facility will include three main towers of varying height, but none taller than 140-feet in height and between 16 to 37 feet in diameter. The towers may be split into parallel trains of smaller diameter. Supporting this facility will be several heat exchangers, transfer pumps, compressors, and storage area for make-up chemicals.

The Project will have stationary source emissions from dilute amine storage tanks, fresh amine storage tanks, sulfuric acid tanks, cooling towers, steam generators, and fugitive emissions from components. The permitted fugitive emissions are from valves, threads, flanges, and other components associated with the Project and has been estimated using the California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities. Tanks will have trace amounts of volatile organic compound (VOC) and will not be included in the criteria pollutant emissions summary below but will be included in the health risk assessment. Stationary source emission calculations can be found in **Appendix B**. **Table 4-6** summarizes the baseline emissions from existing facilities where the new carbon capture facilities will be located. **Table 4-7** summarizes the post-project permitted source emission increases from the existing facilities and the new carbon capture facilities.

Stationary Source Emissions Assumptions:

- Baseline Emissions used 2022 Annual Emissions Inventory for COGEN32, SGS 2868 and SGS 2972.
- Baseline Emissions used average emissions 2009-2016 Annual Emissions Inventory for GP32 in order to portray a fair representation of the baseline emissions of what the GP32 was operating at prior to being idled and what the facility will be operating at prior to the start of the current Project.
- The Del Sur Compressors will increase fuel usage by 100% with the implementation of the Project.
- A cooling tower will be added at each facility.
- Three utility steam generators will be added at each post-combustion facilities and two utility steam generators at the pre-combustion facility.
- The new carbon capture facilities with amine units will have additional fugitive emissions and were calculated using the California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities based on the component counts of all valves, pump seals, others, connectors, and flanges associated with these facilities.
- Existing natural gas turbines at COGEN32 will have increased fuel usage as a result of this Project (Fuel increases can be found in **Appendix B**).
- Existing steam generators at SGS 2868 and SGS 2972 will have increased fuel usage as a result of this Project, however, these increases will be offset by decreases at other existing steam generators at Belridge. (Fuel increases can be found in **Appendix B**) Additionally, these increases will continue to be less than the current permitted levels requiring no changes to the existing permits to operate. Therefore, increased emissions for these existing steam generators were not included for permitted emissions increases; however, these emissions will be included in the health risk assessment since the location of these emissions have changed.

Table 4-6. Baseline Project (Operational) Emissions

Emissions Source	Pollutant (tons/year)					
	ROG	NOX	CO	SOX	PM_{10}	$PM_{2.5}$
Pre-Combustion						
Gas Plant 32	5.63	2.99	20.43	0.54	0.44	0.44
Del Sur Compressors	0.25	0.12	1.04	0.08	0.01	0.01
Post-Combustion						
COGEN 32	19.80	9.16	630.08	24.75	39.60	39.60
SGS 2868	14.72	21.41	50.25	5.62	20.34	20.34
SGS 2972	9.14	22.88	56.36	6.40	22.20	22.20
Permitted Source Baseline	**49.54**	**56.56**	**758.16**	**37.39**	**82.59**	**82.59**
Source: Trinity Consultants 2023						

Table 4-7. Permitted (Operational) Emissions Increase

Emissions Source	Pollutant (tons/year)					
	ROG	NOX	CO	SOX	PM_{10}	$PM_{2.5}$
Cooling Tower – Pre-Combustion	-	-	-	-	0.39	0.39
New Cooling Tower – Cogen 32	-	-	-	-	3.22	3.22
New Cooling Tower – SGS 2972	-	-	-	-	2.80	2.80
New Cooling Tower – SGS 2868	-	-	-	-	2.52	2.52
Del Sur Compressors	0.25	0.12	1.04	0.08	0.01	0.01
New Steam Generators – Pre-C	3.13	3.47	10.69	5.69	4.33	4.33
Cogen 32	3.40	3.77	11.62	6.19	4.70	4.70
New Steam Generators – Cogen 32	5.35	5.93	18.26	9.72	7.39	7.39
New Steam Generators – SGS 2972	6.50	7.21	22.21	11.83	8.99	8.99
New Steam Generators – SGS 2868	5.85	6.49	19.99	10.64	8.09	8.09
Pre-Combustion Fugitive*	0.33	-	-	-	-	-
Cogen 32 Fugitive*	0.23	-	-	-	-	-
SGS 2972 Fugitive*	0.33	-	-	-	-	-
SGS 2868 Fugitive*	0.33	-	-	-	-	-
Permitted Source Increase	**38.6**	**41.3**	**127.83**	**67.60**	**60.25**	**60.25**
Source: Trinity Consultants 2023 *From new capture facility equipment.						

4.2.3 Total Emissions of All Oil and Gas Activities on a Per Well Basis

A suggested mitigation of the Project is to enter into a Voluntary Emission Reduction Agreement (VERA) to reduce the Project's impacts from NO_X, ROG, and PM_{10} net incremental emissions that are not addressed as conditions of SJVAPCD permitting to a no net increase over criteria pollutants that would otherwise exist without development of the Project. The Oil and Gas Emission Reduction Agreement (OG-ERA) is a required mitigation for new well permits under the Oil and Gas Conformity Review and Minor Activities Permit. One of the menu options to achieve the mandated emission reductions is to pay a calculated mitigation fee. The Kern County Planning Department has calculated total emissions of all oil and gas activities on a per well basis and is segmented into 1000 foot well depth increments. The VERA fee would be calculated based on the calculated emission tonnage for the total wells of the Project. **Table 4-12** list the Project's wells, well depths and associated total emissions (NO_X, ROG, and PM_{10}).

Table 4-8. Total Emissions on a Per Well Basis

Description	Depth (ft)	Emissions (Tons)
Injector	8,000-9,000	6.17
Injector	8,000-9,000	6.17
Injector	8,000-9,000	6.17
Injector	8,000-9,000	6.17
Injector	8,000-9,000	6.17
Injector	8,000-9,000	6.17
Injector	8,000-9,000	6.17
Injector	8,000-9,000	6.17
Injector	8,000-9,000	6.17
Monitoring	8,000-9,000	6.17
Monitoring	8,000-9,000	6.17
Monitoring	8,000-9,000	6.17
Monitoring	8,000-9,000	6.17
Monitoring	8,000-9,000	6.17
Monitoring	8,000-9,000	6.17
Monitoring	8,000-9,000	6.17
Monitoring	8,000-9,000	6.17
Monitoring	8,000-9,000	6.17
Total		**104.89**

4.3 Potential Impact on Sensitive Receptors

Sensitive receptors are defined as locations where young children, chronically ill individuals, the elderly or people who are more sensitive than the general population reside, such as schools, hospitals, nursing homes, and daycare centers. There are no known sensitive receptors within 2 miles of the Project site.

4.4 Potential Impacts to Visibility to Nearby Areas

Visibility impact analyses are intended for stationary sources of emissions which are subject to the Prevention of Significant Deterioration (PSD) requirements in 40 CFR Part 60; they are not usually conducted for area sources. Because the Project's PM_{10} emissions increase is predicted to be less than the PSD threshold levels, an impact at any Class 1 area or military/airspace operation within 100 kilometers of the Project (including San Rafael Wilderness, Domeland Wilderness, Edwards Air Force Base, China Lake Naval Weapons Station, and the entire R-2508 Airspace Complex) is extremely unlikely. Therefore, based on the Project's predicted less-than significant PM_{10} emissions after mitigation, the Project would be expected to have a less than significant impact to visibility at any Class 1 area or military/airspace operation.

4.5 Potential Impacts from Carbon Monoxide

Ambient CO concentrations normally correspond closely to the spatial and temporal distributions of vehicular traffic. Relatively high concentrations of CO would be expected along heavily traveled roads and near busy intersections. CO concentrations are also influenced by wind speed and atmospheric mixing. CO concentrations may be more uniformly distributed when inversion conditions are prevalent in the valley. Under certain meteorological conditions, CO concentrations along a congested roadway or intersection may reach unhealthful levels for sensitive receptors, e.g. children, the elderly, hospital patients, etc. This localized impact can result in elevated levels of CO, or "hotspots" even though concentrations at the closest air quality monitoring station may be below NAAQS and CAAQS.

The localized Project impacts depend on whether ambient CO levels in the Project vicinity would be above or below NAAQS. If ambient levels are below the standards, a project is considered to have significant impacts if a project's emissions exceed one or more of these standards. If ambient levels already exceed a state standard, a project's emissions are considered significant if they would increase one-hour CO concentrations by 10 ppm or more or eight-hour CO concentrations by 0.45 ppm or more. There are two criteria established by the SJVAPCD's GAMAQI by which CO "Hot Spot" modeling is required:

1. A traffic study for the project indicates that the Level of Service (LOS) on one or more streets or at one or more intersections in the project vicinity would be reduced to LOS E or F; or
2. A traffic study indicates that the project would substantially worsen an already existing LOS F on one or more streets or at one or more intersections in the project vicinity.

According to the traffic study (Stantec 2023) prepared for this Project existing Project roadway segments currently operate at an LOS B or better and would reach no worse than an LOS D during construction of the Project. Therefore, CO "Hotspot" Modeling was not required or conducted for this Project and no concentrated excessive CO emissions are expected to be caused once the proposed Project is completed.

4.6 Predicted Health Risk Impacts

GAMAQI recommends that Lead Agencies consider situations wherein a new or modified source of Hazardous Air Pollutants (HAPs) is proposed for a location near an existing residential area or other sensitive receptor when evaluating potential impacts related to Hazardous Air Pollutants (HAPs).

The proposed Project would result in emissions of HAPs of diesel particulate matter (DPM) from construction equipment exhaust and operational emissions from combustion emissions from steam generators, tanks emissions and particulate emissions from the cooling towers and would be located near existing residents and workers; therefore, an assessment of the potential risk to the population attributable to emissions of hazardous air pollutants from the proposed Project is required.

To predict the potential health risk to the population attributable to emissions of HAPs from the proposed Project, ambient air concentrations were predicted with dispersion modeling to arrive at a conservative estimate of increased individual carcinogenic risk that might occur as a result of continuous exposure over a 3-year construction timeline for the facilities and a 67-year lifetime for operational exposure. Similarly, predicted concentrations were used to calculate non-cancer chronic and acute hazard indices (HIs), which are the ratio of expected exposure to acceptable exposure. The basis for evaluating potential health risk is the identification of sources with increased HAPs.

Health risk is determined using the Hotspots Analysis and Reporting Program (HARP2) software distributed by the CARB; HARP2 requires peak 1-hour emission rates and annual-averaged emission rates for all pollutants for each modeling source (CARB 2015). Assumptions used to calculate the emission rates for the proposed Project are outlined below.

The most recent version of EPA's AMS/EPA Regulatory Model - AERMOD was used to predict the dispersion of emissions from the proposed Project. The analysis employed all of the regulatory default AERMOD model keyword parameters, including elevated terrain options.

For construction health impacts, diesel particulate matter emissions from diesel on-site construction equipment and HHD trucks from hauling and vendor trips were modeled as area sources for on-site construction activity on the property. Diesel particulate matter was calculated using CalEEMod for on-site

construction equipment. A unit emission rate of 1 grams/second (g/sec) was input to AERMOD for the area source.

For operational health impacts, combustion emissions from steam generators, tanks emissions and particulate emissions from the cooling towers were modeled as point sources. Cooling tower HAP emissions were calculated using AP-42 emission factors. Steam generator combustion HAP emissions were calculated using the SJVAPCD's Toxic Profile #237. Tank emissions were calculated using AP-42 and the Tanks ESP Program. Fugitive leaks were modeled as an area source and calculated using site specific gas composition and emission factors from CAPCOA. A unit emission rate of 1 grams/second (g/sec) was input to AERMOD for the volume sources.

Discrete receptors were placed on houses within close proximity of the Project site. Additionally, a tier of discrete receptors was placed 110 meters from the project boundary to represent all workers in every direction of the project site. This will generate a worst-case scenario for the off-site oil-field and ag workers located within a close proximity to the Project. A total of 598 discrete off-site receptors were analyzed. Elevated terrain options were employed for the Project area.

SJVAPCD-provided, AERMET UStar processed meteorological datasets for the Missouri Triangle monitoring station, calendar years 2004 through 2018 was input to AERMOD (SJVAPCD 2018). This was the most recent available dataset available at the time the modeling was conducted. Rural dispersion parameters were used because the operation and the majority of the land surrounding the facility is considered "rural" under the Auer land use classification method (Auer 1978).

Plot files generated by AERMOD were uploaded to the Air Dispersion Modeling and Risk Assessment Tool (ADMRT) program in the Hotspots Analysis and Reporting Program Version 2 (HARP 2) (CARB 2015). ADMRT post-processing was used to assess the potential for excess cancer risk and chronic and acute non-cancer effects using the most recent health effects data from the California EPA Office of Environmental Health Hazard Assessment (OEHHA). HARP2 site parameters were set for the mandatory minimum pathways of inhalation, soil ingestion, dermal, and mother's milk. In addition to the aforementioned pathways, the home-grown garden pathway was included as well. Risk reports were generated using the derived OEHHA analysis method for carcinogenic risk and non-carcinogenic chronic and acute risk. Site parameters are included in the HARP2 output files. Total cancer risk was predicted for each receptor. A hazard index was computed for chronic non-cancer health effects for each applicable endpoint and each receptor. A hazard index for acute non-cancer health effects was computed for each applicable endpoint and each receptor.

SJVAPCD has set the level of significance for carcinogenic risk at twenty in one million, which is understood as the possibility of causing twenty additional cancer cases in a population of one million people. The level of significance for chronic and acute non-cancer risk is a hazard index of 1.0. All receptors were modeled as residential receptors with a 70-year exposure. This is conservative since all on-site receptors, worker receptors and business receptors would be exposed less than 70 years.

The carcinogenic risk and the health hazard index (HI) for chronic non-cancer risk at the point of maximum impact (PMI) do not exceed the significance levels of twenty in one million (20×10^{-6}) and 1.0, respectively for the proposed Project. The PMIs are identified by receptor location and risk and are provided in **Table 4-9**. The electronic AERMOD and HARP2 output files are provided in **Attachment E**.

Table 4-9. Potential Maximum Impacts Predicted by HARP

	Value	UTM East	UTM North
Excess Cancer Risk	6.65E-06	251003.06	3926087.12
Chronic Hazard Index	1.55E-02	251950.08	3925329.29
Acute Hazard Index	4.74E-02	251003.06	3926087.12

As shown above in **Table 4-9**, the maximum predicted cancer risk for the proposed Project is 6.65E-06. The maximum chronic non-cancer hazard index for the proposed Project is 1.55E-02. The maximum acute non-cancer hazard index for the proposed Project is 4.74E-02. Since the PMI remained below the significance threshold for cancer, chronic, and acute risk, this Project would not have an adverse effect to any of the surrounding communities.

The potential health risk attributable to the proposed Project is determined to be *less than significant* based on the following conclusions:

1. Potential carcinogenic risk from the proposed Project is below the significance level of twenty in a million at each of the modeled receptors; and
2. The hazard index for the potential chronic non-cancer risk from the proposed Project is below the significance level of 1.0 at each of the modeled receptors.
3. The hazard index for the potential acute non-cancer risk from the proposed Project is below the significance level of 1.0 at each of the modeled receptors.

Therefore, the potential risk to the population attributable to emissions of HAPs from the proposed Project would be less than significant.

4.7 Potential Impacts from Valley Fever

The proposed Project has the potential to generate fugitive dust and suspend Valley Fever spores with the dust that could then reach nearby sensitive receptors. It is possible that onsite workers could be exposed to Valley Fever spores as fugitive dust is generated during construction. In order to mitigate potential risk, the proposed Project would provide training and personal protective respiratory equipment to construction workers and provide information to all construction personnel and visitors about Valley Fever. Therefore, the exposure to Valley Fever would be minimized. With the implementation of the mitigation measures, dust from the construction of the proposed project would not add significantly to the existing exposure level of people to this fungus, including construction workers, and impacts would be reduced to less-than-significant levels.

4.8 Potential Impacts from Asbestos

Naturally occurring asbestos can be released from serpentinite and ultramafic rocks when the rock is broken or crushed. At the point of release, the asbestos fibers may become airborne, causing air quality and human health hazards. These rocks have been commonly used for unpaved gravel roads, landscaping, fill projects, and other improvement projects in some localities. Asbestos may be released to the atmosphere due to vehicular traffic on unpaved roads, during grading of development projects, and at mining operations.

Serpentinite and/or ultramafic rock are known to be present in 44 of California's 58 counties. These rocks are particularly abundant in the counties associated with the Sierra Nevada foothills, the Klamath Mountains, and Coast Ranges. However, according to information provided by the Department of Conservation Division of Mines and Geology, the project site is not located in an area where naturally occurring asbestos is likely to be present (CDCDMG, 2000). Therefore, impacts associated with exposure of construction workers and nearby sensitive receptors to asbestos would be less than significant.

4.9 Odor Impacts and Mitigation

The SJVAPCD's GAMAQI states "An analysis of potential odor impacts should be conducted for both of the following two situations:

1. Generators – projects that would potentially generate odorous emissions proposed to locate near existing sensitive receptors or other land uses where people may congregate, and
2. Receivers – residential or other sensitive receptor projects or other projects built for the intent of attracting people locating near existing odor sources." (SJVAPCD 2015).

The GAMAQI also states, "The District has identified some common types of facilities that have been known to produce odors in the San Joaquin Valley Air Basin. These are presented in Table 6 (Screening Levels for Potential Odor Sources), along with a reasonable distance from the source within which, the degree of odors could possibly be significant. [Table 6] can be used as a screening tool to qualitatively assess a project's potential to adversely affect area receptors." (SJVAPCD, 2015). Because the Project is an existing oil and gas operation and there are no receptors located within a 1-mile radius of the Project, the Project is not expected to be a new source of objectionable odors.

Based on the provisions of the SJVAPCD's GAMAQI, the proposed Project would not exceed any screening trigger levels to be considered a source of objectionable odors or odorous compounds (SJVAPCD, 2015). Furthermore, the Project site is a permitted stationary source which is required to abide by the nuisance rules and regulations of the SJVAPCD. Additionally, the Project emissions estimates indicate that it would not be expected to adversely impact surrounding receptors. As such, the proposed Project would not be a source of any odorous compounds nor would it likely be impacted by any odorous source.

4.10 Impacts to Ambient Air Quality

As stated in the GAMAQI (2015, p 96-97), SJVAPCD has developed screening levels for requiring an Ambient Air Quality Analysis (AAQA). The SJVAPCD recommends that an AAQA be performed for all criteria pollutants when emissions of any criteria pollutant resulting from project construction or operational activities exceed the 100 pounds per day screening level, after compliance with Rule 9510 requirements and implementation of all enforceable mitigation measures.

The Project will be entering into a VERA which will reduce average daily emissions for construction and operational activities associated with this Project to a no net increase level. Therefore, an AAQA is not required for this Project.

4.11 Impacts to Greenhouse Gases and Climate Change

The proposed Project will have GHG emissions from construction and operation. These GHG emissions include emissions from area, energy, mobile, water, and waste sources. New regulations and new technologies in the future, and phase out of old equipment over time, will lead to a reduction of GHG emissions, but the reduction is not currently quantifiable. Additionally, the Project, as proposed, has the capacity to capture and sequester up to roughly 1.6 million metric tons of CO_2 per year, with a total sequestration capacity up to 40 million metric tons of CO_2. The installed capture facilities will have a capture efficiency of 95% at the pre-combustion facility and 90% at the post-combustion facilities. The Project will achieve net negative GHG emissions impact.

Table 4-10. Estimated GHG Emissions for First Source – Belridge Facilities (MT/Year)

Year	Pre-Combustion Emissions (De Sur and GP32)	Post-Combustion Emissions (COGEN32, SGS2972 & SGS2868)	Total Plants Emissions	Capture Facilities Mobile & Indirect Electricity Emissions	Captured and Injected Emissions
Baseline	249,050	870,126	1,119,176	-	-
Capture Year 1 (2027)	276,945	1,128,497	1,405,442	17,609	700,000
Capture Years 2-19 (2028-2045) per year	312,749	1,460,688	1,773,437	40,249	1,600,000
Total Years 1-19 (2027-2045)	**5,906,418**	**27,420,889**	**33,327,307**	**742,091**	**29,500,000**

In addition to Aera Energy-sourced CO2, the Project will have the capacity to import CO_2 from outside sources. With the addition of imported CO_2, Aera Energy may sequester up to 3.3 million metric tons per year. Although no outside sources of CO_2 have been identified at this time, it is reasonable to assume that Aera Energy would begin importing CO_2 in year 5 of project operation.

The Project will not result in emissions of hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF_6), or the other gases identified as GHG in AB32. The proposed Project may be subject to future regulations developed by CARB to address GHG emissions.

4.11.1 Feasible and Reasonable Mitigation Relative to Global Warming

CEQA requires that all feasible and reasonable mitigation be applied to the project to reduce the impacts from construction and operations on air quality. The SJVAPCD's "Non-Residential On-Site Mitigation Checklist" was utilized in preparing the mitigation measures and evaluating the project's features. These measures include using controls that limit the exhaust from construction equipment and using alternatives to diesel when possible. Additional reductions would be achieved through the regulatory process of the air district and CARB as required changes to diesel engines are implemented which would affect the product delivery trucks and limits on idling.

Since the Project reduces GHG emissions it is possible to determine whether the Project individually would have a significant impact on global warming or climate change, the Project would contribute to reductions in cumulative GHG emissions in California as well as related health effects. Therefore, it is possible to assess, with certainty, whether the Project's contribution would be cumulatively considerable, within the meaning of CEQA Guidelines Sections 15065(a)(3) and 15130.

The strategies currently being implemented by CARB may help in reducing the Project's GHG emissions and are summarized in the table below.

Table 4-11. Select CARB GHG Emission Reduction Strategies

Strategy	Description of Strategy
Vehicle Climate Change Standards	AB 1493 (Pavley) required the state to develop and adopt regulations that achieve the maximum feasible and cost-effective reduction of climate change emissions emitted by passenger vehicles and light duty trucks. Regulations were adopted by CARB in Sept. 2004.
Diesel Anti-Idling	In July 2004, CARB adopted a measure to limit diesel-fueled retail motor vehicle idling.
Other Light-Duty Vehicle Technology	New standards would be adopted to phase in beginning in the 2017 model year.
Alternative Fuels: Biodiesel Blends	CARB would develop regulations to require the use of 1% to 4% Biodiesel displacement of California diesel fuel.
Alternative Fuels: Ethanol	Increased use of ethanol fuel.
Heavy-Duty Vehicle Emission Reduction Measures	Increased efficiency in the design of heavy-duty vehicles and an educational program for the heavy-duty vehicle sector.

Not all of these measures are currently appropriate or applicable to the proposed Project. While future legislation could further reduce the Project's GHG footprint, the analysis of this is speculative and in accordance with CEQA Guidelines Section 15145, will not be further evaluated in this AQIA.

CEQA Guidelines Section 15130 notes that sometimes the only feasible mitigation for cumulative impacts may involve the adoption of ordinances or regulations rather than the imposition of conditions on a project-by-project basis. Global climate change is this type of issue. The causes and effects may not be just regional or statewide, they may also be worldwide. Given the uncertainties in identifying, let alone quantifying the impact of any single project on global warming and climate change, and the efforts made to reduce emissions of GHGs from the Project through design, in accordance with CEQA Section 15130, any further feasible emissions reductions would be accomplished through CARB regulations adopted pursuant to AB32. Given that the Project has a net negative impact on GHG emissions it can be assumed the Project will comply with any local and statewide air quality and climate plans.

5. CUMULATIVE IMPACTS

By its very nature, air pollution has a cumulative impact. The District's nonattainment status is a result of past and present development within the SJVAB. Furthermore, attainment of ambient air quality standards can be jeopardized by increasing emissions-generating activities in the region. No single project would be sufficient in size, by itself, to result in nonattainment of the regional air quality standards. Instead, a project's emissions may be individually limited, but cumulatively considerable when taken in combination with past, present, and future development within the San Joaquin Valley Air Basin. When assessing whether there is a new significant cumulative effect, the Lead Agency shall consider whether the incremental effects of the project are cumulatively considerable. "Cumulatively considerable" means that the incremental effects of an individual project are significant when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects [CCR §15064(h)(1)]. Per CEQA Guidelines §15064(h)(3) a Lead Agency may determine that a project's incremental contribution to a cumulative effect is not cumulatively considerable if the project will comply with the requirements in a previously approved plan or mitigation program, including, but not limited to an air quality attainment or maintenance plan that provides specific requirements that will avoid or substantially lessen the cumulative problem within the geographic area in which the project is located. (SJVAPCD 2015)

Attachment A of Kern County's *Guidelines for Preparing an Air Quality Assessment for Use in Environmental Impact Reports* states "The following threshold[s] are defined for purposes of determining cumulative effects as the baseline for "considerable". Projects in the San Joaquin Valley Air Pollution Control District…will be subject to the following significance thresholds". The thresholds outlined in the guidelines mirror the individual project significance thresholds of 15 tons per year for PM_{10} and 10 tons per year for NO_X and ROG. Therefore, owing to the inherently cumulative nature of air quality impacts, the threshold for whether a project would make a cumulatively considerable contribution to a significant cumulative impact is simply whether the project would exceed project-level thresholds. This AQIA, however, also considered the impacts of the proposed Project in conjunction with the impacts of other projects previously proposed in the area. The following cumulative impacts were considered:

- Cumulative O_3 Impacts (ROG and NOx) from numerous sources within the region including transport from outside the region. O_3 is formed through chemical reactions of ROG and NOx in the presence of sunlight.
- Cumulative CO Impacts produced primarily by vehicular emissions.
- Cumulative PM_{10} Impacts from within the region and locally from the various projects. Such projects may cumulatively produce a significant amount of PM10 if several projects conduct grading or earthmoving activities at the same time; and
- Hazardous Air Pollutant (HAP) Impacts on sensitive receptors.

5.1 Cumulative Regional Air Quality Impacts

The most recent, certified SJVAB Emission Inventory data available from the SJVAPCD is based on data gathered for the 2020 annual inventory[2]. This data will be used to assist the SJVAPCD in demonstrating attainment of Federal 1-hour O_3 Standards (SJVAPCD 2007). **Table 5-1** provides a comparative look at the impacts proposed by the proposed Project to the SJVAB Emissions Inventory.

[2] SJVAPCD Emissions for Aggregated Stationary, Area-Wide, Mobile, and Natural Sources

Table 5-1. Comparative Analysis Based on SJV Air Basin 2020 Inventory - Tons per Year

	ROG	NOx	CO	SOx	PM_{10}	$PM_{2.5}$
Kern County - 2020	21,535	15,878	27,339	511	13,651	3,723
SJVAB - 2020	108,113	74,205	162,425	2,847	96,652	21,535
Proposed Project*	0.008	0.040	0.515	0.002	0.008	0.003
Proposed Project's % of Kern	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Proposed Project's % of SJVAB	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Note: This is the latest inventory available as of May 2023
*Does not include permitted emissions that will be offset during permitting process or well emissions that will be mitigated through a VERA.
Source: CARB 2022b

As shown in **Table 5-1** the proposed Project does not pose a substantial increase to basin emissions, as such basin emissions would be essentially the same if the Project is approved.

Table 5-1, **5-2**, and **5-3** provide CARB Emissions Inventory projections for the year 2025 for both the SJVAB and the Kern County portion of the air basin. Looking at the SJVAB Emissions predicted by the CARB year 2025 emissions inventory, the Kern County portion of the air basin is a moderate source of the emissions. The proposed Project produces a small portion of the total emissions in both Kern County and the entire SJVAB.

Table 5-2. Emission Inventory SJVAB 2025 Projection - Tons per Year

	ROG	NOx	CO	SOx	PM10	PM2.5
Total Emissions	107,347	52,451	145,964	2,920	95,922	21,280
Percent Stationary Sources	32.78%	19.28%	6.93%	85.00%	5.97%	15.44%
Percent Area-Wide Sources	52.70%	5.15%	13.30%	3.75%	89.38%	71.87%
Percent Mobile Sources	14.52%	75.57%	79.77%	11.25%	4.68%	12.86%
Total Stationary Source Emissions	35,186	10,111	10,111	2,482	5,731	3,285
Total Area-Wide Source Emissions	56,575	2,701	19,418	110	85,739	15,294
Total Mobile Source Emissions	15,586	39,639	116,435	329	4,490	2,738

Source: CARB 2022b
Note: Total may not add due to rounding

Table 5-3. Emission Inventory SJVAB - Kern County Portion 2025 Projection - Tons per Year

	ROG	NOx	CO	SOx	PM10	PM2.5
Total Emissions	21,353	10,804	24,674	475	13,651	3,687
Percent Stationary Sources	53.50%	25.68%	15.83%	84.62%	11.76%	31.68%
Percent Area-Wide Sources	34.70%	4.05%	7.69%	0.00%	82.62%	56.44%
Percent Mobile Sources	11.97%	70.27%	76.33%	15.38%	5.61%	10.89%
Total Stationary Source Emissions	11,425	2,774	3,906	402	1,606	1,168
Total Area-Wide Source Emissions	7,410	438	1,898	0	11,279	2,081
Total Mobile Source Emissions	2,555	7,592	18,834	73	767	402

Source: CARB 2022b
Note: Total may not add due to rounding

Table 5-4. 2025 Emissions Projections - Proposed Project, Kern County, and SJVAB

	ROG	NOx	PM_{10}
Proposed Project	0.008	0.040	0.008
Kern County	24,893	21,645	19,637
SJVAB	107,347	52,451	95,922
Proposed Project Percent of Kern County	[illegible]	[illegible]	[illegible]
Proposed Project Percent of SJVAB	[illegible]	[illegible]	[illegible]
Kern County Percent of SJVAB	23.19%	41.27%	20.47%
Source: CARB 2022b			

As shown above, the proposed Project would pose an inconsequential impact on regional O_3 and PM_{10} formation. The regional contribution to these cumulative impacts would be negligible and additionally, the Project would not exceed cumulatively considerable thresholds since the Project would be less than thresholds outlined in Kern County's *Guidelines for Preparing an Air Quality Assessment for Use in Environmental Impact Reports*. Therefore, this Project would not be considered cumulatively considerable in its contribution to regional O_3 and PM_{10} impacts.

5.2 Cumulative Local Air Quality Impacts

No tentative development projects within a one-mile radius of the proposed Project area were identified. The cumulative projects are typically listed only as geographical reference to demonstrate the construction activity within a one-mile radius of the proposed Project. The number and sizes of these projects are of no particular significance since the cumulative considerable thresholds established by Kern County are based on Project specific thresholds which are inherently cumulative in nature.

As no cumulative projects were identified within a one-mile radius, emissions estimates were not calculated. Additionally, any projects either currently under construction or, at a minimum, approved by the planning department for consistency with applicable regulation, for the purposes of this analysis, it is assumed that they are in conformance with the regional AQAP.

5.3 Cumulative Hazardous Air Pollutants

The GAMAQI also states that when evaluating potential impacts related to HAPs, "*impacts of local pollutants (CO, HAPs) are cumulatively significant when modeling shows that the combined emissions from the project and other existing and planned projects will exceed air quality standards*." Because the Project would not be a significant source of HAPs, the proposed Project would also *not be expected to pose a significant cumulative CO or HAPs impact*.

5.4 Cumulative Carbon Monoxide (CO) – Mobile Sources

The SJVAPCD's GAMAQI has identified CO impacts from impacted traffic intersections and roadway segments as being potentially cumulatively considerable. Traffic increases and added congestion caused by a project can combine to cause a violation of the SJVAPCD's CO standard also known as a "Hotspot". There are two criteria established by the GAMAQI by which CO "Hot Spot" modeling is required:

- A traffic study for the project indicates that the Level of Service (LOS) on one or more streets or at one or more intersections in the project vicinity will be reduced to LOS E or F; or
- A traffic study indicates that the project will substantially worsen an already existing LOS F on one or more streets or at one or more intersections in the project vicinity.

According to the traffic study (Stantec 2023) that was prepared for this Project, all roadway segments continue to operate at LOS less than or equal to B. Therefore, due to the location and traffic increase anticipated from this Project, impacted intersections and roadway segments are anticipated to operate at a LOS of C or better. Therefore, CO "Hotspot" Modeling was not conducted for this Project and no concentrated excessive CO emissions are expected to be caused once the proposed Project is completed.

6. CONSISTENCY WITH THE AIR QUALITY ATTAINMENT PLAN

Air quality impacts from proposed projects within Kern County are controlled through policies and provisions of the SJVAPCD and the Kern County General Plan (KCPD 2009). In order to demonstrate that a proposed project would not cause further air quality degradation in either the SJVAPCD's plan to improve air quality within the air basin or the federal requirements to meet certain air quality compliance goals, each project should also demonstrate consistency with the SJVAPCD's adopted Air Quality Attainment Plans (AQAP) for O_3 and PM_{10}. The SJVAPCD is required to submit a "Rate of Progress" document to CARB that demonstrates past and planned progress toward reaching attainment for all criteria pollutants. The California Clean Air Act (CCAA) requires air pollution control districts with severe or extreme air quality problems to provide for a 5% reduction in non-attainment emissions per year. The AQAP prepared for the San Joaquin Valley by the SJVAPCD complies with this requirement. CARB reviews, approves or amends the document and forwards the plan to the EPA for final review and approval within the SIP.

Air pollution sources associated with stationary sources are regulated through the permitting authority of the SJVAPCD under the New and Modified Stationary Source Review Rule (SJVAPCD Rule 2201). Owners of any new or modified equipment that emits, reduces or controls air contaminants, except those specifically exempted by the SJVAPCD, are required to apply for an Authority to Construct and Permit to Operate (SJVAPCD Rule 2010). Additionally, best available control technology (BACT) is required on specific types of stationary equipment and are required to offset both stationary source emission increases along with increases in cargo carrier emissions if the specified threshold levels are exceeded (SJVAPCD Rule 2201, 4.7.1). Through this mechanism, the SJVAPCD would ensure that all stationary sources within the project area would be subject to the standards of the SJVAPCD to ensure that new developments do not result in net increases in stationary sources of criteria air pollutants.

6.1 Required Evaluation Guidelines

State CEQA Guidelines and the Federal Clean Air Act (Sections 176 and 316) contain specific references on the need to evaluate consistencies between the proposed project and the applicable AQAP for the project site. To accomplish this, CARB has developed a three-step approach to determine project conformity with the applicable AQAP:

1. *Determination that an AQAP is being implemented in the area where the project is being proposed*. The SJVAPCD has implemented the current, modified AQAP as approved by CARB.
2. *The proposed project must be consistent with the growth assumptions of the applicable AQAP*. The proposed Project land use type was not anticipated in the current growth assumptions. Therefore, growth assumptions in the Kern County General Plans will be modified with the approval of the proposed Project.
3. *The project must contain in its design all reasonably available and feasible air quality control measures*. The proposed Project incorporates various policy and rule-required implementation measures that will reduce related emissions.

The CCAA and AQAP identify transportation control measures as methods to further reduce emissions from mobile sources. Strategies identified to reduce vehicular emissions such as reductions in vehicle trips, vehicle use, vehicle miles traveled, vehicle idling, and traffic congestion, in order to reduce vehicular emissions, can be implemented as control measures under the CCAA as well. Additional measures may also be implemented through the building process such as providing electrical outlets on exterior walls of structures to encourage use of electrical landscape maintenance equipment or measures such as electrical outlets for electrical systems on diesel trucks to reduce or eliminate idling time.

As the growth represented by the proposed Project will be updated in the Kern County General Plan and incorporated into the AQAP, conclusions may be drawn from the following criteria:

1. That, by definition, the proposed emissions from the Project are below the SJVAPCD's established emissions impact thresholds;
2. That the primary source of emissions from the Project will be motor vehicles that are licensed through the State of California and whose emissions are already incorporated into CARB's San Joaquin Valley Emissions Inventory.

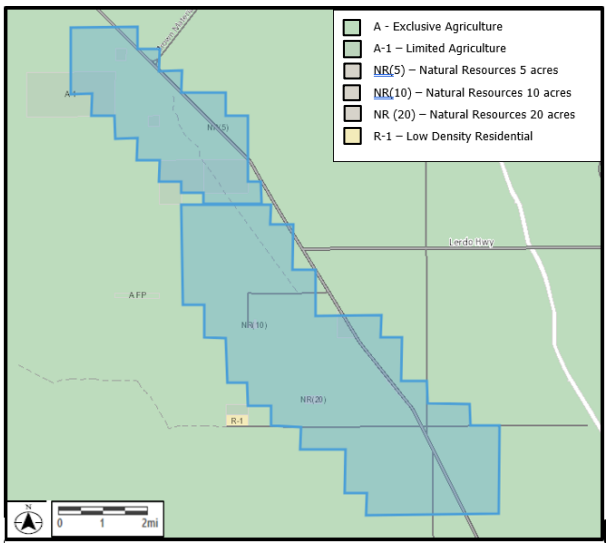
Based on these factors, the Project appears to be *consistent with the AQAP*.

6.2 Consistency with the Kern County Council of Government's Regional Conformity Analysis

The Kern Council of Governments (Kern COG) Regional Conformity Analysis (Kern COG 2018) Determination demonstrates that the regional transportation expenditure plans (Destination 2042 Regional Transportation Plan and Federal Transportation Improvement Program) in the Kern County portion of the San Joaquin Valley air quality attainment areas would not hinder the efforts set out in CARB's SIP for each area's non-attainment pollutants (CO, O_3, and PM_{10}). The analysis uses an adopted regional growth forecast, governed by both the adopted Kern COG Policy and Procedure Manual and a Memorandum of Understanding between the County of Kern and Kern COG (representing itself and outlying municipal member agencies).

The Kern COG Regional Conformity Analysis considers General Plan Amendments (GPA) and zone changes that were enacted at the time of the analysis as projected growth within the area based on land use designations incorporated within the Kern County General Plan. Land use designations that are altered based on subsequent GPAs that were not included in the Regional Conformity Analysis were not incorporated into the Kern COG analysis. Consequently, if a proposed project is not included in the regional growth forecast using the latest planning assumptions, it may not be said to conform to the regional growth forecast. Under the current Kern County Zoning, the Project site is designated as "A: Exclusive Agriculture, A-1: Limited Agriculture and NR(20): Natural Resources (20 acres)" (see **Figure 6-1**).

Figure 6-1. Kern County Zoning



Item 2 under Section 3 – Model Maintenance Procedure, of the Kern COG Regional Transportation Modeling Policy and Procedure Manual states "*Land Use Data – General Plan land capacity data or "Build -out capacity" is used to distribute the forecasted County totals, and may be updated as new information becomes available, and is revised in regular consultation with local planning departments.*"

Under current policies, only after a General Plan Amendment (GPA) is approved, can housing and employment assumptions be updated to reflect the capacity changes. Since the proposed development does not require a GPA but does require a zone change, the existing growth forecast could be modified to reflect these changes. In order to determine whether the forecasted growth for the Project area is sufficient to account for the projected increases in employment, an analysis based on Kern COG regional forecast was conducted.

The adopted growth forecast for the project site is distributed to Traffic Analysis Zones (TAZ). In order to evaluate the impacts to the proposed Project area, a one-mile radius analysis was conducted that included TAZ 2066, 2069, and 2070. In order to be considered "consistent" and, therefore, in conformance with the AQAP, population, housing and employment increases would need to occur over the same time as the adopted growth forecast. As the proposed Project is occurring at an existing oil and gas operation and add only a small amount of additional operational workers; it is assumed that the employment increase associated with the proposed Project is within the adopted growth forecast.

7. MITIGATION AND OTHER RECOMMENDED MEASURES

To ensure that Project is in compliance with all applicable SJVAPCD rules and regulations and emissions are further reduced, the applicant should implement and comply with a number of measures that are either recommended as a "good operating practice" for environmental stewardship or they are required by regulation. Some of the listed measures are regulatory requirements or construction requirements that would result in further emission reductions through their inclusion in Project construction and long-term design. The following measures either have been applied to the Project through the CalEEMod model and would be incorporated into the Project by design or would be implemented in conjunction with SJVAPCD rules as conditions of approval.

7.1 SJVAPCD Required PM_{10} Reduction Measures

As the Project would be completed in compliance with SJVAPCD Regulation VIII, dust control measures would be taken to ensure compliance specifically during grading and construction phases. The required Regulation VIII measures are as follows:

- Water previously exposed surfaces (soil) whenever visible dust is capable of drifting from the site or approaches 20% opacity.
- Water all unpaved haul roads a minimum of three-times/day or whenever visible dust from such roads is capable of drifting from the site or approaches 20% opacity.
- Reduce speed on unpaved roads to less than 15 miles per hour.
- Install and maintain a track out control device that meets the specifications of SJVAPCD Rule 8041 if the site exceeds 150 vehicle trips per day or more than 20 vehicle trips per day by vehicles with three or more axles.
- Stabilize all disturbed areas, including storage piles, which are not being actively utilized for production purposes using water, chemical stabilizers or by covering with a tarp or other suitable cover.
- Control fugitive dust emissions during land clearing, grubbing, scraping, excavation, leveling, grading, or cut and fill operations with application of water or by presoaking.
- When transporting materials offsite, maintain a freeboard limit of at least 6 inches and cover or effectively wet to limit visible dust emissions.
- Limit and remove the accumulation of mud and/or dirt from adjacent public roadways at the end of each workday. (Use of dry rotary brushes is prohibited except when preceded or accompanied by sufficient wetting to limit visible dust emissions and use of blowers is expressly forbidden).
- Stabilize the surface of storage piles following the addition or removal of materials using water or chemical stabilizer/suppressants.
- Remove visible track-out from the site at the end of each workday.
- Cease grading or other activities that cause excessive (greater than 20% opacity) dust formation during periods of high winds (greater than 20 mph over a one-hour period).

7.2 Recommended Measures to Reduce Equipment Exhaust

In addition, the GAMAQI guidance document lists the following measures as approved and recommended for construction activities. These measures are recommended:

- Maintain all construction equipment as recommended by manufacturer manuals.
- Shut down equipment when not in use for extended periods.
- Use electric equipment for construction whenever possible in lieu of diesel or gasoline powered equipment.

- Curtail use of high-emitting construction equipment during periods of high or excessive ambient pollutant concentrations.
- All construction vehicles shall be equipped with proper emissions control equipment and kept in good and proper running order to substantially reduce NOx emissions.
- On-Road and Off-Road diesel equipment shall use diesel particulate filters if permitted under manufacturer's guidelines.
- On-Road and Off-Road diesel equipment shall use cooled exhaust gas recirculation (EGR) if permitted under manufacturer's guidelines.
- All construction workers shall be encouraged to shuttle (car-pool) to retail establishments or to remain on-site during lunch breaks.
- All construction activities within the project area shall be discontinued during the first stage smog alerts.
- Construction and grading activities shall not be allowed during first stage O_3 alerts. First stage O_3 alerts are declared when the O_3 level exceeds 0.20 ppm (1-hour average).

7.3 Other Measures to Reduce Project Impacts

The following measures are recommended to further reduce the potential for long-term emissions from the Project. These measures are required as a matter of regulatory compliance:

- The Project design shall comply with applicable standards set forth in Title 24 of the Uniform Building Code to minimize total consumption of energy.
- Applicants shall be required to comply with applicable mitigation measures in the AQAP, SJVAPCD Rules, Traffic Control Measures, Regulation VIII and Indirect Source Rules for the SJVAPCD.
- The developer shall comply with the provisions of SJVAPCD Rule 4601 - Architectural Coatings, during the construction of all buildings and facilities. Application of architectural coatings shall be completed in a manner that poses the least emissions impacts whenever such application is deemed proficient.
- The applicant shall comply with the provisions of SJVAPCD Rule 4641 during the construction and pavement of all roads and parking areas within the project area. Specifically, the applicant shall not allow the use of:
  - Rapid cure cutback asphalt;
  - Medium cure cutback asphalt;
  - Slow cure cutback asphalt (as specified in SJVAPCD Rule 4641, Section 5.1.3); or Emulsified asphalt (as specified in SJVAPCD Rule 4641, Section 5.1.4).
  - The developer shall comply with applicable provisions of SJVAPCD Rule 9510 (Indirect Source Review).

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APPENDIX A. EXISTING AIR QUALITY MONITORING DATA

Top 4 Summary: Highest 4 Daily Maximum 8-Hour Ozone Averages

at Bakersfield-5558 California Avenue

iADAM

	2019		2020		2021	
	Date	8-Hr Average	Date	8-Hr Average	Date	8-Hr Average
National 2015 Std (0.070 ppm):						
First High:	Jul 25	0.088	Aug 21	0.098	Aug 28	0.080
Second High:	Jun 4	0.085	Aug 22	0.094	Jun 17	0.079
Third High:	Jun 5	0.081	Aug 19	0.085	Aug 29	0.079
Fourth High:	Jun 18	0.081	Sep 5	0.083	Jun 18	0.077
California Std (0.070 ppm):						
First High:	Jul 25	0.088	Aug 21	0.098	Aug 28	0.081
Second High:	Jun 4	0.086	Aug 22	0.094	Aug 29	0.080
Third High:	Jun 5	0.082	Aug 19	0.086	Jun 17	0.079
Fourth High:	Jun 18	0.082	Sep 5	0.083	Jun 18	0.077
National 2015 Std (0.070 ppm):						
# Days Above the Standard:		24		25		11
Nat'l Standard Design Value:		0.087		0.085		0.080
National Year Coverage:		99		99		100
California Std (0.070 ppm):						
# Days Above the Standard:		28		25		11
California Designation Value:		0.096		0.094		0.088
Expected Peak Day Concentration:		0.096		0.095		0.090
California Year Coverage:		97		97		99

Notes:

Eight-hour ozone averages and related statistics are available at Bakersfield-5558 California Avenue between 1994 and 2021. Some years in this range may not be represented.

All averages expressed in parts per million.

An exceedance of a standard is not necessarily related to a violation of the standard.

State and national statistics may differ for the following reasons:

National 8-hour averages are truncated to three decimal places; State 8-hour averages are rounded to three decimal places.

State criteria for ensuring that data are sufficiently complete for calculating 8-hour averages are more stringent than the national criteria.

Daily maximum 8-hour averages associated with the National 0.070 ppm standard exclude those 8-hour averages that have first hours between midnight and 6:00 am, Pacific Standard Time.

Daily maximum 8-hour averages associated with the National 0.070 ppm standard include only those 8-hour averages from days that have sufficient data for the day to be considered valid.

Year Coverage indicates the extent to which available monitoring data represent the time of the year when concentrations are expected to be highest. 0 means that data represent none of the high period; 100 means that data represent the entire high period. A high Year Coverage does not mean that there was sufficient data for annual statistics to be considered valid.

* means there was insufficient data available to determine the value.

Top 4 Summary: Highest 4 Daily Maximum 8-Hour Ozone Averages

at Oildale-3311 Manor Street

iADAM

	2019		2020		2021	
	Date	8-Hr Average	Date	8-Hr Average	Date	8-Hr Average
National 2015 Std (0.070 ppm):						
First High:	Jul 25	0.086	Aug 21	0.096	Aug 29	0.095
Second High:	Aug 14	0.079	Aug 22	0.096	Aug 28	0.094
Third High:	Aug 6	0.077	Sep 5	0.085	Jul 27	0.087
Fourth High:	Aug 15	0.076	Aug 19	0.083	Aug 4	0.086
California Std (0.070 ppm):						
First High:	Jul 25	0.087	Aug 21	0.096	Aug 29	0.095
Second High:	Aug 14	0.080	Aug 22	0.096	Aug 28	0.094
Third High:	Aug 6	0.077	Sep 5	0.086	Jul 27	0.088
Fourth High:	Aug 15	0.077	Aug 19	0.083	Aug 4	0.086
National 2015 Std (0.070 ppm):						
# Days Above the Standard:		16		23		43
Nat'l Standard Design Value:		0.084		0.083		0.081
National Year Coverage:		99		99		99
California Std (0.070 ppm):						
# Days Above the Standard:		20		24		46
California Designation Value:		0.093		0.093		0.088
Expected Peak Day Concentration:		0.093		0.093		0.092
California Year Coverage:		98		99		97

Notes:

- Eight-hour ozone averages and related statistics are available at Oildale-3311 Manor Street between 1983 and 2021. Some years in this range may not be represented.
- All averages expressed in parts per million.
- An exceedance of a standard is not necessarily related to a violation of the standard.
- State and national statistics may differ for the following reasons:
  - National 8-hour averages are truncated to three decimal places; State 8-hour averages are rounded to three decimal places.
  - State criteria for ensuring that data are sufficiently complete for calculating 8-hour averages are more stringent than the national criteria.
- Daily maximum 8-hour averages associated with the National 0.070 ppm standard exclude those 8-hour averages that have first hours between midnight and 6:00 am, Pacific Standard Time.

Daily maximum 8-hour averages associated with the National 0.070 ppm standard include only those 8-hour averages from days that have sufficient data for the day to be considered valid.

Year Coverage indicates the extent to which available monitoring data represent the time of the year when concentrations are expected to be highest. 0 means that data represent none of the high period; 100 means that data represent the entire high period. A high Year Coverage does not mean that there was sufficient data for annual statistics to be considered valid.

* means there was insufficient data available to determine the value.

Top 4 Summary: Highest 4 Daily Maximum 8-Hour Ozone Averages

at Maricopa-Stanislaus Street

	2019		2020		2021	
	Date	8-Hr Average	Date	8-Hr Average	Date	8-Hr Average
National 2015 Std (0.070 ppm):						
First High:	Nov 9	0.080	Aug 21	0.095	Jun 18	0.077
Second High:	Sep 14	0.077	Aug 22	0.095	Oct 2	0.076
Third High:	Oct 16	0.077	Aug 19	0.091	Oct 3	0.075
Fourth High:	Nov 7	0.077	Sep 6	0.091	Aug 29	0.073
California Std (0.070 ppm):						
First High:	Nov 9	0.080	Aug 21	0.096	Jun 18	0.077
Second High:	Sep 14	0.078	Aug 22	0.096	Oct 2	0.076
Third High:	Oct 16	0.078	Sep 6	0.092	Oct 3	0.076
Fourth High:	Nov 7	0.078	Aug 19	0.091	Aug 29	0.074
National 2015 Std (0.070 ppm):						
# Days Above the Standard:		41		38		10
Nat'l Standard Design Value:		0.083		0.085		0.080
National Year Coverage:		99		94		96
California Std (0.070 ppm):						
# Days Above the Standard:		45		40		11
California Designation Value:		0.085		0.093		0.091
Expected Peak Day Concentration:		0.089		0.094		0.091
California Year Coverage:		98		92		94

Notes:

Eight-hour ozone averages and related statistics are available at Maricopa-Stanislaus Street between 1987 and 2021. Some years in this range may not be represented.

All averages expressed in parts per million.

An exceedance of a standard is not necessarily related to a violation of the standard.

State and national statistics may differ for the following reasons:

National 8-hour averages are truncated to three decimal places; State 8-hour averages are rounded to three decimal places.

State criteria for ensuring that data are sufficiently complete for calculating 8-hour averages are more stringent than the national criteria.

Daily maximum 8-hour averages associated with the National 0.070 ppm standard exclude those 8-hour averages that have first hours between midnight and 6:00 am, Pacific Standard Time.

Daily maximum 8-hour averages associated with the National 0.070 ppm standard include only those 8-hour averages from days that have sufficient data for the day to be considered valid.

Year Coverage indicates the extent to which available monitoring data represent the time of the year when concentrations are expected to be highest. 0 means that data represent none of the high period; 100 means that data represent the entire high period. A high Year Coverage does not mean that there was sufficient data for annual statistics to be considered valid.

* means there was insufficient data available to determine the value.

Top 4 Summary: Highest 4 Daily Maximum Hourly Ozone Measurements

at Bakersfield-5558 California Avenue

iADAM

	2019		2020		2021	
	Date	Measurement	Date	Measurement	Date	Measurement
First High:	Jul 25	0.097	Aug 21	0.110	Jun 29	0.090
Second High:	Jun 4	0.095	Aug 19	0.107	Aug 28	0.087
Third High:	Jun 11	0.092	Aug 22	0.107	Jul 27	0.083
Fourth High:	Jun 18	0.092	Aug 24	0.091	Sep 7	0.083
California:						
# Days Above the Standard:		2		3		0
California Designation Value:		0.10		0.10		0.10
Expected Peak Day Concentration:		0.102		0.101		0.095
National:						
# Days Above the Standard:		*0*		*0*		*0*
3-Year Estimated Expected Number of Exceedance Days:		*0.0*		*0.0*		*0.0*
1-Year Estimated Expected Number of Exceedance Days:		*0.0*		*0.0*		*0.0*
Nat'l Standard Design Value:		*0.104*		*0.107*		*0.097*
Year Coverage:		99		99		99

Notes:

Hourly ozone measurements and related statistics are available at Bakersfield-5558 California Avenue between 1994 and 2021. Some years in this range may not be represented.

All concentrations expressed in parts per million.

The national 1-hour ozone standard was revoked in June 2005. Statistics related to the national 1-hour ozone standard are shown in or .

An exceedance of a standard is not necessarily related to a violation of the standard.

Year Coverage indicates the extent to which available monitoring data represent the time of the year when concentrations are expected to be highest. 0 means that data represent none of the high period; 100 means that data represent the entire high period. A high Year Coverage does not mean that there was sufficient data for annual statistics to be considered valid.

* means there was insufficient data available to determine the value.

Top 4 Summary: Highest 4 Daily Maximum Hourly Ozone Measurements

at Oildale-3311 Manor Street

iADAM

	2019		2020		2021	
	Date	Measurement	Date	Measurement	Date	Measurement
First High:	Jul 25	0.099	Aug 21	0.109	Aug 28	0.107
Second High:	Aug 6	0.091	Aug 22	0.107	Aug 29	0.102
Third High:	Aug 14	0.089	Aug 19	0.101	Aug 3	0.099
Fourth High:	Aug 31	0.086	Sep 5	0.093	Sep 9	0.099
California:						
# Days Above the Standard:		1		3		6
California Designation Value:		0.10		0.10		0.10
Expected Peak Day Concentration:		0.098		0.099		0.099
National:						
# Days Above the Standard:		*0*		*0*		*0*
3-Year Estimated Expected Number of Exceedance Days:		*0.0*		*0.0*		*0.0*
1-Year Estimated Expected Number of Exceedance Days:		*0.0*		*0.0*		*0.0*
Nat'l Standard Design Value:		*0.100*		*0.102*		*0.102*
Year Coverage:		99		99		98

Notes:

Hourly ozone measurements and related statistics are available at Oildale-3311 Manor Street between 1983 and 2021. Some years in this range may not be represented.

All concentrations expressed in parts per million.

The national 1-hour ozone standard was revoked in June 2005. Statistics related to the national 1-hour ozone standard are shown in or .

An exceedance of a standard is not necessarily related to a violation of the standard.

Year Coverage indicates the extent to which available monitoring data represent the time of the year when concentrations are expected to be highest. 0 means that data represent none of the high period; 100 means that data represent the entire high period. A high Year Coverage does not mean that there was sufficient data for annual statistics to be considered valid.

* means there was insufficient data available to determine the value.

Top 4 Summary: Highest 4 Daily Maximum Hourly Ozone Measurements

at Maricopa-Stanislaus Street

iADAM

	2019		2020		2021	
	Date	Measurement	Date	Measurement	Date	Measurement
First High:	Nov 7	0.086	Aug 19	0.122	Jun 18	0.083
Second High:	Nov 9	0.085	Aug 21	0.112	Oct 1	0.082
Third High:	Sep 14	0.084	Aug 22	0.103	Aug 7	0.080
Fourth High:	Oct 16	0.084	Sep 15	0.098	Oct 30	0.080
California:						
# Days Above the Standard:		0		7		0
California Designation Value:		0.09		0.10		0.10
Expected Peak Day Concentration:		0.092		0.099		0.096
National:						
# Days Above the Standard:		*0*		*0*		*0*
3-Year Estimated Expected Number of Exceedance Days:		*0.0*		*0.0*		*0.0*
1-Year Estimated Expected Number of Exceedance Days:		*0.0*		*0.0*		*0.0*
Nat'l Standard Design Value:		*0.096*		*0.098*		*0.098*
Year Coverage:		98		91		96

Notes:

Hourly ozone measurements and related statistics are available at Maricopa-Stanislaus Street between 1987 and 2021. Some years in this range may not be represented.

All concentrations expressed in parts per million.

The national 1-hour ozone standard was revoked in June 2005. Statistics related to the national 1-hour ozone standard are shown in or .

An exceedance of a standard is not necessarily related to a violation of the standard.

Year Coverage indicates the extent to which available monitoring data represent the time of the year when concentrations are expected to be highest. 0 means that data represent none of the high period; 100 means that data represent the entire high period. A high Year Coverage does not mean that there was sufficient data for annual statistics to be considered valid.

* means there was insufficient data available to determine the value.

Top 4 Summary: Highest 4 Daily 24-Hour PM10 Averages

at Bakersfield-5558 California Avenue

iADAM

	2019		2020		2021	
	Date	24-Hr Average	Date	24-Hr Average	Date	24-Hr Average
National:						
First High:	Jan 5	116.3	Nov 5	193.8	Oct 11	437.5
Second High:	Nov 5	94.9	Oct 2	131.1	Oct 4	185.7
Third High:	Nov 11	75.9	Sep 12	118.6	Dec 13	164.7
Fourth High:	Oct 31	74.5	Aug 31	100.8	Aug 20	144.3
California:						
First High:	Jan 5	125.9	Nov 5	196.8	Oct 11	439.3
Second High:	Nov 5	96.5	Oct 2	128.2	Oct 4	183.1
Third High:	Nov 11	77.3	Sep 12	117.1	Dec 13	168.0
Fourth High:	Oct 31	76.4	Sep 18	97.7	Aug 20	140.8
National:						
Estimated # Days > 24-Hr Std:		0.0		*		*
Measured # Days > 24-Hr Std:		0		1		3
3-Yr Avg Est # Days > 24-Hr Std:		0.0		*		*
Annual Average:		*38.8*		*46.0*		*49.0*
3-Year Average:		*41*		*42*		*
California:						
Estimated # Days > 24-Hr Std:		108.1		*		*
Measured # Days > 24-Hr Std:		17		18		124
Annual Average:		39.0		*		*
3-Year Maximum Annual Average:		43		39		*
Year Coverage:		94		89		0

Notes:

Daily PM10 averages and related statistics are available at Bakersfield-5558 California Avenue between 1994 and 2021. Some years in this range may not be represented.

All averages expressed in micrograms per cubic meter.

The national annual average PM10 standard was revoked in December 2006 and is no longer in effect. Statistics related to the revoked standard are shown in *italics* or *italics* .

An exceedance of a standard is not necessarily related to a violation of the standard.

All values listed above represent midnight-to-midnight 24-hour averages and may be related to an exceptional event.

State and national statistics may differ for the following reasons:

- State statistics are based on California approved samplers, whereas national statistics are based on samplers using federal reference or equivalent methods. State and national statistics may therefore be based on different samplers.
- State statistics for 1998 and later are based on local conditions (except for sites in the South Coast Air Basin, where State statistics for 2002 and later are based on local conditions). National statistics are based on standard conditions.
- State criteria for ensuring that data are sufficiently complete for calculating valid annual averages are more stringent than the national criteria.

Measurements are usually collected every six days. Measured days counts the days that a measurement was greater than the level of the standard; Estimated days mathematically estimates how many days concentrations would have been greater than the level of the standard had each day been monitored.

3-Year statistics represent the listed year and the 2 years before the listed year.

Year Coverage indicates the extent to which available monitoring data represent the time of the year when concentrations are expected to be highest. 0 means that data represent none of the high period; 100 means that data represent the entire high period. A high Year Coverage does not mean that there was sufficient data for annual statistics to be considered valid.

* means there was insufficient data available to determine the value.

Top 4 Summary: Highest 4 Daily 24-Hour PM10 Averages

iADAM

at Oildale-3311 Manor Street

	2019		2020		2021	
	Date	24-Hr Average	Date	24-Hr Average	Date	24-Hr Average
National:						
First High:	Oct 30	389.3	Sep 8	517.2	Oct 11	421.4
Second High:	Oct 27	382.7	Nov 6	277.8	Oct 4	164.3
Third High:	Nov 25	339.6	Aug 22	230.4	Oct 25	150.2
Fourth High:	Oct 28	233.7	Sep 14	225.3	Oct 1	137.6
California:						
First High:	Oct 30	392.1	Nov 6	277.3	Oct 11	423.0
Second High:	Oct 27	384.2	Aug 22	221.0	Oct 4	161.1
Third High:	Nov 25	344.1	Sep 15	219.6	Oct 25	149.3
Fourth High:	Oct 28	238.0	Sep 14	219.3	Oct 1	135.2
National:						
Estimated # Days > 24-Hr Std:		8.1		17.4		2.2
Measured # Days > 24-Hr Std:		8		15		2
3-Yr Avg Est # Days > 24-Hr Std:		*		10.0		9.0
Annual Average:		*46.6*		*57.3*		*50.0*
3-Year Average:		*52*		*53*		*51*
California:						
Estimated # Days > 24-Hr Std:		*		*		135.6
Measured # Days > 24-Hr Std:		118		123		129
Annual Average:		*		*		49.4
3-Year Maximum Annual Average:		*		*		49
Year Coverage:		0		0		0

Notes:

Daily PM10 averages and related statistics are available at Oildale-3311 Manor Street between 1988 and 2021. Some years in this range may not be represented.

All averages expressed in micrograms per cubic meter.

The national annual average PM10 standard was revoked in December 2006 and is no longer in effect. Statistics related to the revoked standard are shown in *italics* or *italics* .

An exceedance of a standard is not necessarily related to a violation of the standard.

All values listed above represent midnight-to-midnight 24-hour averages and may be related to an exceptional event.

State and national statistics may differ for the following reasons:

- State statistics are based on California approved samplers, whereas national statistics are based on samplers using federal reference or equivalent methods. State and national statistics may therefore be based on different samplers.
- State statistics for 1998 and later are based on local conditions (except for sites in the South Coast Air Basin, where State statistics for 2002 and later are based on local conditions). National statistics are based on standard conditions.
- State criteria for ensuring that data are sufficiently complete for calculating valid annual averages are more stringent than the national criteria.

Measurements are usually collected every six days. Measured days counts the days that a measurement was greater than the level of the standard; Estimated days mathematically estimates how many days concentrations would have been greater than the level of the standard had each day been monitored.

3-Year statistics represent the listed year and the 2 years before the listed year.

Year Coverage indicates the extent to which available monitoring data represent the time of the year when concentrations are expected to be highest. 0 means that data represent none of the high period; 100 means that data represent the entire high period. A high Year Coverage does not mean that there was sufficient data for annual statistics to be considered valid.

* means there was insufficient data available to determine the value.

Top 4 Summary: Highest 4 Daily 24-Hour PM2.5 Averages

at Bakersfield-5558 California Avenue

iADAM

	2019		2020		2021	
	Date	24-Hr Average	Date	24-Hr Average	Date	24-Hr Average
National:						
First High:	Jan 27	59.1	Aug 22	150.7	Oct 30	72.3
Second High:	Jan 29	57.6	Jul 4	141.9	Oct 4	69.4
Third High:	Jan 28	53.1	Aug 21	130.2	Oct 29	66.4
Fourth High:	Jan 26	52.3	Aug 20	82.7	Nov 19	59.5
California:						
First High:	Jan 27	59.1	Aug 22	159.7	Oct 30	72.3
Second High:	Jan 29	57.6	Jul 4	143.9	Oct 4	70.5
Third High:	Jan 28	53.1	Aug 21	136.8	Oct 29	66.4
Fourth High:	Jan 26	52.3	Aug 23	88.9	Nov 19	59.5
National:						
'06 Estimated # Days > 24-Hr Std:		12.3		46.4		43.2
'06 Measured # Days > 24-Hr Std:		12		44		40
2006 24-Hr Std Design Value:		61		64		60
2006 24-Hr Std 98th Percentile:		43.4		79.2		56.9
2006 Annual Std Design Value:		15.2		16.4		16.1
2012 Annual Std Design Value:		15.2		16.4		16.1
'06 Annual Average:		11.8		19.7		16.5
California:						
Annual Std Designation Value:		16		20		20
Annual Average:		11.5		19.7		16.6
Year Coverage:		98		97		95

Notes:

Daily PM2.5 averages and related statistics are available at Bakersfield-5558 California Avenue between 1999 and 2021. Some years in this range may not be represented.

All averages expressed in micrograms per cubic meter.

An exceedance of a standard is not necessarily related to a violation of the standard.

State statistics are based on California approved samplers, whereas national statistics are based on samplers using federal reference or equivalent methods. State and national statistics may therefore be based on different samplers.

Year Coverage indicates the extent to which available monitoring data represent the time of the year when concentrations are expected to be highest. 0 means that data represent none of the high period; 100 means that data represent the entire high period. A high Year Coverage does not mean that there was sufficient data for annual statistics to be considered valid.

* means there was insufficient data available to determine the value.

Top 4 Summary: Highest 4 Daily 24-Hour PM2.5 Averages

at Bakersfield-Golden State Highway

iADAM

	2019		2020		2021	
	Date	24-Hr Average	Date	24-Hr Average	Date	24-Hr Average
National:						
First High:	Jan 27	66.1	Aug 22	150.2	Oct 4	78.5
Second High:	Jan 30	47.4	Sep 15	81.5	Dec 4	63.3
Third High:	Nov 8	44.3	Oct 3	76.9	Nov 19	59.1
Fourth High:	Nov 17	36.7	Aug 19	50.2	Nov 20	59.1
California:						
First High:	Jan 27	66.1	Aug 22	150.2	Oct 4	78.5
Second High:	Jan 30	47.4	Sep 15	81.5	Dec 4	63.3
Third High:	Nov 8	44.3	Oct 3	76.9	Nov 19	59.1
Fourth High:	Nov 17	36.7	Aug 19	50.2	Nov 20	59.1
National:						
'06 Estimated # Days > 24-Hr Std:		12.2		33.9		45.6
'06 Measured # Days > 24-Hr Std:		4		10		43
2006 24-Hr Std Design Value:		59		61		59
2006 24-Hr Std 98th Percentile:		44.3		76.9		54.3
2006 Annual Std Design Value:		15.5		16.6		16.6
2012 Annual Std Design Value:		15.5		16.6		16.6
'06 Annual Average:		12.3		19.4		17.8
California:						
Annual Std Designation Value:		18		18		*
Annual Average:		12.4		*		*
Year Coverage:		99		91		91

Notes:

Daily PM2.5 averages and related statistics are available at Bakersfield-Golden State Highway between 1999 and 2021. Some years in this range may not be represented.

All averages expressed in micrograms per cubic meter.

An exceedance of a standard is not necessarily related to a violation of the standard.

State statistics are based on California approved samplers, whereas national statistics are based on samplers using federal reference or equivalent methods. State and national statistics may therefore be based on different samplers.

Year Coverage indicates the extent to which available monitoring data represent the time of the year when concentrations are expected to be highest. 0 means that data represent none of the high period; 100 means that data represent the entire high period. A high Year Coverage does not mean that there was sufficient data for annual statistics to be considered valid.

* means there was insufficient data available to determine the value.

Top 4 Summary: Highest 4 Daily 24-Hour PM2.5 Averages

at Bakersfield-410 E Planz Road

iADAM

	2019		2020		2021	
	Date	24-Hr Average	Date	24-Hr Average	Date	24-Hr Average
National:						
First High:	Jan 27	83.7	Aug 22	158.6	Oct 4	70.5
Second High:	Oct 30	49.3	Sep 15	82.4	Jan 16	55.8
Third High:	Nov 8	46.7	Oct 3	81.4	Jan 19	54.8
Fourth High:	Nov 17	34.5	Aug 19	57.1	Jan 31	52.7
California:						
First High:	Jan 27	83.7	Aug 22	158.6	Oct 4	70.5
Second High:	Oct 30	49.3	Sep 15	82.4	Jan 16	55.8
Third High:	Nov 8	46.7	Oct 3	81.4	Jan 19	54.8
Fourth High:	Nov 17	34.5	Aug 19	57.1	Jan 31	52.7
National:						
'06 Estimated # Days > 24-Hr Std:		10.0		51.3		53.0
'06 Measured # Days > 24-Hr Std:		3		17		17
2006 24-Hr Std Design Value:		59		63		61
2006 24-Hr Std 98th Percentile:		46.7		81.4		54.8
2006 Annual Std Design Value:		16.9		17.6		17.8
2012 Annual Std Design Value:		16.9		17.6		17.8
'06 Annual Average:		13.0		20.3		20.0
California:						
Annual Std Designation Value:		13		13		13
Annual Average:		13.0		*		*
Year Coverage:		92		91		92

Notes:

Daily PM2.5 averages and related statistics are available at Bakersfield-410 E Planz Road between 2000 and 2021. Some years in this range may not be represented.

All averages expressed in micrograms per cubic meter.

An exceedance of a standard is not necessarily related to a violation of the standard.

State statistics are based on California approved samplers, whereas national statistics are based on samplers using federal reference or equivalent methods. State and national statistics may therefore be based on different samplers.

Year Coverage indicates the extent to which available monitoring data represent the time of the year when concentrations are expected to be highest. 0 means that data represent none of the high period; 100 means that data represent the entire high period. A high Year Coverage does not mean that there was sufficient data for annual statistics to be considered valid.

* means there was insufficient data available to determine the value.

Top 4 Summary: Highest 4 Daily Maximum Hourly Nitrogen Dioxide Measurements

at Bakersfield-5558 California Avenue

iADAM

	2019		2020		2021	
	Date	Measurement	Date	Measurement	Date	Measurement
National:						
First High:	Nov 8	67.1	Nov 30	50.4	Oct 4	57.2
Second High:	Nov 12	63.8	Nov 5	50.3	Dec 1	56.2
Third High:	Nov 13	62.6	Dec 10	49.9	Dec 2	54.8
Fourth High:	Nov 4	60.4	Dec 2	47.8	Nov 30	54.6
California:						
First High:	Nov 8	67	Nov 5	50	Oct 4	57
Second High:	Nov 12	63	Nov 30	50	Dec 1	56
Third High:	Nov 13	62	Dec 10	49	Nov 30	54
Fourth High:	Nov 4	60	Dec 2	47	Dec 2	54
National:						
1-Hour Standard Design Value:		54		50		49
1-Hour Standard 98th Percentile:		53.9		44.9		48.4
# Days Above the Standard:		0		0		0
Annual Standard Design Value:		12		11		11
California:						
1-Hour Std Designation Value:		70		60		60
Expected Peak Day Concentration:		66		61		60
# Days Above the Standard:		0		0		0
Annual Std Designation Value:		12		12		11
Annual Average:		11		11		10
Year Coverage:		99		99		98

Notes:

Hourly nitrogen dioxide measurements and related statistics are available at Bakersfield-5558 California Avenue between 1994 and 2021. Some years in this range may not be represented.

All concentrations expressed in parts per billion.
An exceedance of a standard is not necessarily related to a violation of the standard.
Year Coverage indicates the extent to which available monitoring data represent the time of the year when concentrations are expected to be highest. 0 means that data represent none of the high period; 100 means that data represent the entire high period. A high Year Coverage does not mean that there was sufficient data for annual statistics to be considered valid.
* means there was insufficient data available to determine the value.

Top 4 Summary: Highest 4 Daily Maximum Hourly Nitrogen Dioxide Measurements

at Shafter-Walker Street

	2019		2020		2021	
	Date	Measurement	Date	Measurement	Date	Measurement
National:						
First High:	Nov 8	49.3	Dec 2	40.9	Dec 1	47.8
Second High:	Nov 1	45.8	Oct 30	39.7	Nov 30	46.0
Third High:	Nov 18	43.3	Nov 16	35.3	Dec 2	37.5
Fourth High:	Nov 9	40.8	Nov 28	34.2	Sep 30	36.7
California:						
First High:	Nov 8	49	Dec 2	40	Dec 1	47
Second High:	Nov 1	45	Oct 30	39	Nov 30	46
Third High:	Nov 18	43	Nov 16	35	Dec 2	37
Fourth High:	Nov 9	40	Nov 2	34	Sep 30	36
National:						
1-Hour Standard Design Value:		38		36		34
1-Hour Standard 98th Percentile:		36.9		32.5		32.9
# Days Above the Standard:		0		0		0
Annual Standard Design Value:		9		9		8
California:						
1-Hour Std Designation Value:		50		40		40
Expected Peak Day Concentration:		46		44		42
# Days Above the Standard:		0		0		0
Annual Std Designation Value:		9		9		8
Annual Average:		8		8		8
Year Coverage:		98		99		87

Notes:

Hourly nitrogen dioxide measurements and related statistics are available at Shafter-Walker Street between 1989 and 2021. Some years in this range may not be represented.

All concentrations expressed in parts per billion.
An exceedance of a standard is not necessarily related to a violation of the standard.
Year Coverage indicates the extent to which available monitoring data represent the time of the year when concentrations are expected to be highest. 0 means that data represent none of the high period; 100 means that data represent the entire high period. A high Year Coverage does not mean that there was sufficient data for annual statistics to be considered valid.
* means there was insufficient data available to determine the value.

Welcome to California

Air Resources Board

View a Different Site
View a Different Substance

Annual Toxics Summary

Bakersfield-5558 California Avenue

Lead

nanograms per cubic meter

iADAM FAQs

Read About Estimated Risk

Year	Months Present	Minimum	Median	Mean	90th Percentile	Maximum	Standard Deviation	Number of Observations	Detection Limit	Estimated Risk
2022	----------	0.65	3.6	*	5.4	6.1	1.80	15	1.3	*
2021	----------	0.65	2.8	*	5.8	9.9	2.28	24	1.3	*
2020	----------	1.5	*	*	*	5.7	1.38	9	1.3	*
2019	----------	0.65	3.5	3.70	6.3	8.5	1.91	34	1.3	0.1
2018	----------	0.65	3.6	3.92	7.0	11.7	2.38	37	1.3	0.1
2017	----------	0.65	3.5	*	7.5	12.6	2.60	29	1.3	*
2016	----------	0.65	4.3	*	6.9	19.8	3.57	33	1.3	*
2015	----------	0.65	3.2	3.34	7.6	9.5	2.50	33	1.3	0.1
2014	----------	0.85	3.6	*	8.8	14	3.78	16	1.7	*
2013	----------	0.5	2.9	*	5.3	6.7	1.71	21	1.0	*
2012	----------	1.7	3.4	4.02	8.2	14	2.74	32	1.5	0.1
2011	----------	0.75	4.0	*	9.1	11	2.90	20	1.5	*
2010	----------	0.75	2.5	*	5.7	8.2	2.07	18	1.5	*
2009	----------	1.5	4.5	5.27	11.2	14	3.22	29	1.5	0.2
2008	----------	*	*	*	*	*	*	0	*	*
2007	----------	0.75	7.1	*	11.7	13	3.23	24	1.5	*
2006	----------	*	*	*	*	*	*	0	*	*
2005	----------	*	*	*	*	*	*	0	*	*
2004	----------	*	*	*	*	*	*	0	*	*
2003	----------	4.0	*	*	*	7.0	1.64	5	3.0	*
2002	----------	1.5	7.0	6.78	10	17	3.34	36	3.0	0.2
2001	----------	2	5.0	5.83	9.2	26	4.41	39	4.0	0.2
2000	----------	2	5.0	5.92	14.1	22	4.76	40	4.0	0.2
1999	----------	2	5.0	5.70	11.2	25	4.55	39	4.0	0.2
1998	----------	2	7.0	9.43	14	78	11.8	42	4.0	0.3
1997	----------	2	7.0	7.92	14	20	4.40	34	4.0	0.3
1996	----------	2	7.0	7.69	14.5	35	6.10	36	4.0	0.3
1995	----------	2	8.0	8.68	15.1	21	5.14	30	4.0	0.3
1994	----------	2	10	*	16	39	7.11	25	4.0	*
1993	----------	*	*	*	*	*	*	0	*	*
1992	----------	*	*	*	*	*	*	0	*	*
1991	----------	*	*	*	*	*	*	0	*	*
1990	----------	*	*	*	*	*	*	0	*	*
1989	----------	*	*	*	*	*	*	0	*	*

Graph It!

Toxics Statistics Home

Notes: Values below the Limit of Detection (LoD) assumed to be ½ LoD.
Means and risks shown only for years with data in all 12 months.
"*" means there was insufficient or no data available to determine the value.

Data Descriptions Page

APPENDIX B. PROJECT EMISSION CALCULATIONS

Aera Energy
Bakersfield, CA

GHG Emissions - Pre Combustion

Project Increase GHG Emissions

Utility Steam Generators (NEW)
Inputs

Parameters	Value	Unit
Fuel Rating	65	MMBtu/hr
Annual Fuel Use	569400	MMBTU/yr

Emission Factors

Pollutant	Emission Factor	Unit
CO2	116.89	lb/MMBtu
CH4	0.0022	lb/MMBtu
N2O	0.0002	lb/MMBtu

Potential to Emit

Emissions Unit	Hourly Emissions (lb/hr)				Daily Emissions (lbs/day)				Yearly Emissions (MT/yr)			
	CO2	CH4	CH4	CO2e	CO2	CH4	CH4	CO2e	CO2	CH4	CH4	CO2e
Utility SG 1	7597.78	0.14	0.01	7605.63	182346.77	3.44	0.34	182535.23	30189.64	0.57	0.06	30220.84
Utility SG 2	7597.78	0.14	0.01	7605.63	182346.77	3.44	0.34	182535.23	30189.64	0.57	0.06	30220.84

Del Sur Compressors	Annual Emission Inventory Yearly Process Rates		GHG Emissions (MT/yr)			
	2022 MMSCFD*	2022 MMBTU*	CO2	CH4	N2O	CO2e
Compressors Increase	60.47	60470.44	3206.15	0.060	0.006	3209.46

*Assumed 100% fuel usage increase over baseline

Increase Total:	63585.43	1.20	0.12	63651.15

Baseline GHG Emissions

Emissions Unit	Annual Emission Inventory Yearly Process Rates (Million Cubic Feet Burned)									AVG	GHG Emissions (MT/yr)			
	2009	2010	2011	2012	2013	2014	2015	2016	AVG	MMBTU	CO2	CH4	N2O	CO2e
S-1543-5-21	59.61	49.43	65.49	38.56	73.48	32.08	98.59	38.19	56.93	56928.00	3018.33	0.06	0.01	3021.45
S-1543-6-22	30.50	57.69	35.00	35.47	1.15	0.00	0.00	0.00	19.98	19976.33	1059.15	0.02	0.00	1060.24
S-1543-7-16	45.41	24.91	22.17	21.10	21.82	5.04	1.85	7.01	18.66	18664.32	989.58	0.02	0.00	990.61
S-1543-9-4	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	2.50	0.13	0.00	0.00	0.13
S-1543-10-4	0.00	0.00	0.00	0.20	0.00	0.00	0.00	0.00	0.03	25.00	1.33	0.00	0.00	1.33
S-1543-11-4	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	1.25	0.07	0.00	0.00	0.07
S-1543-12-4	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	1.25	0.07	0.00	0.00	0.07
S-1543-25-6	16.51	21.49	30.31	3.20	0.00	0.00	0.00	0.00	8.94	8939.23	473.96	0.01	0.00	474.45
S-1543-26-5	18.13	1.24	0.00	0.00	0.00	0.00	0.00	0.00	2.42	2421.25	128.37	0.00	0.00	128.51
S-1543-27-5	21.90	21.72	17.67	3.95	0.00	0.00	0.00	0.00	8.16	8155.52	432.41	0.01	0.00	432.85
S-1543-33-15	23.01	60.18	28.63	15.61	34.21	26.67	47.78	117.59	44.21	44209.83	2344.01	0.04	0.00	2346.43
S-1543-34-3	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	2.50	0.13	0.00	0.00	0.13
S-1543-35-3	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	2.50	0.13	0.00	0.00	0.13
S-1543-36-3	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	2.50	0.13	0.00	0.00	0.13
S-1543-37-3	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	3.75	0.20	0.00	0.00	0.20
S-1543-39-3	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	2.50	0.13	0.00	0.00	0.13
S-1543-40-3	0.00	0.00	0.00	0.44	0.00	0.00	0.00	0.00	0.06	55.00	2.92	0.00	0.00	2.92

	Emission Inventory VOC Emissions (tons/yr)									GHG Emissions (MT/yr)			
	2009	2010	2011	2012	2013	2014	2015	2016	AVG	CO2	CH4	N2O	CO2e
S-1543-4-24*	1.04	0.89	0.90	0.71	3.02	4.76	2.82	1.43	1.9463	0.000	1.765613477	0.00	44.14

*Assumed 100% VOC Emissions were CH4

	GHG Emissions (MT/yr)			
	CO2	CH4	N2O	CO2e
Gas Stream	237384			237384

Del Sur Compressors	Annual Emission Inventory Yearly Process Rates		GHG Emissions (MT/yr)			
	2022 MMSCFD	2022 MMBTU	CO2	CH4	N2O	CO2e
S-1548-433	25.94	25942.05	1375.45	0.026	0.003	1376.87
S-1548-434	34.53	34528.39	1830.70	0.035	0.003	1832.59

Baseline Total:	249041.19	1.99	0.02	249097.38

Post-Project GHG Emissions

	GHG Emissions (MT/yr)			
	CO2	CH4	N2O	CO2e
Baseline Total:	249041.19	1.99	0.02	249097.38
Increase Total:	63585.43	1.20	0.12	63651.15
Post-Project Total:	312626.62	3.18	0.14	312748.53

Aera Energy
Bakersfield, CA

GHG Emissions - COGEN32

Project Increase GHG Emissions

Utility Steam Generators (NEW)
Inputs

Parameters	Value	Unit
Fuel Rating	85	MMBtu/hr
Annual Fuel Use	648240	MMBTU/yr

Existing Steam Generators
Inputs

Parameters	Value	Unit
Fuel Rating	235.4	MMBtu/hr
Annual Fuel Use Increase -148	446964.55	MMBTU/yr
Annual Fuel Use Increase -149	444019.81	MMBTU/yr
Annual Fuel Use Increase -151	346165.09	MMBTU/yr

Emission Factors

Pollutant	Emission Factor	Unit
CO2	116.89	lb/MMBtu
CH4	0.0022	lb/MMBtu
N2O	0.0002	lb/MMBtu

Potential to Emit

	Hourly Emissions (lb/hr)				Daily Emissions (lbs/day)				Yearly Emissions (tpy)			
Emissions Unit	CO2	CH4	CH4	CO2e	CO2	CH4	CH4	CO2e	CO2	CH4	CH4	CO2e
Utility SG 1	9935.56	0.19	0.02	9945.83	238453.46	4.50	0.45	238699.92	37886.05	0.71	0.07	37925.21
Utility SG 2	9935.56	0.19	0.02	9945.83	238453.46	4.50	0.45	238699.92	37886.05	0.71	0.07	37925.21
Utility SG 3	9935.56	0.19	0.02	9945.83	238453.46	4.50	0.45	238699.92	37886.05	0.71	0.07	37925.21
S-1547-148	27515.66	0.52	0.05						26122.61	0.49	0.05	26149.61
S-1547-149									25950.51	0.49	0.05	25977.33
S-1547-151									20231.44	0.38	0.04	20252.35

Baseline Emissions

Parameters

Permit ID	Fuel Limit (MMbtu/day)	Heat Rating (MMbtu/hr)	Emissions Factors (lb/MMBtu)		
			CO2	CH4	N2O
S-1547-148	5650	235.4	116.89	0.0022	0.0002
S-1547-149	5650	235.4	116.89	0.0022	0.0002
S-1547-151	5650	235.4	116.89	0.0022	0.0002

Fuel Usage*

Permit ID	Fuel Usage** (MMBtu/yr)	Fuel Usage (MMscf/yr)
	2022	2022
S-1547-148	1615285.45	1615.29
S-1547-149	1618230.19	1618.23
S-1547-151	1716084.91	1716.08

*Fuel Data from 2022 Annual Emissions Inventory
** A HHV value of 1000 MMBtu/MMscf is assumed

Historical Emissions

Permit ID	Annual Emissions (tpy)			
	2022			
	CO2	CH4	N2O	CO2e
S-1547-148	94404.51	1.78	0.18	94502.09
S-1547-149	94576.62	1.78	0.18	94674.37
S-1547-151	100295.68	1.89	0.19	100399.35

Post-Project GHG Emissions

Cogen 32 GHG Emissions Summary

Emission Unit	Annual Emissions (MT/yr)			
	CO2	CH4	N2O	CO2e
Baseline				
S-1547-148	85642.33	1.62	0.16	85730.85
S-1547-149	85798.46	1.62	0.16	85887.14
S-1547-151	90986.71	1.72	0.17	91080.76
Project Increase				
Utility SG 1	34369.64	0.65	0.06	34405.17
Utility SG 2	34369.64	0.65	0.06	34405.17
Utility SG 3	34369.64	0.65	0.06	34405.17
S-1547-148	23698.03	0.45	0.04	23722.53
S-1547-149	23541.90	0.44	0.04	23566.23
S-1547-151	18353.65	0.35	0.03	18372.62

Aera Energy
Bakersfield, CA

GHG Emissions - SGS2972

Project Increase GHG Emissions

Utility Steam Generators (NEW)

Inputs

Parameters	Value	Unit
Fuel Rating	100	MMBtu/hr
Annual Fuel Use	788400	MMBTU/yr

Existing Steam Generators

Inputs

Parameters	Value	Unit
Fuel Rating	85	MMBtu/hr
Annual Fuel Use Increase -1162	170097.80	MMBTU/yr
Annual Fuel Use Increase -1163	144573.56	MMBTU/yr
Annual Fuel Use Increase -1164	126675.68	MMBTU/yr
Annual Fuel Use Increase -1173	143804.30	MMBTU/yr
Annual Fuel Use Increase -1174	166959.81	MMBTU/yr
Annual Fuel Use Increase -1175	153737.11	MMBTU/yr
Annual Fuel Use Increase -1176	93957.67	MMBTU/yr
Annual Fuel Use Increase -1177	121608.21	MMBTU/yr
Annual Fuel Use Increase -1178	81904.40	MMBTU/yr
Annual Fuel Use Increase -1180	161065.31	MMBTU/yr
Annual Fuel Use Increase -1261	138470.21	MMBTU/yr

Emission Factors

Pollutant	Emission Factor	Unit
CO2	116.89	lb/MMBtu
CH4	0.0022	lb/MMBtu
N2O	0.0002	lb/MMBtu

Potential to Emit

	Hourly Emissions (lb/hr)				Daily Emissions (lbs/day)				Yearly Emissions (tpy)			
Emissions Unit	**CO2**	**CH4**	**CH4**	**CO2e**	**CO2**	**CH4**	**CH4**	**CO2e**	**CO2**	**CH4**	**CH4**	**CO2e**
Utility SG 1	11688.90	0.22	0.02	11700.98	280533.49	5.29	0.53	280823.44	46077.63	0.87	0.09	46125.25
Utility SG 2	11688.90	0.22	0.02	11700.98	280533.49	5.29	0.53	280823.44	46077.63	0.87	0.09	46125.25
Utility SG 3	11688.90	0.22	0.02	11700.98	280533.49	5.29	0.53	280823.44	46077.63	0.87	0.09	46125.25
S-1547-1162									9941.28	0.19	0.02	9951.55
S-1547-1163									8449.53	0.16	0.02	8458.26
S-1547-1164									7403.49	0.14	0.01	7411.15
S-1547-1173									8404.57	0.16	0.02	8413.25
S-1547-1174									9757.88	0.18	0.02	9767.96
S-1547-1175									8985.08	0.17	0.02	8994.37
S-1547-1176									5491.31	0.10	0.01	5496.98
S-1547-1177									7107.33	0.13	0.01	7114.67
S-1547-1178									4786.86	0.09	0.01	4791.81
S-1547-1180									9413.38	0.18	0.02	9423.11
S-1547-1261									8092.82	0.15	0.02	8101.18

Baseline Emissions

Parameters

Permit ID	Fuel Limit (MMbtu/yr)	Heat Rating (MMbtu/hr)	Emissions Factors (lb/MMBtu)		
			CO2	CH4	N2O
S-1547-1162	672000	85	116.89	0.0022	0.0002
S-1547-1163	672000	85	116.89	0.0022	0.0002
S-1547-1164	672000	85	116.89	0.0022	0.0002
S-1547-1173	672000	85	116.89	0.0022	0.0002
S-1547-1174	672000	85	116.89	0.0022	0.0002
S-1547-1175	672000	85	116.89	0.0022	0.0002
S-1547-1176	672000	85	116.89	0.0022	0.0002
S-1547-1177	672000	85	116.89	0.0022	0.0002
S-1547-1178	672000	85	116.89	0.0022	0.0002
S-1547-1180	672000	85	116.89	0.0022	0.0002
S-1547-1261	876000	100	116.89	0.0022	0.0002

Fuel Usage*

Permit ID	Fuel Usage** (MMBtu/yr)	Fuel Usage (MMscf/yr)
	2022	2022
S-1547-1162	501902.20	501.90
S-1547-1163	527426.44	527.43
S-1547-1164	545324.32	545.32
S-1547-1173	528195.70	528.20
S-1547-1174	505040.19	505.04
S-1547-1175	518262.89	518.26
S-1547-1176	578042.33	578.04
S-1547-1177	550391.79	550.39
S-1547-1178	590095.60	590.10
S-1547-1180	510934.69	510.93
S-1547-1261	737529.79	737.53

*Fuel Data from 2022 Annual Emissions Inventory

** A HHV value of 1000 MMBtu/MMscf is assumed

Historical Emissions

Permit ID	Annual Emissions (tpy)			
	2022			
	CO2	CH4	N2O	CO2e
S-1547-1162	29333.41	0.55	0.06	29363.73
S-1547-1163	30825.16	0.58	0.06	30857.02
S-1547-1164	31871.19	0.60	0.06	31904.14
S-1547-1173	30870.12	0.58	0.06	30902.03
S-1547-1174	29516.81	0.56	0.06	29547.32
S-1547-1175	30289.60	0.57	0.06	30320.91
S-1547-1176	33783.38	0.64	0.06	33818.30
S-1547-1177	32167.36	0.61	0.06	32200.61
S-1547-1178	34487.83	0.65	0.07	34523.47
S-1547-1180	29861.31	0.56	0.06	29892.17
S-1547-1261	43104.54	0.81	0.08	43149.09

Post-Project GHG Emissions

SGS 2972 GHG Emissions Summary

Emission Unit	Annual Emissions (MT/yr)			
	CO2	CH4	N2O	CO2e
Baseline				
S-1547-1162	26610.82	0.50	0.05	26638.33
S-1547-1163	27964.12	0.53	0.05	27993.02
S-1547-1164	28913.06	0.55	0.05	28942.94
S-1547-1173	28004.90	0.53	0.05	28033.85
S-1547-1174	26777.20	0.51	0.05	26804.88
S-1547-1175	27478.27	0.52	0.05	27506.67
S-1547-1176	30647.77	0.58	0.06	30679.44
S-1547-1177	29181.74	0.55	0.06	29211.90
S-1547-1178	31286.83	0.59	0.06	31319.17
S-1547-1180	27089.73	0.51	0.05	27117.72
S-1547-1261	39103.78	0.74	0.07	39144.20
Project Increase				
Utility SG 1	41800.92	0.79	0.08	41844.12
Utility SG 2	41800.92	0.79	0.08	41844.12
Utility SG 3	41800.92	0.79	0.08	41844.12
S-1547-1162	9018.57	0.17	0.02	9027.90
S-1547-1163	7665.28	0.14	0.01	7673.20
S-1547-1164	6716.34	0.13	0.01	6723.28
S-1547-1173	7624.49	0.14	0.01	7632.38
S-1547-1174	8852.20	0.17	0.02	8861.35
S-1547-1175	8151.13	0.15	0.02	8159.56
S-1547-1176	4981.63	0.09	0.01	4986.78
S-1547-1177	6447.66	0.12	0.01	6454.32
S-1547-1178	4342.57	0.08	0.01	4347.05
S-1547-1180	8539.67	0.16	0.02	8548.50
S-1547-1261	7341.68	0.14	0.01	7349.27

Aera Energy
Bakersfield, CA

GHG Emissions - SGS2868

Project Increase GHG Emissions

Utility Steam Generators (NEW)

Inputs

Parameters	Value	Unit
Fuel Rating	100	MMBtu/hr
Annual Fuel Use	709560	MMBTU/yr

Existing Steam Generators

Inputs

Parameters	Value	Unit
Fuel Rating	85	MMBtu/hr
Annual Fuel Use Increase -1142	312466.35	MMBTU/yr
Annual Fuel Use Increase -1143	176610.82	MMBTU/yr
Annual Fuel Use Increase -1144	218437.75	MMBTU/yr
Annual Fuel Use Increase -1145	174625.48	MMBTU/yr
Annual Fuel Use Increase -1146	98346.45	MMBTU/yr
Annual Fuel Use Increase -1147	275334.38	MMBTU/yr
Annual Fuel Use Increase -1148	226224.13	MMBTU/yr
Annual Fuel Use Increase -1149	131760.46	MMBTU/yr
Annual Fuel Use Increase -1150	120997.29	MMBTU/yr
Annual Fuel Use Increase -1151	213585.98	MMBTU/yr

Emission Factors

Pollutant	Emission Factor	Unit
CO2	116.8889524	lb/MMBtu
CH4	0.00220462	lb/MMBtu
N2O	0.000220462	lb/MMBtu

Potential to Emit

	Hourly Emissions (lb/hr)				Daily Emissions (lbs/day)				Yearly Emissions (tpy)			
Emissions Unit	**CO2**	**CH4**	**CH4**	**CO2e**	**CO2**	**CH4**	**CH4**	**CO2e**	**CO2**	**CH4**	**CH4**	**CO2e**
Utility SG 1	11688.90	0.22	0.02	11700.98	280533.49	5.29	0.53	280823.44	41469.86	0.78	0.08	41512.72
Utility SG 2	11688.90	0.22	0.02	11700.98	280533.49	5.29	0.53	280823.44	41469.86	0.78	0.08	41512.72
Utility SG 3	11688.90	0.22	0.02	11700.98	280533.49	5.29	0.53	280823.44	41469.86	0.78	0.08	41512.72
Annual Fuel Use Increase -1142									18261.93	0.34	0.03	18280.81
Annual Fuel Use Increase -1143									10321.93	0.19	0.02	10332.60
Annual Fuel Use Increase -1144									12766.48	0.24	0.02	12779.67
Annual Fuel Use Increase -1145									10205.89	0.19	0.02	10216.44
Annual Fuel Use Increase -1146									5747.81	0.11	0.01	5753.75
Annual Fuel Use Increase -1147									16091.77	0.30	0.03	16108.41
Annual Fuel Use Increase -1148									13221.55	0.25	0.02	13235.22
Annual Fuel Use Increase -1149									7700.67	0.15	0.01	7708.63
Annual Fuel Use Increase -1150									7071.62	0.13	0.01	7078.93
Annual Fuel Use Increase -1151									12482.92	0.24	0.02	12495.82

Baseline Emissions

Parameters

Permit ID	Fuel Limit (MMscf/yr)	Heat Rating (MMbtu/hr)	Emissions Factors (lb/MMBtu)		
			CO2	CH4	N2O
S-1547-1142	730	85	116.89	0.0022	0.0002
S-1547-1143	730	85	116.89	0.0022	0.0002
S-1547-1144	730	85	116.89	0.0022	0.0002
S-1547-1145	730	85	116.89	0.0022	0.0002
S-1547-1146	730	85	116.89	0.0022	0.0002
S-1547-1147	730	85	116.89	0.0022	0.0002
S-1547-1148	730	85	116.89	0.0022	0.0002
S-1547-1149	730	85	116.89	0.0022	0.0002
S-1547-1150	730	85	116.89	0.0022	0.0002
S-1547-1151	730	85	116.89	0.0022	0.0002

Fuel Usage*

Permit ID	Fuel Usage** (MMBtu/yr)	Fuel Usage (MMScf/yr)
	2022	2022
S-1547-1142	417533.65	417.53
S-1547-1143	553389.18	553.39
S-1547-1144	511562.25	511.56
S-1547-1145	555374.52	555.37
S-1547-1146	631653.55	631.65
S-1547-1147	454665.62	454.67
S-1547-1148	503775.87	503.78
S-1547-1149	598239.54	598.24
S-1547-1150	609002.71	609.00
S-1547-1151	516414.02	516.41

*Fuel Data from 2022 Annual Emissions Inventory

** A HHV value of 1000 MMBtu/MMscf is assumed

Historical Emissions

Permit ID	Annual Emissions (tpy)			
	2022			
	CO2	CH4	N2O	CO2e
S-1547-1142	24402.53547	0.460251518	0.046025152	24427.75725
S-1547-1143	32342.54076	0.610006427	0.061000643	32375.96911
S-1547-1144	29897.98774	0.563900184	0.056390018	29928.88948
S-1547-1145	32458.57292	0.612194887	0.061219489	32492.1212
S-1547-1146	36916.66087	0.696278025	0.069627802	36954.81691
S-1547-1147	26572.69401	0.50118246	0.050118246	26600.15881
S-1547-1148	29442.91684	0.555317179	0.055531718	29473.34823
S-1547-1149	34963.79656	0.659445427	0.065944543	34999.93417
S-1547-1150	35592.84439	0.671309777	0.067130978	35629.63217
S-1547-1151	30181.5469	0.569248338	0.056924834	30212.74171

Post-Project GHG Emissions

SGS 2868 Emissions Summary

Emission Unit	Annual Emissions (MT/yr)			
	CO2	CH4	N2O	CO2e
Baseline				
S-1547-1142	22137.61	0.42	0.04	22160.49
S-1547-1143	29340.66	0.55	0.06	29370.99
S-1547-1144	27123.00	0.51	0.05	27151.03
S-1547-1145	29445.92	0.56	0.06	29476.36
S-1547-1146	33490.23	0.63	0.06	33524.85
S-1547-1147	24106.34	0.45	0.05	24131.26
S-1547-1148	26710.16	0.50	0.05	26737.77
S-1547-1149	31718.62	0.60	0.06	31751.41
S-1547-1150	32289.29	0.61	0.06	32322.66
S-1547-1151	27380.24	0.52	0.05	27408.54
Project Increase				
Utility SG 1	37620.83	0.71	0.07	37659.71
Utility SG 2	37620.83	0.71	0.07	37659.71
Utility SG 3	37620.83	0.71	0.07	37659.71
S-1547-1142	16566.95	0.31	0.03	16584.07
S-1547-1143	9363.89	0.18	0.02	9373.57
S-1547-1144	11581.56	0.22	0.02	11593.53
S-1547-1145	9258.63	0.17	0.02	9268.20
S-1547-1146	5214.32	0.10	0.01	5219.71
S-1547-1147	14598.21	0.28	0.03	14613.30
S-1547-1148	11994.39	0.23	0.02	12006.79
S-1547-1149	6985.93	0.13	0.01	6993.15
S-1547-1150	6415.27	0.12	0.01	6421.90
S-1547-1151	11324.32	0.21	0.02	11336.02

Aera Energy
Bakersfield, CA

Assumptions

- SDS provides little information about the cycloamine's so they are approximated using the following assumptions:
  - Molecular weight is directly proportional to relative vapor density
  - Vapor pressure of pure water is 0.2 psi. The dilute amine solution has a lower vapor pressure than water. Hence the cycloamine is less volatile than water and the concentrated amine solution is conservatively assumed to have the same vapor pressure as the dilute solution.
  - Chemical data from SDS provided by Anthony Gurrola on 4/24/23
- Raw water and cooling water meet the definition of clean produced water, so no emissions are calculated from those tanks
- Pressure vessels do not breath and hence the only emissions from those systems are fugitive and accounted for in fugitive sections

Chemical Information

Chemical Name	Molecular Weight[1]	Liquid Density[2] (lb/gal)	Vapor Pressure (psi)	Percent Composition by Weight	
Dow Monoethanolamine	61.08	8.51	0.00725189	99.8% Monoethanolamine, 0.2% Diethanolamine	-4.926493154
Piperazine	86	8.65	0.06767871	69% Piperazine, 33% Water, 0.3% Ethylenediamine	-2.692983624

[1]Molecular weight of amine compounds is calculated using relative vapour density data. $MW_{compound}$ = Relative Density * MW_{air} = 4.5 * 9

[2]Liquid Density = Specific $Gravity_{compound}$ * $Density_{water}$

Tank Specifications

Tank Name	Annual Throughput[3] (gal/yr)	Max Hourly Throughput (gal/hr)	Diameter (ft)	Height (ft)	Construction Material	Nominal Operating Pressure (psig)	Min Vent Relieving Pressure (psig)	Max Vent Relieving Pressure (psig)	Max Liquid Level (ft)	Min Liquid Level	Roof Slope[4] (in/ft)	Max. Pump Rate (gal/hr)	# of Combo PV Vents	# of P Vents	# of V Vents	# of Open Vents	Contents
Dilute Amine Storage	1,051,200,000	120000	30	24	Stainless Steel	0	0.144505159	0.216757739	22	2	0.75	120000	1	1	0	0	Dow Monoethanolamine
Fresh Amine Storage	70,490	4	15	18	Stainless Steel	0	0.144505159	0.216757739	16	2	0.75	4	1	1	0	0	Dow Monoethanolamine
Piperazine	2,313	20	10	15	Stainless Steel	0	0.144505159	0.216757739	13	2	0.75	20	1	1	0	0	Piperazone

[3]Annual Throughput calculated as follows:

- Dilute Amine Throughput = Max Hourly Throughput * 8760 hours
- Fresh Amine & Piperazine = Yearly Chemical Usage (tpy) * 2000 (lbs/ton) / density (lbs/gal)
- Yearly chemical usage from "Post-C Chemicals.xlsx" provided by Aera Energy

[4]Tank roof slope is unkown at this time so, per AP-42, Section 7.1, a conservative value of 0.0625 ft/ft or 0.75 in/ft is used.

Tank ESP Results

	Max Hourly Emissions (lbs/hr)		Total Annual Emissions (lbs/yr)	
Tank Name	Standing Losses	Working Losses	Standing Losses	Working Losses
Dilute Amine Storage	1.57966E-05	0.002438274	0.000379118	0.058518582
Fresh Amine Storage	2.99869E-06	4.72266E-07	7.19685E-05	2.28014E-05
Piperazine	0.000269452	0.000569438	0.006466852	0.000180426

Criteria Pollutant Emissions

	Weight Percent	VOC Emissions	
Tank Name	VOC	lb/hr	tpy
Dilute Amine Storage	100.00%	0.002454071	2.94488E-05
Fresh Amine Storage	100.00%	3.47096E-06	4.7385E-08
Piperazine	69.30%	0.000581351	2.30328E-06

HAP Emissions

	VOC Composition				Hourly Emissions (Lb HAP/hr)				Annual Emissions (lbs HAP/yr)			
Tank Name	Methanolamine	Diethanolamine	Piperazine	Ethylenediamine	Methanolamine	Diethanolamine	Piperazine	Ethylenediamine	Methanolamine	Diethanolamine	Piperazine	Ethylenediamine
Dilute Monoethanolamine Storage	99.80%	0.20%	0.00%	0.00%	2.45E-03	4.91E-06	0.00E+00	0.00E+00	5.88E-02	1.18E-04	0.00E+00	0.00E+00
Fresh Monoethanolamine Storage	99.80%	0.20%	0.00%	0.00%	3.46E-06	6.94E-09	0.00E+00	0.00E+00	9.46E-05	1.90E-07	0.00E+00	0.00E+00
Piperazine	0%	0%	99.57%	0.43%	0.00E+00	0.00E+00	5.79E-04	2.52E-06	0.00E+00	0.00E+00	4.59E-03	1.99E-05

Aera Energy
Bakersfield, CA
S-1547

Assumptions

- SDS provides little information about the cycloamine's so they are approximated using the following assumptions:
  - Molecular weight is directly proportional to relative vapor density
  - Vapor pressure of pure water is 0.2 psi. The dilute cylic amine solution has a lower vapor pressure than water. Hence the cycloamine is less volatile than water and the concentrated amine solution is conservatively assumed to have the same vapor pressure as the dilute solution.
  - Chemical data from SDS provided by Anthony Gurrola on 4/24/23
- Raw water and cooling water meet the definition of clean produced water, so no emissions are calculated from those tanks
- Pressure vessels do not breath and hence the only emissions from those systems are fugitive and accounted for in fugitive sections

Chemical Information

Chemical Name	Molecular Weight[1]	Liquid Density[2] (lb/gal)	Vapor Pressure[3] (psi)	Percent Composition by Weight
Dilute Cyclic Amine	130.5	8.91	1.89E-03	52% Cycloamine, 41.5% Water, 0.5% Ethylene Glycol
Concentrated Cyclic Amine	130.5	8.89	1.89E-03	99.5% Cycloamine, 0.5% Ethylene Glycol
Sulfuric Acid	98.08	15.36	1.93E-02	96% Sulfuric Acid, 4% Water

[1]Molecular weight of amine compounds is calculated using relative vapour density data. $MW_{compound}$ = Relative Density * MW_{air} = 4.5 * 9

[2]Liquid Density = Specific $Gravity_{compound}$ * $Density_{water}$

Tank Specifications

Tank Name	Annual Throughput[3] (gal/yr)	Max Hourly Throughput (gal/hr)	Diameter (ft)	Height (ft)	Construction Material	Nominal Operating Pressure (psig)	Min Vent Relieving Pressure (psig)	Max Vent Relieving Pressure (psig)	Max Liquid Level (ft)	Min Liquid Level	Roof Slope[4] (in/ft)	Max. Pump Rate (gal/hr)	# of Combo PV Vents	# of P Vents	# of V Vents	# of Open Vents	Contents
Dilute Cyclic Amine	2,093,640,000	239000	30	32	SS	0	0.144505159	0.216757739	30	2	0.75	239000	1	1	0	0	Dilute Cyclic Amine
Concentrated Cyclic Amine	67,511	20	15	18	FRP or SS	0	0.144505159	0.216757739	16	2	0.75	20	1	1	0	0	Concentrated Cylic Amine
Sulfuric Acid	19,536	10	10	15	CS, FRP, or Poly	0	0.144505159	0.216757739	13	2	0.75	10	1	1	0	0	Sulfuric Acid

[3]Annual Throughput calculated as follows:

- Dilute Amine Throughput = Max Hourly Throughput * 8760 hours
- Fresh Amine & Sulfuric Acid = Yearly Chemical Usage (tpy) * 2000 (lbs/ton) / density (lbs/gal)
- Yearly chemical usage from "Post-C Chemicals.xlsx" provided by Aera Energy

[4]Tank roof slope is unkown at this time so, per AP-42, Section 7.1, a conservative value of 0.0625 ft/ft or 0.75 in/ft is used.

Tank ESP Results

	Max Hourly Emissions (lbs/hr)		Total Annual Emissions (lbs/yr)	
Tank Name	Standing Losses	Working Losses	Standing Losses	Working Losses
Dilute Cyclic Amine	3.52098E-09	1.32238E-06	4.89983E-05	0.011145283
Concentrated Cyclic Amine	5.97761E-13	7.73796E-13	8.28307E-09	2.51338E-09
Sulfuric Acid	2.54497E-08	5.17803E-08	0.000327629	9.76726E-05

Criteria Pollutant Emissions

	Weight Percent	Weight Percent	VOC Emissions		Sulfur Compound Emissions	
Tank Name	VOC	Sulfur Compounds	lb/hr	tpy	lb/hr	tpy
Dilute Cyclic Amine	52.50%	0%	6.96097E-07	2.9385E-06	0	0
Concentrated Cyclic Amine	100%	0%	1.37156E-12	5.39822E-12	0	0
Sulfuric Acid	0%	96%	0	0	7.41408E-08	2.04145E-07

HAP Emissions

	VOC Composition		Hourly Emissions (Lb HAP/hr)			Annual Emissions (lbs HAP/yr)		
Tank Name	Cycloamine	Ethylene Glycol	Cycloamine	Ethylene Glycol	Sulfuric Acid	Cycloamine	Ethylene Glycol	Sulfuric Acid
Dilute Cyclic Amine	99%	0.95%	6.89468E-07	6.6295E-09	0	0.005821026	5.59714E-05	0
Concentrated Cyclic Amine	99.50%	0.50%	1.3647E-12	6.85778E-15	0	1.07425E-08	5.39822E-11	0
Sulfuric Acid	0%	0%	0	0	7.41408E-08	0	0	0.000408289

Aera Energy
Bakersfield, CA

CCS Cooling Tower Emissions - Pre Combustion

Assumptions
- When calculating potential emissions PM = PM10 = PM2.5

Inputs

Parameter	Value	Units
Cooling Water Recirculation Rate	1200	gpm
Circulating Water TDS	3000	ppmw
Drift Rate	0.005	%

Criteria Emissions

Equipment	Total Drift Rate[2] (lbs/min)	PM10 Emissions (lb/hr)	PM10 Emissions (tpy)	PM2.5 Emissions (lb/hr)	PM2.5 Emissions (tpy)
Cooling Tower	0.50	0.09	0.39	0.09	0.39

[1]Assuming density of water to be 8.3454 lb/gal
[2]Total Drift Rate (lbs PM/min) = Cooling Water Recirculation Rate (gpm) * Density Water (lbs/gal) * Drift Rate (%)/100

HAP Emissions

Pollutant	TDS_{HAP}[6]	Total Liquid Drift[4] (lb/gal)	Wt % HAP in Solution[3]	Hourly Emissions[5] (lb HAP/hr)	Annual Emissions[6] (lb HAP/yr)
Sulfuric Acid	2.97357E-05	0.0017	96%	8.74E-09	7.65E-05

[3]See tank emission calculations page C13*D26*(C14/10^6)*0.001*60*E26
[4]Per AP-42 Section 13.4, Table 13.4-1, Induced Draft Tower Type
[5]Hourly Emissions (lb HAP/hr) = Cooling Water Recirculation Rate (gpm) * Total Liquid Drift (lb/gal) * $TDS/10^6$ * 60 min/hr * Wt% HAP
[5]Annual Emissions (lb HAP/yr) = Cooling Water Recirculation Rate (gpm) * Total Liquid Drift (lb/gal) * $TDS/10^6$ * 60 min/hr * 8760 hr/yr * Wt% HAP
[6]TDS_{HAP}= Sulfuric Acid Solution Usage (gal/yr) * wt% HAP / Cooling Water Use (gal/yr)

Aera Energy
Bakersfield, CA

CCS Cooling Tower Emissions - Cogen 32

Assumptions
- When calculating potential emissions PM = PM10 = PM2.5

Inputs

Parameter	Value	Units
Cooling Water Recirculation Rate	9775	gpm
Circulating Water TDS	3000	ppmw
Drift Rate	0.005	%

Criteria Emissions

Equipment	Total Drift Rate[2] (lbs/min)	PM10 Emissions (lb/hr)	PM10 Emissions (tpy)	PM2.5 Emissions (lb/hr)	PM2.5 Emissions (tpy)
Cooling Tower	4.08	0.73	3.22	0.73	3.22

[1]Assuming density of water to be 8.3454 lb/gal
[2]Total Drift Rate (lbs PM/min) = Cooling Water Recirculation Rate (gpm) * Density Water (lbs/gal) * Drift Rate (%)/100

HAP Emissions

Pollutant	TDS_{HAP}[6]	Total Liquid Drift[4] (lb/gal)	Wt % HAP in Solution[3]	Hourly Emissions[5] (lb HAP/hr)	Annual Emissions[6] (lb HAP/yr)
Sulfuric Acid	3.65042E-06	0.0017	96%	1.07E-09	9.39E-06

[3]See tank emission calculations page C13*D26*(C14/10^6)*0.001*60*E26
[4]Per AP-42 Section 13.4, Table 13.4-1, Induced Draft Tower Type
[5]Hourly Emissions (lb HAP/hr) = Cooling Water Recirculation Rate (gpm) * Total Liquid Drift (lb/gal) * $TDS/10^6$ * 60 min/hr * Wt% HAP
[5]Annual Emissions (lb HAP/yr) = Cooling Water Recirculation Rate (gpm) * Total Liquid Drift (lb/gal) * $TDS/10^6$ * 60 min/hr * 8760 hr/yr * Wt% HAP
[6]TDS_{HAP}= Sulfuric Acid Solution Usage (gal/yr) * wt% HAP / Cooling Water Use (gal/yr)

Aera Energy
Bakersfield, CA

CCS Cooling Tower Emissions - SGS 2972

Assumptions
- When calculating potential emissions PM = PM10 = PM2.5

Inputs

Parameter	Value	Units
Cooling Water Recirculation Rate	8500	gpm
Circulating Water TDS	3000	ppmw
Drift Rate	0.005	%

Criteria Emissions

Equipment	Total Drift Rate[2] (lbs/min)	PM10 Emissions (lb/hr)	PM10 Emissions (tpy)	PM2.5 Emissions (lb/hr)	PM2.5 Emissions (tpy)
Cooling Tower	3.55	0.64	2.80	0.64	2.80

[1]Assuming density of water to be 8.3454 lb/gal
[2]Total Drift Rate (lbs PM/min) = Cooling Water Recirculation Rate (gpm) * Density Water (lbs/gal) * Drift Rate (%)/100

HAP Emissions

Pollutant	TDS_{HAP}[6]	Total Liquid Drift[4] (lb/gal)	Wt % HAP in Solution[3]	Hourly Emissions[5] (lb HAP/hr)	Annual Emissions[6] (lb HAP/yr)
Sulfuric Acid	4.19798E-06	0.0017	96%	1.23E-09	1.08E-05

[3]See tank emission calculations page
[4]Per AP-42 Section 13.4, Table 13.4-1, Induced Draft Tower Type
[5]Hourly Emissions (lb HAP/hr) = Cooling Water Recirculation Rate (gpm) * Total Liquid Drift (lb/gal) * $TDS/10^6$ * 60 min/hr * Wt% HAP
[5]Annual Emissions (lb HAP/yr) = Cooling Water Recirculation Rate (gpm) * Total Liquid Drift (lb/gal) * $TDS/10^6$ * 60 min/hr * 8760 hr/yr * Wt% HAP
[6]TDS_{HAP}= Sulfuric Acid Solution Usage (gal/yr) * wt% HAP / Cooling Water Use (gal/yr)

Aera Energy
Bakersfield, CA

CCS Cooling Tower Emissions - SGS 2868

Assumptions
- When calculating potential emissions PM = PM10 = PM2.5

Inputs

Parameter	Value	Units
Cooling Water Recirculation Rate	7650	gpm
Circulating Water TDS	3000	ppmw
Drift Rate	0.005	%

Criteria Emissions

Equipment	Total Drift Rate (lbs/min)	PM10 Emissions (lb/hr)	PM10 Emissions (tpy)	PM2.5 Emissions (lb/hr)	PM2.5 Emissions (tpy)
Cooling Tower	3.19	0.57	2.52	0.57	2.52

[1]Assuming density of water to be 8.3454 lb/gal
[2]Total Drift Rate (lbs PM/min) = Cooling Water Recirculation Rate (gpm) * Density Water (lbs/gal) * Drift Rate (%)/100

HAP Emissions

Pollutant	TDS_{HAP}[6]	Total Liquid Drift[4] (lb/gal)	Wt % HAP in Solution[3]	Hourly Emissions[5] (lb HAP/hr)	Annual Emissions[6] (lb HAP/yr)
Sulfuric Acid	4.66442E-06	0.0017	96%	1.37E-09	1.20E-05

[3]See tank emission calculations page
[4]Per AP-42 Section 13.4, Table 13.4-1, Induced Draft Tower Type
[5]Hourly Emissions (lb HAP/hr) = Cooling Water Recirculation Rate (gpm) * Total Liquid Drift (lb/gal) * $TDS/10^6$ * 60 min/hr * Wt% HAP
[5]Annual Emissions (lb HAP/yr) = Cooling Water Recirculation Rate (gpm) * Total Liquid Drift (lb/gal) * $TDS/10^6$ * 60 min/hr * 8760 hr/yr * Wt% HAP
[6]TDS_{HAP}= Sulfuric Acid Solution Usage (gal/yr) * wt% HAP / Cooling Water Use (gal/yr)

Aera Energy
Bakersfield, CA

CCS Steam Generator Emissions - Pre Combustion

Project Increase Criteria Emissions and HAPS

Utility Steam Generators (NEW)

Inputs

Parameters	Value	Unit
Fuel Rating	65	MMBtu/hr
Annual Fuel Use	569400	MMBTU/yr

Emission Factors

Pollutant	Emission Factor	Unit
NOx	0.0061	lb/MMBtu
SOx	0.01	lb/MMBtu
CO	0.01878	lb/MMBtu
PM10	0.0076	lb/MMBtu
VOC	0.0055	lb/MMBtu

Potential to Emit

	Hourly Emissions (lb/hr)					Daily Emissions (lbs/day)					Yearly Emissions (tpy)				
Emissions Unit	NOx	SOx	CO	PM10	VOC	NOx	SOx	CO	PM10	VOC	NOx	SOx	CO	PM10	VOC
Utility SG 1	0.3965	0.65	1.2207	0.494	0.3575	9.516	15.6	29.2968	11.856	8.58	1.73667	2.847	5.346666	2.16372	1.56585
Utility SG 2	0.3965	0.65	1.2207	0.494	0.3575	9.516	15.6	29.2968	11.856	8.58	1.73667	2.847	5.346666	2.16372	1.56585
Total											**3.47**	**5.69**	**10.69**	**4.33**	**3.13**

HAP Emissions

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
Utility SG 1	37011.00	0.07	Acenaphthene	83329	5.40E-07	2.00E-02	3.51E-08
			Acenaphthylene	208968	3.70E-07	1.37E-02	2.41E-08
			Acetaldehyde	75070	1.40E-02	5.18E+02	9.10E-04
			Acrolein	107028	1.40E-02	5.18E+02	9.10E-04
			Anthracene	120127	2.40E-06	8.88E-02	1.56E-07
			Benz[a]anthracene	56553	1.30E-06	4.81E-02	8.45E-08
			Benzene	71432	1.60E-03	5.92E+01	1.04E-04
			Benzo[a]pyrene	50328	3.70E-07	1.37E-02	2.41E-08
			Benzo[b]fluoranthene	205992	3.70E-07	1.37E-02	2.41E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	1.37E-02	2.41E-08
			Benzo[k]fluoranthene	207089	3.70E-07	1.37E-02	2.41E-08
			Chrysene	218019	1.13E-06	4.18E-02	7.35E-08
			Dibenz[a,h]anthracene	53703	3.70E-07	1.37E-02	2.41E-08
			Ethyl benzene	100414	1.20E-02	4.44E+02	7.80E-04
			Fluoranthene	206440	1.40E-06	5.18E-02	9.10E-08
			Fluorene	86737	2.40E-06	8.88E-02	1.56E-07
			Formaldehyde	50000	3.30E-02	1.22E+03	2.15E-03
			Hydrogen sulfide	7783064	1.70E-01	6.29E+03	1.11E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	1.37E-02	2.41E-08
			Naphthalene	91203	1.87E-04	6.92E+00	1.22E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	9.99E-01	1.76E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	7.77E+00	1.37E-05
			Phenanthrene	85018	1.20E-05	4.44E-01	7.80E-07
			Propylene	115071	6.00E-01	2.22E+04	3.90E-02
			Pyrene	129000	2.00E-06	7.40E-02	1.30E-07
			Toluene	108883	2.00E-02	7.40E+02	1.30E-03
			Xylenes (mixed)	1330207	2.50E-02	9.25E+02	1.63E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
Utility SG 2	37011.00	0.07	Acenaphthene	83329	5.40E-07	2.00E-02	3.51E-08
			Acenaphthylene	208968	3.70E-07	1.37E-02	2.41E-08
			Acetaldehyde	75070	1.40E-02	5.18E+02	9.10E-04
			Acrolein	107028	1.40E-02	5.18E+02	9.10E-04
			Anthracene	120127	2.40E-06	8.88E-02	1.56E-07
			Benz[a]anthracene	56553	1.30E-06	4.81E-02	8.45E-08
			Benzene	71432	1.60E-03	5.92E+01	1.04E-04
			Benzo[a]pyrene	50328	3.70E-07	1.37E-02	2.41E-08
			Benzo[b]fluoranthene	205992	3.70E-07	1.37E-02	2.41E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	1.37E-02	2.41E-08
			Benzo[k]fluoranthene	207089	3.70E-07	1.37E-02	2.41E-08
			Chrysene	218019	1.13E-06	4.18E-02	7.35E-08
			Dibenz[a,h]anthracene	53703	3.70E-07	1.37E-02	2.41E-08
			Ethyl benzene	100414	1.20E-02	4.44E+02	7.80E-04
			Fluoranthene	206440	1.40E-06	5.18E-02	9.10E-08
			Fluorene	86737	2.40E-06	8.88E-02	1.56E-07
			Formaldehyde	50000	3.30E-02	1.22E+03	2.15E-03
			Hydrogen sulfide	7783064	1.70E-01	6.29E+03	1.11E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	1.37E-02	2.41E-08
			Naphthalene	91203	1.87E-04	6.92E+00	1.22E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	9.99E-01	1.76E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	7.77E+00	1.37E-05
			Phenanthrene	85018	1.20E-05	4.44E-01	7.80E-07
			Propylene	115071	6.00E-01	2.22E+04	3.90E-02
			Pyrene	129000	2.00E-06	7.40E-02	1.30E-07
			Toluene	108883	2.00E-02	7.40E+02	1.30E-03
			Xylenes (mixed)	1330207	2.50E-02	9.25E+02	1.63E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Baseline Criteria Emissions

Emissions Unit	Annual Emission Inventories (tons/yr)				
	NOX	**VOC**	**SOX**	**CO**	**PM10**
2009	6.69	6.00	0.64	28.04	0.55
2010	2.74	6.98	0.75	27.74	0.63
2011	1.68	5.52	0.50	20.00	0.49
2012	1.52	3.59	0.35	12.22	0.34
2013	2.74	6.58	0.49	16.79	0.42
2014	1.21	6.79	0.26	11.08	0.22
2015	2.90	4.48	0.40	20.82	0.29
2016	4.43	5.08	0.91	26.75	0.58
Average	**2.99**	**5.63**	**0.54**	**20.43**	**0.44**

Aera Energy
Bakersfield, CA

CCS Steam Generator Emissions - Cogen 32

Project Increase Criteria Emissions and HAPS

Utility Steam Generators (NEW)
Inputs

Parameters	Value	Unit
Fuel Rating	85	MMBtu/hr
Annual Fuel Use	648240	MMBTU/yr

Existing Steam Generators
Inputs

Parameters	Value	Unit
Fuel Rating	235.4	MMBtu/hr
Annual Fuel Use Increase -148	446964.55	MMBTU/yr
Annual Fuel Use Increase -149	444019.81	MMBTU/yr
Annual Fuel Use Increase -151	346165.09	MMBTU/yr

Emission Factors

Pollutant	Emission Factor	Unit
NOx	0.0061	lb/MMBtu
SOx	0.01	lb/MMBtu
CO	0.01878	lb/MMBtu
PM10	0.0076	lb/MMBtu
VOC	0.0055	lb/MMBtu

Potential to Emit

	Hourly Emissions (lb/hr)					Daily Emissions (lbs/day)					Yearly Emissions (tpy)				
Emissions Unit	NOx	SOx	CO	PM10	VOC	NOx	SOx	CO	PM10	VOC	NOx	SOx	CO	PM10	VOC
Utility SG 1	0.52	0.85	1.60	0.65	0.47	12.44	20.40	38.31	15.50	11.22	1.98	3.24	6.09	2.46	1.78
Utility SG 2	0.52	0.85	1.60	0.65	0.47	12.44	20.40	38.31	15.50	11.22	1.98	3.24	6.09	2.46	1.78
Utility SG 3	0.52	0.85	1.60	0.65	0.47	12.44	20.40	38.31	15.50	11.22	1.98	3.24	6.09	2.46	1.78
S-1547-148											1.36	2.23	4.20	1.70	1.23
S-1547-149											1.35	2.22	4.17	1.69	1.22
S-1547-151											1.06	1.73	3.25	1.32	0.95
Total											**9.70**	**15.91**	**29.88**	**12.09**	**8.75**

HAP Emissions

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
Utility SG 1	648.24	0.09	Acenaphthene	83329	5.40E-07	3.50E-04	4.59E-08
			Acenaphthylene	208968	3.70E-07	2.40E-04	3.15E-08
			Acetaldehyde	75070	1.40E-02	9.08E+00	1.19E-03
			Acrolein	107028	1.40E-02	9.08E+00	1.19E-03
			Anthracene	120127	2.40E-06	1.56E-03	2.04E-07
			Benz[a]anthracene	56553	1.30E-06	8.43E-04	1.11E-07
			Benzene	71432	1.60E-03	1.04E+00	1.36E-04
			Benzo[a]pyrene	50328	3.70E-07	2.40E-04	3.15E-08
			Benzo[b]fluoranthene	205992	3.70E-07	2.40E-04	3.15E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	2.40E-04	3.15E-08
			Benzo[k]fluoranthene	207089	3.70E-07	2.40E-04	3.15E-08
			Chrysene	218019	1.13E-06	7.33E-04	9.61E-08
			Dibenz[a,h]anthracene	53703	3.70E-07	2.40E-04	3.15E-08
			Ethyl benzene	100414	1.20E-02	7.78E+00	1.02E-03
			Fluoranthene	206440	1.40E-06	9.08E-04	1.19E-07
			Fluorene	86737	2.40E-06	1.56E-03	2.04E-07
			Formaldehyde	50000	3.30E-02	2.14E+01	2.81E-03
			Hydrogen sulfide	7783064	1.70E-01	1.10E+02	1.45E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	2.40E-04	3.15E-08
			Naphthalene	91203	1.87E-04	1.21E-01	1.59E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	1.75E-02	2.30E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	1.36E-01	1.79E-05
			Phenanthrene	85018	1.20E-05	7.78E-03	1.02E-06
			Propylene	115071	6.00E-01	3.89E+02	5.10E-02
			Pyrene	129000	2.00E-06	1.30E-03	1.70E-07
			Toluene	108883	2.00E-02	1.30E+01	1.70E-03
			Xylenes (mixed)	1330207	2.50E-02	1.62E+01	2.13E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
Utility SG 2	648.24	0.09	Acenaphthene	83329	5.40E-07	3.50E-04	4.59E-08
			Acenaphthylene	208968	3.70E-07	2.40E-04	3.15E-08
			Acetaldehyde	75070	1.40E-02	9.08E+00	1.19E-03
			Acrolein	107028	1.40E-02	9.08E+00	1.19E-03
			Anthracene	120127	2.40E-06	1.56E-03	2.04E-07
			Benz[a]anthracene	56553	1.30E-06	8.43E-04	1.11E-07
			Benzene	71432	1.60E-03	1.04E+00	1.36E-04
			Benzo[a]pyrene	50328	3.70E-07	2.40E-04	3.15E-08
			Benzo[b]fluoranthene	205992	3.70E-07	2.40E-04	3.15E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	2.40E-04	3.15E-08
			Benzo[k]fluoranthene	207089	3.70E-07	2.40E-04	3.15E-08
			Chrysene	218019	1.13E-06	7.33E-04	9.61E-08
			Dibenz[a,h]anthracene	53703	3.70E-07	2.40E-04	3.15E-08
			Ethyl benzene	100414	1.20E-02	7.78E+00	1.02E-03
			Fluoranthene	206440	1.40E-06	9.08E-04	1.19E-07
			Fluorene	86737	2.40E-06	1.56E-03	2.04E-07
			Formaldehyde	50000	3.30E-02	2.14E+01	2.81E-03
			Hydrogen sulfide	7783064	1.70E-01	1.10E+02	1.45E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	2.40E-04	3.15E-08
			Naphthalene	91203	1.87E-04	1.21E-01	1.59E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	1.75E-02	2.30E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	1.36E-01	1.79E-05
			Phenanthrene	85018	1.20E-05	7.78E-03	1.02E-06
			Propylene	115071	6.00E-01	3.89E+02	5.10E-02
			Pyrene	129000	2.00E-06	1.30E-03	1.70E-07
			Toluene	108883	2.00E-02	1.30E+01	1.70E-03
			Xylenes (mixed)	1330207	2.50E-02	1.62E+01	2.13E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
Utility SG 3	648.24	0.09	Acenaphthene	83329	5.40E-07	3.50E-04	4.59E-08
			Acenaphthylene	208968	3.70E-07	2.40E-04	3.15E-08
			Acetaldehyde	75070	1.40E-02	9.08E+00	1.19E-03
			Acrolein	107028	1.40E-02	9.08E+00	1.19E-03
			Anthracene	120127	2.40E-06	1.56E-03	2.04E-07
			Benz[a]anthracene	56553	1.30E-06	8.43E-04	1.11E-07
			Benzene	71432	1.60E-03	1.04E+00	1.36E-04
			Benzo[a]pyrene	50328	3.70E-07	2.40E-04	3.15E-08
			Benzo[b]fluoranthene	205992	3.70E-07	2.40E-04	3.15E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	2.40E-04	3.15E-08
			Benzo[k]fluoranthene	207089	3.70E-07	2.40E-04	3.15E-08
			Chrysene	218019	1.13E-06	7.33E-04	9.61E-08
			Dibenz[a,h]anthracene	53703	3.70E-07	2.40E-04	3.15E-08
			Ethyl benzene	100414	1.20E-02	7.78E+00	1.02E-03
			Fluoranthene	206440	1.40E-06	9.08E-04	1.19E-07
			Fluorene	86737	2.40E-06	1.56E-03	2.04E-07
			Formaldehyde	50000	3.30E-02	2.14E+01	2.81E-03
			Hydrogen sulfide	7783064	1.70E-01	1.10E+02	1.45E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	2.40E-04	3.15E-08
			Naphthalene	91203	1.87E-04	1.21E-01	1.59E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	1.75E-02	2.30E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	1.36E-01	1.79E-05
			Phenanthrene	85018	1.20E-05	7.78E-03	1.02E-06
			Propylene	115071	6.00E-01	3.89E+02	5.10E-02
			Pyrene	129000	2.00E-06	1.30E-03	1.70E-07
			Toluene	108883	2.00E-02	1.30E+01	1.70E-03
			Xylenes (mixed)	1330207	2.50E-02	1.62E+01	2.13E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[3] (lb/yr)	Hourly Emissions[4] (lb/hr)
S-1547-148	446.96	0.24	Acenaphthene	83329	5.00E-06	2.23E-03	1.18E-06
			Acenaphthylene	208968	1.90E-06	8.49E-04	4.47E-07
			Acetaldehyde	75070	3.90E-02	1.74E+01	9.18E-03
			Acrolein	107028	3.90E-02	1.74E+01	9.18E-03
			Ammonia	120127	1.55E+01	6.91E+03	3.64E+00
			Anthracene	56553	1.60E-05	7.15E-03	3.77E-06
			Benz[a]anthracene	71432	2.90E-06	1.30E-03	6.83E-07
			Benzene	50328	3.50E-03	1.56E+00	8.24E-04
			Benzo[a]pyrene	205992	1.50E-06	6.70E-04	3.53E-07
			Benzo[b]fluoranthene	191242	1.50E-06	6.70E-04	3.53E-07
			Benzo[g,h,i]perylene	207089	1.50E-06	6.70E-04	3.53E-07
			Benzo[k]fluoranthene	218019	1.50E-06	6.70E-04	3.53E-07
			Chrysene	53703	3.70E-06	1.65E-03	8.71E-07
			Dibenz[a,h]anthracene	100414	1.50E-06	6.70E-04	3.53E-07
			Ethyl benzene	206440	4.80E-03	2.15E+00	1.13E-03
			Fluoranthene	86737	1.00E-05	4.47E-03	2.35E-06
			Fluorene	50000	1.90E-05	8.49E-03	4.47E-06
			Formaldehyde	7783064	1.30E-01	5.81E+01	3.06E-02
			Indeno[1,2,3-cd]pyrene	193395	1.50E-06	6.70E-04	3.53E-07
			Naphthalene	91203	5.82E-04	2.60E-01	1.37E-04
			PAHs, total, w/o individ. components reported	1151	1.70E-04	7.60E-02	4.00E-05
			Phenanthrene	85018	9.20E-05	4.11E-02	2.17E-05
			Propylene	115071	1.60E+00	7.15E+02	3.77E-01
			Pyrene	129000	1.20E-05	5.36E-03	2.82E-06
			Toluene	108883	1.70E-02	7.60E+00	4.00E-03
			Xylenes (mixed)	1330207	2.80E-02	1.25E+01	6.59E-03

[1]Emission Factors from SJVAPCD Toxic Profile #255 for NG-fired Turbines and Source Test Reports 2018 (Ammonia)
[2]Emission Factors from SJVAPCD Toxic Profile #219 for Oilfield NG-fired and Waste Gas Flare
[3]Annual Emissions = Emission Factor*Annual Process Rate
[4]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[3] (lb/yr)	Hourly Emissions[4] (lb/hr)
S-1547-149	444.02	0.24	Acenaphthene	83329	5.00E-06	2.22E-03	1.18E-06
			Acenaphthylene	208968	1.90E-06	8.44E-04	4.47E-07
			Acetaldehyde	75070	3.90E-02	1.73E+01	9.18E-03
			Acrolein	107028	3.90E-02	1.73E+01	9.18E-03
			Ammonia	120127	5.04E+00	2.24E+03	1.19E+00
			Anthracene	56553	1.60E-05	7.10E-03	3.77E-06
			Benz[a]anthracene	71432	2.90E-06	1.29E-03	6.83E-07
			Benzene	50328	3.50E-03	1.55E+00	8.24E-04
			Benzo[a]pyrene	205992	1.50E-06	6.66E-04	3.53E-07
			Benzo[b]fluoranthene	191242	1.50E-06	6.66E-04	3.53E-07
			Benzo[g,h,i]perylene	207089	1.50E-06	6.66E-04	3.53E-07
			Benzo[k]fluoranthene	218019	1.50E-06	6.66E-04	3.53E-07
			Chrysene	53703	3.70E-06	1.64E-03	8.71E-07
			Dibenz[a,h]anthracene	100414	1.50E-06	6.66E-04	3.53E-07
			Ethyl benzene	206440	4.80E-03	2.13E+00	1.13E-03
			Fluoranthene	86737	1.00E-05	4.44E-03	2.35E-06
			Fluorene	50000	1.90E-05	8.44E-03	4.47E-06
			Formaldehyde	7783064	1.30E-01	5.77E+01	3.06E-02
			Indeno[1,2,3-cd]pyrene	193395	1.50E-06	6.66E-04	3.53E-07
			Naphthalene	91203	5.82E-04	2.58E-01	1.37E-04
			PAHs, total, w/o individ. components reported	1151	1.70E-04	7.55E-02	4.00E-05
			Phenanthrene	85018	9.20E-05	4.08E-02	2.17E-05
			Propylene	115071	1.60E+00	7.10E+02	3.77E-01
			Pyrene	129000	1.20E-05	5.33E-03	2.82E-06
			Toluene	108883	1.70E-02	7.55E+00	4.00E-03
			Xylenes (mixed)	1330207	2.80E-02	1.24E+01	6.59E-03

[1]Emission Factors from SJVAPCD Toxic Profile #255 for NG-fired Turbines and Source Test Reports 2018 (Ammonia)
[2]Emission Factors from SJVAPCD Toxic Profile #219 for Oilfield NG-fired and Waste Gas Flare
[3]Annual Emissions = Emission Factor*Annual Process Rate
[4]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[3] (lb/yr)	Hourly Emissions[4] (lb/hr)
S-1547-151	346.17	0.24	Acenaphthene	83329	5.00E-06	1.73E-03	1.18E-06
			Acenaphthylene	208968	1.90E-06	6.58E-04	4.47E-07
			Acetaldehyde	75070	3.90E-02	1.35E+01	9.18E-03
			Acrolein	107028	3.90E-02	1.35E+01	9.18E-03
			Ammonia	120127	1.73E+00	5.99E+02	4.07E-01
			Anthracene	56553	1.60E-05	5.54E-03	3.77E-06
			Benz[a]anthracene	71432	2.90E-06	1.00E-03	6.83E-07
			Benzene	50328	3.50E-03	1.21E+00	8.24E-04
			Benzo[a]pyrene	205992	1.50E-06	5.19E-04	3.53E-07
			Benzo[b]fluoranthene	191242	1.50E-06	5.19E-04	3.53E-07
			Benzo[g,h,i]perylene	207089	1.50E-06	5.19E-04	3.53E-07
			Benzo[k]fluoranthene	218019	1.50E-06	5.19E-04	3.53E-07
			Chrysene	53703	3.70E-06	1.28E-03	8.71E-07
			Dibenz[a,h]anthracene	100414	1.50E-06	5.19E-04	3.53E-07
			Ethyl benzene	206440	4.80E-03	1.66E+00	1.13E-03
			Fluoranthene	86737	1.00E-05	3.46E-03	2.35E-06
			Fluorene	50000	1.90E-05	6.58E-03	4.47E-06
			Formaldehyde	7783064	1.30E-01	4.50E+01	3.06E-02
			Indeno[1,2,3-cd]pyrene	193395	1.50E-06	5.19E-04	3.53E-07
			Naphthalene	91203	5.82E-04	2.01E-01	1.37E-04
			PAHs, total, w/o individ. components reported	1151	1.70E-04	5.88E-02	4.00E-05
			Phenanthrene	85018	9.20E-05	3.18E-02	2.17E-05
			Propylene	115071	1.60E+00	5.54E+02	3.77E-01
			Pyrene	129000	1.20E-05	4.15E-03	2.82E-06
			Toluene	108883	1.70E-02	5.88E+00	4.00E-03
			Xylenes (mixed)	1330207	2.80E-02	9.69E+00	6.59E-03

[1]Emission Factors from SJVAPCD Toxic Profile #255 for NG-fired Turbines and Source Test Reports 2018 (Ammonia)
[2]Emission Factors from SJVAPCD Toxic Profile #219 for Oilfield NG-fired and Waste Gas Flare
[3]Annual Emissions = Emission Factor*Annual Process Rate
[4]Hourly Emissions = Emission Factor*Hourly Process Rate

Baseline Criteria Emissions

Injection Steam Generators (EXISTING)

	Annual Emission Inventory (tons/yr)				
	2022				
Permit ID	NOx	SOx	CO	PM10	VOC
S-1547-148	2.99	8.08	205.63	12.92	6.46
S-1547-149	2.99	8.09	206.00	12.95	6.47
S-1547-151	3.17	8.58	218.46	13.73	6.86
Total	**9.16**	**24.75**	**630.08**	**39.60**	**19.80**

Aera Energy
Bakersfield, CA

CCS Steam Generator Emissions - SGS 2972

Project Increase Criteria Emissions and HAPS

Utility Steam Generators (NEW)
Inputs

Parameters	Value	Unit
Fuel Rating	100	MMBtu/hr
Annual Fuel Use	788400	MMBTU/yr

Existing Steam Generators
Inputs

Parameters	Value	Unit
Fuel Rating	85	MMBtu/hr
Annual Fuel Use Increase -1162	170097.80	MMBTU/yr
Annual Fuel Use Increase -1163	144573.56	MMBTU/yr
Annual Fuel Use Increase -1164	126675.68	MMBTU/yr
Annual Fuel Use Increase -1173	143804.30	MMBTU/yr
Annual Fuel Use Increase -1174	166959.81	MMBTU/yr
Annual Fuel Use Increase -1175	153737.11	MMBTU/yr
Annual Fuel Use Increase -1176	93957.67	MMBTU/yr
Annual Fuel Use Increase -1177	121608.21	MMBTU/yr
Annual Fuel Use Increase -1178	81904.40	MMBTU/yr
Annual Fuel Use Increase -1180	161065.31	MMBTU/yr
Annual Fuel Use Increase -1261	138470.21	MMBTU/yr

Emission Factors

Pollutant	Emission Factor	Unit
NOx	0.0061	lb/MMBtu
SOx	0.01	lb/MMBtu
CO	0.01878	lb/MMBtu
PM10	0.0076	lb/MMBtu
VOC	0.0055	lb/MMBtu

Potential to Emit

	Hourly Emissions (lb/hr)					Daily Emissions (lbs/day)					Yearly Emissions (tpy)				
Emissions Unit	NOx	SOx	CO	PM10	VOC	NOx	SOx	CO	PM10	VOC	NOx	SOx	CO	PM10	VOC
Utility SG 1	0.61	1.00	1.88	0.76	0.55	14.64	24.00	45.07	18.24	13.20	2.40	3.94	7.40	3.00	2.17
Utility SG 2	0.61	1.00	1.88	0.76	0.55	14.64	24.00	45.07	18.24	13.20	2.40	3.94	7.40	3.00	2.17
Utility SG 3	0.61	1.00	1.88	0.76	0.55	14.64	24.00	45.07	18.24	13.20	2.40	3.94	7.40	3.00	2.17
Permitted Increase (Subtotal)											**7.21**	**11.83**	**22.21**	**8.99**	**6.50**
S-1547-1162											0.52	0.85	1.60	0.65	0.47
S-1547-1163											0.44	0.72	1.36	0.55	0.40
S-1547-1164											0.39	0.63	1.19	0.48	0.35
S-1547-1173											0.44	0.72	1.35	0.55	0.40
S-1547-1174											0.51	0.83	1.57	0.63	0.46
S-1547-1175											0.47	0.77	1.44	0.58	0.42
S-1547-1176											0.29	0.47	0.88	0.36	0.26
S-1547-1177											0.37	0.61	1.14	0.46	0.33
S-1547-1178											0.25	0.41	0.77	0.31	0.23
S-1547-1180											0.49	0.81	1.51	0.61	0.44
S-1547-1261											0.42	0.69	1.30	0.53	0.38
HRA Total Increase											**11.80**	**19.34**	**36.32**	**14.70**	**10.64**

HAP Emissions

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
Utility SG 1	788.40	0.10	Acenaphthene	83329	5.40E-07	4.26E-04	5.40E-08
			Acenaphthylene	208968	3.70E-07	2.92E-04	3.70E-08
			Acetaldehyde	75070	1.40E-02	1.10E+01	1.40E-03
			Acrolein	107028	1.40E-02	1.10E+01	1.40E-03
			Anthracene	120127	2.40E-06	1.89E-03	2.40E-07
			Benz[a]anthracene	56553	1.30E-06	1.02E-03	1.30E-07
			Benzene	71432	1.60E-03	1.26E+00	1.60E-04
			Benzo[a]pyrene	50328	3.70E-07	2.92E-04	3.70E-08
			Benzo[b]fluoranthene	205992	3.70E-07	2.92E-04	3.70E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	2.92E-04	3.70E-08
			Benzo[k]fluoranthene	207089	3.70E-07	2.92E-04	3.70E-08
			Chrysene	218019	1.13E-06	8.91E-04	1.13E-07
			Dibenz[a,h]anthracene	53703	3.70E-07	2.92E-04	3.70E-08
			Ethyl benzene	100414	1.20E-02	9.46E+00	1.20E-03
			Fluoranthene	206440	1.40E-06	1.10E-03	1.40E-07
			Fluorene	86737	2.40E-06	1.89E-03	2.40E-07
			Formaldehyde	50000	3.30E-02	2.60E+01	3.30E-03
			Hydrogen sulfide	7783064	1.70E-01	1.34E+02	1.70E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	2.92E-04	3.70E-08
			Naphthalene	91203	1.87E-04	1.47E-01	1.87E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	2.13E-02	2.70E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	1.66E-01	2.10E-05
			Phenanthrene	85018	1.20E-05	9.46E-03	1.20E-06
			Propylene	115071	6.00E-01	4.73E+02	6.00E-02
			Pyrene	129000	2.00E-06	1.58E-03	2.00E-07
			Toluene	108883	2.00E-02	1.58E+01	2.00E-03
			Xylenes (mixed)	1330207	2.50E-02	1.97E+01	2.50E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
Utility SG 2	788.40	0.10	Acenaphthene	83329	5.40E-07	4.26E-04	5.40E-08
			Acenaphthylene	208968	3.70E-07	2.92E-04	3.70E-08
			Acetaldehyde	75070	1.40E-02	1.10E+01	1.40E-03
			Acrolein	107028	1.40E-02	1.10E+01	1.40E-03
			Anthracene	120127	2.40E-06	1.89E-03	2.40E-07
			Benz[a]anthracene	56553	1.30E-06	1.02E-03	1.30E-07
			Benzene	71432	1.60E-03	1.26E+00	1.60E-04
			Benzo[a]pyrene	50328	3.70E-07	2.92E-04	3.70E-08
			Benzo[b]fluoranthene	205992	3.70E-07	2.92E-04	3.70E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	2.92E-04	3.70E-08
			Benzo[k]fluoranthene	207089	3.70E-07	2.92E-04	3.70E-08
			Chrysene	218019	1.13E-06	8.91E-04	1.13E-07
			Dibenz[a,h]anthracene	53703	3.70E-07	2.92E-04	3.70E-08
			Ethyl benzene	100414	1.20E-02	9.46E+00	1.20E-03
			Fluoranthene	206440	1.40E-06	1.10E-03	1.40E-07
			Fluorene	86737	2.40E-06	1.89E-03	2.40E-07
			Formaldehyde	50000	3.30E-02	2.60E+01	3.30E-03
			Hydrogen sulfide	7783064	1.70E-01	1.34E+02	1.70E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	2.92E-04	3.70E-08
			Naphthalene	91203	1.87E-04	1.47E-01	1.87E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	2.13E-02	2.70E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	1.66E-01	2.10E-05
			Phenanthrene	85018	1.20E-05	9.46E-03	1.20E-06
			Propylene	115071	6.00E-01	4.73E+02	6.00E-02
			Pyrene	129000	2.00E-06	1.58E-03	2.00E-07
			Toluene	108883	2.00E-02	1.58E+01	2.00E-03
			Xylenes (mixed)	1330207	2.50E-02	1.97E+01	2.50E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
Utility SG 3	788.40	0.10	Acenaphthene	83329	5.40E-07	4.26E-04	5.40E-08
			Acenaphthylene	208968	3.70E-07	2.92E-04	3.70E-08
			Acetaldehyde	75070	1.40E-02	1.10E+01	1.40E-03
			Acrolein	107028	1.40E-02	1.10E+01	1.40E-03
			Anthracene	120127	2.40E-06	1.89E-03	2.40E-07
			Benz[a]anthracene	56553	1.30E-06	1.02E-03	1.30E-07
			Benzene	71432	1.60E-03	1.26E+00	1.60E-04
			Benzo[a]pyrene	50328	3.70E-07	2.92E-04	3.70E-08
			Benzo[b]fluoranthene	205992	3.70E-07	2.92E-04	3.70E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	2.92E-04	3.70E-08
			Benzo[k]fluoranthene	207089	3.70E-07	2.92E-04	3.70E-08
			Chrysene	218019	1.13E-06	8.91E-04	1.13E-07
			Dibenz[a,h]anthracene	53703	3.70E-07	2.92E-04	3.70E-08
			Ethyl benzene	100414	1.20E-02	9.46E+00	1.20E-03
			Fluoranthene	206440	1.40E-06	1.10E-03	1.40E-07
			Fluorene	86737	2.40E-06	1.89E-03	2.40E-07
			Formaldehyde	50000	3.30E-02	2.60E+01	3.30E-03
			Hydrogen sulfide	7783064	1.70E-01	1.34E+02	1.70E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	2.92E-04	3.70E-08
			Naphthalene	91203	1.87E-04	1.47E-01	1.87E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	2.13E-02	2.70E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	1.66E-01	2.10E-05
			Phenanthrene	85018	1.20E-05	9.46E-03	1.20E-06
			Propylene	115071	6.00E-01	4.73E+02	6.00E-02
			Pyrene	129000	2.00E-06	1.58E-03	2.00E-07
			Toluene	108883	2.00E-02	1.58E+01	2.00E-03
			Xylenes (mixed)	1330207	2.50E-02	1.97E+01	2.50E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
S-1547-1162	170.10	0.09	Acenaphthene	83329	5.40E-07	9.19E-05	4.59E-08
			Acenaphthylene	208968	3.70E-07	6.29E-05	3.15E-08
			Acetaldehyde	75070	1.40E-02	2.38E+00	1.19E-03
			Acrolein	107028	1.40E-02	2.38E+00	1.19E-03
			Anthracene	120127	2.40E-06	4.08E-04	2.04E-07
			Benz[a]anthracene	56553	1.30E-06	2.21E-04	1.11E-07
			Benzene	71432	1.60E-03	2.72E-01	1.36E-04
			Benzo[a]pyrene	50328	3.70E-07	6.29E-05	3.15E-08
			Benzo[b]fluoranthene	205992	3.70E-07	6.29E-05	3.15E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	6.29E-05	3.15E-08
			Benzo[k]fluoranthene	207089	3.70E-07	6.29E-05	3.15E-08
			Chrysene	218019	1.13E-06	1.92E-04	9.61E-08
			Dibenz[a,h]anthracene	53703	3.70E-07	6.29E-05	3.15E-08
			Ethyl benzene	100414	1.20E-02	2.04E+00	1.02E-03
			Fluoranthene	206440	1.40E-06	2.38E-04	1.19E-07
			Fluorene	86737	2.40E-06	4.08E-04	2.04E-07
			Formaldehyde	50000	3.30E-02	5.61E+00	2.81E-03
			Hydrogen sulfide	7783064	1.70E-01	2.89E+01	1.45E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	6.29E-05	3.15E-08
			Naphthalene	91203	1.87E-04	3.18E-02	1.59E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	4.59E-03	2.30E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	3.57E-02	1.79E-05
			Phenanthrene	85018	1.20E-05	2.04E-03	1.02E-06
			Propylene	115071	6.00E-01	1.02E+02	5.10E-02
			Pyrene	129000	2.00E-06	3.40E-04	1.70E-07
			Toluene	108883	2.00E-02	3.40E+00	1.70E-03
			Xylenes (mixed)	1330207	2.50E-02	4.25E+00	2.13E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

3	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
S-1547-1163	144.57	0.09	Acenaphthene	83329	5.40E-07	7.81E-05	4.59E-08
			Acenaphthylene	208968	3.70E-07	5.35E-05	3.15E-08
			Acetaldehyde	75070	1.40E-02	2.02E+00	1.19E-03
			Acrolein	107028	1.40E-02	2.02E+00	1.19E-03
			Anthracene	120127	2.40E-06	3.47E-04	2.04E-07
			Benz[a]anthracene	56553	1.30E-06	1.88E-04	1.11E-07
			Benzene	71432	1.60E-03	2.31E-01	1.36E-04
			Benzo[a]pyrene	50328	3.70E-07	5.35E-05	3.15E-08
			Benzo[b]fluoranthene	205992	3.70E-07	5.35E-05	3.15E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	5.35E-05	3.15E-08
			Benzo[k]fluoranthene	207089	3.70E-07	5.35E-05	3.15E-08
			Chrysene	218019	1.13E-06	1.63E-04	9.61E-08
			Dibenz[a,h]anthracene	53703	3.70E-07	5.35E-05	3.15E-08
			Ethyl benzene	100414	1.20E-02	1.73E+00	1.02E-03
			Fluoranthene	206440	1.40E-06	2.02E-04	1.19E-07
			Fluorene	86737	2.40E-06	3.47E-04	2.04E-07
			Formaldehyde	50000	3.30E-02	4.77E+00	2.81E-03
			Hydrogen sulfide	7783064	1.70E-01	2.46E+01	1.45E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	5.35E-05	3.15E-08
			Naphthalene	91203	1.87E-04	2.70E-02	1.59E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	3.90E-03	2.30E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	3.04E-02	1.79E-05
			Phenanthrene	85018	1.20E-05	1.73E-03	1.02E-06
			Propylene	115071	6.00E-01	8.67E+01	5.10E-02
			Pyrene	129000	2.00E-06	2.89E-04	1.70E-07
			Toluene	108883	2.00E-02	2.89E+00	1.70E-03
			Xylenes (mixed)	1330207	2.50E-02	3.61E+00	2.13E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
S-1547-1164	126.68	0.09	Acenaphthene	83329	5.40E-07	6.84E-05	4.59E-08
			Acenaphthylene	208968	3.70E-07	4.69E-05	3.15E-08
			Acetaldehyde	75070	1.40E-02	1.77E+00	1.19E-03
			Acrolein	107028	1.40E-02	1.77E+00	1.19E-03
			Anthracene	120127	2.40E-06	3.04E-04	2.04E-07
			Benz[a]anthracene	56553	1.30E-06	1.65E-04	1.11E-07
			Benzene	71432	1.60E-03	2.03E-01	1.36E-04
			Benzo[a]pyrene	50328	3.70E-07	4.69E-05	3.15E-08
			Benzo[b]fluoranthene	205992	3.70E-07	4.69E-05	3.15E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	4.69E-05	3.15E-08
			Benzo[k]fluoranthene	207089	3.70E-07	4.69E-05	3.15E-08
			Chrysene	218019	1.13E-06	1.43E-04	9.61E-08
			Dibenz[a,h]anthracene	53703	3.70E-07	4.69E-05	3.15E-08
			Ethyl benzene	100414	1.20E-02	1.52E+00	1.02E-03
			Fluoranthene	206440	1.40E-06	1.77E-04	1.19E-07
			Fluorene	86737	2.40E-06	3.04E-04	2.04E-07
			Formaldehyde	50000	3.30E-02	4.18E+00	2.81E-03
			Hydrogen sulfide	7783064	1.70E-01	2.15E+01	1.45E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	4.69E-05	3.15E-08
			Naphthalene	91203	1.87E-04	2.37E-02	1.59E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	3.42E-03	2.30E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	2.66E-02	1.79E-05
			Phenanthrene	85018	1.20E-05	1.52E-03	1.02E-06
			Propylene	115071	6.00E-01	7.60E+01	5.10E-02
			Pyrene	129000	2.00E-06	2.53E-04	1.70E-07
			Toluene	108883	2.00E-02	2.53E+00	1.70E-03
			Xylenes (mixed)	1330207	2.50E-02	3.17E+00	2.13E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
S-1547-1173	143.80	0.09	Acenaphthene	83329	5.40E-07	7.77E-05	4.59E-08
			Acenaphthylene	208968	3.70E-07	5.32E-05	3.15E-08
			Acetaldehyde	75070	1.40E-02	2.01E+00	1.19E-03
			Acrolein	107028	1.40E-02	2.01E+00	1.19E-03
			Anthracene	120127	2.40E-06	3.45E-04	2.04E-07
			Benz[a]anthracene	56553	1.30E-06	1.87E-04	1.11E-07
			Benzene	71432	1.60E-03	2.30E-01	1.36E-04
			Benzo[a]pyrene	50328	3.70E-07	5.32E-05	3.15E-08
			Benzo[b]fluoranthene	205992	3.70E-07	5.32E-05	3.15E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	5.32E-05	3.15E-08
			Benzo[k]fluoranthene	207089	3.70E-07	5.32E-05	3.15E-08
			Chrysene	218019	1.13E-06	1.62E-04	9.61E-08
			Dibenz[a,h]anthracene	53703	3.70E-07	5.32E-05	3.15E-08
			Ethyl benzene	100414	1.20E-02	1.73E+00	1.02E-03
			Fluoranthene	206440	1.40E-06	2.01E-04	1.19E-07
			Fluorene	86737	2.40E-06	3.45E-04	2.04E-07
			Formaldehyde	50000	3.30E-02	4.75E+00	2.81E-03
			Hydrogen sulfide	7783064	1.70E-01	2.44E+01	1.45E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	5.32E-05	3.15E-08
			Naphthalene	91203	1.87E-04	2.69E-02	1.59E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	3.88E-03	2.30E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	3.02E-02	1.79E-05
			Phenanthrene	85018	1.20E-05	1.73E-03	1.02E-06
			Propylene	115071	6.00E-01	8.63E+01	5.10E-02
			Pyrene	129000	2.00E-06	2.88E-04	1.70E-07
			Toluene	108883	2.00E-02	2.88E+00	1.70E-03
			Xylenes (mixed)	1330207	2.50E-02	3.60E+00	2.13E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
S-1547-1174	166.96	0.09	Acenaphthene	83329	5.40E-07	9.02E-05	4.59E-08
			Acenaphthylene	208968	3.70E-07	6.18E-05	3.15E-08
			Acetaldehyde	75070	1.40E-02	2.34E+00	1.19E-03
			Acrolein	107028	1.40E-02	2.34E+00	1.19E-03
			Anthracene	120127	2.40E-06	4.01E-04	2.04E-07
			Benz[a]anthracene	56553	1.30E-06	2.17E-04	1.11E-07
			Benzene	71432	1.60E-03	2.67E-01	1.36E-04
			Benzo[a]pyrene	50328	3.70E-07	6.18E-05	3.15E-08
			Benzo[b]fluoranthene	205992	3.70E-07	6.18E-05	3.15E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	6.18E-05	3.15E-08
			Benzo[k]fluoranthene	207089	3.70E-07	6.18E-05	3.15E-08
			Chrysene	218019	1.13E-06	1.89E-04	9.61E-08
			Dibenz[a,h]anthracene	53703	3.70E-07	6.18E-05	3.15E-08
			Ethyl benzene	100414	1.20E-02	2.00E+00	1.02E-03
			Fluoranthene	206440	1.40E-06	2.34E-04	1.19E-07
			Fluorene	86737	2.40E-06	4.01E-04	2.04E-07
			Formaldehyde	50000	3.30E-02	5.51E+00	2.81E-03
			Hydrogen sulfide	7783064	1.70E-01	2.84E+01	1.45E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	6.18E-05	3.15E-08
			Naphthalene	91203	1.87E-04	3.12E-02	1.59E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	4.51E-03	2.30E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	3.51E-02	1.79E-05
			Phenanthrene	85018	1.20E-05	2.00E-03	1.02E-06
			Propylene	115071	6.00E-01	1.00E+02	5.10E-02
			Pyrene	129000	2.00E-06	3.34E-04	1.70E-07
			Toluene	108883	2.00E-02	3.34E+00	1.70E-03
			Xylenes (mixed)	1330207	2.50E-02	4.17E+00	2.13E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
S-1547-1175	153.74	0.09	Acenaphthene	83329	5.40E-07	8.30E-05	4.59E-08
			Acenaphthylene	208968	3.70E-07	5.69E-05	3.15E-08
			Acetaldehyde	75070	1.40E-02	2.15E+00	1.19E-03
			Acrolein	107028	1.40E-02	2.15E+00	1.19E-03
			Anthracene	120127	2.40E-06	3.69E-04	2.04E-07
			Benz[a]anthracene	56553	1.30E-06	2.00E-04	1.11E-07
			Benzene	71432	1.60E-03	2.46E-01	1.36E-04
			Benzo[a]pyrene	50328	3.70E-07	5.69E-05	3.15E-08
			Benzo[b]fluoranthene	205992	3.70E-07	5.69E-05	3.15E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	5.69E-05	3.15E-08
			Benzo[k]fluoranthene	207089	3.70E-07	5.69E-05	3.15E-08
			Chrysene	218019	1.13E-06	1.74E-04	9.61E-08
			Dibenz[a,h]anthracene	53703	3.70E-07	5.69E-05	3.15E-08
			Ethyl benzene	100414	1.20E-02	1.84E+00	1.02E-03
			Fluoranthene	206440	1.40E-06	2.15E-04	1.19E-07
			Fluorene	86737	2.40E-06	3.69E-04	2.04E-07
			Formaldehyde	50000	3.30E-02	5.07E+00	2.81E-03
			Hydrogen sulfide	7783064	1.70E-01	2.61E+01	1.45E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	5.69E-05	3.15E-08
			Naphthalene	91203	1.87E-04	2.87E-02	1.59E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	4.15E-03	2.30E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	3.23E-02	1.79E-05
			Phenanthrene	85018	1.20E-05	1.84E-03	1.02E-06
			Propylene	115071	6.00E-01	9.22E+01	5.10E-02
			Pyrene	129000	2.00E-06	3.07E-04	1.70E-07
			Toluene	108883	2.00E-02	3.07E+00	1.70E-03
			Xylenes (mixed)	1330207	2.50E-02	3.84E+00	2.13E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
S-1547-1176	93.96	0.09	Acenaphthene	83329	5.40E-07	5.07E-05	4.59E-08
			Acenaphthylene	208968	3.70E-07	3.48E-05	3.15E-08
			Acetaldehyde	75070	1.40E-02	1.32E+00	1.19E-03
			Acrolein	107028	1.40E-02	1.32E+00	1.19E-03
			Anthracene	120127	2.40E-06	2.25E-04	2.04E-07
			Benz[a]anthracene	56553	1.30E-06	1.22E-04	1.11E-07
			Benzene	71432	1.60E-03	1.50E-01	1.36E-04
			Benzo[a]pyrene	50328	3.70E-07	3.48E-05	3.15E-08
			Benzo[b]fluoranthene	205992	3.70E-07	3.48E-05	3.15E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	3.48E-05	3.15E-08
			Benzo[k]fluoranthene	207089	3.70E-07	3.48E-05	3.15E-08
			Chrysene	218019	1.13E-06	1.06E-04	9.61E-08
			Dibenz[a,h]anthracene	53703	3.70E-07	3.48E-05	3.15E-08
			Ethyl benzene	100414	1.20E-02	1.13E+00	1.02E-03
			Fluoranthene	206440	1.40E-06	1.32E-04	1.19E-07
			Fluorene	86737	2.40E-06	2.25E-04	2.04E-07
			Formaldehyde	50000	3.30E-02	3.10E+00	2.81E-03
			Hydrogen sulfide	7783064	1.70E-01	1.60E+01	1.45E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	3.48E-05	3.15E-08
			Naphthalene	91203	1.87E-04	1.76E-02	1.59E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	2.54E-03	2.30E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	1.97E-02	1.79E-05
			Phenanthrene	85018	1.20E-05	1.13E-03	1.02E-06
			Propylene	115071	6.00E-01	5.64E+01	5.10E-02
			Pyrene	129000	2.00E-06	1.88E-04	1.70E-07
			Toluene	108883	2.00E-02	1.88E+00	1.70E-03
			Xylenes (mixed)	1330207	2.50E-02	2.35E+00	2.13E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
S-1547-1177	121.61	0.09	Acenaphthene	83329	5.40E-07	6.57E-05	4.59E-08
			Acenaphthylene	208968	3.70E-07	4.50E-05	3.15E-08
			Acetaldehyde	75070	1.40E-02	1.70E+00	1.19E-03
			Acrolein	107028	1.40E-02	1.70E+00	1.19E-03
			Anthracene	120127	2.40E-06	2.92E-04	2.04E-07
			Benz[a]anthracene	56553	1.30E-06	1.58E-04	1.11E-07
			Benzene	71432	1.60E-03	1.95E-01	1.36E-04
			Benzo[a]pyrene	50328	3.70E-07	4.50E-05	3.15E-08
			Benzo[b]fluoranthene	205992	3.70E-07	4.50E-05	3.15E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	4.50E-05	3.15E-08
			Benzo[k]fluoranthene	207089	3.70E-07	4.50E-05	3.15E-08
			Chrysene	218019	1.13E-06	1.37E-04	9.61E-08
			Dibenz[a,h]anthracene	53703	3.70E-07	4.50E-05	3.15E-08
			Ethyl benzene	100414	1.20E-02	1.46E+00	1.02E-03
			Fluoranthene	206440	1.40E-06	1.70E-04	1.19E-07
			Fluorene	86737	2.40E-06	2.92E-04	2.04E-07
			Formaldehyde	50000	3.30E-02	4.01E+00	2.81E-03
			Hydrogen sulfide	7783064	1.70E-01	2.07E+01	1.45E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	4.50E-05	3.15E-08
			Naphthalene	91203	1.87E-04	2.27E-02	1.59E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	3.28E-03	2.30E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	2.55E-02	1.79E-05
			Phenanthrene	85018	1.20E-05	1.46E-03	1.02E-06
			Propylene	115071	6.00E-01	7.30E+01	5.10E-02
			Pyrene	129000	2.00E-06	2.43E-04	1.70E-07
			Toluene	108883	2.00E-02	2.43E+00	1.70E-03
			Xylenes (mixed)	1330207	2.50E-02	3.04E+00	2.13E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
S-1547-1178	81.90	0.09	Acenaphthene	83329	5.40E-07	4.42E-05	4.59E-08
			Acenaphthylene	208968	3.70E-07	3.03E-05	3.15E-08
			Acetaldehyde	75070	1.40E-02	1.15E+00	1.19E-03
			Acrolein	107028	1.40E-02	1.15E+00	1.19E-03
			Anthracene	120127	2.40E-06	1.97E-04	2.04E-07
			Benz[a]anthracene	56553	1.30E-06	1.06E-04	1.11E-07
			Benzene	71432	1.60E-03	1.31E-01	1.36E-04
			Benzo[a]pyrene	50328	3.70E-07	3.03E-05	3.15E-08
			Benzo[b]fluoranthene	205992	3.70E-07	3.03E-05	3.15E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	3.03E-05	3.15E-08
			Benzo[k]fluoranthene	207089	3.70E-07	3.03E-05	3.15E-08
			Chrysene	218019	1.13E-06	9.26E-05	9.61E-08
			Dibenz[a,h]anthracene	53703	3.70E-07	3.03E-05	3.15E-08
			Ethyl benzene	100414	1.20E-02	9.83E-01	1.02E-03
			Fluoranthene	206440	1.40E-06	1.15E-04	1.19E-07
			Fluorene	86737	2.40E-06	1.97E-04	2.04E-07
			Formaldehyde	50000	3.30E-02	2.70E+00	2.81E-03
			Hydrogen sulfide	7783064	1.70E-01	1.39E+01	1.45E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	3.03E-05	3.15E-08
			Naphthalene	91203	1.87E-04	1.53E-02	1.59E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	2.21E-03	2.30E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	1.72E-02	1.79E-05
			Phenanthrene	85018	1.20E-05	9.83E-04	1.02E-06
			Propylene	115071	6.00E-01	4.91E+01	5.10E-02
			Pyrene	129000	2.00E-06	1.64E-04	1.70E-07
			Toluene	108883	2.00E-02	1.64E+00	1.70E-03
			Xylenes (mixed)	1330207	2.50E-02	2.05E+00	2.13E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
S-1547-1180	161.07	0.09	Acenaphthene	83329	5.40E-07	8.70E-05	4.59E-08
			Acenaphthylene	208968	3.70E-07	5.96E-05	3.15E-08
			Acetaldehyde	75070	1.40E-02	2.25E+00	1.19E-03
			Acrolein	107028	1.40E-02	2.25E+00	1.19E-03
			Anthracene	120127	2.40E-06	3.87E-04	2.04E-07
			Benz[a]anthracene	56553	1.30E-06	2.09E-04	1.11E-07
			Benzene	71432	1.60E-03	2.58E-01	1.36E-04
			Benzo[a]pyrene	50328	3.70E-07	5.96E-05	3.15E-08
			Benzo[b]fluoranthene	205992	3.70E-07	5.96E-05	3.15E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	5.96E-05	3.15E-08
			Benzo[k]fluoranthene	207089	3.70E-07	5.96E-05	3.15E-08
			Chrysene	218019	1.13E-06	1.82E-04	9.61E-08
			Dibenz[a,h]anthracene	53703	3.70E-07	5.96E-05	3.15E-08
			Ethyl benzene	100414	1.20E-02	1.93E+00	1.02E-03
			Fluoranthene	206440	1.40E-06	2.25E-04	1.19E-07
			Fluorene	86737	2.40E-06	3.87E-04	2.04E-07
			Formaldehyde	50000	3.30E-02	5.32E+00	2.81E-03
			Hydrogen sulfide	7783064	1.70E-01	2.74E+01	1.45E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	5.96E-05	3.15E-08
			Naphthalene	91203	1.87E-04	3.01E-02	1.59E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	4.35E-03	2.30E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	3.38E-02	1.79E-05
			Phenanthrene	85018	1.20E-05	1.93E-03	1.02E-06
			Propylene	115071	6.00E-01	9.66E+01	5.10E-02
			Pyrene	129000	2.00E-06	3.22E-04	1.70E-07
			Toluene	108883	2.00E-02	3.22E+00	1.70E-03
			Xylenes (mixed)	1330207	2.50E-02	4.03E+00	2.13E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
S-1547-1261	138.47	0.09	Acenaphthene	83329	5.40E-07	7.48E-05	4.59E-08
			Acenaphthylene	208968	3.70E-07	5.12E-05	3.15E-08
			Acetaldehyde	75070	1.40E-02	1.94E+00	1.19E-03
			Acrolein	107028	1.40E-02	1.94E+00	1.19E-03
			Anthracene	120127	2.40E-06	3.32E-04	2.04E-07
			Benz[a]anthracene	56553	1.30E-06	1.80E-04	1.11E-07
			Benzene	71432	1.60E-03	2.22E-01	1.36E-04
			Benzo[a]pyrene	50328	3.70E-07	5.12E-05	3.15E-08
			Benzo[b]fluoranthene	205992	3.70E-07	5.12E-05	3.15E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	5.12E-05	3.15E-08
			Benzo[k]fluoranthene	207089	3.70E-07	5.12E-05	3.15E-08
			Chrysene	218019	1.13E-06	1.56E-04	9.61E-08
			Dibenz[a,h]anthracene	53703	3.70E-07	5.12E-05	3.15E-08
			Ethyl benzene	100414	1.20E-02	1.66E+00	1.02E-03
			Fluoranthene	206440	1.40E-06	1.94E-04	1.19E-07
			Fluorene	86737	2.40E-06	3.32E-04	2.04E-07
			Formaldehyde	50000	3.30E-02	4.57E+00	2.81E-03
			Hydrogen sulfide	7783064	1.70E-01	2.35E+01	1.45E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	5.12E-05	3.15E-08
			Naphthalene	91203	1.87E-04	2.59E-02	1.59E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	3.74E-03	2.30E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	2.91E-02	1.79E-05
			Phenanthrene	85018	1.20E-05	1.66E-03	1.02E-06
			Propylene	115071	6.00E-01	8.31E+01	5.10E-02
			Pyrene	129000	2.00E-06	2.77E-04	1.70E-07
			Toluene	108883	2.00E-02	2.77E+00	1.70E-03
			Xylenes (mixed)	1330207	2.50E-02	3.46E+00	2.13E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Baseline Criteria Emissions

Injection Steam Generators (EXISTING)

	Annual Emissions (tpy)				
Permit ID	NOx	SOx	CO	PM10	VOC
S-1547-1162	1.53	0.53	4.64	1.91	0.75
S-1547-1163	1.61	0.55	4.88	2.00	0.79
S-1547-1164	1.66	0.57	5.04	2.07	0.82
S-1547-1173	2.11	0.55	4.89	2.01	0.79
S-1547-1174	2.02	0.53	4.67	1.92	0.76
S-1547-1175	2.07	0.54	4.79	1.97	0.78
S-1547-1176	2.31	0.61	5.35	2.20	0.87
S-1547-1177	2.20	0.58	5.09	2.09	0.83
S-1547-1178	2.36	0.62	5.46	2.24	0.89
S-1547-1180	2.04	0.54	4.73	1.94	0.77
S-1547-1261	2.95	0.77	6.82	1.84	1.11
Total	**22.88**	**6.40**	**56.36**	**22.20**	**9.14**

Aera Energy
Bakersfield, CA

CCS Steam Generator Emissions - SGS 2868

Project Increase Criteria Emissions and HAPS

Utility Steam Generators (NEW)
Inputs

Parameters	Value	Unit
Fuel Rating	100	MMBtu/hr
Annual Fuel Use	709560	MMBTU/yr

Existing Steam Generators
Inputs

Parameters	Value	Unit
Fuel Rating	85	MMBtu/hr
Annual Fuel Use Increase -1142	312466.35	MMBTU/yr
Annual Fuel Use Increase -1143	176610.82	MMBTU/yr
Annual Fuel Use Increase -1144	218437.75	MMBTU/yr
Annual Fuel Use Increase -1145	174625.48	MMBTU/yr
Annual Fuel Use Increase -1146	98346.45	MMBTU/yr
Annual Fuel Use Increase -1147	275334.38	MMBTU/yr
Annual Fuel Use Increase -1148	226224.13	MMBTU/yr
Annual Fuel Use Increase -1149	131760.46	MMBTU/yr
Annual Fuel Use Increase -1150	120997.29	MMBTU/yr
Annual Fuel Use Increase -1151	213585.98	MMBTU/yr

Emission Factors

Pollutant	Emission Factor	Unit
NOx	0.0061	lb/MMBtu
SOx	0.01	lb/MMBtu
CO	0.01878	lb/MMBtu
PM10	0.0076	lb/MMBtu
VOC	0.0055	lb/MMBtu

Potential to Emit

	Hourly Emissions (lb/hr)					Daily Emissions (lbs/day)					Yearly Emissions (tpy)				
Emissions Unit	NOx	SOx	CO	PM10	VOC	NOx	SOx	CO	PM10	VOC	NOx	SOx	CO	PM10	VOC
Utility SG 1	0.61	1	1.878	0.76	0.55	14.64	24	45.072	18.24	13.2	2.164158	3.5478	6.662768	2.696328	1.95129
Utility SG 2	0.61	1	1.878	0.76	0.55	14.64	24	45.072	18.24	13.2	2.164158	3.5478	6.662768	2.696328	1.95129
Utility SG 3	0.61	1	1.878	0.76	0.55	14.64	24	45.072	18.24	13.2	2.164158	3.5478	6.662768	2.696328	1.95129
Permitted Increase (Subtotal)											**6.49**	**10.64**	**19.99**	**8.09**	**5.85**
S-1547-1142											0.95	1.56	2.93	1.19	0.86
S-1547-1143											0.54	0.88	1.66	0.67	0.49
S-1547-1144											0.67	1.09	2.05	0.83	0.60
S-1547-1145											0.53	0.87	1.64	0.66	0.48
S-1547-1146											0.30	0.49	0.92	0.37	0.27
S-1547-1147											0.84	1.38	2.59	1.05	0.76
S-1547-1148											0.69	1.13	2.12	0.86	0.62
S-1547-1149											0.40	0.66	1.24	0.50	0.36
S-1547-1150											0.37	0.60	1.14	0.46	0.33
S-1547-1151											0.65	1.07	2.01	0.81	0.59
HRA Total Increase											**12.44**	**20.39**	**38.28**	**15.49**	**11.21**

HAP Emissions

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
Utility SG 1	709.56	0.10	Acenaphthene	83329	5.40E-07	3.83E-04	5.40E-08
			Acenaphthylene	208968	3.70E-07	2.63E-04	3.70E-08
			Acetaldehyde	75070	1.40E-02	9.93E+00	1.40E-03
			Acrolein	107028	1.40E-02	9.93E+00	1.40E-03
			Anthracene	120127	2.40E-06	1.70E-03	2.40E-07
			Benz[a]anthracene	56553	1.30E-06	9.22E-04	1.30E-07
			Benzene	71432	1.60E-03	1.14E+00	1.60E-04
			Benzo[a]pyrene	50328	3.70E-07	2.63E-04	3.70E-08
			Benzo[b]fluoranthene	205992	3.70E-07	2.63E-04	3.70E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	2.63E-04	3.70E-08
			Benzo[k]fluoranthene	207089	3.70E-07	2.63E-04	3.70E-08
			Chrysene	218019	1.13E-06	8.02E-04	1.13E-07
			Dibenz[a,h]anthracene	53703	3.70E-07	2.63E-04	3.70E-08
			Ethyl benzene	100414	1.20E-02	8.51E+00	1.20E-03
			Fluoranthene	206440	1.40E-06	9.93E-04	1.40E-07
			Fluorene	86737	2.40E-06	1.70E-03	2.40E-07
			Formaldehyde	50000	3.30E-02	2.34E+01	3.30E-03
			Hydrogen sulfide	7783064	1.70E-01	1.21E+02	1.70E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	2.63E-04	3.70E-08
			Naphthalene	91203	1.87E-04	1.33E-01	1.87E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	1.92E-02	2.70E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	1.49E-01	2.10E-05
			Phenanthrene	85018	1.20E-05	8.51E-03	1.20E-06
			Propylene	115071	6.00E-01	4.26E+02	6.00E-02
			Pyrene	129000	2.00E-06	1.42E-03	2.00E-07
			Toluene	108883	2.00E-02	1.42E+01	2.00E-03
			Xylenes (mixed)	1330207	2.50E-02	1.77E+01	2.50E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
Utility SG 2	709.56	0.10	Acenaphthene	83329	5.40E-07	3.83E-04	5.40E-08
			Acenaphthylene	208968	3.70E-07	2.63E-04	3.70E-08
			Acetaldehyde	75070	1.40E-02	9.93E+00	1.40E-03
			Acrolein	107028	1.40E-02	9.93E+00	1.40E-03
			Anthracene	120127	2.40E-06	1.70E-03	2.40E-07
			Benz[a]anthracene	56553	1.30E-06	9.22E-04	1.30E-07
			Benzene	71432	1.60E-03	1.14E+00	1.60E-04
			Benzo[a]pyrene	50328	3.70E-07	2.63E-04	3.70E-08
			Benzo[b]fluoranthene	205992	3.70E-07	2.63E-04	3.70E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	2.63E-04	3.70E-08
			Benzo[k]fluoranthene	207089	3.70E-07	2.63E-04	3.70E-08
			Chrysene	218019	1.13E-06	8.02E-04	1.13E-07
			Dibenz[a,h]anthracene	53703	3.70E-07	2.63E-04	3.70E-08
			Ethyl benzene	100414	1.20E-02	8.51E+00	1.20E-03
			Fluoranthene	206440	1.40E-06	9.93E-04	1.40E-07
			Fluorene	86737	2.40E-06	1.70E-03	2.40E-07
			Formaldehyde	50000	3.30E-02	2.34E+01	3.30E-03
			Hydrogen sulfide	7783064	1.70E-01	1.21E+02	1.70E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	2.63E-04	3.70E-08
			Naphthalene	91203	1.87E-04	1.33E-01	1.87E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	1.92E-02	2.70E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	1.49E-01	2.10E-05
			Phenanthrene	85018	1.20E-05	8.51E-03	1.20E-06
			Propylene	115071	6.00E-01	4.26E+02	6.00E-02
			Pyrene	129000	2.00E-06	1.42E-03	2.00E-07
			Toluene	108883	2.00E-02	1.42E+01	2.00E-03
			Xylenes (mixed)	1330207	2.50E-02	1.77E+01	2.50E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
Utility SG 3	709.56	0.10	Acenaphthene	83329	5.40E-07	3.83E-04	5.40E-08
			Acenaphthylene	208968	3.70E-07	2.63E-04	3.70E-08
			Acetaldehyde	75070	1.40E-02	9.93E+00	1.40E-03
			Acrolein	107028	1.40E-02	9.93E+00	1.40E-03
			Anthracene	120127	2.40E-06	1.70E-03	2.40E-07
			Benz[a]anthracene	56553	1.30E-06	9.22E-04	1.30E-07
			Benzene	71432	1.60E-03	1.14E+00	1.60E-04
			Benzo[a]pyrene	50328	3.70E-07	2.63E-04	3.70E-08
			Benzo[b]fluoranthene	205992	3.70E-07	2.63E-04	3.70E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	2.63E-04	3.70E-08
			Benzo[k]fluoranthene	207089	3.70E-07	2.63E-04	3.70E-08
			Chrysene	218019	1.13E-06	8.02E-04	1.13E-07
			Dibenz[a,h]anthracene	53703	3.70E-07	2.63E-04	3.70E-08
			Ethyl benzene	100414	1.20E-02	8.51E+00	1.20E-03
			Fluoranthene	206440	1.40E-06	9.93E-04	1.40E-07
			Fluorene	86737	2.40E-06	1.70E-03	2.40E-07
			Formaldehyde	50000	3.30E-02	2.34E+01	3.30E-03
			Hydrogen sulfide	7783064	1.70E-01	1.21E+02	1.70E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	2.63E-04	3.70E-08
			Naphthalene	91203	1.87E-04	1.33E-01	1.87E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	1.92E-02	2.70E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	1.49E-01	2.10E-05
			Phenanthrene	85018	1.20E-05	8.51E-03	1.20E-06
			Propylene	115071	6.00E-01	4.26E+02	6.00E-02
			Pyrene	129000	2.00E-06	1.42E-03	2.00E-07
			Toluene	108883	2.00E-02	1.42E+01	2.00E-03
			Xylenes (mixed)	1330207	2.50E-02	1.77E+01	2.50E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
S-1547-1142	312.47	0.09	Acenaphthene	83329	5.40E-07	1.69E-04	4.59E-08
			Acenaphthylene	208968	3.70E-07	1.16E-04	3.15E-08
			Acetaldehyde	75070	1.40E-02	4.37E+00	1.19E-03
			Acrolein	107028	1.40E-02	4.37E+00	1.19E-03
			Anthracene	120127	2.40E-06	7.50E-04	2.04E-07
			Benz[a]anthracene	56553	1.30E-06	4.06E-04	1.11E-07
			Benzene	71432	1.60E-03	5.00E-01	1.36E-04
			Benzo[a]pyrene	50328	3.70E-07	1.16E-04	3.15E-08
			Benzo[b]fluoranthene	205992	3.70E-07	1.16E-04	3.15E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	1.16E-04	3.15E-08
			Benzo[k]fluoranthene	207089	3.70E-07	1.16E-04	3.15E-08
			Chrysene	218019	1.13E-06	3.53E-04	9.61E-08
			Dibenz[a,h]anthracene	53703	3.70E-07	1.16E-04	3.15E-08
			Ethyl benzene	100414	1.20E-02	3.75E+00	1.02E-03
			Fluoranthene	206440	1.40E-06	4.37E-04	1.19E-07
			Fluorene	86737	2.40E-06	7.50E-04	2.04E-07
			Formaldehyde	50000	3.30E-02	1.03E+01	2.81E-03
			Hydrogen sulfide	7783064	1.70E-01	5.31E+01	1.45E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	1.16E-04	3.15E-08
			Naphthalene	91203	1.87E-04	5.84E-02	1.59E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	8.44E-03	2.30E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	6.56E-02	1.79E-05
			Phenanthrene	85018	1.20E-05	3.75E-03	1.02E-06
			Propylene	115071	6.00E-01	1.87E+02	5.10E-02
			Pyrene	129000	2.00E-06	6.25E-04	1.70E-07
			Toluene	108883	2.00E-02	6.25E+00	1.70E-03
			Xylenes (mixed)	1330207	2.50E-02	7.81E+00	2.13E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
S-1547-1143	176.61	0.09	Acenaphthene	83329	5.40E-07	9.54E-05	4.59E-08
			Acenaphthylene	208968	3.70E-07	6.53E-05	3.15E-08
			Acetaldehyde	75070	1.40E-02	2.47E+00	1.19E-03
			Acrolein	107028	1.40E-02	2.47E+00	1.19E-03
			Anthracene	120127	2.40E-06	4.24E-04	2.04E-07
			Benz[a]anthracene	56553	1.30E-06	2.30E-04	1.11E-07
			Benzene	71432	1.60E-03	2.83E-01	1.36E-04
			Benzo[a]pyrene	50328	3.70E-07	6.53E-05	3.15E-08
			Benzo[b]fluoranthene	205992	3.70E-07	6.53E-05	3.15E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	6.53E-05	3.15E-08
			Benzo[k]fluoranthene	207089	3.70E-07	6.53E-05	3.15E-08
			Chrysene	218019	1.13E-06	2.00E-04	9.61E-08
			Dibenz[a,h]anthracene	53703	3.70E-07	6.53E-05	3.15E-08
			Ethyl benzene	100414	1.20E-02	2.12E+00	1.02E-03
			Fluoranthene	206440	1.40E-06	2.47E-04	1.19E-07
			Fluorene	86737	2.40E-06	4.24E-04	2.04E-07
			Formaldehyde	50000	3.30E-02	5.83E+00	2.81E-03
			Hydrogen sulfide	7783064	1.70E-01	3.00E+01	1.45E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	6.53E-05	3.15E-08
			Naphthalene	91203	1.87E-04	3.30E-02	1.59E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	4.77E-03	2.30E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	3.71E-02	1.79E-05
			Phenanthrene	85018	1.20E-05	2.12E-03	1.02E-06
			Propylene	115071	6.00E-01	1.06E+02	5.10E-02
			Pyrene	129000	2.00E-06	3.53E-04	1.70E-07
			Toluene	108883	2.00E-02	3.53E+00	1.70E-03
			Xylenes (mixed)	1330207	2.50E-02	4.42E+00	2.13E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
S-1547-1144	218.44	0.09	Acenaphthene	83329	5.40E-07	1.18E-04	4.59E-08
			Acenaphthylene	208968	3.70E-07	8.08E-05	3.15E-08
			Acetaldehyde	75070	1.40E-02	3.06E+00	1.19E-03
			Acrolein	107028	1.40E-02	3.06E+00	1.19E-03
			Anthracene	120127	2.40E-06	5.24E-04	2.04E-07
			Benz[a]anthracene	56553	1.30E-06	2.84E-04	1.11E-07
			Benzene	71432	1.60E-03	3.50E-01	1.36E-04
			Benzo[a]pyrene	50328	3.70E-07	8.08E-05	3.15E-08
			Benzo[b]fluoranthene	205992	3.70E-07	8.08E-05	3.15E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	8.08E-05	3.15E-08
			Benzo[k]fluoranthene	207089	3.70E-07	8.08E-05	3.15E-08
			Chrysene	218019	1.13E-06	2.47E-04	9.61E-08
			Dibenz[a,h]anthracene	53703	3.70E-07	8.08E-05	3.15E-08
			Ethyl benzene	100414	1.20E-02	2.62E+00	1.02E-03
			Fluoranthene	206440	1.40E-06	3.06E-04	1.19E-07
			Fluorene	86737	2.40E-06	5.24E-04	2.04E-07
			Formaldehyde	50000	3.30E-02	7.21E+00	2.81E-03
			Hydrogen sulfide	7783064	1.70E-01	3.71E+01	1.45E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	8.08E-05	3.15E-08
			Naphthalene	91203	1.87E-04	4.08E-02	1.59E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	5.90E-03	2.30E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	4.59E-02	1.79E-05
			Phenanthrene	85018	1.20E-05	2.62E-03	1.02E-06
			Propylene	115071	6.00E-01	1.31E+02	5.10E-02
			Pyrene	129000	2.00E-06	4.37E-04	1.70E-07
			Toluene	108883	2.00E-02	4.37E+00	1.70E-03
			Xylenes (mixed)	1330207	2.50E-02	5.46E+00	2.13E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
S-1547-1145	174.63	0.09	Acenaphthene	83329	5.40E-07	9.43E-05	4.59E-08
			Acenaphthylene	208968	3.70E-07	6.46E-05	3.15E-08
			Acetaldehyde	75070	1.40E-02	2.44E+00	1.19E-03
			Acrolein	107028	1.40E-02	2.44E+00	1.19E-03
			Anthracene	120127	2.40E-06	4.19E-04	2.04E-07
			Benz[a]anthracene	56553	1.30E-06	2.27E-04	1.11E-07
			Benzene	71432	1.60E-03	2.79E-01	1.36E-04
			Benzo[a]pyrene	50328	3.70E-07	6.46E-05	3.15E-08
			Benzo[b]fluoranthene	205992	3.70E-07	6.46E-05	3.15E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	6.46E-05	3.15E-08
			Benzo[k]fluoranthene	207089	3.70E-07	6.46E-05	3.15E-08
			Chrysene	218019	1.13E-06	1.97E-04	9.61E-08
			Dibenz[a,h]anthracene	53703	3.70E-07	6.46E-05	3.15E-08
			Ethyl benzene	100414	1.20E-02	2.10E+00	1.02E-03
			Fluoranthene	206440	1.40E-06	2.44E-04	1.19E-07
			Fluorene	86737	2.40E-06	4.19E-04	2.04E-07
			Formaldehyde	50000	3.30E-02	5.76E+00	2.81E-03
			Hydrogen sulfide	7783064	1.70E-01	2.97E+01	1.45E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	6.46E-05	3.15E-08
			Naphthalene	91203	1.87E-04	3.27E-02	1.59E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	4.71E-03	2.30E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	3.67E-02	1.79E-05
			Phenanthrene	85018	1.20E-05	2.10E-03	1.02E-06
			Propylene	115071	6.00E-01	1.05E+02	5.10E-02
			Pyrene	129000	2.00E-06	3.49E-04	1.70E-07
			Toluene	108883	2.00E-02	3.49E+00	1.70E-03
			Xylenes (mixed)	1330207	2.50E-02	4.37E+00	2.13E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
S-1547-1146	98.35	0.09	Acenaphthene	83329	5.40E-07	5.31E-05	4.59E-08
			Acenaphthylene	208968	3.70E-07	3.64E-05	3.15E-08
			Acetaldehyde	75070	1.40E-02	1.38E+00	1.19E-03
			Acrolein	107028	1.40E-02	1.38E+00	1.19E-03
			Anthracene	120127	2.40E-06	2.36E-04	2.04E-07
			Benz[a]anthracene	56553	1.30E-06	1.28E-04	1.11E-07
			Benzene	71432	1.60E-03	1.57E-01	1.36E-04
			Benzo[a]pyrene	50328	3.70E-07	3.64E-05	3.15E-08
			Benzo[b]fluoranthene	205992	3.70E-07	3.64E-05	3.15E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	3.64E-05	3.15E-08
			Benzo[k]fluoranthene	207089	3.70E-07	3.64E-05	3.15E-08
			Chrysene	218019	1.13E-06	1.11E-04	9.61E-08
			Dibenz[a,h]anthracene	53703	3.70E-07	3.64E-05	3.15E-08
			Ethyl benzene	100414	1.20E-02	1.18E+00	1.02E-03
			Fluoranthene	206440	1.40E-06	1.38E-04	1.19E-07
			Fluorene	86737	2.40E-06	2.36E-04	2.04E-07
			Formaldehyde	50000	3.30E-02	3.25E+00	2.81E-03
			Hydrogen sulfide	7783064	1.70E-01	1.67E+01	1.45E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	3.64E-05	3.15E-08
			Naphthalene	91203	1.87E-04	1.84E-02	1.59E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	2.66E-03	2.30E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	2.07E-02	1.79E-05
			Phenanthrene	85018	1.20E-05	1.18E-03	1.02E-06
			Propylene	115071	6.00E-01	5.90E+01	5.10E-02
			Pyrene	129000	2.00E-06	1.97E-04	1.70E-07
			Toluene	108883	2.00E-02	1.97E+00	1.70E-03
			Xylenes (mixed)	1330207	2.50E-02	2.46E+00	2.13E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
S-1547-1147	275.33	0.09	Acenaphthene	83329	5.40E-07	1.49E-04	4.59E-08
			Acenaphthylene	208968	3.70E-07	1.02E-04	3.15E-08
			Acetaldehyde	75070	1.40E-02	3.85E+00	1.19E-03
			Acrolein	107028	1.40E-02	3.85E+00	1.19E-03
			Anthracene	120127	2.40E-06	6.61E-04	2.04E-07
			Benz[a]anthracene	56553	1.30E-06	3.58E-04	1.11E-07
			Benzene	71432	1.60E-03	4.41E-01	1.36E-04
			Benzo[a]pyrene	50328	3.70E-07	1.02E-04	3.15E-08
			Benzo[b]fluoranthene	205992	3.70E-07	1.02E-04	3.15E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	1.02E-04	3.15E-08
			Benzo[k]fluoranthene	207089	3.70E-07	1.02E-04	3.15E-08
			Chrysene	218019	1.13E-06	3.11E-04	9.61E-08
			Dibenz[a,h]anthracene	53703	3.70E-07	1.02E-04	3.15E-08
			Ethyl benzene	100414	1.20E-02	3.30E+00	1.02E-03
			Fluoranthene	206440	1.40E-06	3.85E-04	1.19E-07
			Fluorene	86737	2.40E-06	6.61E-04	2.04E-07
			Formaldehyde	50000	3.30E-02	9.09E+00	2.81E-03
			Hydrogen sulfide	7783064	1.70E-01	4.68E+01	1.45E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	1.02E-04	3.15E-08
			Naphthalene	91203	1.87E-04	5.15E-02	1.59E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	7.43E-03	2.30E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	5.78E-02	1.79E-05
			Phenanthrene	85018	1.20E-05	3.30E-03	1.02E-06
			Propylene	115071	6.00E-01	1.65E+02	5.10E-02
			Pyrene	129000	2.00E-06	5.51E-04	1.70E-07
			Toluene	108883	2.00E-02	5.51E+00	1.70E-03
			Xylenes (mixed)	1330207	2.50E-02	6.88E+00	2.13E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
S-1547-1148	226.22	0.09	Acenaphthene	83329	5.40E-07	1.22E-04	4.59E-08
			Acenaphthylene	208968	3.70E-07	8.37E-05	3.15E-08
			Acetaldehyde	75070	1.40E-02	3.17E+00	1.19E-03
			Acrolein	107028	1.40E-02	3.17E+00	1.19E-03
			Anthracene	120127	2.40E-06	5.43E-04	2.04E-07
			Benz[a]anthracene	56553	1.30E-06	2.94E-04	1.11E-07
			Benzene	71432	1.60E-03	3.62E-01	1.36E-04
			Benzo[a]pyrene	50328	3.70E-07	8.37E-05	3.15E-08
			Benzo[b]fluoranthene	205992	3.70E-07	8.37E-05	3.15E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	8.37E-05	3.15E-08
			Benzo[k]fluoranthene	207089	3.70E-07	8.37E-05	3.15E-08
			Chrysene	218019	1.13E-06	2.56E-04	9.61E-08
			Dibenz[a,h]anthracene	53703	3.70E-07	8.37E-05	3.15E-08
			Ethyl benzene	100414	1.20E-02	2.71E+00	1.02E-03
			Fluoranthene	206440	1.40E-06	3.17E-04	1.19E-07
			Fluorene	86737	2.40E-06	5.43E-04	2.04E-07
			Formaldehyde	50000	3.30E-02	7.47E+00	2.81E-03
			Hydrogen sulfide	7783064	1.70E-01	3.85E+01	1.45E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	8.37E-05	3.15E-08
			Naphthalene	91203	1.87E-04	4.23E-02	1.59E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	6.11E-03	2.30E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	4.75E-02	1.79E-05
			Phenanthrene	85018	1.20E-05	2.71E-03	1.02E-06
			Propylene	115071	6.00E-01	1.36E+02	5.10E-02
			Pyrene	129000	2.00E-06	4.52E-04	1.70E-07
			Toluene	108883	2.00E-02	4.52E+00	1.70E-03
			Xylenes (mixed)	1330207	2.50E-02	5.66E+00	2.13E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
S-1547-1149	131.76	0.09	Acenaphthene	83329	5.40E-07	7.12E-05	4.59E-08
			Acenaphthylene	208968	3.70E-07	4.88E-05	3.15E-08
			Acetaldehyde	75070	1.40E-02	1.84E+00	1.19E-03
			Acrolein	107028	1.40E-02	1.84E+00	1.19E-03
			Anthracene	120127	2.40E-06	3.16E-04	2.04E-07
			Benz[a]anthracene	56553	1.30E-06	1.71E-04	1.11E-07
			Benzene	71432	1.60E-03	2.11E-01	1.36E-04
			Benzo[a]pyrene	50328	3.70E-07	4.88E-05	3.15E-08
			Benzo[b]fluoranthene	205992	3.70E-07	4.88E-05	3.15E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	4.88E-05	3.15E-08
			Benzo[k]fluoranthene	207089	3.70E-07	4.88E-05	3.15E-08
			Chrysene	218019	1.13E-06	1.49E-04	9.61E-08
			Dibenz[a,h]anthracene	53703	3.70E-07	4.88E-05	3.15E-08
			Ethyl benzene	100414	1.20E-02	1.58E+00	1.02E-03
			Fluoranthene	206440	1.40E-06	1.84E-04	1.19E-07
			Fluorene	86737	2.40E-06	3.16E-04	2.04E-07
			Formaldehyde	50000	3.30E-02	4.35E+00	2.81E-03
			Hydrogen sulfide	7783064	1.70E-01	2.24E+01	1.45E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	4.88E-05	3.15E-08
			Naphthalene	91203	1.87E-04	2.46E-02	1.59E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	3.56E-03	2.30E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	2.77E-02	1.79E-05
			Phenanthrene	85018	1.20E-05	1.58E-03	1.02E-06
			Propylene	115071	6.00E-01	7.91E+01	5.10E-02
			Pyrene	129000	2.00E-06	2.64E-04	1.70E-07
			Toluene	108883	2.00E-02	2.64E+00	1.70E-03
			Xylenes (mixed)	1330207	2.50E-02	3.29E+00	2.13E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
S-1547-1150	121.00	0.09	Acenaphthene	83329	5.40E-07	6.53E-05	4.59E-08
			Acenaphthylene	208968	3.70E-07	4.48E-05	3.15E-08
			Acetaldehyde	75070	1.40E-02	1.69E+00	1.19E-03
			Acrolein	107028	1.40E-02	1.69E+00	1.19E-03
			Anthracene	120127	2.40E-06	2.90E-04	2.04E-07
			Benz[a]anthracene	56553	1.30E-06	1.57E-04	1.11E-07
			Benzene	71432	1.60E-03	1.94E-01	1.36E-04
			Benzo[a]pyrene	50328	3.70E-07	4.48E-05	3.15E-08
			Benzo[b]fluoranthene	205992	3.70E-07	4.48E-05	3.15E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	4.48E-05	3.15E-08
			Benzo[k]fluoranthene	207089	3.70E-07	4.48E-05	3.15E-08
			Chrysene	218019	1.13E-06	1.37E-04	9.61E-08
			Dibenz[a,h]anthracene	53703	3.70E-07	4.48E-05	3.15E-08
			Ethyl benzene	100414	1.20E-02	1.45E+00	1.02E-03
			Fluoranthene	206440	1.40E-06	1.69E-04	1.19E-07
			Fluorene	86737	2.40E-06	2.90E-04	2.04E-07
			Formaldehyde	50000	3.30E-02	3.99E+00	2.81E-03
			Hydrogen sulfide	7783064	1.70E-01	2.06E+01	1.45E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	4.48E-05	3.15E-08
			Naphthalene	91203	1.87E-04	2.26E-02	1.59E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	3.27E-03	2.30E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	2.54E-02	1.79E-05
			Phenanthrene	85018	1.20E-05	1.45E-03	1.02E-06
			Propylene	115071	6.00E-01	7.26E+01	5.10E-02
			Pyrene	129000	2.00E-06	2.42E-04	1.70E-07
			Toluene	108883	2.00E-02	2.42E+00	1.70E-03
			Xylenes (mixed)	1330207	2.50E-02	3.02E+00	2.13E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
S-1547-1151	213.59	0.09	Acenaphthene	83329	5.40E-07	1.15E-04	4.59E-08
			Acenaphthylene	208968	3.70E-07	7.90E-05	3.15E-08
			Acetaldehyde	75070	1.40E-02	2.99E+00	1.19E-03
			Acrolein	107028	1.40E-02	2.99E+00	1.19E-03
			Anthracene	120127	2.40E-06	5.13E-04	2.04E-07
			Benz[a]anthracene	56553	1.30E-06	2.78E-04	1.11E-07
			Benzene	71432	1.60E-03	3.42E-01	1.36E-04
			Benzo[a]pyrene	50328	3.70E-07	7.90E-05	3.15E-08
			Benzo[b]fluoranthene	205992	3.70E-07	7.90E-05	3.15E-08
			Benzo[g,h,i]perylene	191242	3.70E-07	7.90E-05	3.15E-08
			Benzo[k]fluoranthene	207089	3.70E-07	7.90E-05	3.15E-08
			Chrysene	218019	1.13E-06	2.41E-04	9.61E-08
			Dibenz[a,h]anthracene	53703	3.70E-07	7.90E-05	3.15E-08
			Ethyl benzene	100414	1.20E-02	2.56E+00	1.02E-03
			Fluoranthene	206440	1.40E-06	2.99E-04	1.19E-07
			Fluorene	86737	2.40E-06	5.13E-04	2.04E-07
			Formaldehyde	50000	3.30E-02	7.05E+00	2.81E-03
			Hydrogen sulfide	7783064	1.70E-01	3.63E+01	1.45E-02
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	7.90E-05	3.15E-08
			Naphthalene	91203	1.87E-04	3.99E-02	1.59E-05
			PAHs, total, w/o individ. components reported	1151	2.70E-05	5.77E-03	2.30E-06
			PAHs, total, with individ. components also reported	1150	2.10E-04	4.49E-02	1.79E-05
			Phenanthrene	85018	1.20E-05	2.56E-03	1.02E-06
			Propylene	115071	6.00E-01	1.28E+02	5.10E-02
			Pyrene	129000	2.00E-06	4.27E-04	1.70E-07
			Toluene	108883	2.00E-02	4.27E+00	1.70E-03
			Xylenes (mixed)	1330207	2.50E-02	5.34E+00	2.13E-03

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Baseline Criteria Emissions

Injection Steam Generators (EXISTING)

Permit ID	Annual Emissions (tpy)				
	NOx	SOx	CO	PM10	VOC
S-1547-1142	1.67	0.44	3.92	1.59	1.15
S-1547-1143	2.21	0.58	5.20	2.10	1.52
S-1547-1144	2.05	0.54	4.80	1.94	1.41
S-1547-1145	2.22	0.58	5.21	2.11	1.53
S-1547-1146	2.53	0.66	5.93	2.40	1.74
S-1547-1147	1.82	0.48	4.27	1.73	1.25
S-1547-1148	2.02	0.53	4.73	1.91	1.39
S-1547-1149	2.39	0.63	5.62	2.27	1.65
S-1547-1150	2.44	0.64	5.72	2.31	1.67
S-1547-1151	2.07	0.54	4.85	1.96	1.42
Total	**21.41**	**5.62**	**50.25**	**20.34**	**14.72**

Aera Energy, LLC
Bakersfield, CA
Gas Plant 32

Fugitive Emissions

Component Counts

Component Media	Component Counts				
	Valves	Connectors	Flanges	Pump Seals	Other
Gas	6	14	33	0	17
Light Liquid	49	40	143	16	57
Total	55	54	176	16	74

Emission Calculations

Component Media	Component Type Emission Factor (kg THC/hr/source)[1]					Max Hourly Emissions[2]	Daily Emissions[2] (lb	Annual Emissions[2] (lb VOC/yr)
	Valves	Connectors	Flanges	Pump Seals	Others			
Gas/Light Liquid	3.50E-05	1.20E-05	2.80E-05	9.96E-04	1.47E-04	7.57E-02	1.82E+00	6.63E+02

[1]Emission factors from TABLE IV-2c, CAPCOA

[2]VOC content is conservatively assumed to be equal to THC

Aera Energy, LLC
Bakersfield, CA
Cogen 32

Fugitive Emissions

Component Counts

Component Media	Component Counts				
	Valves	Connectors	Flanges	Pump Seals	Other
Gas	6	12	31	0	15
Light Liquid	32	27	103	10	39
Total	38	39	134	10	54

Emission Calculations

Component Media	Component Type Emission Factor (kg THC/hr/source)[1]					Max Hourly Emissions[2]	Daily Emissions[2] (lb	Annual Emissions[2] (lb VOC/yr)
	Valves	Connectors	Flanges	Pump Seals	Others			
Gas/Light Liquid	3.50E-05	1.20E-05	2.80E-05	9.96E-04	1.47E-04	5.17E-02	1.24E+00	4.53E+02

[1]Emission factors from TABLE IV-2c, CAPCOA

[2]VOC content is conservatively assumed to be equal to THC

Aera Energy, LLC
Bakersfield, CA
Steam Generator Setting 2972

Fugitive Emissions

Component Counts

Component Media	Component Counts				
	Valves	Connectors	Flanges	Pump Seals	Other
Gas	6	14	33	0	17
Light Liquid	49	40	143	16	57
Total	55	54	176	16	74

Emission Calculations

Component Media	Component Type Emission Factor (kg THC/hr/source)[1]					Max Hourly Emissions[2]	Daily Emissions[2] (lb	Annual Emissions[2] (lb VOC/yr)
	Valves	Connectors	Flanges	Pump Seals	Others			
Gas/Light Liquid	3.50E-05	1.20E-05	2.80E-05	9.96E-04	1.47E-04	7.57E-02	1.82E+00	6.63E+02

[1]Emission factors from TABLE IV-2c, CAPCOA
[2]VOC content is conservatively assumed to be equal to THC

Aera Energy, LLC
Bakersfield, CA
Steam Generator Setting 2868

Fugitive Emissions

Component Counts

Component Media	Component Counts				
	Valves	Connectors	Flanges	Pump Seals	Other
Gas	6	14	33	0	17
Light Liquid	49	40	143	16	57
Total	55	54	176	16	74

Emission Calculations

Component Media	Component Type Emission Factor (kg THC/hr/source)[1]					Max Hourly Emissions[2]	Daily Emissions[2] (lb	Annual Emissions[2] (lb VOC/yr)
	Valves	Connectors	Flanges	Pump Seals	Others			
Gas/Light Liquid	3.50E-05	1.20E-05	2.80E-05	9.96E-04	1.47E-04	7.57E-02	1.82E+00	6.63E+02

[1]Emission factors from TABLE IV-2c, CAPCOA
[2]VOC content is conservatively assumed to be equal to THC

Aera Energy
Bakersfield, CA
Del Sur Compressors

Emission Factors

Pollutant	Emission Factor	Unit	Conversion (bhp-hr to Btu)	Conversion (gr to lb)	Emission Factor (lb/MMBtu)
NOx	0.071	gr/bhp-hr	0.000393	0.0001429	0.0040
SOx		gr/bhp-hr	0.000393	0.0001429	0.0025
CO	0.613	gr/bhp-hr	0.000393	0.0001429	0.0344
PM10	0.003	gr/bhp-hr	0.000393	0.0001429	0.0002
VOC	0.150	gr/bhp-hr	0.000393	0.0001429	0.0084

Annual Emission Inventory Data 2022

Emissions Unit/Permit ID	Annual Process Rate (MMft^3/yr)	Hourly Process Rate (ft^3/hr)	Conversion (ft^3 to Btu)	Annual Process Rate (MMBtu/yr)	Hourly Process Rate (MMBtu/hr)
433	25.94	0.00296	1,000.00	25,942.05	2.96
434	34.53	0.00394	1,000.00	34,528.39	3.94

Total Emissions (Permit ID #433):

Pollutant	Emission Factor (lb/MMBtu)	Annual Process Rate (MMBtu/yr)	Hourly Process Rate (MMBtu/hr)	Annual Emissions (lb/yr)	Hourly Emissions (lb/hr)
NOx	0.0040	25,942.05	2.96	103.49	0.0118
SOx	0.0025			65.06	0.0074
CO	0.0344			893.52	0.1020
PM10	0.0002			4.37	0.0005
VOC	0.0084			218.64	0.0250

Total Emissions (Permit ID #434):

Pollutant	Emission Factor (lb/MMBtu)	Annual Process Rate (MMBtu/yr)	Hourly Process Rate (MMBtu/hr)	Annual Emissions (lb/yr)	Hourly Emissions (lb/hr)
NOx	0.0040	34,528.39	3.94	137.74	0.0157
SOx	0.0025			86.60	0.0099
CO	0.0344			1,189.26	0.1358
PM10	0.0002			5.82	0.0007
VOC	0.0084			291.01	0.0332

HAP Emissions

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
433	25.94	0.003	Acenaphthene	83329	5.40E-07	1.40E-05	1.60E-09
			Acenaphthylene	208968	3.70E-07	9.60E-06	1.10E-09
			Acetaldehyde	75070	1.40E-02	3.63E-01	4.15E-05
			Acrolein	107028	1.40E-02	3.63E-01	4.15E-05
			Anthracene	120127	2.40E-06	6.23E-05	7.11E-09
			Benz[a]anthracene	56553	1.30E-06	3.37E-05	3.85E-09
			Benzene	71432	1.60E-03	4.15E-02	4.74E-06
			Benzo[a]pyrene	50328	3.70E-07	9.60E-06	1.10E-09
			Benzo[b]fluoranthene	205992	3.70E-07	9.60E-06	1.10E-09
			Benzo[g,h,i]perylene	191242	3.70E-07	9.60E-06	1.10E-09
			Benzo[k]fluoranthene	207089	3.70E-07	9.60E-06	1.10E-09
			Chrysene	218019	1.13E-06	2.93E-05	3.35E-09
			Dibenz[a,h]anthracene	53703	3.70E-07	9.60E-06	1.10E-09
			Ethyl benzene	100414	1.20E-02	3.11E-01	3.55E-05
			Fluoranthene	206440	1.40E-06	3.63E-05	4.15E-09
			Fluorene	86737	2.40E-06	6.23E-05	7.11E-09
			Formaldehyde	50000	3.30E-02	8.56E-01	9.77E-05
			Hydrogen sulfide	7783064	1.70E-01	4.41E+00	5.03E-04
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	9.60E-06	1.10E-09
			Naphthalene	91203	1.87E-04	4.85E-03	5.54E-07
			PAHs, total, w/o individ. components reported	1151	2.70E-05	7.00E-04	8.00E-08
			PAHs, total, with individ. components also reported	1150	2.10E-04	5.45E-03	6.22E-07
			Phenanthrene	85018	1.20E-05	3.11E-04	3.55E-08
			Propylene	115071	6.00E-01	1.56E+01	1.78E-03
			Pyrene	129000	2.00E-06	5.19E-05	5.92E-09
			Toluene	108883	2.00E-02	5.19E-01	5.92E-05
			Xylenes (mixed)	1330207	2.50E-02	6.49E-01	7.40E-05

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators

[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Emissions Unit/Permit ID	Annual Process Rate (MMscf/yr)	Hourly Process Rate (MMscf/hr)	Listed Substance	CAS No.	Emission Factor (lb/MMscf)[1]	Annual Emissions[2] (lb/yr)	Hourly Emissions[3] (lb/hr)
434	34.53	0.00	Acenaphthene	83329	5.40E-07	1.86E-05	2.13E-09
			Acenaphthylene	208968	3.70E-07	1.28E-05	1.46E-09
			Acetaldehyde	75070	1.40E-02	4.83E-01	5.52E-05
			Acrolein	107028	1.40E-02	4.83E-01	5.52E-05
			Anthracene	120127	2.40E-06	8.29E-05	9.46E-09
			Benz[a]anthracene	56553	1.30E-06	4.49E-05	5.12E-09
			Benzene	71432	1.60E-03	5.52E-02	6.31E-06
			Benzo[a]pyrene	50328	3.70E-07	1.28E-05	1.46E-09
			Benzo[b]fluoranthene	205992	3.70E-07	1.28E-05	1.46E-09
			Benzo[g,h,i]perylene	191242	3.70E-07	1.28E-05	1.46E-09
			Benzo[k]fluoranthene	207089	3.70E-07	1.28E-05	1.46E-09
			Chrysene	218019	1.13E-06	3.90E-05	4.45E-09
			Dibenz[a,h]anthracene	53703	3.70E-07	1.28E-05	1.46E-09
			Ethyl benzene	100414	1.20E-02	4.14E-01	4.73E-05
			Fluoranthene	206440	1.40E-06	4.83E-05	5.52E-09
			Fluorene	86737	2.40E-06	8.29E-05	9.46E-09
			Formaldehyde	50000	3.30E-02	1.14E+00	1.30E-04
			Hydrogen sulfide	7783064	1.70E-01	5.87E+00	6.70E-04
			Indeno[1,2,3-cd]pyrene	193395	3.70E-07	1.28E-05	1.46E-09
			Naphthalene	91203	1.87E-04	6.46E-03	7.37E-07
			PAHs, total, w/o individ. components reported	1151	2.70E-05	9.32E-04	1.06E-07
			PAHs, total, with individ. components also reported	1150	2.10E-04	7.25E-03	8.28E-07
			Phenanthrene	85018	1.20E-05	4.14E-04	4.73E-08
			Propylene	115071	6.00E-01	2.07E+01	2.36E-03
			Pyrene	129000	2.00E-06	6.91E-05	7.88E-09
			Toluene	108883	2.00E-02	6.91E-01	7.88E-05
			Xylenes (mixed)	1330207	2.50E-02	8.63E-01	9.85E-05

[1]Emission Factors from SJVAPCD Toxic Profile #237 for NG-fired Steam Generators
[2]Annual Emissions = Emission Factor*Annual Process Rate
[3]Hourly Emissions = Emission Factor*Hourly Process Rate

Aera Energy
Bakersfield, CA

CCS Mobile Source Emissions

Table 1: EMFAC2021 Information

Source	Region	Calendar Year	Season	Vehicle Class	Fuel	Model Year	Speed	Scenario
EMFAC2021	Kern County	2022	Annual Average	LDA, LDT1, LDT2	Gasoline	Aggregate	Aggregate	Baseline
EMFAC2022	Kern County	2026	Annual Average	LDA, LDT1, LDT2	Gasoline	Aggregate	Aggregate	Increase

Table 2: EMFAC2021 Emission Factors

Running - Emission Factors (g/mile)									
ROG	CO	NO_X	PM_{10}	$PM_{2.5}$	SO_X	CO_2	N_2O	CH_4	Scenario
0.0248	1.4257	0.1264	0.0166	0.0166	0.0033	337.1356	0.0093	0.0057	Baseline
0.0152	1.0242	0.0790	0.0163	0.0057	0.0031	309.7350	0.0066	0.0036	Increase

Table 3: Baseline Operating Exhaust Emissions

Operating Period	Trips Per Day	Miles Traveled	Emissions [1]									
			ROC	CO	NO_X	PM_{10}	$PM_{2.5}$	SO_X	CO_2	N_2O	CH_4	Units
Daily	50	2,500	0.137	7.858	0.696	0.091	0.091	0.018	1858.142	0.051	0.031	lbs/day
Annual	18250	912,500	0.025	1.434	0.127	0.017	0.017	0.003	307.723	0.008	0.005	tons/yr

1. EMFAC2021 Emission Factors listed in Table 2
2. Trip miles: 50
3. CO_2, N_2O, and CH_4 reported in tonne/yr

Table 4: Project Increase Operating Mobile Exhaust Emissions

Operating Period	Trips Per Day	Miles Traveled	Emissions [1]									
			ROC	CO	NO_X	PM_{10}	$PM_{2.5}$	SO_X	CO_2	N_2O	CH_4	Units
Daily	25	1,250	0.042	2.822	0.218	0.045	0.016	0.008	853.561	0.018	0.010	lbs/day
Annual	9125	456,250	0.008	0.515	0.040	0.008	0.003	0.002	141.357	0.003	0.002	tons/yr

1. EMFAC2021 Emission Factors listed in Table 2
2. Round trip miles: 50
3. CO_2, N_2O, and CH_4 reported in tonne/yr

Construction Equipment and Schedule

On-Site Roads 20 Days

Equipment	Horsepower	Number
Cat 14 Grader	259	1
Cat 623 Water Wagon	407	1
Cat 815 Compactor	232	1
Cat 875 Challenger	585	1
Cat D6	207	2
PICKUP,1/2 TON,2X4	130	2

Manpower	Number
Crew	6
Management	2
TOTAL	**8**

Start Date: 1/30/2025

Construction Equipment and Schedule

Facilities Pad Grading

80 20 days per facility

Equipment	Horsepower	Number
Cat 14 Grader	259	2
Cat 623 Water Wagon	407	2
Cat 815 Compactor	232	2
Cat 875 Challenger	585	2
Cat D6	207	2
GENERATOR,6-10KW,DIESEL	18	2
MECHANIC'S TRUCK,1.5 TON,2X4	130	1
PICKUP,1/2 TON,2X4	130	2

Manpower	Number
Crew	13
Management	2
TOTAL	**15**

GP32 Start Date:	6/2/2025
32 Cogen Start Date:	1/30/2025
SP286B Start Date:	8/21/2025
SP2972 Start Date:	2/12/2026

Construction Equipment and Schedule

CO2 Capture Facilities

502 Each Facility

Equipment	Horsepower	Number
BACKHOE/LOADER,.75-1CY	67	6
COMPACTOR,ROLLER,24-33"	8	3
COMPRESSOR,100-200 CFM,DIESEL	50	6
CRANE,10-14 TON,HYDRAULIC,RT	6	3
FLATBED,1 TON,2X4	42	3
FORKLIFT,7-9K#,YARD	300	3
FORKLIFT,8-9K# RT TELE BOOM	73	6
FUEL/LUBE TRUCK,2 TON,2X4	73	1
GENERATOR,6-10KW,DIESEL	18	6
GOLF CART	18	3
LOADER,SKIDSTEER 36-45HP	45	1
MANLIFT,40-50',ELECTRIC	60	3
MECHANIC'S TRUCK,2.5 TON,4X6	130	3
PEOPLE MOVER,16-30 PASS	150	3
PICKUP,3/4 TON,4X4,SUPERCAB	180	6
SCISSOR LIFT,<20'	475	6
SUV,6-9 PASSENGER 4X4	200	3
TAMPER,100-150#	45	3
TRUCK,1.5 TON,2X4,W/CRANE	8	3
WELDER,400-500 AMP DIESEL	18	9
WELDER,8PAK ELEC,RECTIFIER	X	9
WHEEL LOADER,2.5-3.0CY	42	3

Manpower	Number
Crew	90
Management	6
TOTAL	**96**

GP32 Start Date: 6/30/2025
32 Cogen Start Date: 2/27/2025

SP286B Start Date:	9/18/2025
SP2972 Start Date:	3/12/2026

Construction Equipment and Schedule

Compressor Station Construction

80 days

Equipment	Horsepower	Number
BACKHOE/LOADER,.75-1CY	67	2
COMPACTOR,ROLLER,24-33"	8	1
COMPRESSOR,100-200 CFM,DIESEL	50	3
CRANE,10-14 TON,HYDRAULIC,RT	6	1
FLATBED,1 TON,2X4	42	2
FORKLIFT,7-9K#,YARD	300	1
FORKLIFT,8-9K# RT TELE BOOM	73	2
FUEL/LUBE TRUCK,2 TON,2X4	73	1
GENERATOR,6-10KW,DIESEL	18	2
GOLF CART	18	3
LOADER,SKIDSTEER 36-45HP	45	1
MANLIFT,40-50',ELECTRIC	60	1
MECHANIC'S TRUCK,2.5 TON,4X6	130	1
PEOPLE MOVER,16-30 PASS	150	5
PICKUP,3/4 TON,4X4,SUPERCAB	180	4
SCISSOR LIFT,<20'	475	2
SUV,6-9 PASSENGER 4X4	200	1
TAMPER,100-150#	45	1
TRUCK,1.5 TON,2X4,W/CRANE	8	1
WELDER,400-500 AMP DIESEL	18	3
WELDER,8PAK ELEC,RECTIFIER	X	1
WHEEL LOADER,2.5-3.0CY	42	2

Manpower	Number
Crew	26
Management	2
TOTAL	**28**

Start Date: 1/1/2025

Construction Equipment and Schedule

CO2 Main Pipeline

390 Days

Equipment	Horsepower	Number
BACKHOE/LOADER,.75-1CY	67	3
CAT 325 Excavator	172	3
BOOMTRUCK,10-13 TON	226	2
CAT 815 COMPACTOR	232	1
COMPACTOR,40-66" ROLLER,RIDE ON	33	1
PICKUP,1/2 TON,4X4	130	4
PICKUP,3/4 TON,4X4	130	4
WELDER,500-800 AMP DIESEL MULTI PURPOSE	48	4
WHEEL LOADER,3.0-3.5CY	125	1
Vacuum Truck/Hydro-excavator	425	1
SIDEBOOM, 14OK#,300HP (583)	300	4
CRANE,10-14 TON,HYDRAULIC,RT	62	1

Manpower	Number
Crew	27
Management	2
TOTAL	**29**

Start Date: 1/1/2025

Construction Equipment and Schedule

Distribution Pipelines

260 Days

Equipment	Horsepower	Number
BACKHOE/LOADER,.75-1CY	67	2
CAT 325 Excavator	172	3
BOOMTRUCK,10-13 TON	226	2
CAT 815 COMPACTOR	232	1
COMPACTOR,40-66" ROLLER,RIDE ON	33	1
PICKUP,1/2 TON,4X4	130	4
PICKUP,3/4 TON,4X4	130	4
WELDER,500-800 AMP DIESEL MULTI PURPOSE	48	3
Vacuum Truck/Hydro-excavator	425	1
WHEEL LOADER,3.0-3.5CY	125	1
CRANE,10-14 TON,HYDRAULIC,RT	62	1

Manpower	Number
Crew	21
Management	2
TOTAL	**23**

Start Date: 1/1/2025

Construction Equipment and Schedule

Electrical Transmission Line

60 Days

Equipment	Horsepower	Number
Cat D6	207	1
Cat 623 Water Wagon	407	1
BOOMTRUCK,23-28 TON	226	1
PICKUP,3/4 TON,4X4,CREWCAB	180	2
PICKUP,3/4 TON,4X4,DIESEL,SUPERCAB	180	1
TRAILER,CABLE PULLER,20-30K PULL	x	1
TRAILER,POLE	x	1
TRUCK,2 TON,2X4,BUCKET	210	2
TRUCK,2 TON,2X4,DIGGER	210	1
UTILITY TRUCK,1 TON Cable Tensioner	180	1

Manpower	Number
Crew	10
Management	2
TOTAL	**12**

Start Date: 4/24/2025

Construction Equipment and Schedule

Intra-Field Electrical Distribution

60 days

Equipment	Horsepower	Number
Cat D6	207	1
Cat 623 Water Wagon	407	1
BOOMTRUCK,23-28 TON	226	1
PICKUP,3/4 TON,4X4,CREWCAB	180	2
PICKUP,3/4 TON,4X4,DIESEL,SUPERCAB	180	1
TRAILER,CABLE PULLER,20-30K PULL	x	1
TRAILER,POLE	x	1
TRUCK,2 TON,2X4,BUCKET	210	2
TRUCK,2 TON,2X4,DIGGER	210	1
UTILITY TRUCK,1 TON Cable Tensioner	180	1

Manpower	Number
Crew	10
Management	2
TOTAL	**12**

Start Date: 2/12/2026

Construction Equipment and Schedule

Onsite Electrical Substations

130 Days

Equipment	Horsepower	Number
BACKHOE/LOADER,1-1.25CY	92	3
BORING SYSTEM,30-36",AUGER,DIESEL	68	1
COMPACTOR,24-33" ROLLER,WALKBEHIND	8	1
COMPRESSOR,100-200 CFM,DIESEL	50	1
CONCRETE VIBRATOR,HEAVY DUTY	6	1
CRANE,70-79 TON,HYDRAULIC,RT	250	1
FORKLIFT,7-9K#,YARD	73	1
LOADER,SKIDSTEER 36-45HP	45	1
MANLIFT,40' RT,GAS OR DSL	60	1
MANLIFT,60' RT,GAS OR DSL	60	1
MORTAR MIXER,6-9 CU FT	7	1
PICKUP,3/4 TON,4X4,CREWCAB	130	2
REBAR BENDER,#2-#8 BAR ELEC	x	1
TRENCHER,3-5'	80	1
TRUCK,3/4 TON,2X4,ELECT. MAINT	x	1

Manpower	Number
Crew	16
Management	2
TOTAL	**18**

Start Date: 1/30/2025

Construction Equipment and Schedule

Water Pipelines

87 Days

Equipment	Horsepower	Number
BACKHOE/LOADER,.75-1CY	67	2
CAT 325 Excavator	172	2
BOOMTRUCK,10-13 TON	226	2
CAT 815 COMPACTOR	232	1
COMPACTOR,40-66" ROLLER,RIDE ON	33	1
PICKUP,1/2 TON,4X4	130	4
PICKUP,3/4 TON,4X4	130	4
WELDER,500-800 AMP DIESEL MULTI PURPOSE	48	3
WHEEL LOADER,3.0-3.5CY	125	1

Manpower	Number
Crew	18
Management	2
TOTAL	**20**

Start Date: 1/30/2025

Construction Equipment and Schedule

Tulare CVR Pipeline Pipeline

60 Days

Equipment	Horsepower	Number
BACKHOE/LOADER,.75-1CY	67	2
CAT 325 Excavator	172	2
BOOMTRUCK,10-13 TON	226	2
CAT 815 COMPACTOR	232	1
COMPACTOR,40-66" ROLLER,RIDE ON	33	1
PICKUP,1/2 TON,4X4	130	4
PICKUP,3/4 TON,4X4	130	4
WELDER,500-800 AMP DIESEL MULTI PURPOSE	48	3
WHEEL LOADER,3.0-3.5CY	125	1

Manpower	Number
Crew	18
Management	2
TOTAL	**20**

Start Date: 1/1/2025

Construction Equipment and Schedule

Steam Pipelines

88 Days

Equipment	Horsepower	Number
BACKHOE/LOADER,.75-1CY	67	2
CAT 325 Excavator	172	2
BOOMTRUCK,10-13 TON	226	2
CAT 815 COMPACTOR	232	1
COMPACTOR,40-66" ROLLER,RIDE ON	33	1
PICKUP,1/2 TON,4X4	130	4
PICKUP,3/4 TON,4X4	130	4
WELDER,500-800 AMP DIESEL MULTI PURPOSE	48	3
WHEEL LOADER,3.0-3.5CY	125	1

Manpower	Number
Crew	18
Management	2
TOTAL	**20**

Start Date: 7/17/2025

Construction Equipment and Schedule

Demolition

40 Days

Equipment	Horsepower	Number
Cat 14 Grader	259	1
Cat 623 Water Wagon	407	1
Cat 815 Compactor	232	1
Cat 875 Challenger	585	1
CAT 325 Excavator	172	1
Excavator with Shear	172	1
Vacuum Truck/Hydro-excavator	425	1
GENERATOR,6-10KW,DIESEL	18	2
MECHANIC'S TRUCK,1.5 TON,2X4	130	1
PICKUP,1/2 TON,2X4	130	2

Manpower	Number
Crew	10
Management	2
TOTAL	**12**

Start Date: 1/30/2025

CCS - On-Site Roads Custom Report

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1. Basic Project Information

1.1. Basic Project Information

Data Field	Value
Project Name	CCS - On-Site Roads
Construction Start Date	1/30/2025
Lead Agency	—
Land Use Scale	Project/site
Analysis Level for Defaults	County
Windspeed (m/s)	2.70
Precipitation (days)	16.2
Location	35.453174, -119.708967
County	Kern-San Joaquin
City	Unincorporated
Air District	San Joaquin Valley APCD
Air Basin	San Joaquin Valley
TAZ	2947
EDFZ	5
Electric Utility	Pacific Gas & Electric Company
Gas Utility	Southern California Gas
App Version	2022.1.1.14

1.2. Land Use Types

Land Use Subtype	Size	Unit	Lot Acreage	Building Area (sq ft)	Landscape Area (sq ft)	Special Landscape Area (sq ft)	Population	Description
Other Asphalt Surfaces	40.0	Acre	40.0	0.00	0.00	—	—	—

1.3. User-Selected Emission Reduction Measures by Emissions Sector

Sector	#	Measure Title
Construction	C-10-A	Water Exposed Surfaces
Construction	C-11	Limit Vehicle Speeds on Unpaved Roads

2. Emissions Summary

2.1. Construction Emissions Compared Against Thresholds

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Un/Mit.	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	3.92	8.53	30.5	21.9	0.07	1.20	0.25	1.46	1.11	0.06	1.17	—	7,340	7,340	0.29	0.07	0.03	7,367
Mit.	3.92	8.53	30.5	21.9	0.07	1.20	0.25	1.46	1.11	0.06	1.17	—	7,340	7,340	0.29	0.07	0.03	7,367
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	0.21	0.47	1.67	1.21	< 0.005	0.07	0.01	0.08	0.06	< 0.005	0.06	—	403	403	0.02	< 0.005	0.02	404
Mit.	0.21	0.47	1.67	1.21	< 0.005	0.07	0.01	0.08	0.06	< 0.005	0.06	—	403	403	0.02	< 0.005	0.02	404
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Annual (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	0.04	0.09	0.30	0.22	< 0.005	0.01	< 0.005	0.01	0.01	< 0.005	0.01	—	66.7	66.7	< 0.005	< 0.005	< 0.005	66.9
Mit.	0.04	0.09	0.30	0.22	< 0.005	0.01	< 0.005	0.01	0.01	< 0.005	0.01	—	66.7	66.7	< 0.005	< 0.005	< 0.005	66.9

% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

2.2. Construction Emissions by Year, Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	3.92	8.53	30.5	21.9	0.07	1.20	0.25	1.46	1.11	0.06	1.17	—	7,340	7,340	0.29	0.07	0.03	7,367
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.21	0.47	1.67	1.21	< 0.005	0.07	0.01	0.08	0.06	< 0.005	0.06	—	403	403	0.02	< 0.005	0.02	404
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.04	0.09	0.30	0.22	< 0.005	0.01	< 0.005	0.01	0.01	< 0.005	0.01	—	66.7	66.7	< 0.005	< 0.005	< 0.005	66.9

2.3. Construction Emissions by Year, Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	3.92	8.53	30.5	21.9	0.07	1.20	0.25	1.46	1.11	0.06	1.17	—	7,340	7,340	0.29	0.07	0.03	7,367
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

2025	0.21	0.47	1.67	1.21	< 0.005	0.07	0.01	0.08	0.06	< 0.005	0.06	—	403	403	0.02	< 0.005	0.02	404
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.04	0.09	0.30	0.22	< 0.005	0.01	< 0.005	0.01	0.01	< 0.005	0.01	—	66.7	66.7	< 0.005	< 0.005	< 0.005	66.9

3. Construction Emissions Details

3.1. Paving (2025) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	3.87	3.25	30.4	21.0	0.07	1.20	—	1.20	1.11	—	1.11	—	7,096	7,096	0.29	0.06	—	7,121
Paving	—	5.24	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.21	0.18	1.67	1.15	< 0.005	0.07	—	0.07	0.06	—	0.06	—	389	389	0.02	< 0.005	—	390
Paving	—	0.29	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.04	0.03	0.30	0.21	< 0.005	0.01	—	0.01	0.01	—	0.01	—	64.4	64.4	< 0.005	< 0.005	—	64.6

Paving	—	0.05	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.05	0.04	0.09	0.92	0.00	0.00	0.25	0.25	0.00	0.06	0.06	—	244	244	< 0.005	0.01	0.03	246
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	< 0.005	< 0.005	< 0.005	0.06	0.00	0.00	0.01	0.01	0.00	< 0.005	< 0.005	—	13.9	13.9	< 0.005	< 0.005	0.02	14.1
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	< 0.005	< 0.005	< 0.005	0.01	0.00	0.00	< 0.005	< 0.005	0.00	< 0.005	< 0.005	—	2.30	2.30	< 0.005	< 0.005	< 0.005	2.33
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.2. Paving (2025) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	3.87	3.25	30.4	21.0	0.07	1.20	—	1.20	1.11	—	1.11	—	7,096	7,096	0.29	0.06	—	7,121
Paving	—	5.24	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.21	0.18	1.67	1.15	< 0.005	0.07	—	0.07	0.06	—	0.06	—	389	389	0.02	< 0.005	—	390
Paving	—	0.29	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.04	0.03	0.30	0.21	< 0.005	0.01	—	0.01	0.01	—	0.01	—	64.4	64.4	< 0.005	< 0.005	—	64.6
Paving	—	0.05	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.05	0.04	0.09	0.92	0.00	0.00	0.25	0.25	0.00	0.06	0.06	—	244	244	< 0.005	0.01	0.03	246
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Worker	< 0.005	< 0.005	< 0.005	0.06	0.00	0.00	0.01	0.01	0.00	< 0.005	< 0.005	—	13.9	13.9	< 0.005	< 0.005	0.02	14.1
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	< 0.005	< 0.005	< 0.005	0.01	0.00	0.00	< 0.005	< 0.005	0.00	< 0.005	< 0.005	—	2.30	2.30	< 0.005	< 0.005	< 0.005	2.33
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

5. Activity Data

5.1. Construction Schedule

Phase Name	Phase Type	Start Date	End Date	Days Per Week	Work Days per Phase	Phase Description
Paving	Paving	1/30/2025	2/26/2025	5.00	20.0	—

5.2. Off-Road Equipment

5.2.1. Unmitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Paving	Graders	Diesel	Average	1.00	8.00	259	0.41
Paving	Off-Highway Trucks	Diesel	Average	1.00	8.00	408	0.38
Paving	Rubber Tired Loaders	Diesel	Average	1.00	8.00	232	0.36
Paving	Crawler Tractors	Diesel	Average	1.00	8.00	585	0.43
Paving	Rubber Tired Dozers	Diesel	Average	2.00	8.00	207	0.40

5.2.2. Mitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor

Paving	Graders	Diesel	Average	1.00	8.00	259	0.41
Paving	Off-Highway Trucks	Diesel	Average	1.00	8.00	408	0.38
Paving	Rubber Tired Loaders	Diesel	Average	1.00	8.00	232	0.36
Paving	Crawler Tractors	Diesel	Average	1.00	8.00	585	0.43
Paving	Rubber Tired Dozers	Diesel	Average	2.00	8.00	207	0.40

5.3. Construction Vehicles

5.3.1. Unmitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Paving	—	—	—	—
Paving	Worker	8.00	45.0	LDA,LDT1,LDT2
Paving	Vendor	—	10.6	HHDT,MHDT
Paving	Hauling	0.00	20.0	HHDT
Paving	Onsite truck	—	—	HHDT

5.3.2. Mitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Paving	—	—	—	—
Paving	Worker	8.00	45.0	LDA,LDT1,LDT2
Paving	Vendor	—	10.6	HHDT,MHDT
Paving	Hauling	0.00	20.0	HHDT
Paving	Onsite truck	—	—	HHDT

5.4. Vehicles

5.4.1. Construction Vehicle Control Strategies

Non-applicable. No control strategies activated by user.

5.5. Architectural Coatings

Phase Name	Residential Interior Area Coated (sq ft)	Residential Exterior Area Coated (sq ft)	Non-Residential Interior Area Coated (sq ft)	Non-Residential Exterior Area Coated (sq ft)	Parking Area Coated (sq ft)

5.6. Dust Mitigation

5.6.1. Construction Earthmoving Activities

Phase Name	Material Imported (cy)	Material Exported (cy)	Acres Graded (acres)	Material Demolished (sq. ft.)	Acres Paved (acres)
Paving	0.00	0.00	0.00	0.00	40.0

5.6.2. Construction Earthmoving Control Strategies

Non-applicable. No control strategies activated by user.

5.7. Construction Paving

Land Use	Area Paved (acres)	% Asphalt
Other Asphalt Surfaces	40.0	100%

5.8. Construction Electricity Consumption and Emissions Factors

kWh per Year and Emission Factor (lb/MWh)

Year	kWh per Year	CO2	CH4	N2O
2025	0.00	204	0.03	< 0.005

5.18. Vegetation

5.18.1. Land Use Change

5.18.1.1. Unmitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.2. Sequestration

5.18.2.1. Unmitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

5.18.2.2. Mitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

8. User Changes to Default Data

Screen	Justification
Construction: Construction Phases	Work days per phase provided by Applicant.

Construction: Off-Road Equipment	Construction equipment provided by Applicant.
Construction: Trips and VMT	Estimated trip length.

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5.18. Vegetation

5.18.1. Land Use Change

5.18.1.1. Unmitigated

5.18.1.2. Mitigated

5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

5.18.1.2. Mitigated

5.18.2. Sequestration

5.18.2.1. Unmitigated

5.18.2.2. Mitigated

8. User Changes to Default Data

1. Basic Project Information

1.1. Basic Project Information

Data Field	Value
Project Name	CCS - Facilities Pad Grading GP32
Construction Start Date	6/2/2025
Lead Agency	—
Land Use Scale	Project/site
Analysis Level for Defaults	County
Windspeed (m/s)	2.70
Precipitation (days)	16.2
Location	35.453174, -119.708967
County	Kern-San Joaquin
City	Unincorporated
Air District	San Joaquin Valley APCD
Air Basin	San Joaquin Valley
TAZ	2947
EDFZ	5
Electric Utility	Pacific Gas & Electric Company
Gas Utility	Southern California Gas
App Version	2022.1.1.14

1.2. Land Use Types

Land Use Subtype	Size	Unit	Lot Acreage	Building Area (sq ft)	Landscape Area (sq ft)	Special Landscape Area (sq ft)	Population	Description
User Defined Industrial	1.00	User Defined Unit	40.0	0.00	0.00	—	—	—

1.3. User-Selected Emission Reduction Measures by Emissions Sector

Sector	#	Measure Title
Construction	C-10-A	Water Exposed Surfaces
Construction	C-11	Limit Vehicle Speeds on Unpaved Roads

2. Emissions Summary

2.1. Construction Emissions Compared Against Thresholds

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Un/Mit.	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	7.47	6.27	55.9	47.7	0.13	2.23	15.7	17.9	2.06	7.08	9.13	—	14,952	14,952	0.60	0.13	1.89	15,008
Mit.	7.47	6.27	55.9	47.7	0.13	2.23	4.44	6.67	2.06	1.92	3.98	—	14,952	14,952	0.60	0.13	1.89	15,008
% Reduced	—	—	—	—	—	—	72%	63%	—	73%	56%	—	—	—	—	—	—	—
Average Daily (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	0.41	0.34	3.06	2.57	0.01	0.12	0.86	0.98	0.11	0.39	0.50	—	817	817	0.03	0.01	0.04	820
Mit.	0.41	0.34	3.06	2.57	0.01	0.12	0.24	0.37	0.11	0.11	0.22	—	817	817	0.03	0.01	0.04	820
% Reduced	—	—	—	—	—	—	72%	63%	—	73%	56%	—	—	—	—	—	—	—
Annual (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	0.07	0.06	0.56	0.47	< 0.005	0.02	0.16	0.18	0.02	0.07	0.09	—	135	135	0.01	< 0.005	0.01	136
Mit.	0.07	0.06	0.56	0.47	< 0.005	0.02	0.04	0.07	0.02	0.02	0.04	—	135	135	0.01	< 0.005	0.01	136

% Reduced	—	—	—	—	—	—	72%	63%	—	73%	56%	—	—	—	—	—	—	—

2.2. Construction Emissions by Year, Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	7.47	6.27	55.9	47.7	0.13	2.23	15.7	17.9	2.06	7.08	9.13	—	14,952	14,952	0.60	0.13	1.89	15,008
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.41	0.34	3.06	2.57	0.01	0.12	0.86	0.98	0.11	0.39	0.50	—	817	817	0.03	0.01	0.04	820
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.07	0.06	0.56	0.47	< 0.005	0.02	0.16	0.18	0.02	0.07	0.09	—	135	135	0.01	< 0.005	0.01	136

2.3. Construction Emissions by Year, Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	7.47	6.27	55.9	47.7	0.13	2.23	4.44	6.67	2.06	1.92	3.98	—	14,952	14,952	0.60	0.13	1.89	15,008
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

2025	0.41	0.34	3.06	2.57	0.01	0.12	0.24	0.37	0.11	0.11	0.22	—	817	817	0.03	0.01	0.04	820
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.07	0.06	0.56	0.47	< 0.005	0.02	0.04	0.07	0.02	0.02	0.04	—	135	135	0.01	< 0.005	0.01	136

3. Construction Emissions Details

3.1. Grading (2025) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	7.36	6.18	55.8	44.9	0.13	2.23	—	2.23	2.06	—	2.06	—	14,430	14,430	0.59	0.12	—	14,479
Dust From Material Movement	—	—	—	—	—	—	15.2	15.2	—	6.96	6.96	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.40	0.34	3.05	2.46	0.01	0.12	—	0.12	0.11	—	0.11	—	791	791	0.03	0.01	—	793
Dust From Material Movement	—	—	—	—	—	—	0.83	0.83	—	0.38	0.38	—	—	—	—	—	—	—

Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.07	0.06	0.56	0.45	< 0.005	0.02	—	0.02	0.02	—	0.02	—	131	131	0.01	< 0.005	—	131
Dust From Material Movement	—	—	—	—	—	—	0.15	0.15	—	0.07	0.07	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.10	0.09	0.14	2.74	0.00	0.00	0.48	0.48	0.00	0.11	0.11	—	522	522	0.02	0.02	1.89	529
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.01	< 0.005	0.01	0.11	0.00	0.00	0.03	0.03	0.00	0.01	0.01	—	26.0	26.0	< 0.005	< 0.005	0.04	26.3
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	< 0.005	< 0.005	< 0.005	0.02	0.00	0.00	< 0.005	< 0.005	0.00	< 0.005	< 0.005	—	4.31	4.31	< 0.005	< 0.005	0.01	4.36
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.2. Grading (2025) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	7.36	6.18	55.8	44.9	0.13	2.23	—	2.23	2.06	—	2.06	—	14,430	14,430	0.59	0.12	—	14,479
Dust From Material Movement	—	—	—	—	—	—	3.96	3.96	—	1.81	1.81	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.40	0.34	3.05	2.46	0.01	0.12	—	0.12	0.11	—	0.11	—	791	791	0.03	0.01	—	793
Dust From Material Movement	—	—	—	—	—	—	0.22	0.22	—	0.10	0.10	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.07	0.06	0.56	0.45	< 0.005	0.02	—	0.02	0.02	—	0.02	—	131	131	0.01	< 0.005	—	131

Dust From Material Movement	—	—	—	—	—	—	0.04	0.04	—	0.02	0.02	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.10	0.09	0.14	2.74	0.00	0.00	0.48	0.48	0.00	0.11	0.11	—	522	522	0.02	0.02	1.89	529
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.01	< 0.005	0.01	0.11	0.00	0.00	0.03	0.03	0.00	0.01	0.01	—	26.0	26.0	< 0.005	< 0.005	0.04	26.3
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	< 0.005	< 0.005	< 0.005	0.02	0.00	0.00	< 0.005	< 0.005	0.00	< 0.005	< 0.005	—	4.31	4.31	< 0.005	< 0.005	0.01	4.36
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

5. Activity Data

5.1. Construction Schedule

Phase Name	Phase Type	Start Date	End Date	Days Per Week	Work Days per Phase	Phase Description

Grading	Grading	6/2/2025	6/27/2025	5.00	20.0	—

5.2. Off-Road Equipment

5.2.1. Unmitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Grading	Graders	Diesel	Average	2.00	8.00	259	0.41
Grading	Rubber Tired Dozers	Diesel	Average	2.00	8.00	207	0.40
Grading	Off-Highway Trucks	Diesel	Average	2.00	8.00	407	0.38
Grading	Rubber Tired Loaders	Diesel	Average	2.00	8.00	232	0.36
Grading	Crawler Tractors	Diesel	Average	2.00	8.00	585	0.43
Grading	Generator Sets	Diesel	Average	2.00	8.00	18.0	0.74
Grading	Other Construction Equipment	Diesel	Average	3.00	8.00	130	0.42

5.2.2. Mitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Grading	Graders	Diesel	Average	2.00	8.00	259	0.41
Grading	Rubber Tired Dozers	Diesel	Average	2.00	8.00	207	0.40
Grading	Off-Highway Trucks	Diesel	Average	2.00	8.00	407	0.38
Grading	Rubber Tired Loaders	Diesel	Average	2.00	8.00	232	0.36
Grading	Crawler Tractors	Diesel	Average	2.00	8.00	585	0.43
Grading	Generator Sets	Diesel	Average	2.00	8.00	18.0	0.74
Grading	Other Construction Equipment	Diesel	Average	3.00	8.00	130	0.42

5.3. Construction Vehicles

5.3.1. Unmitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Grading	—	—	—	—
Grading	Worker	15.0	45.0	LDA,LDT1,LDT2
Grading	Vendor	—	10.6	HHDT,MHDT
Grading	Hauling	0.00	20.0	HHDT
Grading	Onsite truck	—	—	HHDT

5.3.2. Mitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Grading	—	—	—	—
Grading	Worker	15.0	45.0	LDA,LDT1,LDT2
Grading	Vendor	—	10.6	HHDT,MHDT
Grading	Hauling	0.00	20.0	HHDT
Grading	Onsite truck	—	—	HHDT

5.4. Vehicles

5.4.1. Construction Vehicle Control Strategies

Non-applicable. No control strategies activated by user.

5.5. Architectural Coatings

Phase Name	Residential Interior Area Coated (sq ft)	Residential Exterior Area Coated (sq ft)	Non-Residential Interior Area Coated (sq ft)	Non-Residential Exterior Area Coated (sq ft)	Parking Area Coated (sq ft)

5.6. Dust Mitigation

5.6.1. Construction Earthmoving Activities

Phase Name	Material Imported (cy)	Material Exported (cy)	Acres Graded (acres)	Material Demolished (sq. ft.)	Acres Paved (acres)
Grading	—	—	40.0	0.00	—

5.6.2. Construction Earthmoving Control Strategies

Non-applicable. No control strategies activated by user.

5.7. Construction Paving

Land Use	Area Paved (acres)	% Asphalt
User Defined Industrial	0.00	0%

5.8. Construction Electricity Consumption and Emissions Factors

kWh per Year and Emission Factor (lb/MWh)

Year	kWh per Year	CO2	CH4	N2O
2025	0.00	204	0.03	< 0.005

5.18. Vegetation

5.18.1. Land Use Change

5.18.1.1. Unmitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.2. Sequestration

5.18.2.1. Unmitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

5.18.2.2. Mitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

8. User Changes to Default Data

Screen	Justification
Land Use	Project acreage is 2,636 but disturbed land would be 40 acres per Applicant.
Construction: Construction Phases	Work Days per Phase provided by Applicant.
Construction: Off-Road Equipment	Construction equipment provided by Applicant.
Construction: Dust From Material Movement	40 acres of disturbed land.
Construction: Trips and VMT	Estimated trip length.

CCS - Facilities Pad Grading 32 Cogen v2 Custom Report

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5.18. Vegetation

5.18.1. Land Use Change

5.18.1.1. Unmitigated

5.18.1.2. Mitigated

5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

5.18.1.2. Mitigated

5.18.2. Sequestration

5.18.2.1. Unmitigated

5.18.2.2. Mitigated

8. User Changes to Default Data

1. Basic Project Information

1.1. Basic Project Information

Data Field	Value
Project Name	CCS - Facilities Pad Grading 32 Cogen v2
Construction Start Date	1/30/2025
Lead Agency	—
Land Use Scale	Project/site
Analysis Level for Defaults	County
Windspeed (m/s)	2.70
Precipitation (days)	16.2
Location	35.453174, -119.708967
County	Kern-San Joaquin
City	Unincorporated
Air District	San Joaquin Valley APCD
Air Basin	San Joaquin Valley
TAZ	2947
EDFZ	5
Electric Utility	Pacific Gas & Electric Company
Gas Utility	Southern California Gas
App Version	2022.1.1.14

1.2. Land Use Types

Land Use Subtype	Size	Unit	Lot Acreage	Building Area (sq ft)	Landscape Area (sq ft)	Special Landscape Area (sq ft)	Population	Description
User Defined Industrial	1.00	User Defined Unit	40.0	0.00	0.00	—	—	—

1.3. User-Selected Emission Reduction Measures by Emissions Sector

Sector	#	Measure Title
Construction	C-10-A	Water Exposed Surfaces
Construction	C-11	Limit Vehicle Speeds on Unpaved Roads

2. Emissions Summary

2.1. Construction Emissions Compared Against Thresholds

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Un/Mit.	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	7.46	6.26	55.9	46.7	0.13	2.23	15.7	17.9	2.06	7.08	9.13	—	14,887	14,887	0.59	0.13	0.05	14,941
Mit.	7.46	6.26	55.9	46.7	0.13	2.23	4.44	6.67	2.06	1.92	3.98	—	14,887	14,887	0.59	0.13	0.05	14,941
% Reduced	—	—	—	—	—	—	72%	63%	—	73%	56%	—	—	—	—	—	—	—
Average Daily (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	0.41	0.34	3.06	2.57	0.01	0.12	0.86	0.98	0.11	0.39	0.50	—	817	817	0.03	0.01	0.04	820
Mit.	0.41	0.34	3.06	2.57	0.01	0.12	0.24	0.37	0.11	0.11	0.22	—	817	817	0.03	0.01	0.04	820
% Reduced	—	—	—	—	—	—	72%	63%	—	73%	56%	—	—	—	—	—	—	—
Annual (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	0.07	0.06	0.56	0.47	< 0.005	0.02	0.16	0.18	0.02	0.07	0.09	—	135	135	0.01	< 0.005	0.01	136
Mit.	0.07	0.06	0.56	0.47	< 0.005	0.02	0.04	0.07	0.02	0.02	0.04	—	135	135	0.01	< 0.005	0.01	136

% Reduced	—	—	—	—	—	—	72%	63%	—	73%	56%	—	—	—	—	—	—	—

2.2. Construction Emissions by Year, Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	7.46	6.26	55.9	46.7	0.13	2.23	15.7	17.9	2.06	7.08	9.13	—	14,887	14,887	0.59	0.13	0.05	14,941
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.41	0.34	3.06	2.57	0.01	0.12	0.86	0.98	0.11	0.39	0.50	—	817	817	0.03	0.01	0.04	820
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.07	0.06	0.56	0.47	< 0.005	0.02	0.16	0.18	0.02	0.07	0.09	—	135	135	0.01	< 0.005	0.01	136

2.3. Construction Emissions by Year, Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	7.46	6.26	55.9	46.7	0.13	2.23	4.44	6.67	2.06	1.92	3.98	—	14,887	14,887	0.59	0.13	0.05	14,941
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

2025	0.41	0.34	3.06	2.57	0.01	0.12	0.24	0.37	0.11	0.11	0.22	—	817	817	0.03	0.01	0.04	820
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.07	0.06	0.56	0.47	< 0.005	0.02	0.04	0.07	0.02	0.02	0.04	—	135	135	0.01	< 0.005	0.01	136

3. Construction Emissions Details

3.1. Grading (2025) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	7.36	6.18	55.8	44.9	0.13	2.23	—	2.23	2.06	—	2.06	—	14,430	14,430	0.59	0.12	—	14,479
Dust From Material Movement	—	—	—	—	—	—	15.2	15.2	—	6.96	6.96	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.40	0.34	3.05	2.46	0.01	0.12	—	0.12	0.11	—	0.11	—	791	791	0.03	0.01	—	793
Dust From Material Movement	—	—	—	—	—	—	0.83	0.83	—	0.38	0.38	—	—	—	—	—	—	—

Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.07	0.06	0.56	0.45	< 0.005	0.02	—	0.02	0.02	—	0.02	—	131	131	0.01	< 0.005	—	131
Dust From Material Movement	—	—	—	—	—	—	0.15	0.15	—	0.07	0.07	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.10	0.08	0.18	1.73	0.00	0.00	0.48	0.48	0.00	0.11	0.11	—	457	457	< 0.005	0.02	0.05	462
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.01	< 0.005	0.01	0.11	0.00	0.00	0.03	0.03	0.00	0.01	0.01	—	26.0	26.0	< 0.005	< 0.005	0.04	26.3
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	< 0.005	< 0.005	< 0.005	0.02	0.00	0.00	< 0.005	< 0.005	0.00	< 0.005	< 0.005	—	4.31	4.31	< 0.005	< 0.005	0.01	4.36
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.2. Grading (2025) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	7.36	6.18	55.8	44.9	0.13	2.23	—	2.23	2.06	—	2.06	—	14,430	14,430	0.59	0.12	—	14,479
Dust From Material Movement	—	—	—	—	—	—	3.96	3.96	—	1.81	1.81	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.40	0.34	3.05	2.46	0.01	0.12	—	0.12	0.11	—	0.11	—	791	791	0.03	0.01	—	793
Dust From Material Movement	—	—	—	—	—	—	0.22	0.22	—	0.10	0.10	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.07	0.06	0.56	0.45	< 0.005	0.02	—	0.02	0.02	—	0.02	—	131	131	0.01	< 0.005	—	131

Dust From Material Movement	—	—	—	—	—	—	0.04	0.04	—	0.02	0.02	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.10	0.08	0.18	1.73	0.00	0.00	0.48	0.48	0.00	0.11	0.11	—	457	457	< 0.005	0.02	0.05	462
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.01	< 0.005	0.01	0.11	0.00	0.00	0.03	0.03	0.00	0.01	0.01	—	26.0	26.0	< 0.005	< 0.005	0.04	26.3
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	< 0.005	< 0.005	< 0.005	0.02	0.00	0.00	< 0.005	< 0.005	0.00	< 0.005	< 0.005	—	4.31	4.31	< 0.005	< 0.005	0.01	4.36
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

5. Activity Data

5.1. Construction Schedule

Phase Name	Phase Type	Start Date	End Date	Days Per Week	Work Days per Phase	Phase Description

Grading	Grading	1/30/2025	2/26/2025	5.00	20.0	—

5.2. Off-Road Equipment

5.2.1. Unmitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Grading	Graders	Diesel	Average	2.00	8.00	259	0.41
Grading	Rubber Tired Dozers	Diesel	Average	2.00	8.00	207	0.40
Grading	Off-Highway Trucks	Diesel	Average	2.00	8.00	407	0.38
Grading	Rubber Tired Loaders	Diesel	Average	2.00	8.00	232	0.36
Grading	Crawler Tractors	Diesel	Average	2.00	8.00	585	0.43
Grading	Generator Sets	Diesel	Average	2.00	8.00	18.0	0.74
Grading	Other Construction Equipment	Diesel	Average	3.00	8.00	130	0.42

5.2.2. Mitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Grading	Graders	Diesel	Average	2.00	8.00	259	0.41
Grading	Rubber Tired Dozers	Diesel	Average	2.00	8.00	207	0.40
Grading	Off-Highway Trucks	Diesel	Average	2.00	8.00	407	0.38
Grading	Rubber Tired Loaders	Diesel	Average	2.00	8.00	232	0.36
Grading	Crawler Tractors	Diesel	Average	2.00	8.00	585	0.43
Grading	Generator Sets	Diesel	Average	2.00	8.00	18.0	0.74
Grading	Other Construction Equipment	Diesel	Average	3.00	8.00	130	0.42

5.3. Construction Vehicles

5.3.1. Unmitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Grading	—	—	—	—
Grading	Worker	15.0	45.0	LDA,LDT1,LDT2
Grading	Vendor	—	10.6	HHDT,MHDT
Grading	Hauling	0.00	20.0	HHDT
Grading	Onsite truck	—	—	HHDT

5.3.2. Mitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Grading	—	—	—	—
Grading	Worker	15.0	45.0	LDA,LDT1,LDT2
Grading	Vendor	—	10.6	HHDT,MHDT
Grading	Hauling	0.00	20.0	HHDT
Grading	Onsite truck	—	—	HHDT

5.4. Vehicles

5.4.1. Construction Vehicle Control Strategies

Non-applicable. No control strategies activated by user.

5.5. Architectural Coatings

Phase Name	Residential Interior Area Coated (sq ft)	Residential Exterior Area Coated (sq ft)	Non-Residential Interior Area Coated (sq ft)	Non-Residential Exterior Area Coated (sq ft)	Parking Area Coated (sq ft)

5.6. Dust Mitigation

5.6.1. Construction Earthmoving Activities

Phase Name	Material Imported (cy)	Material Exported (cy)	Acres Graded (acres)	Material Demolished (sq. ft.)	Acres Paved (acres)
Grading	—	—	40.0	0.00	—

5.6.2. Construction Earthmoving Control Strategies

Non-applicable. No control strategies activated by user.

5.7. Construction Paving

Land Use	Area Paved (acres)	% Asphalt
User Defined Industrial	0.00	0%

5.8. Construction Electricity Consumption and Emissions Factors

kWh per Year and Emission Factor (lb/MWh)

Year	kWh per Year	CO2	CH4	N2O
2025	0.00	204	0.03	< 0.005

5.18. Vegetation

5.18.1. Land Use Change

5.18.1.1. Unmitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.2. Sequestration

5.18.2.1. Unmitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

5.18.2.2. Mitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

8. User Changes to Default Data

Screen	Justification
Land Use	Project acreage is 2,636 but disturbed land would be 40 acres per Applicant.
Construction: Construction Phases	Work Days per Phase provided by Applicant.
Construction: Off-Road Equipment	Construction equipment provided by Applicant.
Construction: Dust From Material Movement	40 acres of disturbed land.
Construction: Trips and VMT	Estimated trip length.

CCS - Facilities Pad Grading SP286B Custom Report

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5.18.1. Land Use Change

5.18.1.1. Unmitigated

5.18.1.2. Mitigated

5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

5.18.1.2. Mitigated

5.18.2. Sequestration

5.18.2.1. Unmitigated

5.18.2.2. Mitigated

8. User Changes to Default Data

1. Basic Project Information

1.1. Basic Project Information

Data Field	Value
Project Name	CCS - Facilities Pad Grading SP286B
Construction Start Date	8/21/2025
Lead Agency	—
Land Use Scale	Project/site
Analysis Level for Defaults	County
Windspeed (m/s)	2.70
Precipitation (days)	16.2
Location	35.453174, -119.708967
County	Kern-San Joaquin
City	Unincorporated
Air District	San Joaquin Valley APCD
Air Basin	San Joaquin Valley
TAZ	2947
EDFZ	5
Electric Utility	Pacific Gas & Electric Company
Gas Utility	Southern California Gas
App Version	2022.1.1.14

1.2. Land Use Types

Land Use Subtype	Size	Unit	Lot Acreage	Building Area (sq ft)	Landscape Area (sq ft)	Special Landscape Area (sq ft)	Population	Description
User Defined Industrial	1.00	User Defined Unit	40.0	0.00	0.00	—	—	—

1.3. User-Selected Emission Reduction Measures by Emissions Sector

Sector	#	Measure Title
Construction	C-10-A	Water Exposed Surfaces
Construction	C-11	Limit Vehicle Speeds on Unpaved Roads

2. Emissions Summary

2.1. Construction Emissions Compared Against Thresholds

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Un/Mit.	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	7.47	6.27	55.9	47.7	0.13	2.23	15.7	17.9	2.06	7.08	9.13	—	14,952	14,952	0.60	0.13	1.89	15,008
Mit.	7.47	6.27	55.9	47.7	0.13	2.23	4.44	6.67	2.06	1.92	3.98	—	14,952	14,952	0.60	0.13	1.89	15,008
% Reduced	—	—	—	—	—	—	72%	63%	—	73%	56%	—	—	—	—	—	—	—
Average Daily (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	0.41	0.34	3.06	2.57	0.01	0.12	0.86	0.98	0.11	0.39	0.50	—	817	817	0.03	0.01	0.04	820
Mit.	0.41	0.34	3.06	2.57	0.01	0.12	0.24	0.37	0.11	0.11	0.22	—	817	817	0.03	0.01	0.04	820
% Reduced	—	—	—	—	—	—	72%	63%	—	73%	56%	—	—	—	—	—	—	—
Annual (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	0.07	0.06	0.56	0.47	< 0.005	0.02	0.16	0.18	0.02	0.07	0.09	—	135	135	0.01	< 0.005	0.01	136
Mit.	0.07	0.06	0.56	0.47	< 0.005	0.02	0.04	0.07	0.02	0.02	0.04	—	135	135	0.01	< 0.005	0.01	136

% Reduced	—	—	—	—	—	—	72%	63%	—	73%	56%	—	—	—	—	—	—	—

2.2. Construction Emissions by Year, Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	7.47	6.27	55.9	47.7	0.13	2.23	15.7	17.9	2.06	7.08	9.13	—	14,952	14,952	0.60	0.13	1.89	15,008
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.41	0.34	3.06	2.57	0.01	0.12	0.86	0.98	0.11	0.39	0.50	—	817	817	0.03	0.01	0.04	820
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.07	0.06	0.56	0.47	< 0.005	0.02	0.16	0.18	0.02	0.07	0.09	—	135	135	0.01	< 0.005	0.01	136

2.3. Construction Emissions by Year, Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	7.47	6.27	55.9	47.7	0.13	2.23	4.44	6.67	2.06	1.92	3.98	—	14,952	14,952	0.60	0.13	1.89	15,008
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

2025	0.41	0.34	3.06	2.57	0.01	0.12	0.24	0.37	0.11	0.11	0.22	—	817	817	0.03	0.01	0.04	820
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.07	0.06	0.56	0.47	< 0.005	0.02	0.04	0.07	0.02	0.02	0.04	—	135	135	0.01	< 0.005	0.01	136

3. Construction Emissions Details

3.1. Grading (2025) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	7.36	6.18	55.8	44.9	0.13	2.23	—	2.23	2.06	—	2.06	—	14,430	14,430	0.59	0.12	—	14,479
Dust From Material Movement	—	—	—	—	—	—	15.2	15.2	—	6.96	6.96	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.40	0.34	3.05	2.46	0.01	0.12	—	0.12	0.11	—	0.11	—	791	791	0.03	0.01	—	793
Dust From Material Movement	—	—	—	—	—	—	0.83	0.83	—	0.38	0.38	—	—	—	—	—	—	—

Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.07	0.06	0.56	0.45	< 0.005	0.02	—	0.02	0.02	—	0.02	—	131	131	0.01	< 0.005	—	131
Dust From Material Movement	—	—	—	—	—	—	0.15	0.15	—	0.07	0.07	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.10	0.09	0.14	2.74	0.00	0.00	0.48	0.48	0.00	0.11	0.11	—	522	522	0.02	0.02	1.89	529
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.01	< 0.005	0.01	0.11	0.00	0.00	0.03	0.03	0.00	0.01	0.01	—	26.0	26.0	< 0.005	< 0.005	0.04	26.3
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	< 0.005	< 0.005	< 0.005	0.02	0.00	0.00	< 0.005	< 0.005	0.00	< 0.005	< 0.005	—	4.31	4.31	< 0.005	< 0.005	0.01	4.36
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.2. Grading (2025) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	7.36	6.18	55.8	44.9	0.13	2.23	—	2.23	2.06	—	2.06	—	14,430	14,430	0.59	0.12	—	14,479
Dust From Material Movement	—	—	—	—	—	—	3.96	3.96	—	1.81	1.81	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.40	0.34	3.05	2.46	0.01	0.12	—	0.12	0.11	—	0.11	—	791	791	0.03	0.01	—	793
Dust From Material Movement	—	—	—	—	—	—	0.22	0.22	—	0.10	0.10	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.07	0.06	0.56	0.45	< 0.005	0.02	—	0.02	0.02	—	0.02	—	131	131	0.01	< 0.005	—	131

Dust From Material Movement	—	—	—	—	—	—	0.04	0.04	—	0.02	0.02	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.10	0.09	0.14	2.74	0.00	0.00	0.48	0.48	0.00	0.11	0.11	—	522	522	0.02	0.02	1.89	529
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.01	< 0.005	0.01	0.11	0.00	0.00	0.03	0.03	0.00	0.01	0.01	—	26.0	26.0	< 0.005	< 0.005	0.04	26.3
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	< 0.005	< 0.005	< 0.005	0.02	0.00	0.00	< 0.005	< 0.005	0.00	< 0.005	< 0.005	—	4.31	4.31	< 0.005	< 0.005	0.01	4.36
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

5. Activity Data

5.1. Construction Schedule

Phase Name	Phase Type	Start Date	End Date	Days Per Week	Work Days per Phase	Phase Description

Grading	Grading	8/21/2025	9/17/2025	5.00	20.0	—

5.2. Off-Road Equipment

5.2.1. Unmitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Grading	Graders	Diesel	Average	2.00	8.00	259	0.41
Grading	Rubber Tired Dozers	Diesel	Average	2.00	8.00	207	0.40
Grading	Off-Highway Trucks	Diesel	Average	2.00	8.00	407	0.38
Grading	Rubber Tired Loaders	Diesel	Average	2.00	8.00	232	0.36
Grading	Crawler Tractors	Diesel	Average	2.00	8.00	585	0.43
Grading	Generator Sets	Diesel	Average	2.00	8.00	18.0	0.74
Grading	Other Construction Equipment	Diesel	Average	3.00	8.00	130	0.42

5.2.2. Mitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Grading	Graders	Diesel	Average	2.00	8.00	259	0.41
Grading	Rubber Tired Dozers	Diesel	Average	2.00	8.00	207	0.40
Grading	Off-Highway Trucks	Diesel	Average	2.00	8.00	407	0.38
Grading	Rubber Tired Loaders	Diesel	Average	2.00	8.00	232	0.36
Grading	Crawler Tractors	Diesel	Average	2.00	8.00	585	0.43
Grading	Generator Sets	Diesel	Average	2.00	8.00	18.0	0.74
Grading	Other Construction Equipment	Diesel	Average	3.00	8.00	130	0.42

5.3. Construction Vehicles

5.3.1. Unmitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Grading	—	—	—	—
Grading	Worker	15.0	45.0	LDA,LDT1,LDT2
Grading	Vendor	—	10.6	HHDT,MHDT
Grading	Hauling	0.00	20.0	HHDT
Grading	Onsite truck	—	—	HHDT

5.3.2. Mitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Grading	—	—	—	—
Grading	Worker	15.0	45.0	LDA,LDT1,LDT2
Grading	Vendor	—	10.6	HHDT,MHDT
Grading	Hauling	0.00	20.0	HHDT
Grading	Onsite truck	—	—	HHDT

5.4. Vehicles

5.4.1. Construction Vehicle Control Strategies

Non-applicable. No control strategies activated by user.

5.5. Architectural Coatings

Phase Name	Residential Interior Area Coated (sq ft)	Residential Exterior Area Coated (sq ft)	Non-Residential Interior Area Coated (sq ft)	Non-Residential Exterior Area Coated (sq ft)	Parking Area Coated (sq ft)

5.6. Dust Mitigation

5.6.1. Construction Earthmoving Activities

Phase Name	Material Imported (cy)	Material Exported (cy)	Acres Graded (acres)	Material Demolished (sq. ft.)	Acres Paved (acres)
Grading	—	—	40.0	0.00	—

5.6.2. Construction Earthmoving Control Strategies

Non-applicable. No control strategies activated by user.

5.7. Construction Paving

Land Use	Area Paved (acres)	% Asphalt
User Defined Industrial	0.00	0%

5.8. Construction Electricity Consumption and Emissions Factors

kWh per Year and Emission Factor (lb/MWh)

Year	kWh per Year	CO2	CH4	N2O
2025	0.00	204	0.03	< 0.005

5.18. Vegetation

5.18.1. Land Use Change

5.18.1.1. Unmitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.2. Sequestration

5.18.2.1. Unmitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

5.18.2.2. Mitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

8. User Changes to Default Data

Screen	Justification
Land Use	Project acreage is 2,636 but disturbed land would be 40 acres per Applicant.
Construction: Construction Phases	Work Days per Phase provided by Applicant.
Construction: Off-Road Equipment	Construction equipment provided by Applicant.
Construction: Dust From Material Movement	40 acres of disturbed land.
Construction: Trips and VMT	Estimated trip length.

CCS - Facilities Pad Grading SP2972 Custom Report

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5.18.1. Land Use Change

5.18.1.1. Unmitigated

5.18.1.2. Mitigated

5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

5.18.1.2. Mitigated

5.18.2. Sequestration

5.18.2.1. Unmitigated

5.18.2.2. Mitigated

8. User Changes to Default Data

1. Basic Project Information

1.1. Basic Project Information

Data Field	Value
Project Name	CCS - Facilities Pad Grading SP2972
Construction Start Date	2/12/2026
Lead Agency	—
Land Use Scale	Project/site
Analysis Level for Defaults	County
Windspeed (m/s)	2.70
Precipitation (days)	16.2
Location	35.453174, -119.708967
County	Kern-San Joaquin
City	Unincorporated
Air District	San Joaquin Valley APCD
Air Basin	San Joaquin Valley
TAZ	2947
EDFZ	5
Electric Utility	Pacific Gas & Electric Company
Gas Utility	Southern California Gas
App Version	2022.1.1.14

1.2. Land Use Types

Land Use Subtype	Size	Unit	Lot Acreage	Building Area (sq ft)	Landscape Area (sq ft)	Special Landscape Area (sq ft)	Population	Description
User Defined Industrial	1.00	User Defined Unit	40.0	0.00	0.00	—	—	—

1.3. User-Selected Emission Reduction Measures by Emissions Sector

Sector	#	Measure Title
Construction	C-10-A	Water Exposed Surfaces
Construction	C-11	Limit Vehicle Speeds on Unpaved Roads

2. Emissions Summary

2.1. Construction Emissions Compared Against Thresholds

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Un/Mit.	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	7.47	6.27	55.9	47.7	0.13	2.23	15.7	17.9	2.06	7.08	9.13	—	14,952	14,952	0.60	0.13	1.89	15,008
Mit.	7.47	6.27	55.9	47.7	0.13	2.23	4.44	6.67	2.06	1.92	3.98	—	14,952	14,952	0.60	0.13	1.89	15,008
% Reduced	—	—	—	—	—	—	72%	63%	—	73%	56%	—	—	—	—	—	—	—
Average Daily (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	0.41	0.34	3.06	2.57	0.01	0.12	0.86	0.98	0.11	0.39	0.50	—	817	817	0.03	0.01	0.04	820
Mit.	0.41	0.34	3.06	2.57	0.01	0.12	0.24	0.37	0.11	0.11	0.22	—	817	817	0.03	0.01	0.04	820
% Reduced	—	—	—	—	—	—	72%	63%	—	73%	56%	—	—	—	—	—	—	—
Annual (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	0.07	0.06	0.56	0.47	< 0.005	0.02	0.16	0.18	0.02	0.07	0.09	—	135	135	0.01	< 0.005	0.01	136
Mit.	0.07	0.06	0.56	0.47	< 0.005	0.02	0.04	0.07	0.02	0.02	0.04	—	135	135	0.01	< 0.005	0.01	136

% Reduced	—	—	—	—	—	—	72%	63%	—	73%	56%	—	—	—	—	—	—	—

2.2. Construction Emissions by Year, Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	7.47	6.27	55.9	47.7	0.13	2.23	15.7	17.9	2.06	7.08	9.13	—	14,952	14,952	0.60	0.13	1.89	15,008
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.41	0.34	3.06	2.57	0.01	0.12	0.86	0.98	0.11	0.39	0.50	—	817	817	0.03	0.01	0.04	820
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.07	0.06	0.56	0.47	< 0.005	0.02	0.16	0.18	0.02	0.07	0.09	—	135	135	0.01	< 0.005	0.01	136

2.3. Construction Emissions by Year, Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	7.47	6.27	55.9	47.7	0.13	2.23	4.44	6.67	2.06	1.92	3.98	—	14,952	14,952	0.60	0.13	1.89	15,008
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

2025	0.41	0.34	3.06	2.57	0.01	0.12	0.24	0.37	0.11	0.11	0.22	—	817	817	0.03	0.01	0.04	820
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.07	0.06	0.56	0.47	< 0.005	0.02	0.04	0.07	0.02	0.02	0.04	—	135	135	0.01	< 0.005	0.01	136

3. Construction Emissions Details

3.1. Grading (2025) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	7.36	6.18	55.8	44.9	0.13	2.23	—	2.23	2.06	—	2.06	—	14,430	14,430	0.59	0.12	—	14,479
Dust From Material Movement	—	—	—	—	—	—	15.2	15.2	—	6.96	6.96	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.40	0.34	3.05	2.46	0.01	0.12	—	0.12	0.11	—	0.11	—	791	791	0.03	0.01	—	793
Dust From Material Movement	—	—	—	—	—	—	0.83	0.83	—	0.38	0.38	—	—	—	—	—	—	—

Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.07	0.06	0.56	0.45	< 0.005	0.02	—	0.02	0.02	—	0.02	—	131	131	0.01	< 0.005	—	131
Dust From Material Movement	—	—	—	—	—	—	0.15	0.15	—	0.07	0.07	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.10	0.09	0.14	2.74	0.00	0.00	0.48	0.48	0.00	0.11	0.11	—	522	522	0.02	0.02	1.89	529
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.01	< 0.005	0.01	0.11	0.00	0.00	0.03	0.03	0.00	0.01	0.01	—	26.0	26.0	< 0.005	< 0.005	0.04	26.3
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	< 0.005	< 0.005	< 0.005	0.02	0.00	0.00	< 0.005	< 0.005	0.00	< 0.005	< 0.005	—	4.31	4.31	< 0.005	< 0.005	0.01	4.36
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.2. Grading (2025) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	7.36	6.18	55.8	44.9	0.13	2.23	—	2.23	2.06	—	2.06	—	14,430	14,430	0.59	0.12	—	14,479
Dust From Material Movement	—	—	—	—	—	—	3.96	3.96	—	1.81	1.81	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.40	0.34	3.05	2.46	0.01	0.12	—	0.12	0.11	—	0.11	—	791	791	0.03	0.01	—	793
Dust From Material Movement	—	—	—	—	—	—	0.22	0.22	—	0.10	0.10	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.07	0.06	0.56	0.45	< 0.005	0.02	—	0.02	0.02	—	0.02	—	131	131	0.01	< 0.005	—	131

Dust From Material Movement	—	—	—	—	—	—	0.04	0.04	—	0.02	0.02	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.10	0.09	0.14	2.74	0.00	0.00	0.48	0.48	0.00	0.11	0.11	—	522	522	0.02	0.02	1.89	529
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.01	< 0.005	0.01	0.11	0.00	0.00	0.03	0.03	0.00	0.01	0.01	—	26.0	26.0	< 0.005	< 0.005	0.04	26.3
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	< 0.005	< 0.005	< 0.005	0.02	0.00	0.00	< 0.005	< 0.005	0.00	< 0.005	< 0.005	—	4.31	4.31	< 0.005	< 0.005	0.01	4.36
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

5. Activity Data

5.1. Construction Schedule

Phase Name	Phase Type	Start Date	End Date	Days Per Week	Work Days per Phase	Phase Description

Grading	Grading	8/21/2025	9/17/2025	5.00	20.0	—

5.2. Off-Road Equipment

5.2.1. Unmitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Grading	Graders	Diesel	Average	2.00	8.00	259	0.41
Grading	Rubber Tired Dozers	Diesel	Average	2.00	8.00	207	0.40
Grading	Off-Highway Trucks	Diesel	Average	2.00	8.00	407	0.38
Grading	Rubber Tired Loaders	Diesel	Average	2.00	8.00	232	0.36
Grading	Crawler Tractors	Diesel	Average	2.00	8.00	585	0.43
Grading	Generator Sets	Diesel	Average	2.00	8.00	18.0	0.74
Grading	Other Construction Equipment	Diesel	Average	3.00	8.00	130	0.42

5.2.2. Mitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Grading	Graders	Diesel	Average	2.00	8.00	259	0.41
Grading	Rubber Tired Dozers	Diesel	Average	2.00	8.00	207	0.40
Grading	Off-Highway Trucks	Diesel	Average	2.00	8.00	407	0.38
Grading	Rubber Tired Loaders	Diesel	Average	2.00	8.00	232	0.36
Grading	Crawler Tractors	Diesel	Average	2.00	8.00	585	0.43
Grading	Generator Sets	Diesel	Average	2.00	8.00	18.0	0.74
Grading	Other Construction Equipment	Diesel	Average	3.00	8.00	130	0.42

5.3. Construction Vehicles

5.3.1. Unmitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Grading	—	—	—	—
Grading	Worker	15.0	45.0	LDA,LDT1,LDT2
Grading	Vendor	—	10.6	HHDT,MHDT
Grading	Hauling	0.00	20.0	HHDT
Grading	Onsite truck	—	—	HHDT

5.3.2. Mitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Grading	—	—	—	—
Grading	Worker	15.0	45.0	LDA,LDT1,LDT2
Grading	Vendor	—	10.6	HHDT,MHDT
Grading	Hauling	0.00	20.0	HHDT
Grading	Onsite truck	—	—	HHDT

5.4. Vehicles

5.4.1. Construction Vehicle Control Strategies

Non-applicable. No control strategies activated by user.

5.5. Architectural Coatings

Phase Name	Residential Interior Area Coated (sq ft)	Residential Exterior Area Coated (sq ft)	Non-Residential Interior Area Coated (sq ft)	Non-Residential Exterior Area Coated (sq ft)	Parking Area Coated (sq ft)

5.6. Dust Mitigation

5.6.1. Construction Earthmoving Activities

Phase Name	Material Imported (cy)	Material Exported (cy)	Acres Graded (acres)	Material Demolished (sq. ft.)	Acres Paved (acres)
Grading	—	—	40.0	0.00	—

5.6.2. Construction Earthmoving Control Strategies

Non-applicable. No control strategies activated by user.

5.7. Construction Paving

Land Use	Area Paved (acres)	% Asphalt
User Defined Industrial	0.00	0%

5.8. Construction Electricity Consumption and Emissions Factors

kWh per Year and Emission Factor (lb/MWh)

Year	kWh per Year	CO2	CH4	N2O
2025	0.00	204	0.03	< 0.005

5.18. Vegetation

5.18.1. Land Use Change

5.18.1.1. Unmitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.2. Sequestration

5.18.2.1. Unmitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

5.18.2.2. Mitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

8. User Changes to Default Data

Screen	Justification
Land Use	Project acreage is 2,636 but disturbed land would be 40 acres per Applicant.
Construction: Construction Phases	Work Days per Phase provided by Applicant.
Construction: Off-Road Equipment	Construction equipment provided by Applicant.
Construction: Dust From Material Movement	40 acres of disturbed land.
Construction: Trips and VMT	Estimated trip length.

CCS - CO2 Capture Facility - GP32 Custom Report

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5.18.2.1. Unmitigated

5.18.2.2. Mitigated

8. User Changes to Default Data

1. Basic Project Information

1.1. Basic Project Information

Data Field	Value
Project Name	CCS - CO2 Capture Facility - GP32
Construction Start Date	6/30/2025
Lead Agency	—
Land Use Scale	Project/site
Analysis Level for Defaults	County
Windspeed (m/s)	2.70
Precipitation (days)	16.2
Location	35.453174, -119.708967
County	Kern-San Joaquin
City	Unincorporated
Air District	San Joaquin Valley APCD
Air Basin	San Joaquin Valley
TAZ	2947
EDFZ	5
Electric Utility	Pacific Gas & Electric Company
Gas Utility	Southern California Gas
App Version	2022.1.1.14

1.2. Land Use Types

Land Use Subtype	Size	Unit	Lot Acreage	Building Area (sq ft)	Landscape Area (sq ft)	Special Landscape Area (sq ft)	Population	Description
User Defined Industrial	1.00	User Defined Unit	40.0	0.00	0.00	—	—	—

1.3. User-Selected Emission Reduction Measures by Emissions Sector

Sector	#	Measure Title
Construction	C-10-A	Water Exposed Surfaces
Construction	C-11	Limit Vehicle Speeds on Unpaved Roads

2. Emissions Summary

2.1. Construction Emissions Compared Against Thresholds

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Un/Mit.	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	32.9	18.0	126	117	0.21	7.93	3.05	11.0	7.32	0.72	8.04	—	24,843	24,843	1.08	0.28	12.1	24,965
Mit.	32.9	18.0	126	117	0.21	7.93	3.05	11.0	7.32	0.72	8.04	—	24,843	24,843	1.08	0.28	12.1	24,965
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	32.8	17.9	127	111	0.21	7.93	3.05	11.0	7.32	0.72	8.04	—	24,428	24,428	0.99	0.28	0.31	24,536
Mit.	32.8	17.9	127	111	0.21	7.93	3.05	11.0	7.32	0.72	8.04	—	24,428	24,428	0.99	0.28	0.31	24,536
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	23.2	12.6	89.0	78.9	0.15	5.58	2.16	7.73	5.15	0.51	5.65	—	17,486	17,486	0.70	0.20	3.36	17,567
Mit.	23.2	12.6	89.0	78.9	0.15	5.58	2.16	7.73	5.15	0.51	5.65	—	17,486	17,486	0.70	0.20	3.36	17,567

% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Annual (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	4.24	2.30	16.2	14.4	0.03	1.02	0.39	1.41	0.94	0.09	1.03	—	2,895	2,895	0.12	0.03	0.56	2,908
Mit.	4.24	2.30	16.2	14.4	0.03	1.02	0.39	1.41	0.94	0.09	1.03	—	2,895	2,895	0.12	0.03	0.56	2,908
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

2.2. Construction Emissions by Year, Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	32.9	18.0	126	117	0.21	7.93	3.05	11.0	7.32	0.72	8.04	—	24,843	24,843	1.08	0.28	12.1	24,965
2026	32.6	17.7	124	115	0.21	7.81	3.05	10.9	7.21	0.72	7.92	—	24,773	24,773	0.98	0.28	10.9	24,891
2027	32.4	17.6	124	114	0.21	7.88	3.05	10.9	7.15	0.72	7.87	—	24,709	24,709	0.98	0.28	9.75	24,826
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	32.8	17.9	127	111	0.21	7.93	3.05	11.0	7.32	0.72	8.04	—	24,428	24,428	0.99	0.28	0.31	24,536
2026	32.5	17.6	125	109	0.21	7.81	3.05	10.9	7.21	0.72	7.92	—	24,368	24,368	0.98	0.28	0.28	24,476
2027	32.3	17.6	124	108	0.21	7.88	3.05	10.9	7.15	0.72	7.87	—	24,313	24,313	0.98	0.28	0.25	24,421
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	11.9	6.49	45.8	40.6	0.08	2.87	1.09	3.97	2.65	0.26	2.91	—	8,885	8,885	0.36	0.10	1.89	8,926
2026	23.2	12.6	89.0	78.9	0.15	5.58	2.16	7.73	5.15	0.51	5.65	—	17,486	17,486	0.70	0.20	3.36	17,567
2027	9.62	5.23	36.9	32.6	0.06	2.34	0.90	3.24	2.13	0.21	2.34	—	7,265	7,265	0.29	0.08	1.25	7,298
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

2025	2.17	1.18	8.36	7.41	0.01	0.52	0.20	0.72	0.48	0.05	0.53	—	1,471	1,471	0.06	0.02	0.31	1,478
2026	4.24	2.30	16.2	14.4	0.03	1.02	0.39	1.41	0.94	0.09	1.03	—	2,895	2,895	0.12	0.03	0.56	2,908
2027	1.76	0.95	6.73	5.95	0.01	0.43	0.16	0.59	0.39	0.04	0.43	—	1,203	1,203	0.05	0.01	0.21	1,208

2.3. Construction Emissions by Year, Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	32.9	18.0	126	117	0.21	7.93	3.05	11.0	7.32	0.72	8.04	—	24,843	24,843	1.08	0.28	12.1	24,965
2026	32.6	17.7	124	115	0.21	7.81	3.05	10.9	7.21	0.72	7.92	—	24,773	24,773	0.98	0.28	10.9	24,891
2027	32.4	17.6	124	114	0.21	7.88	3.05	10.9	7.15	0.72	7.87	—	24,709	24,709	0.98	0.28	9.75	24,826
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	32.8	17.9	127	111	0.21	7.93	3.05	11.0	7.32	0.72	8.04	—	24,428	24,428	0.99	0.28	0.31	24,536
2026	32.5	17.6	125	109	0.21	7.81	3.05	10.9	7.21	0.72	7.92	—	24,368	24,368	0.98	0.28	0.28	24,476
2027	32.3	17.6	124	108	0.21	7.88	3.05	10.9	7.15	0.72	7.87	—	24,313	24,313	0.98	0.28	0.25	24,421
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	11.9	6.49	45.8	40.6	0.08	2.87	1.09	3.97	2.65	0.26	2.91	—	8,885	8,885	0.36	0.10	1.89	8,926
2026	23.2	12.6	89.0	78.9	0.15	5.58	2.16	7.73	5.15	0.51	5.65	—	17,486	17,486	0.70	0.20	3.36	17,567
2027	9.62	5.23	36.9	32.6	0.06	2.34	0.90	3.24	2.13	0.21	2.34	—	7,265	7,265	0.29	0.08	1.25	7,298
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	2.17	1.18	8.36	7.41	0.01	0.52	0.20	0.72	0.48	0.05	0.53	—	1,471	1,471	0.06	0.02	0.31	1,478
2026	4.24	2.30	16.2	14.4	0.03	1.02	0.39	1.41	0.94	0.09	1.03	—	2,895	2,895	0.12	0.03	0.56	2,908
2027	1.76	0.95	6.73	5.95	0.01	0.43	0.16	0.59	0.39	0.04	0.43	—	1,203	1,203	0.05	0.01	0.21	1,208

3. Construction Emissions Details

3.1. Building Construction (2025) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	32.2	17.4	125	99.7	0.21	7.93	—	7.93	7.32	—	7.32	—	21,502	21,502	0.96	0.18	—	21,579
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	32.2	17.4	125	99.7	0.21	7.93	—	7.93	7.32	—	7.32	—	21,502	21,502	0.96	0.18	—	21,579
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	11.7	6.31	45.4	36.1	0.08	2.87	—	2.87	2.65	—	2.65	—	7,785	7,785	0.35	0.06	—	7,812
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	2.13	1.15	8.29	6.58	0.01	0.52	—	0.52	0.48	—	0.48	—	1,289	1,289	0.06	0.01	—	1,293
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.67	0.57	0.93	17.6	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	3,341	3,341	0.11	0.10	12.1	3,386
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.61	0.51	1.13	11.1	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	2,925	2,925	0.02	0.10	0.31	2,957
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.22	0.19	0.37	4.55	0.00	0.00	1.09	1.09	0.00	0.26	0.26	—	1,101	1,101	0.01	0.04	1.89	1,114
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.04	0.03	0.07	0.83	0.00	0.00	0.20	0.20	0.00	0.05	0.05	—	182	182	< 0.005	0.01	0.31	184
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.2. Building Construction (2025) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Off-Road Equipment	32.2	17.4	125	99.7	0.21	7.93	—	7.93	7.32	—	7.32	—	21,502	21,502	0.96	0.18	—	21,579
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	32.2	17.4	125	99.7	0.21	7.93	—	7.93	7.32	—	7.32	—	21,502	21,502	0.96	0.18	—	21,579
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	11.7	6.31	45.4	36.1	0.08	2.87	—	2.87	2.65	—	2.65	—	7,785	7,785	0.35	0.06	—	7,812
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	2.13	1.15	8.29	6.58	0.01	0.52	—	0.52	0.48	—	0.48	—	1,289	1,289	0.06	0.01	—	1,293
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.67	0.57	0.93	17.6	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	3,341	3,341	0.11	0.10	12.1	3,386
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.61	0.51	1.13	11.1	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	2,925	2,925	0.02	0.10	0.31	2,957

Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.22	0.19	0.37	4.55	0.00	0.00	1.09	1.09	0.00	0.26	0.26	—	1,101	1,101	0.01	0.04	1.89	1,114
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.04	0.03	0.07	0.83	0.00	0.00	0.20	0.20	0.00	0.05	0.05	—	182	182	< 0.005	0.01	0.31	184
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.3. Building Construction (2026) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	31.9	17.2	124	99.0	0.21	7.81	—	7.81	7.21	—	7.21	—	21,504	21,504	0.96	0.18	—	21,580
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	31.9	17.2	124	99.0	0.21	7.81	—	7.81	7.21	—	7.21	—	21,504	21,504	0.96	0.18	—	21,580
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	22.8	12.3	88.3	70.7	0.15	5.58	—	5.58	5.15	—	5.15	—	15,360	15,360	0.69	0.13	—	15,415
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	4.16	2.24	16.1	12.9	0.03	1.02	—	1.02	0.94	—	0.94	—	2,543	2,543	0.11	0.02	—	2,552
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.63	0.53	0.83	16.2	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	3,269	3,269	0.01	0.10	10.9	3,311
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.59	0.48	1.03	10.1	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	2,864	2,864	0.02	0.10	0.28	2,896
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.43	0.35	0.66	8.24	0.00	0.00	2.16	2.16	0.00	0.51	0.51	—	2,126	2,126	0.01	0.07	3.36	2,152
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.08	0.06	0.12	1.50	0.00	0.00	0.39	0.39	0.00	0.09	0.09	—	352	352	< 0.005	0.01	0.56	356

Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.4. Building Construction (2026) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	31.9	17.2	124	99.0	0.21	7.81	—	7.81	7.21	—	7.21	—	21,504	21,504	0.96	0.18	—	21,580
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	31.9	17.2	124	99.0	0.21	7.81	—	7.81	7.21	—	7.21	—	21,504	21,504	0.96	0.18	—	21,580
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	22.8	12.3	88.3	70.7	0.15	5.58	—	5.58	5.15	—	5.15	—	15,360	15,360	0.69	0.13	—	15,415
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	4.16	2.24	16.1	12.9	0.03	1.02	—	1.02	0.94	—	0.94	—	2,543	2,543	0.11	0.02	—	2,552
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.63	0.53	0.83	16.2	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	3,269	3,269	0.01	0.10	10.9	3,311
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.59	0.48	1.03	10.1	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	2,864	2,864	0.02	0.10	0.28	2,896
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.43	0.35	0.66	8.24	0.00	0.00	2.16	2.16	0.00	0.51	0.51	—	2,126	2,126	0.01	0.07	3.36	2,152
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.08	0.06	0.12	1.50	0.00	0.00	0.39	0.39	0.00	0.09	0.09	—	352	352	< 0.005	0.01	0.56	356
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.5. Building Construction (2027) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Off-Road Equipment	31.9	17.1	123	98.9	0.21	7.88	—	7.88	7.15	—	7.15	—	21,506	21,506	0.96	0.18	—	21,582
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	31.9	17.1	123	98.9	0.21	7.88	—	7.88	7.15	—	7.15	—	21,506	21,506	0.96	0.18	—	21,582
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	9.48	5.09	36.6	29.4	0.06	2.34	—	2.34	2.13	—	2.13	—	6,397	6,397	0.29	0.05	—	6,420
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	1.73	0.93	6.68	5.37	0.01	0.43	—	0.43	0.39	—	0.39	—	1,059	1,059	0.05	0.01	—	1,063
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.52	0.51	0.73	14.9	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	3,203	3,203	0.01	0.10	9.75	3,244
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.48	0.47	0.93	9.28	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	2,807	2,807	0.02	0.10	0.25	2,839

Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.14	0.14	0.25	3.16	0.00	0.00	0.90	0.90	0.00	0.21	0.21	—	868	868	0.01	0.03	1.25	878
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.03	0.03	0.04	0.58	0.00	0.00	0.16	0.16	0.00	0.04	0.04	—	144	144	< 0.005	0.01	0.21	145
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.6. Building Construction (2027) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	31.9	17.1	123	98.9	0.21	7.88	—	7.88	7.15	—	7.15	—	21,506	21,506	0.96	0.18	—	21,582
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	31.9	17.1	123	98.9	0.21	7.88	—	7.88	7.15	—	7.15	—	21,506	21,506	0.96	0.18	—	21,582
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	9.48	5.09	36.6	29.4	0.06	2.34	—	2.34	2.13	—	2.13	—	6,397	6,397	0.29	0.05	—	6,420
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	1.73	0.93	6.68	5.37	0.01	0.43	—	0.43	0.39	—	0.39	—	1,059	1,059	0.05	0.01	—	1,063
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.52	0.51	0.73	14.9	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	3,203	3,203	0.01	0.10	9.75	3,244
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.48	0.47	0.93	9.28	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	2,807	2,807	0.02	0.10	0.25	2,839
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.14	0.14	0.25	3.16	0.00	0.00	0.90	0.90	0.00	0.21	0.21	—	868	868	0.01	0.03	1.25	878
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.03	0.03	0.04	0.58	0.00	0.00	0.16	0.16	0.00	0.04	0.04	—	144	144	< 0.005	0.01	0.21	145

Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

5. Activity Data

5.1. Construction Schedule

Phase Name	Phase Type	Start Date	End Date	Days Per Week	Work Days per Phase	Phase Description
Building Construction	Building Construction	6/30/2025	6/1/2027	5.00	502	—

5.2. Off-Road Equipment

5.2.1. Unmitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Building Construction	Tractors/Loaders/Backhoes	Diesel	Average	6.00	8.00	67.0	0.37
Building Construction	Rollers	Diesel	Average	3.00	8.00	8.00	0.38
Building Construction	Air Compressors	Diesel	Average	6.00	8.00	50.0	0.48
Building Construction	Cranes	Diesel	Average	3.00	8.00	6.00	0.29
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	42.0	0.42
Building Construction	Rough Terrain Forklifts	Diesel	Average	3.00	8.00	300	0.40
Building Construction	Rough Terrain Forklifts	Diesel	Average	6.00	8.00	73.0	0.40
Building Construction	Other Construction Equipment	Diesel	Average	1.00	8.00	73.0	0.42
Building Construction	Generator Sets	Diesel	Average	6.00	8.00	18.0	0.74
Building Construction	Skid Steer Loaders	Diesel	Average	1.00	8.00	45.0	0.37
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	130	0.42

Building Construction	Aerial Lifts	Diesel	Average	6.00	8.00	475	0.31
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	45.0	0.42
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	8.00	0.42
Building Construction	Welders	Diesel	Average	9.00	8.00	18.0	0.45
Building Construction	Rubber Tired Loaders	Diesel	Average	3.00	8.00	42.0	0.36

5.2.2. Mitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Building Construction	Tractors/Loaders/Backhoes	Diesel	Average	6.00	8.00	67.0	0.37
Building Construction	Rollers	Diesel	Average	3.00	8.00	8.00	0.38
Building Construction	Air Compressors	Diesel	Average	6.00	8.00	50.0	0.48
Building Construction	Cranes	Diesel	Average	3.00	8.00	6.00	0.29
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	42.0	0.42
Building Construction	Rough Terrain Forklifts	Diesel	Average	3.00	8.00	300	0.40
Building Construction	Rough Terrain Forklifts	Diesel	Average	6.00	8.00	73.0	0.40
Building Construction	Other Construction Equipment	Diesel	Average	1.00	8.00	73.0	0.42
Building Construction	Generator Sets	Diesel	Average	6.00	8.00	18.0	0.74
Building Construction	Skid Steer Loaders	Diesel	Average	1.00	8.00	45.0	0.37
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	130	0.42
Building Construction	Aerial Lifts	Diesel	Average	6.00	8.00	475	0.31
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	45.0	0.42
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	8.00	0.42

Building Construction	Welders	Diesel	Average	9.00	8.00	18.0	0.45
Building Construction	Rubber Tired Loaders	Diesel	Average	3.00	8.00	42.0	0.36

5.3. Construction Vehicles

5.3.1. Unmitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Building Construction	—	—	—	—
Building Construction	Worker	96.0	45.0	LDA,LDT1,LDT2
Building Construction	Vendor	0.00	10.6	HHDT,MHDT
Building Construction	Hauling	0.00	20.0	HHDT
Building Construction	Onsite truck	—	—	HHDT

5.3.2. Mitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Building Construction	—	—	—	—
Building Construction	Worker	96.0	45.0	LDA,LDT1,LDT2
Building Construction	Vendor	0.00	10.6	HHDT,MHDT
Building Construction	Hauling	0.00	20.0	HHDT
Building Construction	Onsite truck	—	—	HHDT

5.4. Vehicles

5.4.1. Construction Vehicle Control Strategies

Non-applicable. No control strategies activated by user.

5.5. Architectural Coatings

Phase Name	Residential Interior Area Coated (sq ft)	Residential Exterior Area Coated (sq ft)	Non-Residential Interior Area Coated (sq ft)	Non-Residential Exterior Area Coated (sq ft)	Parking Area Coated (sq ft)

5.6. Dust Mitigation

5.6.1. Construction Earthmoving Activities

Phase Name	Material Imported (cy)	Material Exported (cy)	Acres Graded (acres)	Material Demolished (sq. ft.)	Acres Paved (acres)

5.6.2. Construction Earthmoving Control Strategies

Non-applicable. No control strategies activated by user.

5.7. Construction Paving

Land Use	Area Paved (acres)	% Asphalt
User Defined Industrial	0.00	0%

5.8. Construction Electricity Consumption and Emissions Factors

kWh per Year and Emission Factor (lb/MWh)

Year	kWh per Year	CO2	CH4	N2O
2025	0.00	204	0.03	< 0.005
2026	0.00	204	0.03	< 0.005
2027	0.00	204	0.03	< 0.005

5.18. Vegetation

5.18.1. Land Use Change

5.18.1.1. Unmitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.2. Sequestration

5.18.2.1. Unmitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

5.18.2.2. Mitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

8. User Changes to Default Data

Screen	Justification
Land Use	Project acreage is 2,636 but disturbed land would be 40 acres per Applicant.
Construction: Construction Phases	Work Days per Phase provided by Applicant.
Construction: Off-Road Equipment	Construction equipment provided by Applicant.
Construction: Off-Road Equipment EF	CalEEMod Appendix D: Default Data Tables - Table 3.4 OFFROAD Equipment Emission Factors (g/bhp-hr)

Construction: Trips and VMT	Estimated trip length.

CCS - CO2 Capture Facility - 32 Cogen Custom Report

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5.18.1. Land Use Change

5.18.1.1. Unmitigated

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5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

5.18.1.2. Mitigated

5.18.2. Sequestration

5.18.2.1. Unmitigated

5.18.2.2. Mitigated

1. Basic Project Information

1.1. Basic Project Information

Data Field	Value
Project Name	CCS - CO2 Capture Facility - 32 Cogen
Construction Start Date	2/27/2025
Lead Agency	—
Land Use Scale	Project/site
Analysis Level for Defaults	County
Windspeed (m/s)	2.70
Precipitation (days)	16.2
Location	35.453174, -119.708967
County	Kern-San Joaquin
City	Unincorporated
Air District	San Joaquin Valley APCD
Air Basin	San Joaquin Valley
TAZ	2947
EDFZ	5
Electric Utility	Pacific Gas & Electric Company
Gas Utility	Southern California Gas
App Version	2022.1.1.14

1.2. Land Use Types

Land Use Subtype	Size	Unit	Lot Acreage	Building Area (sq ft)	Landscape Area (sq ft)	Special Landscape Area (sq ft)	Population	Description
User Defined Industrial	1.00	User Defined Unit	40.0	0.00	0.00	—	—	—

1.3. User-Selected Emission Reduction Measures by Emissions Sector

Sector	#	Measure Title
Construction	C-10-A	Water Exposed Surfaces
Construction	C-11	Limit Vehicle Speeds on Unpaved Roads

2. Emissions Summary

2.1. Construction Emissions Compared Against Thresholds

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Un/Mit.	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	32.9	18.0	126	117	0.21	7.93	3.05	11.0	7.32	0.72	8.04	—	24,843	24,843	1.08	0.28	12.1	24,965
Mit.	32.9	18.0	126	117	0.21	7.93	3.05	11.0	7.32	0.72	8.04	—	24,843	24,843	1.08	0.28	12.1	24,965
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	32.8	17.9	127	111	0.21	7.93	3.05	11.0	7.32	0.72	8.04	—	24,428	24,428	0.99	0.28	0.31	24,536
Mit.	32.8	17.9	127	111	0.21	7.93	3.05	11.0	7.32	0.72	8.04	—	24,428	24,428	0.99	0.28	0.31	24,536
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	23.2	12.6	89.0	78.9	0.15	5.58	2.16	7.73	5.15	0.51	5.65	—	17,486	17,486	0.70	0.20	3.36	17,567
Mit.	23.2	12.6	89.0	78.9	0.15	5.58	2.16	7.73	5.15	0.51	5.65	—	17,486	17,486	0.70	0.20	3.36	17,567

% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Annual (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	4.24	2.30	16.2	14.4	0.03	1.02	0.39	1.41	0.94	0.09	1.03	—	2,895	2,895	0.12	0.03	0.56	2,908
Mit.	4.24	2.30	16.2	14.4	0.03	1.02	0.39	1.41	0.94	0.09	1.03	—	2,895	2,895	0.12	0.03	0.56	2,908
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

2.2. Construction Emissions by Year, Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	32.9	18.0	126	117	0.21	7.93	3.05	11.0	7.32	0.72	8.04	—	24,843	24,843	1.08	0.28	12.1	24,965
2026	32.6	17.7	124	115	0.21	7.81	3.05	10.9	7.21	0.72	7.92	—	24,773	24,773	0.98	0.28	10.9	24,891
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	32.8	17.9	127	111	0.21	7.93	3.05	11.0	7.32	0.72	8.04	—	24,428	24,428	0.99	0.28	0.31	24,536
2026	32.5	17.6	125	109	0.21	7.81	3.05	10.9	7.21	0.72	7.92	—	24,368	24,368	0.98	0.28	0.28	24,476
2027	32.3	17.6	124	108	0.21	7.88	3.05	10.9	7.15	0.72	7.87	—	24,313	24,313	0.98	0.28	0.25	24,421
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	19.8	10.8	76.2	67.6	0.13	4.78	1.82	6.60	4.41	0.43	4.84	—	14,793	14,793	0.59	0.17	3.14	14,861
2026	23.2	12.6	89.0	78.9	0.15	5.58	2.16	7.73	5.15	0.51	5.65	—	17,486	17,486	0.70	0.20	3.36	17,567
2027	1.84	1.00	7.04	6.22	0.01	0.45	0.17	0.62	0.41	0.04	0.45	—	1,386	1,386	0.06	0.02	0.24	1,392
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	3.61	1.97	13.9	12.3	0.02	0.87	0.33	1.20	0.81	0.08	0.88	—	2,449	2,449	0.10	0.03	0.52	2,460

2026	4.24	2.30	16.2	14.4	0.03	1.02	0.39	1.41	0.94	0.09	1.03	—	2,895	2,895	0.12	0.03	0.56	2,908
2027	0.33	0.18	1.28	1.13	< 0.005	0.08	0.03	0.11	0.07	0.01	0.08	—	229	229	0.01	< 0.005	0.04	231

2.3. Construction Emissions by Year, Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	32.9	18.0	126	117	0.21	7.93	3.05	11.0	7.32	0.72	8.04	—	24,843	24,843	1.08	0.28	12.1	24,965
2026	32.6	17.7	124	115	0.21	7.81	3.05	10.9	7.21	0.72	7.92	—	24,773	24,773	0.98	0.28	10.9	24,891
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	32.8	17.9	127	111	0.21	7.93	3.05	11.0	7.32	0.72	8.04	—	24,428	24,428	0.99	0.28	0.31	24,536
2026	32.5	17.6	125	109	0.21	7.81	3.05	10.9	7.21	0.72	7.92	—	24,368	24,368	0.98	0.28	0.28	24,476
2027	32.3	17.6	124	108	0.21	7.88	3.05	10.9	7.15	0.72	7.87	—	24,313	24,313	0.98	0.28	0.25	24,421
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	19.8	10.8	76.2	67.6	0.13	4.78	1.82	6.60	4.41	0.43	4.84	—	14,793	14,793	0.59	0.17	3.14	14,861
2026	23.2	12.6	89.0	78.9	0.15	5.58	2.16	7.73	5.15	0.51	5.65	—	17,486	17,486	0.70	0.20	3.36	17,567
2027	1.84	1.00	7.04	6.22	0.01	0.45	0.17	0.62	0.41	0.04	0.45	—	1,386	1,386	0.06	0.02	0.24	1,392
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	3.61	1.97	13.9	12.3	0.02	0.87	0.33	1.20	0.81	0.08	0.88	—	2,449	2,449	0.10	0.03	0.52	2,460
2026	4.24	2.30	16.2	14.4	0.03	1.02	0.39	1.41	0.94	0.09	1.03	—	2,895	2,895	0.12	0.03	0.56	2,908
2027	0.33	0.18	1.28	1.13	< 0.005	0.08	0.03	0.11	0.07	0.01	0.08	—	229	229	0.01	< 0.005	0.04	231

3. Construction Emissions Details

3.1. Building Construction (2025) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	32.2	17.4	125	99.7	0.21	7.93	—	7.93	7.32	—	7.32	—	21,502	21,502	0.96	0.18	—	21,579
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	32.2	17.4	125	99.7	0.21	7.93	—	7.93	7.32	—	7.32	—	21,502	21,502	0.96	0.18	—	21,579
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	19.4	10.5	75.6	60.1	0.13	4.78	—	4.78	4.41	—	4.41	—	12,960	12,960	0.58	0.11	—	13,006
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	3.54	1.92	13.8	11.0	0.02	0.87	—	0.87	0.81	—	0.81	—	2,146	2,146	0.10	0.02	—	2,153
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.67	0.57	0.93	17.6	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	3,341	3,341	0.11	0.10	12.1	3,386
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.61	0.51	1.13	11.1	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	2,925	2,925	0.02	0.10	0.31	2,957
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.37	0.31	0.62	7.57	0.00	0.00	1.82	1.82	0.00	0.43	0.43	—	1,833	1,833	0.01	0.06	3.14	1,855
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.07	0.06	0.11	1.38	0.00	0.00	0.33	0.33	0.00	0.08	0.08	—	303	303	< 0.005	0.01	0.52	307
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.2. Building Construction (2025) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Off-Road Equipment	32.2	17.4	125	99.7	0.21	7.93	—	7.93	7.32	—	7.32	—	21,502	21,502	0.96	0.18	—	21,579
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	32.2	17.4	125	99.7	0.21	7.93	—	7.93	7.32	—	7.32	—	21,502	21,502	0.96	0.18	—	21,579
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	19.4	10.5	75.6	60.1	0.13	4.78	—	4.78	4.41	—	4.41	—	12,960	12,960	0.58	0.11	—	13,006
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	3.54	1.92	13.8	11.0	0.02	0.87	—	0.87	0.81	—	0.81	—	2,146	2,146	0.10	0.02	—	2,153
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.67	0.57	0.93	17.6	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	3,341	3,341	0.11	0.10	12.1	3,386
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.61	0.51	1.13	11.1	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	2,925	2,925	0.02	0.10	0.31	2,957

Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.37	0.31	0.62	7.57	0.00	0.00	1.82	1.82	0.00	0.43	0.43	—	1,833	1,833	0.01	0.06	3.14	1,855
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.07	0.06	0.11	1.38	0.00	0.00	0.33	0.33	0.00	0.08	0.08	—	303	303	< 0.005	0.01	0.52	307
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.3. Building Construction (2026) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	31.9	17.2	124	99.0	0.21	7.81	—	7.81	7.21	—	7.21	—	21,504	21,504	0.96	0.18	—	21,580
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	31.9	17.2	124	99.0	0.21	7.81	—	7.81	7.21	—	7.21	—	21,504	21,504	0.96	0.18	—	21,580
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	22.8	12.3	88.3	70.7	0.15	5.58	—	5.58	5.15	—	5.15	—	15,360	15,360	0.69	0.13	—	15,415
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	4.16	2.24	16.1	12.9	0.03	1.02	—	1.02	0.94	—	0.94	—	2,543	2,543	0.11	0.02	—	2,552
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.63	0.53	0.83	16.2	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	3,269	3,269	0.01	0.10	10.9	3,311
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.59	0.48	1.03	10.1	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	2,864	2,864	0.02	0.10	0.28	2,896
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.43	0.35	0.66	8.24	0.00	0.00	2.16	2.16	0.00	0.51	0.51	—	2,126	2,126	0.01	0.07	3.36	2,152
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.08	0.06	0.12	1.50	0.00	0.00	0.39	0.39	0.00	0.09	0.09	—	352	352	< 0.005	0.01	0.56	356

Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.4. Building Construction (2026) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	31.9	17.2	124	99.0	0.21	7.81	—	7.81	7.21	—	7.21	—	21,504	21,504	0.96	0.18	—	21,580
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	31.9	17.2	124	99.0	0.21	7.81	—	7.81	7.21	—	7.21	—	21,504	21,504	0.96	0.18	—	21,580
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	22.8	12.3	88.3	70.7	0.15	5.58	—	5.58	5.15	—	5.15	—	15,360	15,360	0.69	0.13	—	15,415
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	4.16	2.24	16.1	12.9	0.03	1.02	—	1.02	0.94	—	0.94	—	2,543	2,543	0.11	0.02	—	2,552
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.63	0.53	0.83	16.2	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	3,269	3,269	0.01	0.10	10.9	3,311
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.59	0.48	1.03	10.1	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	2,864	2,864	0.02	0.10	0.28	2,896
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.43	0.35	0.66	8.24	0.00	0.00	2.16	2.16	0.00	0.51	0.51	—	2,126	2,126	0.01	0.07	3.36	2,152
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.08	0.06	0.12	1.50	0.00	0.00	0.39	0.39	0.00	0.09	0.09	—	352	352	< 0.005	0.01	0.56	356
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.5. Building Construction (2027) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	31.9	17.1	123	98.9	0.21	7.88	—	7.88	7.15	—	7.15	—	21,506	21,506	0.96	0.18	—	21,582
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	1.81	0.97	6.99	5.61	0.01	0.45	—	0.45	0.41	—	0.41	—	1,220	1,220	0.05	0.01	—	1,225
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.33	0.18	1.28	1.02	< 0.005	0.08	—	0.08	0.07	—	0.07	—	202	202	0.01	< 0.005	—	203
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.48	0.47	0.93	9.28	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	2,807	2,807	0.02	0.10	0.25	2,839
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.03	0.03	0.05	0.60	0.00	0.00	0.17	0.17	0.00	0.04	0.04	—	166	166	< 0.005	0.01	0.24	168
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	< 0.005	< 0.005	0.01	0.11	0.00	0.00	0.03	0.03	0.00	0.01	0.01	—	27.4	27.4	< 0.005	< 0.005	0.04	27.7
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.6. Building Construction (2027) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	31.9	17.1	123	98.9	0.21	7.88	—	7.88	7.15	—	7.15	—	21,506	21,506	0.96	0.18	—	21,582
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	1.81	0.97	6.99	5.61	0.01	0.45	—	0.45	0.41	—	0.41	—	1,220	1,220	0.05	0.01	—	1,225
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.33	0.18	1.28	1.02	< 0.005	0.08	—	0.08	0.07	—	0.07	—	202	202	0.01	< 0.005	—	203
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.48	0.47	0.93	9.28	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	2,807	2,807	0.02	0.10	0.25	2,839
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.03	0.03	0.05	0.60	0.00	0.00	0.17	0.17	0.00	0.04	0.04	—	166	166	< 0.005	0.01	0.24	168
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	< 0.005	< 0.005	0.01	0.11	0.00	0.00	0.03	0.03	0.00	0.01	0.01	—	27.4	27.4	< 0.005	< 0.005	0.04	27.7
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

5. Activity Data

5.1. Construction Schedule

Phase Name	Phase Type	Start Date	End Date	Days Per Week	Work Days per Phase	Phase Description
Building Construction	Building Construction	2/27/2025	1/29/2027	5.00	502	—

5.2. Off-Road Equipment

5.2.1. Unmitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor

Building Construction	Tractors/Loaders/Backh	Diesel	Average	6.00	8.00	67.0	0.37
Building Construction	Rollers	Diesel	Average	3.00	8.00	8.00	0.38
Building Construction	Air Compressors	Diesel	Average	6.00	8.00	50.0	0.48
Building Construction	Cranes	Diesel	Average	3.00	8.00	6.00	0.29
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	42.0	0.42
Building Construction	Rough Terrain Forklifts	Diesel	Average	3.00	8.00	300	0.40
Building Construction	Rough Terrain Forklifts	Diesel	Average	6.00	8.00	73.0	0.40
Building Construction	Other Construction Equipment	Diesel	Average	1.00	8.00	73.0	0.42
Building Construction	Generator Sets	Diesel	Average	6.00	8.00	18.0	0.74
Building Construction	Skid Steer Loaders	Diesel	Average	1.00	8.00	45.0	0.37
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	130	0.42
Building Construction	Aerial Lifts	Diesel	Average	6.00	8.00	475	0.31
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	45.0	0.42
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	8.00	0.42
Building Construction	Welders	Diesel	Average	9.00	8.00	18.0	0.45
Building Construction	Rubber Tired Loaders	Diesel	Average	3.00	8.00	42.0	0.36

5.2.2. Mitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Building Construction	Tractors/Loaders/Backhoes	Diesel	Average	6.00	8.00	67.0	0.37
Building Construction	Rollers	Diesel	Average	3.00	8.00	8.00	0.38
Building Construction	Air Compressors	Diesel	Average	6.00	8.00	50.0	0.48
Building Construction	Cranes	Diesel	Average	3.00	8.00	6.00	0.29

Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	42.0	0.42
Building Construction	Rough Terrain Forklifts	Diesel	Average	3.00	8.00	300	0.40
Building Construction	Rough Terrain Forklifts	Diesel	Average	6.00	8.00	73.0	0.40
Building Construction	Other Construction Equipment	Diesel	Average	1.00	8.00	73.0	0.42
Building Construction	Generator Sets	Diesel	Average	6.00	8.00	18.0	0.74
Building Construction	Skid Steer Loaders	Diesel	Average	1.00	8.00	45.0	0.37
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	130	0.42
Building Construction	Aerial Lifts	Diesel	Average	6.00	8.00	475	0.31
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	45.0	0.42
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	8.00	0.42
Building Construction	Welders	Diesel	Average	9.00	8.00	18.0	0.45
Building Construction	Rubber Tired Loaders	Diesel	Average	3.00	8.00	42.0	0.36

5.3. Construction Vehicles

5.3.1. Unmitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Building Construction	—	—	—	—
Building Construction	Worker	96.0	45.0	LDA,LDT1,LDT2
Building Construction	Vendor	0.00	10.6	HHDT,MHDT
Building Construction	Hauling	0.00	20.0	HHDT
Building Construction	Onsite truck	—	—	HHDT

5.3.2. Mitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Building Construction	—	—	—	—
Building Construction	Worker	96.0	45.0	LDA,LDT1,LDT2
Building Construction	Vendor	0.00	10.6	HHDT,MHDT
Building Construction	Hauling	0.00	20.0	HHDT
Building Construction	Onsite truck	—	—	HHDT

5.4. Vehicles

5.4.1. Construction Vehicle Control Strategies

Non-applicable. No control strategies activated by user.

5.5. Architectural Coatings

Phase Name	Residential Interior Area Coated (sq ft)	Residential Exterior Area Coated (sq ft)	Non-Residential Interior Area Coated (sq ft)	Non-Residential Exterior Area Coated (sq ft)	Parking Area Coated (sq ft)

5.6. Dust Mitigation

5.6.1. Construction Earthmoving Activities

Phase Name	Material Imported (cy)	Material Exported (cy)	Acres Graded (acres)	Material Demolished (sq. ft.)	Acres Paved (acres)

5.6.2. Construction Earthmoving Control Strategies

Non-applicable. No control strategies activated by user.

5.7. Construction Paving

Land Use	Area Paved (acres)	% Asphalt
User Defined Industrial	0.00	0%

5.8. Construction Electricity Consumption and Emissions Factors

kWh per Year and Emission Factor (lb/MWh)

Year	kWh per Year	CO2	CH4	N2O
2025	0.00	204	0.03	< 0.005
2026	0.00	204	0.03	< 0.005
2027	0.00	204	0.03	< 0.005

5.18. Vegetation

5.18.1. Land Use Change

5.18.1.1. Unmitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.2. Sequestration

5.18.2.1. Unmitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

5.18.2.2. Mitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

CCS - CO2 Capture Facility - SP286B Custom Report

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5.18.2.1. Unmitigated

5.18.2.2. Mitigated

8. User Changes to Default Data

1. Basic Project Information

1.1. Basic Project Information

Data Field	Value
Project Name	CCS - CO2 Capture Facility - SP286B
Construction Start Date	9/18/2025
Lead Agency	—
Land Use Scale	Project/site
Analysis Level for Defaults	County
Windspeed (m/s)	2.70
Precipitation (days)	16.2
Location	35.453174, -119.708967
County	Kern-San Joaquin
City	Unincorporated
Air District	San Joaquin Valley APCD
Air Basin	San Joaquin Valley
TAZ	2947
EDFZ	5
Electric Utility	Pacific Gas & Electric Company
Gas Utility	Southern California Gas
App Version	2022.1.1.14

1.2. Land Use Types

Land Use Subtype	Size	Unit	Lot Acreage	Building Area (sq ft)	Landscape Area (sq ft)	Special Landscape Area (sq ft)	Population	Description
User Defined Industrial	1.00	User Defined Unit	40.0	0.00	0.00	—	—	—

1.3. User-Selected Emission Reduction Measures by Emissions Sector

Sector	#	Measure Title
Construction	C-10-A	Water Exposed Surfaces
Construction	C-11	Limit Vehicle Speeds on Unpaved Roads

2. Emissions Summary

2.1. Construction Emissions Compared Against Thresholds

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Un/Mit.	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	32.9	18.0	126	117	0.21	7.93	3.05	11.0	7.32	0.72	8.04	—	24,843	24,843	1.08	0.28	12.1	24,965
Mit.	32.9	18.0	126	117	0.21	7.93	3.05	11.0	7.32	0.72	8.04	—	24,843	24,843	1.08	0.28	12.1	24,965
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	32.8	17.9	127	111	0.21	7.93	3.05	11.0	7.32	0.72	8.04	—	24,428	24,428	0.99	0.28	0.31	24,536
Mit.	32.8	17.9	127	111	0.21	7.93	3.05	11.0	7.32	0.72	8.04	—	24,428	24,428	0.99	0.28	0.31	24,536
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	23.2	12.6	89.0	78.9	0.15	5.58	2.16	7.73	5.15	0.51	5.65	—	17,486	17,486	0.70	0.20	3.36	17,567
Mit.	23.2	12.6	89.0	78.9	0.15	5.58	2.16	7.73	5.15	0.51	5.65	—	17,486	17,486	0.70	0.20	3.36	17,567

% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Annual (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	4.24	2.30	16.2	14.4	0.03	1.02	0.39	1.41	0.94	0.09	1.03	—	2,895	2,895	0.12	0.03	0.56	2,908
Mit.	4.24	2.30	16.2	14.4	0.03	1.02	0.39	1.41	0.94	0.09	1.03	—	2,895	2,895	0.12	0.03	0.56	2,908
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

2.2. Construction Emissions by Year, Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	32.9	18.0	126	117	0.21	7.93	3.05	11.0	7.32	0.72	8.04	—	24,843	24,843	1.08	0.28	12.1	24,965
2026	32.6	17.7	124	115	0.21	7.81	3.05	10.9	7.21	0.72	7.92	—	24,773	24,773	0.98	0.28	10.9	24,891
2027	32.4	17.6	124	114	0.21	7.88	3.05	10.9	7.15	0.72	7.87	—	24,709	24,709	0.98	0.28	9.75	24,826
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	32.8	17.9	127	111	0.21	7.93	3.05	11.0	7.32	0.72	8.04	—	24,428	24,428	0.99	0.28	0.31	24,536
2026	32.5	17.6	125	109	0.21	7.81	3.05	10.9	7.21	0.72	7.92	—	24,368	24,368	0.98	0.28	0.28	24,476
2027	32.3	17.6	124	108	0.21	7.88	3.05	10.9	7.15	0.72	7.87	—	24,313	24,313	0.98	0.28	0.25	24,421
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	6.75	3.68	26.0	23.1	0.04	1.63	0.62	2.25	1.50	0.15	1.65	—	5,043	5,043	0.20	0.06	1.07	5,066
2026	23.2	12.6	89.0	78.9	0.15	5.58	2.16	7.73	5.15	0.51	5.65	—	17,486	17,486	0.70	0.20	3.36	17,567
2027	14.7	7.98	56.3	49.7	0.10	3.58	1.37	4.95	3.25	0.32	3.57	—	11,088	11,088	0.45	0.13	1.91	11,139
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

2025	1.23	0.67	4.74	4.21	0.01	0.30	0.11	0.41	0.27	0.03	0.30	—	835	835	0.03	0.01	0.18	839
2026	4.24	2.30	16.2	14.4	0.03	1.02	0.39	1.41	0.94	0.09	1.03	—	2,895	2,895	0.12	0.03	0.56	2,908
2027	2.68	1.46	10.3	9.08	0.02	0.65	0.25	0.90	0.59	0.06	0.65	—	1,836	1,836	0.07	0.02	0.32	1,844

2.3. Construction Emissions by Year, Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	32.9	18.0	126	117	0.21	7.93	3.05	11.0	7.32	0.72	8.04	—	24,843	24,843	1.08	0.28	12.1	24,965
2026	32.6	17.7	124	115	0.21	7.81	3.05	10.9	7.21	0.72	7.92	—	24,773	24,773	0.98	0.28	10.9	24,891
2027	32.4	17.6	124	114	0.21	7.88	3.05	10.9	7.15	0.72	7.87	—	24,709	24,709	0.98	0.28	9.75	24,826
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	32.8	17.9	127	111	0.21	7.93	3.05	11.0	7.32	0.72	8.04	—	24,428	24,428	0.99	0.28	0.31	24,536
2026	32.5	17.6	125	109	0.21	7.81	3.05	10.9	7.21	0.72	7.92	—	24,368	24,368	0.98	0.28	0.28	24,476
2027	32.3	17.6	124	108	0.21	7.88	3.05	10.9	7.15	0.72	7.87	—	24,313	24,313	0.98	0.28	0.25	24,421
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	6.75	3.68	26.0	23.1	0.04	1.63	0.62	2.25	1.50	0.15	1.65	—	5,043	5,043	0.20	0.06	1.07	5,066
2026	23.2	12.6	89.0	78.9	0.15	5.58	2.16	7.73	5.15	0.51	5.65	—	17,486	17,486	0.70	0.20	3.36	17,567
2027	14.7	7.98	56.3	49.7	0.10	3.58	1.37	4.95	3.25	0.32	3.57	—	11,088	11,088	0.45	0.13	1.91	11,139
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	1.23	0.67	4.74	4.21	0.01	0.30	0.11	0.41	0.27	0.03	0.30	—	835	835	0.03	0.01	0.18	839
2026	4.24	2.30	16.2	14.4	0.03	1.02	0.39	1.41	0.94	0.09	1.03	—	2,895	2,895	0.12	0.03	0.56	2,908
2027	2.68	1.46	10.3	9.08	0.02	0.65	0.25	0.90	0.59	0.06	0.65	—	1,836	1,836	0.07	0.02	0.32	1,844

3. Construction Emissions Details

3.1. Building Construction (2025) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	32.2	17.4	125	99.7	0.21	7.93	—	7.93	7.32	—	7.32	—	21,502	21,502	0.96	0.18	—	21,579
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	32.2	17.4	125	99.7	0.21	7.93	—	7.93	7.32	—	7.32	—	21,502	21,502	0.96	0.18	—	21,579
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	6.62	3.58	25.8	20.5	0.04	1.63	—	1.63	1.50	—	1.50	—	4,418	4,418	0.20	0.04	—	4,434
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	1.21	0.65	4.70	3.74	0.01	0.30	—	0.30	0.27	—	0.27	—	731	731	0.03	0.01	—	734
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.67	0.57	0.93	17.6	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	3,341	3,341	0.11	0.10	12.1	3,386
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.61	0.51	1.13	11.1	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	2,925	2,925	0.02	0.10	0.31	2,957
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.13	0.11	0.21	2.58	0.00	0.00	0.62	0.62	0.00	0.15	0.15	—	625	625	< 0.005	0.02	1.07	632
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.02	0.02	0.04	0.47	0.00	0.00	0.11	0.11	0.00	0.03	0.03	—	103	103	< 0.005	< 0.005	0.18	105
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.2. Building Construction (2025) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Off-Road Equipment	32.2	17.4	125	99.7	0.21	7.93	—	7.93	7.32	—	7.32	—	21,502	21,502	0.96	0.18	—	21,579
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	32.2	17.4	125	99.7	0.21	7.93	—	7.93	7.32	—	7.32	—	21,502	21,502	0.96	0.18	—	21,579
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	6.62	3.58	25.8	20.5	0.04	1.63	—	1.63	1.50	—	1.50	—	4,418	4,418	0.20	0.04	—	4,434
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	1.21	0.65	4.70	3.74	0.01	0.30	—	0.30	0.27	—	0.27	—	731	731	0.03	0.01	—	734
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.67	0.57	0.93	17.6	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	3,341	3,341	0.11	0.10	12.1	3,386
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.61	0.51	1.13	11.1	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	2,925	2,925	0.02	0.10	0.31	2,957

Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.13	0.11	0.21	2.58	0.00	0.00	0.62	0.62	0.00	0.15	0.15	—	625	625	< 0.005	0.02	1.07	632
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.02	0.02	0.04	0.47	0.00	0.00	0.11	0.11	0.00	0.03	0.03	—	103	103	< 0.005	< 0.005	0.18	105
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.3. Building Construction (2026) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	31.9	17.2	124	99.0	0.21	7.81	—	7.81	7.21	—	7.21	—	21,504	21,504	0.96	0.18	—	21,580
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	31.9	17.2	124	99.0	0.21	7.81	—	7.81	7.21	—	7.21	—	21,504	21,504	0.96	0.18	—	21,580
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	22.8	12.3	88.3	70.7	0.15	5.58	—	5.58	5.15	—	5.15	—	15,360	15,360	0.69	0.13	—	15,415
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	4.16	2.24	16.1	12.9	0.03	1.02	—	1.02	0.94	—	0.94	—	2,543	2,543	0.11	0.02	—	2,552
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.63	0.53	0.83	16.2	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	3,269	3,269	0.01	0.10	10.9	3,311
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.59	0.48	1.03	10.1	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	2,864	2,864	0.02	0.10	0.28	2,896
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.43	0.35	0.66	8.24	0.00	0.00	2.16	2.16	0.00	0.51	0.51	—	2,126	2,126	0.01	0.07	3.36	2,152
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.08	0.06	0.12	1.50	0.00	0.00	0.39	0.39	0.00	0.09	0.09	—	352	352	< 0.005	0.01	0.56	356

Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.4. Building Construction (2026) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	31.9	17.2	124	99.0	0.21	7.81	—	7.81	7.21	—	7.21	—	21,504	21,504	0.96	0.18	—	21,580
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	31.9	17.2	124	99.0	0.21	7.81	—	7.81	7.21	—	7.21	—	21,504	21,504	0.96	0.18	—	21,580
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	22.8	12.3	88.3	70.7	0.15	5.58	—	5.58	5.15	—	5.15	—	15,360	15,360	0.69	0.13	—	15,415
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	4.16	2.24	16.1	12.9	0.03	1.02	—	1.02	0.94	—	0.94	—	2,543	2,543	0.11	0.02	—	2,552
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.63	0.53	0.83	16.2	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	3,269	3,269	0.01	0.10	10.9	3,311
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.59	0.48	1.03	10.1	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	2,864	2,864	0.02	0.10	0.28	2,896
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.43	0.35	0.66	8.24	0.00	0.00	2.16	2.16	0.00	0.51	0.51	—	2,126	2,126	0.01	0.07	3.36	2,152
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.08	0.06	0.12	1.50	0.00	0.00	0.39	0.39	0.00	0.09	0.09	—	352	352	< 0.005	0.01	0.56	356
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.5. Building Construction (2027) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Off-Road Equipment	31.9	17.1	123	98.9	0.21	7.88	—	7.88	7.15	—	7.15	—	21,506	21,506	0.96	0.18	—	21,582
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	31.9	17.1	123	98.9	0.21	7.88	—	7.88	7.15	—	7.15	—	21,506	21,506	0.96	0.18	—	21,582
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	14.5	7.77	55.9	44.9	0.10	3.58	—	3.58	3.25	—	3.25	—	9,764	9,764	0.44	0.08	—	9,799
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	2.64	1.42	10.2	8.20	0.02	0.65	—	0.65	0.59	—	0.59	—	1,617	1,617	0.07	0.01	—	1,622
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.52	0.51	0.73	14.9	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	3,203	3,203	0.01	0.10	9.75	3,244
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.48	0.47	0.93	9.28	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	2,807	2,807	0.02	0.10	0.25	2,839

Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.22	0.21	0.38	4.82	0.00	0.00	1.37	1.37	0.00	0.32	0.32	—	1,325	1,325	0.01	0.05	1.91	1,340
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.04	0.04	0.07	0.88	0.00	0.00	0.25	0.25	0.00	0.06	0.06	—	219	219	< 0.005	0.01	0.32	222
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.6. Building Construction (2027) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	31.9	17.1	123	98.9	0.21	7.88	—	7.88	7.15	—	7.15	—	21,506	21,506	0.96	0.18	—	21,582
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	31.9	17.1	123	98.9	0.21	7.88	—	7.88	7.15	—	7.15	—	21,506	21,506	0.96	0.18	—	21,582
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	14.5	7.77	55.9	44.9	0.10	3.58	—	3.58	3.25	—	3.25	—	9,764	9,764	0.44	0.08	—	9,799
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	2.64	1.42	10.2	8.20	0.02	0.65	—	0.65	0.59	—	0.59	—	1,617	1,617	0.07	0.01	—	1,622
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.52	0.51	0.73	14.9	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	3,203	3,203	0.01	0.10	9.75	3,244
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.48	0.47	0.93	9.28	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	2,807	2,807	0.02	0.10	0.25	2,839
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.22	0.21	0.38	4.82	0.00	0.00	1.37	1.37	0.00	0.32	0.32	—	1,325	1,325	0.01	0.05	1.91	1,340
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.04	0.04	0.07	0.88	0.00	0.00	0.25	0.25	0.00	0.06	0.06	—	219	219	< 0.005	0.01	0.32	222

Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

5. Activity Data

5.1. Construction Schedule

Phase Name	Phase Type	Start Date	End Date	Days Per Week	Work Days per Phase	Phase Description
Building Construction	Building Construction	9/18/2025	8/20/2027	5.00	502	—

5.2. Off-Road Equipment

5.2.1. Unmitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Building Construction	Tractors/Loaders/Backhoes	Diesel	Average	6.00	8.00	67.0	0.37
Building Construction	Rollers	Diesel	Average	3.00	8.00	8.00	0.38
Building Construction	Air Compressors	Diesel	Average	6.00	8.00	50.0	0.48
Building Construction	Cranes	Diesel	Average	3.00	8.00	6.00	0.29
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	42.0	0.42
Building Construction	Rough Terrain Forklifts	Diesel	Average	3.00	8.00	300	0.40
Building Construction	Rough Terrain Forklifts	Diesel	Average	6.00	8.00	73.0	0.40
Building Construction	Other Construction Equipment	Diesel	Average	1.00	8.00	73.0	0.42
Building Construction	Generator Sets	Diesel	Average	6.00	8.00	18.0	0.74
Building Construction	Skid Steer Loaders	Diesel	Average	1.00	8.00	45.0	0.37
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	130	0.42

Building Construction	Aerial Lifts	Diesel	Average	6.00	8.00	475	0.31
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	45.0	0.42
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	8.00	0.42
Building Construction	Welders	Diesel	Average	9.00	8.00	18.0	0.45
Building Construction	Rubber Tired Loaders	Diesel	Average	3.00	8.00	42.0	0.36

5.2.2. Mitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Building Construction	Tractors/Loaders/Backhoes	Diesel	Average	6.00	8.00	67.0	0.37
Building Construction	Rollers	Diesel	Average	3.00	8.00	8.00	0.38
Building Construction	Air Compressors	Diesel	Average	6.00	8.00	50.0	0.48
Building Construction	Cranes	Diesel	Average	3.00	8.00	6.00	0.29
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	42.0	0.42
Building Construction	Rough Terrain Forklifts	Diesel	Average	3.00	8.00	300	0.40
Building Construction	Rough Terrain Forklifts	Diesel	Average	6.00	8.00	73.0	0.40
Building Construction	Other Construction Equipment	Diesel	Average	1.00	8.00	73.0	0.42
Building Construction	Generator Sets	Diesel	Average	6.00	8.00	18.0	0.74
Building Construction	Skid Steer Loaders	Diesel	Average	1.00	8.00	45.0	0.37
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	130	0.42
Building Construction	Aerial Lifts	Diesel	Average	6.00	8.00	475	0.31
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	45.0	0.42
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	8.00	0.42

Building Construction	Welders	Diesel	Average	9.00	8.00	18.0	0.45
Building Construction	Rubber Tired Loaders	Diesel	Average	3.00	8.00	42.0	0.36

5.3. Construction Vehicles

5.3.1. Unmitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Building Construction	—	—	—	—
Building Construction	Worker	96.0	45.0	LDA,LDT1,LDT2
Building Construction	Vendor	0.00	10.6	HHDT,MHDT
Building Construction	Hauling	0.00	20.0	HHDT
Building Construction	Onsite truck	—	—	HHDT

5.3.2. Mitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Building Construction	—	—	—	—
Building Construction	Worker	96.0	45.0	LDA,LDT1,LDT2
Building Construction	Vendor	0.00	10.6	HHDT,MHDT
Building Construction	Hauling	0.00	20.0	HHDT
Building Construction	Onsite truck	—	—	HHDT

5.4. Vehicles

5.4.1. Construction Vehicle Control Strategies

Non-applicable. No control strategies activated by user.

5.5. Architectural Coatings

Phase Name	Residential Interior Area Coated (sq ft)	Residential Exterior Area Coated (sq ft)	Non-Residential Interior Area Coated (sq ft)	Non-Residential Exterior Area Coated (sq ft)	Parking Area Coated (sq ft)

5.6. Dust Mitigation

5.6.1. Construction Earthmoving Activities

Phase Name	Material Imported (cy)	Material Exported (cy)	Acres Graded (acres)	Material Demolished (sq. ft.)	Acres Paved (acres)

5.6.2. Construction Earthmoving Control Strategies

Non-applicable. No control strategies activated by user.

5.7. Construction Paving

Land Use	Area Paved (acres)	% Asphalt
User Defined Industrial	0.00	0%

5.8. Construction Electricity Consumption and Emissions Factors

kWh per Year and Emission Factor (lb/MWh)

Year	kWh per Year	CO2	CH4	N2O
2025	0.00	204	0.03	< 0.005
2026	0.00	204	0.03	< 0.005
2027	0.00	204	0.03	< 0.005

5.18. Vegetation

5.18.1. Land Use Change

5.18.1.1. Unmitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.2. Sequestration

5.18.2.1. Unmitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

5.18.2.2. Mitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

8. User Changes to Default Data

Screen	Justification
Land Use	Project acreage is 2,636 but disturbed land would be 40 acres per Applicant.
Construction: Construction Phases	Work Days per Phase provided by Applicant.
Construction: Off-Road Equipment	Construction equipment provided by Applicant.
Construction: Off-Road Equipment EF	CalEEMod Appendix D: Default Data Tables - Table 3.4 OFFROAD Equipment Emission Factors (g/bhp-hr)

Construction: Trips and VMT	Estimated trip length.

CCS - CO2 Capture Facility - SP2972 Custom Report

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5.18.1.1. Unmitigated

5.18.1.2. Mitigated

5.18.2. Sequestration

5.18.2.1. Unmitigated

5.18.2.2. Mitigated

8. User Changes to Default Data

1. Basic Project Information

1.1. Basic Project Information

Data Field	Value
Project Name	CCS - CO2 Capture Facility - SP2972
Construction Start Date	3/12/2026
Lead Agency	—
Land Use Scale	Project/site
Analysis Level for Defaults	County
Windspeed (m/s)	2.70
Precipitation (days)	16.2
Location	35.453174, -119.708967
County	Kern-San Joaquin
City	Unincorporated
Air District	San Joaquin Valley APCD
Air Basin	San Joaquin Valley
TAZ	2947
EDFZ	5
Electric Utility	Pacific Gas & Electric Company
Gas Utility	Southern California Gas
App Version	2022.1.1.14

1.2. Land Use Types

Land Use Subtype	Size	Unit	Lot Acreage	Building Area (sq ft)	Landscape Area (sq ft)	Special Landscape Area (sq ft)	Population	Description
User Defined Industrial	1.00	User Defined Unit	40.0	0.00	0.00	—	—	—

1.3. User-Selected Emission Reduction Measures by Emissions Sector

Sector	#	Measure Title
Construction	C-10-A	Water Exposed Surfaces
Construction	C-11	Limit Vehicle Speeds on Unpaved Roads

2. Emissions Summary

2.1. Construction Emissions Compared Against Thresholds

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Un/Mit.	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	32.6	17.7	124	115	0.21	7.88	3.05	10.9	7.21	0.72	7.92	—	24,773	24,773	0.98	0.28	10.9	24,891
Mit.	32.6	17.7	124	115	0.21	7.88	3.05	10.9	7.21	0.72	7.92	—	24,773	24,773	0.98	0.28	10.9	24,891
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	32.5	17.6	125	109	0.21	7.88	3.05	10.9	7.21	0.72	7.92	—	24,368	24,368	0.98	0.28	0.28	24,476
Mit.	32.5	17.6	125	109	0.21	7.88	3.05	10.9	7.21	0.72	7.92	—	24,368	24,368	0.98	0.28	0.28	24,476
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	23.1	12.6	88.5	78.2	0.15	5.63	2.16	7.78	5.11	0.51	5.61	—	17,445	17,445	0.70	0.20	3.01	17,525
Mit.	23.1	12.6	88.5	78.2	0.15	5.63	2.16	7.78	5.11	0.51	5.61	—	17,445	17,445	0.70	0.20	3.01	17,525

% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Annual (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	4.22	2.29	16.2	14.3	0.03	1.03	0.39	1.42	0.93	0.09	1.02	—	2,888	2,888	0.12	0.03	0.50	2,901
Mit.	4.22	2.29	16.2	14.3	0.03	1.03	0.39	1.42	0.93	0.09	1.02	—	2,888	2,888	0.12	0.03	0.50	2,901
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

2.2. Construction Emissions by Year, Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2026	32.6	17.7	124	115	0.21	7.81	3.05	10.9	7.21	0.72	7.92	—	24,773	24,773	0.98	0.28	10.9	24,891
2027	32.4	17.6	124	114	0.21	7.88	3.05	10.9	7.15	0.72	7.87	—	24,709	24,709	0.98	0.28	9.75	24,826
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2026	32.5	17.6	125	109	0.21	7.81	3.05	10.9	7.21	0.72	7.92	—	24,368	24,368	0.98	0.28	0.28	24,476
2027	32.3	17.6	124	108	0.21	7.88	3.05	10.9	7.15	0.72	7.87	—	24,313	24,313	0.98	0.28	0.25	24,421
2028	28.5	14.3	105	103	0.21	6.01	3.05	9.06	5.55	0.72	6.27	—	24,255	24,255	0.98	0.28	0.23	24,363
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2026	18.8	10.2	71.9	63.8	0.12	4.51	1.74	6.25	4.16	0.41	4.57	—	14,133	14,133	0.57	0.16	2.71	14,198
2027	23.1	12.6	88.5	78.2	0.15	5.63	2.16	7.78	5.11	0.51	5.61	—	17,445	17,445	0.70	0.20	3.01	17,525
2028	2.34	1.17	8.63	8.59	0.02	0.49	0.25	0.74	0.46	0.06	0.51	—	2,002	2,002	0.08	0.02	0.31	2,012
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2026	3.43	1.86	13.1	11.6	0.02	0.82	0.32	1.14	0.76	0.07	0.83	—	2,340	2,340	0.09	0.03	0.45	2,351

2027	4.22	2.29	16.2	14.3	0.03	1.03	0.39	1.42	0.93	0.09	1.02	—	2,888	2,888	0.12	0.03	0.50	2,901
2028	0.43	0.21	1.58	1.57	< 0.005	0.09	0.05	0.14	0.08	0.01	0.09	—	332	332	0.01	< 0.005	0.05	333

2.3. Construction Emissions by Year, Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2026	32.6	17.7	124	115	0.21	7.81	3.05	10.9	7.21	0.72	7.92	—	24,773	24,773	0.98	0.28	10.9	24,891
2027	32.4	17.6	124	114	0.21	7.88	3.05	10.9	7.15	0.72	7.87	—	24,709	24,709	0.98	0.28	9.75	24,826
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2026	32.5	17.6	125	109	0.21	7.81	3.05	10.9	7.21	0.72	7.92	—	24,368	24,368	0.98	0.28	0.28	24,476
2027	32.3	17.6	124	108	0.21	7.88	3.05	10.9	7.15	0.72	7.87	—	24,313	24,313	0.98	0.28	0.25	24,421
2028	28.5	14.3	105	103	0.21	6.01	3.05	9.06	5.55	0.72	6.27	—	24,255	24,255	0.98	0.28	0.23	24,363
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2026	18.8	10.2	71.9	63.8	0.12	4.51	1.74	6.25	4.16	0.41	4.57	—	14,133	14,133	0.57	0.16	2.71	14,198
2027	23.1	12.6	88.5	78.2	0.15	5.63	2.16	7.78	5.11	0.51	5.61	—	17,445	17,445	0.70	0.20	3.01	17,525
2028	2.34	1.17	8.63	8.59	0.02	0.49	0.25	0.74	0.46	0.06	0.51	—	2,002	2,002	0.08	0.02	0.31	2,012
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2026	3.43	1.86	13.1	11.6	0.02	0.82	0.32	1.14	0.76	0.07	0.83	—	2,340	2,340	0.09	0.03	0.45	2,351
2027	4.22	2.29	16.2	14.3	0.03	1.03	0.39	1.42	0.93	0.09	1.02	—	2,888	2,888	0.12	0.03	0.50	2,901
2028	0.43	0.21	1.58	1.57	< 0.005	0.09	0.05	0.14	0.08	0.01	0.09	—	332	332	0.01	< 0.005	0.05	333

3. Construction Emissions Details

3.1. Building Construction (2026) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	31.9	17.2	124	99.0	0.21	7.81	—	7.81	7.21	—	7.21	—	21,504	21,504	0.96	0.18	—	21,580
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	31.9	17.2	124	99.0	0.21	7.81	—	7.81	7.21	—	7.21	—	21,504	21,504	0.96	0.18	—	21,580
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	18.4	9.91	71.4	57.1	0.12	4.51	—	4.51	4.16	—	4.16	—	12,414	12,414	0.56	0.10	—	12,458
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	3.36	1.81	13.0	10.4	0.02	0.82	—	0.82	0.76	—	0.76	—	2,055	2,055	0.09	0.02	—	2,063
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.63	0.53	0.83	16.2	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	3,269	3,269	0.01	0.10	10.9	3,311
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.59	0.48	1.03	10.1	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	2,864	2,864	0.02	0.10	0.28	2,896
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.34	0.28	0.54	6.66	0.00	0.00	1.74	1.74	0.00	0.41	0.41	—	1,718	1,718	0.01	0.06	2.71	1,739
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.06	0.05	0.10	1.22	0.00	0.00	0.32	0.32	0.00	0.07	0.07	—	285	285	< 0.005	0.01	0.45	288
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.2. Building Construction (2026) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Off-Road Equipment	31.9	17.2	124	99.0	0.21	7.81	—	7.81	7.21	—	7.21	—	21,504	21,504	0.96	0.18	—	21,580
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	31.9	17.2	124	99.0	0.21	7.81	—	7.81	7.21	—	7.21	—	21,504	21,504	0.96	0.18	—	21,580
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	18.4	9.91	71.4	57.1	0.12	4.51	—	4.51	4.16	—	4.16	—	12,414	12,414	0.56	0.10	—	12,458
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	3.36	1.81	13.0	10.4	0.02	0.82	—	0.82	0.76	—	0.76	—	2,055	2,055	0.09	0.02	—	2,063
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.63	0.53	0.83	16.2	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	3,269	3,269	0.01	0.10	10.9	3,311
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.59	0.48	1.03	10.1	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	2,864	2,864	0.02	0.10	0.28	2,896

Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.34	0.28	0.54	6.66	0.00	0.00	1.74	1.74	0.00	0.41	0.41	—	1,718	1,718	0.01	0.06	2.71	1,739
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.06	0.05	0.10	1.22	0.00	0.00	0.32	0.32	0.00	0.07	0.07	—	285	285	< 0.005	0.01	0.45	288
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.3. Building Construction (2027) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	31.9	17.1	123	98.9	0.21	7.88	—	7.88	7.15	—	7.15	—	21,506	21,506	0.96	0.18	—	21,582
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	31.9	17.1	123	98.9	0.21	7.88	—	7.88	7.15	—	7.15	—	21,506	21,506	0.96	0.18	—	21,582
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	22.8	12.2	88.0	70.7	0.15	5.63	—	5.63	5.11	—	5.11	—	15,361	15,361	0.69	0.13	—	15,416
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	4.15	2.23	16.1	12.9	0.03	1.03	—	1.03	0.93	—	0.93	—	2,543	2,543	0.11	0.02	—	2,552
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.52	0.51	0.73	14.9	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	3,203	3,203	0.01	0.10	9.75	3,244
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.48	0.47	0.93	9.28	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	2,807	2,807	0.02	0.10	0.25	2,839
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.34	0.34	0.59	7.58	0.00	0.00	2.16	2.16	0.00	0.51	0.51	—	2,084	2,084	0.01	0.07	3.01	2,109
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.06	0.06	0.11	1.38	0.00	0.00	0.39	0.39	0.00	0.09	0.09	—	345	345	< 0.005	0.01	0.50	349

Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.4. Building Construction (2027) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	31.9	17.1	123	98.9	0.21	7.88	—	7.88	7.15	—	7.15	—	21,506	21,506	0.96	0.18	—	21,582
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	31.9	17.1	123	98.9	0.21	7.88	—	7.88	7.15	—	7.15	—	21,506	21,506	0.96	0.18	—	21,582
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	22.8	12.2	88.0	70.7	0.15	5.63	—	5.63	5.11	—	5.11	—	15,361	15,361	0.69	0.13	—	15,416
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	4.15	2.23	16.1	12.9	0.03	1.03	—	1.03	0.93	—	0.93	—	2,543	2,543	0.11	0.02	—	2,552
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.52	0.51	0.73	14.9	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	3,203	3,203	0.01	0.10	9.75	3,244
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.48	0.47	0.93	9.28	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	2,807	2,807	0.02	0.10	0.25	2,839
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.34	0.34	0.59	7.58	0.00	0.00	2.16	2.16	0.00	0.51	0.51	—	2,084	2,084	0.01	0.07	3.01	2,109
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.06	0.06	0.11	1.38	0.00	0.00	0.39	0.39	0.00	0.09	0.09	—	345	345	< 0.005	0.01	0.50	349
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.5. Building Construction (2028) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	28.0	13.9	104	94.7	0.21	6.01	—	6.01	5.55	—	5.55	—	21,502	21,502	0.96	0.18	—	21,578
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	2.30	1.14	8.57	7.78	0.02	0.49	—	0.49	0.46	—	0.46	—	1,767	1,767	0.08	0.01	—	1,774
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.42	0.21	1.56	1.42	< 0.005	0.09	—	0.09	0.08	—	0.08	—	293	293	0.01	< 0.005	—	294
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.46	0.36	0.83	8.64	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	2,754	2,754	0.02	0.10	0.23	2,785
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.04	0.03	0.06	0.81	0.00	0.00	0.25	0.25	0.00	0.06	0.06	—	235	235	< 0.005	0.01	0.31	238
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.01	0.01	0.01	0.15	0.00	0.00	0.05	0.05	0.00	0.01	0.01	—	38.9	38.9	< 0.005	< 0.005	0.05	39.4
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.6. Building Construction (2028) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	28.0	13.9	104	94.7	0.21	6.01	—	6.01	5.55	—	5.55	—	21,502	21,502	0.96	0.18	—	21,578
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	2.30	1.14	8.57	7.78	0.02	0.49	—	0.49	0.46	—	0.46	—	1,767	1,767	0.08	0.01	—	1,774
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.42	0.21	1.56	1.42	< 0.005	0.09	—	0.09	0.08	—	0.08	—	293	293	0.01	< 0.005	—	294
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.46	0.36	0.83	8.64	0.00	0.00	3.05	3.05	0.00	0.72	0.72	—	2,754	2,754	0.02	0.10	0.23	2,785
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.04	0.03	0.06	0.81	0.00	0.00	0.25	0.25	0.00	0.06	0.06	—	235	235	< 0.005	0.01	0.31	238
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.01	0.01	0.01	0.15	0.00	0.00	0.05	0.05	0.00	0.01	0.01	—	38.9	38.9	< 0.005	< 0.005	0.05	39.4
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

5. Activity Data

5.1. Construction Schedule

Phase Name	Phase Type	Start Date	End Date	Days Per Week	Work Days per Phase	Phase Description
Building Construction	Building Construction	3/12/2026	2/11/2028	5.00	502	—

5.2. Off-Road Equipment

5.2.1. Unmitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor

Building Construction	Tractors/Loaders/Backh	Diesel	Average	6.00	8.00	67.0	0.37
Building Construction	Rollers	Diesel	Average	3.00	8.00	8.00	0.38
Building Construction	Air Compressors	Diesel	Average	6.00	8.00	50.0	0.48
Building Construction	Cranes	Diesel	Average	3.00	8.00	6.00	0.29
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	42.0	0.42
Building Construction	Rough Terrain Forklifts	Diesel	Average	3.00	8.00	300	0.40
Building Construction	Rough Terrain Forklifts	Diesel	Average	6.00	8.00	73.0	0.40
Building Construction	Other Construction Equipment	Diesel	Average	1.00	8.00	73.0	0.42
Building Construction	Generator Sets	Diesel	Average	6.00	8.00	18.0	0.74
Building Construction	Skid Steer Loaders	Diesel	Average	1.00	8.00	45.0	0.37
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	130	0.42
Building Construction	Aerial Lifts	Diesel	Average	6.00	8.00	475	0.31
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	45.0	0.42
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	8.00	0.42
Building Construction	Welders	Diesel	Average	9.00	8.00	18.0	0.45
Building Construction	Rubber Tired Loaders	Diesel	Average	3.00	8.00	42.0	0.36

5.2.2. Mitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Building Construction	Tractors/Loaders/Backhoes	Diesel	Average	6.00	8.00	67.0	0.37
Building Construction	Rollers	Diesel	Average	3.00	8.00	8.00	0.38
Building Construction	Air Compressors	Diesel	Average	6.00	8.00	50.0	0.48
Building Construction	Cranes	Diesel	Average	3.00	8.00	6.00	0.29

Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	42.0	0.42
Building Construction	Rough Terrain Forklifts	Diesel	Average	3.00	8.00	300	0.40
Building Construction	Rough Terrain Forklifts	Diesel	Average	6.00	8.00	73.0	0.40
Building Construction	Other Construction Equipment	Diesel	Average	1.00	8.00	73.0	0.42
Building Construction	Generator Sets	Diesel	Average	6.00	8.00	18.0	0.74
Building Construction	Skid Steer Loaders	Diesel	Average	1.00	8.00	45.0	0.37
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	130	0.42
Building Construction	Aerial Lifts	Diesel	Average	6.00	8.00	475	0.31
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	45.0	0.42
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	8.00	0.42
Building Construction	Welders	Diesel	Average	9.00	8.00	18.0	0.45
Building Construction	Rubber Tired Loaders	Diesel	Average	3.00	8.00	42.0	0.36

5.3. Construction Vehicles

5.3.1. Unmitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Building Construction	—	—	—	—
Building Construction	Worker	96.0	45.0	LDA,LDT1,LDT2
Building Construction	Vendor	0.00	10.6	HHDT,MHDT
Building Construction	Hauling	0.00	20.0	HHDT
Building Construction	Onsite truck	—	—	HHDT

5.3.2. Mitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Building Construction	—	—	—	—
Building Construction	Worker	96.0	45.0	LDA,LDT1,LDT2
Building Construction	Vendor	0.00	10.6	HHDT,MHDT
Building Construction	Hauling	0.00	20.0	HHDT
Building Construction	Onsite truck	—	—	HHDT

5.4. Vehicles

5.4.1. Construction Vehicle Control Strategies

Non-applicable. No control strategies activated by user.

5.5. Architectural Coatings

Phase Name	Residential Interior Area Coated (sq ft)	Residential Exterior Area Coated (sq ft)	Non-Residential Interior Area Coated (sq ft)	Non-Residential Exterior Area Coated (sq ft)	Parking Area Coated (sq ft)

5.6. Dust Mitigation

5.6.1. Construction Earthmoving Activities

Phase Name	Material Imported (cy)	Material Exported (cy)	Acres Graded (acres)	Material Demolished (sq. ft.)	Acres Paved (acres)

5.6.2. Construction Earthmoving Control Strategies

Non-applicable. No control strategies activated by user.

5.7. Construction Paving

Land Use	Area Paved (acres)	% Asphalt
User Defined Industrial	0.00	0%

5.8. Construction Electricity Consumption and Emissions Factors

kWh per Year and Emission Factor (lb/MWh)

Year	kWh per Year	CO2	CH4	N2O
2026	0.00	204	0.03	< 0.005
2027	0.00	204	0.03	< 0.005
2028	0.00	204	0.03	< 0.005

5.18. Vegetation

5.18.1. Land Use Change

5.18.1.1. Unmitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.2. Sequestration

5.18.2.1. Unmitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

5.18.2.2. Mitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

8. User Changes to Default Data

Screen	Justification
Land Use	Project acreage is 2,636 but disturbed land would be 40 acres per Applicant.
Construction: Construction Phases	Work Days per Phase provided by Applicant.
Construction: Off-Road Equipment	Construction equipment provided by Applicant.
Construction: Off-Road Equipment EF	CalEEMod Appendix D: Default Data Tables - Table 3.4 OFFROAD Equipment Emission Factors (g/bhp-hr)
Construction: Trips and VMT	Estimated trip length.

CCS - Compressor Station Custom Report

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5.18.1.2. Mitigated

5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

5.18.1.2. Mitigated

5.18.2. Sequestration

5.18.2.1. Unmitigated

5.18.2.2. Mitigated

8. User Changes to Default Data

1. Basic Project Information

1.1. Basic Project Information

Data Field	Value
Project Name	CCS - Compressor Station
Construction Start Date	1/1/2025
Lead Agency	—
Land Use Scale	Project/site
Analysis Level for Defaults	County
Windspeed (m/s)	2.70
Precipitation (days)	16.2
Location	35.453174, -119.708967
County	Kern-San Joaquin
City	Unincorporated
Air District	San Joaquin Valley APCD
Air Basin	San Joaquin Valley
TAZ	2947
EDFZ	5
Electric Utility	Pacific Gas & Electric Company
Gas Utility	Southern California Gas
App Version	2022.1.1.14

1.2. Land Use Types

Land Use Subtype	Size	Unit	Lot Acreage	Building Area (sq ft)	Landscape Area (sq ft)	Special Landscape Area (sq ft)	Population	Description
User Defined Industrial	1.00	User Defined Unit	40.0	0.00	0.00	—	—	—

1.3. User-Selected Emission Reduction Measures by Emissions Sector

Sector	#	Measure Title
Construction	C-10-A	Water Exposed Surfaces
Construction	C-11	Limit Vehicle Speeds on Unpaved Roads

2. Emissions Summary

2.1. Construction Emissions Compared Against Thresholds

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Un/Mit.	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	14.3	7.16	49.9	45.8	0.08	3.10	0.89	3.99	2.86	0.21	3.07	—	9,027	9,027	0.41	0.10	3.52	9,069
Mit.	14.3	7.16	49.9	45.8	0.08	3.10	0.89	3.99	2.86	0.21	3.07	—	9,027	9,027	0.41	0.10	3.52	9,069
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	14.2	7.14	50.0	43.9	0.08	3.10	0.89	3.99	2.86	0.21	3.07	—	8,906	8,906	0.38	0.10	0.09	8,944
Mit.	14.2	7.14	50.0	43.9	0.08	3.10	0.89	3.99	2.86	0.21	3.07	—	8,906	8,906	0.38	0.10	0.09	8,944
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	3.12	1.57	10.9	9.73	0.02	0.68	0.19	0.87	0.63	0.05	0.67	—	1,959	1,959	0.08	0.02	0.33	1,968
Mit.	3.12	1.57	10.9	9.73	0.02	0.68	0.19	0.87	0.63	0.05	0.67	—	1,959	1,959	0.08	0.02	0.33	1,968

% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Annual (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	0.57	0.29	2.00	1.78	< 0.005	0.12	0.04	0.16	0.11	0.01	0.12	—	324	324	0.01	< 0.005	0.06	326
Mit.	0.57	0.29	2.00	1.78	< 0.005	0.12	0.04	0.16	0.11	0.01	0.12	—	324	324	0.01	< 0.005	0.06	326
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

2.2. Construction Emissions by Year, Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	14.3	7.16	49.9	45.8	0.08	3.10	0.89	3.99	2.86	0.21	3.07	—	9,027	9,027	0.41	0.10	3.52	9,069
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	14.2	7.14	50.0	43.9	0.08	3.10	0.89	3.99	2.86	0.21	3.07	—	8,906	8,906	0.38	0.10	0.09	8,944
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	3.12	1.57	10.9	9.73	0.02	0.68	0.19	0.87	0.63	0.05	0.67	—	1,959	1,959	0.08	0.02	0.33	1,968
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.57	0.29	2.00	1.78	< 0.005	0.12	0.04	0.16	0.11	0.01	0.12	—	324	324	0.01	< 0.005	0.06	326

2.3. Construction Emissions by Year, Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e

Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	14.3	7.16	49.9	45.8	0.08	3.10	0.89	3.99	2.86	0.21	3.07	—	9,027	9,027	0.41	0.10	3.52	9,069
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	14.2	7.14	50.0	43.9	0.08	3.10	0.89	3.99	2.86	0.21	3.07	—	8,906	8,906	0.38	0.10	0.09	8,944
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	3.12	1.57	10.9	9.73	0.02	0.68	0.19	0.87	0.63	0.05	0.67	—	1,959	1,959	0.08	0.02	0.33	1,968
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.57	0.29	2.00	1.78	< 0.005	0.12	0.04	0.16	0.11	0.01	0.12	—	324	324	0.01	< 0.005	0.06	326

3. Construction Emissions Details

3.1. Building Construction (2025) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	14.1	7.00	49.6	40.7	0.08	3.10	—	3.10	2.86	—	2.86	—	8,053	8,053	0.37	0.07	—	8,082
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	14.1	7.00	49.6	40.7	0.08	3.10	—	3.10	2.86	—	2.86	—	8,053	8,053	0.37	0.07	—	8,082

Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	3.08	1.53	10.9	8.92	0.02	0.68	—	0.68	0.63	—	0.63	—	1,765	1,765	0.08	0.01	—	1,771
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.56	0.28	1.99	1.63	< 0.005	0.12	—	0.12	0.11	—	0.11	—	292	292	0.01	< 0.005	—	293
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.19	0.16	0.27	5.12	0.00	0.00	0.89	0.89	0.00	0.21	0.21	—	974	974	0.03	0.03	3.52	988
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.18	0.15	0.33	3.23	0.00	0.00	0.89	0.89	0.00	0.21	0.21	—	853	853	0.01	0.03	0.09	862
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.04	0.03	0.07	0.80	0.00	0.00	0.19	0.19	0.00	0.05	0.05	—	194	194	< 0.005	0.01	0.33	197
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Worker	0.01	0.01	0.01	0.15	0.00	0.00	0.04	0.04	0.00	0.01	0.01	—	32.2	32.2	< 0.005	< 0.005	0.06	32.6
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.2. Building Construction (2025) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	14.1	7.00	49.6	40.7	0.08	3.10	—	3.10	2.86	—	2.86	—	8,053	8,053	0.37	0.07	—	8,082
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	14.1	7.00	49.6	40.7	0.08	3.10	—	3.10	2.86	—	2.86	—	8,053	8,053	0.37	0.07	—	8,082
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	3.08	1.53	10.9	8.92	0.02	0.68	—	0.68	0.63	—	0.63	—	1,765	1,765	0.08	0.01	—	1,771
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.56	0.28	1.99	1.63	< 0.005	0.12	—	0.12	0.11	—	0.11	—	292	292	0.01	< 0.005	—	293

Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.19	0.16	0.27	5.12	0.00	0.00	0.89	0.89	0.00	0.21	0.21	—	974	974	0.03	0.03	3.52	988
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.18	0.15	0.33	3.23	0.00	0.00	0.89	0.89	0.00	0.21	0.21	—	853	853	0.01	0.03	0.09	862
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.04	0.03	0.07	0.80	0.00	0.00	0.19	0.19	0.00	0.05	0.05	—	194	194	< 0.005	0.01	0.33	197
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.01	0.01	0.01	0.15	0.00	0.00	0.04	0.04	0.00	0.01	0.01	—	32.2	32.2	< 0.005	< 0.005	0.06	32.6
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

5. Activity Data

5.1. Construction Schedule

Phase Name	Phase Type	Start Date	End Date	Days Per Week	Work Days per Phase	Phase Description

Building Construction	Building Construction	1/1/2025	4/22/2025	5.00	80.0	—

5.2. Off-Road Equipment

5.2.1. Unmitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Building Construction	Tractors/Loaders/Backhoes	Diesel	Average	2.00	8.00	67.0	0.37
Building Construction	Rollers	Diesel	Average	1.00	8.00	8.00	0.38
Building Construction	Air Compressors	Diesel	Average	3.00	8.00	50.0	0.48
Building Construction	Cranes	Diesel	Average	1.00	8.00	6.00	0.29
Building Construction	Other Construction Equipment	Diesel	Average	2.00	8.00	42.0	0.42
Building Construction	Rough Terrain Forklifts	Diesel	Average	1.00	8.00	300	0.40
Building Construction	Rough Terrain Forklifts	Diesel	Average	2.00	8.00	73.0	0.40
Building Construction	Other Construction Equipment	Diesel	Average	1.00	8.00	73.0	0.42
Building Construction	Generator Sets	Diesel	Average	2.00	8.00	18.0	0.74
Building Construction	Skid Steer Loaders	Diesel	Average	1.00	8.00	45.0	0.37
Building Construction	Other Construction Equipment	Diesel	Average	1.00	8.00	130	0.42
Building Construction	Aerial Lifts	Diesel	Average	2.00	8.00	475	0.31
Building Construction	Other Construction Equipment	Diesel	Average	1.00	8.00	45.0	0.42
Building Construction	Other Construction Equipment	Diesel	Average	1.00	8.00	8.00	0.42
Building Construction	Welders	Diesel	Average	3.00	8.00	18.0	0.45
Building Construction	Rubber Tired Loaders	Diesel	Average	2.00	8.00	42.0	0.36

5.2.2. Mitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Building Construction	Tractors/Loaders/Backhoes	Diesel	Average	2.00	8.00	67.0	0.37
Building Construction	Rollers	Diesel	Average	1.00	8.00	8.00	0.38
Building Construction	Air Compressors	Diesel	Average	3.00	8.00	50.0	0.48
Building Construction	Cranes	Diesel	Average	1.00	8.00	6.00	0.29
Building Construction	Other Construction Equipment	Diesel	Average	2.00	8.00	42.0	0.42
Building Construction	Rough Terrain Forklifts	Diesel	Average	1.00	8.00	300	0.40
Building Construction	Rough Terrain Forklifts	Diesel	Average	2.00	8.00	73.0	0.40
Building Construction	Other Construction Equipment	Diesel	Average	1.00	8.00	73.0	0.42
Building Construction	Generator Sets	Diesel	Average	2.00	8.00	18.0	0.74
Building Construction	Skid Steer Loaders	Diesel	Average	1.00	8.00	45.0	0.37
Building Construction	Other Construction Equipment	Diesel	Average	1.00	8.00	130	0.42
Building Construction	Aerial Lifts	Diesel	Average	2.00	8.00	475	0.31
Building Construction	Other Construction Equipment	Diesel	Average	1.00	8.00	45.0	0.42
Building Construction	Other Construction Equipment	Diesel	Average	1.00	8.00	8.00	0.42
Building Construction	Welders	Diesel	Average	3.00	8.00	18.0	0.45
Building Construction	Rubber Tired Loaders	Diesel	Average	2.00	8.00	42.0	0.36

5.3. Construction Vehicles

5.3.1. Unmitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix

Building Construction	—	—	—	—
Building Construction	Worker	28.0	45.0	LDA,LDT1,LDT2
Building Construction	Vendor	0.00	10.6	HHDT,MHDT
Building Construction	Hauling	0.00	20.0	HHDT
Building Construction	Onsite truck	—	—	HHDT

5.3.2. Mitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Building Construction	—	—	—	—
Building Construction	Worker	28.0	45.0	LDA,LDT1,LDT2
Building Construction	Vendor	0.00	10.6	HHDT,MHDT
Building Construction	Hauling	0.00	20.0	HHDT
Building Construction	Onsite truck	—	—	HHDT

5.4. Vehicles

5.4.1. Construction Vehicle Control Strategies

Non-applicable. No control strategies activated by user.

5.5. Architectural Coatings

Phase Name	Residential Interior Area Coated (sq ft)	Residential Exterior Area Coated (sq ft)	Non-Residential Interior Area Coated (sq ft)	Non-Residential Exterior Area Coated (sq ft)	Parking Area Coated (sq ft)

5.6. Dust Mitigation

5.6.1. Construction Earthmoving Activities

Phase Name	Material Imported (cy)	Material Exported (cy)	Acres Graded (acres)	Material Demolished (sq. ft.)	Acres Paved (acres)

5.6.2. Construction Earthmoving Control Strategies

Non-applicable. No control strategies activated by user.

5.7. Construction Paving

Land Use	Area Paved (acres)	% Asphalt
User Defined Industrial	0.00	0%

5.8. Construction Electricity Consumption and Emissions Factors

kWh per Year and Emission Factor (lb/MWh)

Year	kWh per Year	CO2	CH4	N2O
2025	0.00	204	0.03	< 0.005

5.18. Vegetation

5.18.1. Land Use Change

5.18.1.1. Unmitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.2. Sequestration

5.18.2.1. Unmitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

5.18.2.2. Mitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

8. User Changes to Default Data

Screen	Justification
Land Use	Project acreage is 2,636 but disturbed land would be 40 acres per Applicant.
Construction: Construction Phases	Work Days per Phase provided by Applicant.
Construction: Off-Road Equipment	Construction equipment provided by Applicant.
Construction: Trips and VMT	Estimated trip length.
Construction: Off-Road Equipment EF	CalEEMod Appendix D: Default Data Tables - Table 3.4 OFFROAD Equipment Emission Factors (g/bhp-hr)

CCS - CO2 Main Pipeline Custom Report

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5.18.1. Land Use Change

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5.18.1.2. Mitigated

5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

5.18.1.2. Mitigated

5.18.2. Sequestration

5.18.2.1. Unmitigated

5.18.2.2. Mitigated

8. User Changes to Default Data

1. Basic Project Information

1.1. Basic Project Information

Data Field	Value
Project Name	CCS - CO2 Main Pipeline
Construction Start Date	1/1/2025
Lead Agency	—
Land Use Scale	Project/site
Analysis Level for Defaults	County
Windspeed (m/s)	2.70
Precipitation (days)	16.2
Location	35.453174, -119.708967
County	Kern-San Joaquin
City	Unincorporated
Air District	San Joaquin Valley APCD
Air Basin	San Joaquin Valley
TAZ	2947
EDFZ	5
Electric Utility	Pacific Gas & Electric Company
Gas Utility	Southern California Gas
App Version	2022.1.1.14

1.2. Land Use Types

Land Use Subtype	Size	Unit	Lot Acreage	Building Area (sq ft)	Landscape Area (sq ft)	Special Landscape Area (sq ft)	Population	Description
User Defined Industrial	1.00	User Defined Unit	40.0	0.00	0.00	—	—	—

1.3. User-Selected Emission Reduction Measures by Emissions Sector

Sector	#	Measure Title
Construction	C-10-A	Water Exposed Surfaces
Construction	C-11	Limit Vehicle Speeds on Unpaved Roads

2. Emissions Summary

2.1. Construction Emissions Compared Against Thresholds

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Un/Mit.	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	8.36	7.02	57.5	55.4	0.11	3.13	0.92	4.05	2.88	0.22	3.10	—	12,554	12,554	0.50	0.12	3.65	12,608
Mit.	8.36	7.02	57.5	55.4	0.11	3.13	0.92	4.05	2.88	0.22	3.10	—	12,554	12,554	0.50	0.12	3.65	12,608
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	8.35	7.00	57.6	53.4	0.11	3.13	0.92	4.05	2.88	0.22	3.10	—	12,429	12,429	0.48	0.13	0.09	12,478
Mit.	8.35	7.00	57.6	53.4	0.11	3.13	0.92	4.05	2.88	0.22	3.10	—	12,429	12,429	0.48	0.13	0.09	12,478
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	5.96	5.00	41.1	38.5	0.08	2.24	0.65	2.89	2.06	0.15	2.21	—	8,903	8,903	0.34	0.09	1.13	8,939
Mit.	5.96	5.00	41.1	38.5	0.08	2.24	0.65	2.89	2.06	0.15	2.21	—	8,903	8,903	0.34	0.09	1.13	8,939

% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Annual (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	1.09	0.91	7.50	7.02	0.01	0.41	0.12	0.53	0.38	0.03	0.40	—	1,474	1,474	0.06	0.01	0.19	1,480
Mit.	1.09	0.91	7.50	7.02	0.01	0.41	0.12	0.53	0.38	0.03	0.40	—	1,474	1,474	0.06	0.01	0.19	1,480
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

2.2. Construction Emissions by Year, Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	8.36	7.02	57.5	55.4	0.11	3.13	0.92	4.05	2.88	0.22	3.10	—	12,554	12,554	0.50	0.12	3.65	12,608
2026	8.06	6.76	54.2	54.4	0.11	2.98	0.92	3.90	2.74	0.22	2.96	—	12,534	12,534	0.47	0.12	3.28	12,587
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	8.35	7.00	57.6	53.4	0.11	3.13	0.92	4.05	2.88	0.22	3.10	—	12,429	12,429	0.48	0.12	0.09	12,478
2026	8.05	6.75	54.3	52.6	0.11	2.98	0.92	3.90	2.74	0.22	2.96	—	12,412	12,412	0.47	0.13	0.09	12,461
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	5.96	5.00	41.1	38.5	0.08	2.24	0.65	2.89	2.06	0.15	2.21	—	8,903	8,903	0.34	0.09	1.13	8,939
2026	2.85	2.39	19.2	18.8	0.04	1.06	0.32	1.38	0.97	0.08	1.05	—	4,408	4,408	0.17	0.04	0.50	4,426
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	1.09	0.91	7.50	7.02	0.01	0.41	0.12	0.53	0.38	0.03	0.40	—	1,474	1,474	0.06	0.01	0.19	1,480
2026	0.52	0.44	3.51	3.43	0.01	0.19	0.06	0.25	0.18	0.01	0.19	—	730	730	0.03	0.01	0.08	733

2.3. Construction Emissions by Year, Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	8.36	7.02	57.5	55.4	0.11	3.13	0.92	4.05	2.88	0.22	3.10	—	12,554	12,554	0.50	0.12	3.65	12,608
2026	8.06	6.76	54.2	54.4	0.11	2.98	0.92	3.90	2.74	0.22	2.96	—	12,534	12,534	0.47	0.12	3.28	12,587
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	8.35	7.00	57.6	53.4	0.11	3.13	0.92	4.05	2.88	0.22	3.10	—	12,429	12,429	0.48	0.12	0.09	12,478
2026	8.05	6.75	54.3	52.6	0.11	2.98	0.92	3.90	2.74	0.22	2.96	—	12,412	12,412	0.47	0.13	0.09	12,461
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	5.96	5.00	41.1	38.5	0.08	2.24	0.65	2.89	2.06	0.15	2.21	—	8,903	8,903	0.34	0.09	1.13	8,939
2026	2.85	2.39	19.2	18.8	0.04	1.06	0.32	1.38	0.97	0.08	1.05	—	4,408	4,408	0.17	0.04	0.50	4,426
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	1.09	0.91	7.50	7.02	0.01	0.41	0.12	0.53	0.38	0.03	0.40	—	1,474	1,474	0.06	0.01	0.19	1,480
2026	0.52	0.44	3.51	3.43	0.01	0.19	0.06	0.25	0.18	0.01	0.19	—	730	730	0.03	0.01	0.08	733

3. Construction Emissions Details

3.1. Building Construction (2025) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	8.16	6.85	57.2	50.1	0.11	3.13	—	3.13	2.88	—	2.88	—	11,545	11,545	0.47	0.09	—	11,585
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	8.16	6.85	57.2	50.1	0.11	3.13	—	3.13	2.88	—	2.88	—	11,545	11,545	0.47	0.09	—	11,585
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	5.83	4.89	40.9	35.8	0.08	2.24	—	2.24	2.06	—	2.06	—	8,247	8,247	0.33	0.07	—	8,275
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	1.06	0.89	7.46	6.53	0.01	0.41	—	0.41	0.38	—	0.38	—	1,365	1,365	0.06	0.01	—	1,370
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.20	0.17	0.28	5.30	0.00	0.00	0.92	0.92	0.00	0.22	0.22	—	1,009	1,009	0.03	0.03	3.65	1,023
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.19	0.15	0.34	3.34	0.00	0.00	0.92	0.92	0.00	0.22	0.22	—	884	884	0.01	0.03	0.09	893
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.13	0.11	0.22	2.71	0.00	0.00	0.65	0.65	0.00	0.15	0.15	—	656	656	< 0.005	0.02	1.13	664
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.02	0.02	0.04	0.49	0.00	0.00	0.12	0.12	0.00	0.03	0.03	—	109	109	< 0.005	< 0.005	0.19	110
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.2. Building Construction (2025) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	8.16	6.85	57.2	50.1	0.11	3.13	—	3.13	2.88	—	2.88	—	11,545	11,545	0.47	0.09	—	11,585
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Off-Road Equipment	8.16	6.85	57.2	50.1	0.11	3.13	—	3.13	2.88	—	2.88	—	11,545	11,545	0.47	0.09	—	11,585
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	5.83	4.89	40.9	35.8	0.08	2.24	—	2.24	2.06	—	2.06	—	8,247	8,247	0.33	0.07	—	8,275
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	1.06	0.89	7.46	6.53	0.01	0.41	—	0.41	0.38	—	0.38	—	1,365	1,365	0.06	0.01	—	1,370
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.20	0.17	0.28	5.30	0.00	0.00	0.92	0.92	0.00	0.22	0.22	—	1,009	1,009	0.03	0.03	3.65	1,023
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.19	0.15	0.34	3.34	0.00	0.00	0.92	0.92	0.00	0.22	0.22	—	884	884	0.01	0.03	0.09	893
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.13	0.11	0.22	2.71	0.00	0.00	0.65	0.65	0.00	0.15	0.15	—	656	656	< 0.005	0.02	1.13	664
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.02	0.02	0.04	0.49	0.00	0.00	0.12	0.12	0.00	0.03	0.03	—	109	109	< 0.005	< 0.005	0.19	110
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.3. Building Construction (2026) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	7.87	6.60	54.0	49.6	0.11	2.98	—	2.98	2.74	—	2.74	—	11,547	11,547	0.47	0.09	—	11,586
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	7.87	6.60	54.0	49.6	0.11	2.98	—	2.98	2.74	—	2.74	—	11,547	11,547	0.47	0.09	—	11,586
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	2.79	2.34	19.1	17.6	0.04	1.06	—	1.06	0.97	—	0.97	—	4,090	4,090	0.17	0.03	—	4,104
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Off-Road Equipment	0.51	0.43	3.49	3.20	0.01	0.19	—	0.19	0.18	—	0.18	—	677	677	0.03	0.01	—	679
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.19	0.16	0.25	4.88	0.00	0.00	0.92	0.92	0.00	0.22	0.22	—	988	988	< 0.005	0.03	3.28	1,000
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.18	0.15	0.31	3.06	0.00	0.00	0.92	0.92	0.00	0.22	0.22	—	865	865	0.01	0.03	0.09	875
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.06	0.05	0.10	1.23	0.00	0.00	0.32	0.32	0.00	0.08	0.08	—	319	319	< 0.005	0.01	0.50	322
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.01	0.01	0.02	0.23	0.00	0.00	0.06	0.06	0.00	0.01	0.01	—	52.7	52.7	< 0.005	< 0.005	0.08	53.4
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.4. Building Construction (2026) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e

Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	7.87	6.60	54.0	49.6	0.11	2.98	—	2.98	2.74	—	2.74	—	11,547	11,547	0.47	0.09	—	11,586
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	7.87	6.60	54.0	49.6	0.11	2.98	—	2.98	2.74	—	2.74	—	11,547	11,547	0.47	0.09	—	11,586
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	2.79	2.34	19.1	17.6	0.04	1.06	—	1.06	0.97	—	0.97	—	4,090	4,090	0.17	0.03	—	4,104
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.51	0.43	3.49	3.20	0.01	0.19	—	0.19	0.18	—	0.18	—	677	677	0.03	0.01	—	679
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.19	0.16	0.25	4.88	0.00	0.00	0.92	0.92	0.00	0.22	0.22	—	988	988	< 0.005	0.03	3.28	1,000
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.18	0.15	0.31	3.06	0.00	0.00	0.92	0.92	0.00	0.22	0.22	—	865	865	0.01	0.03	0.09	875
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.06	0.05	0.10	1.23	0.00	0.00	0.32	0.32	0.00	0.08	0.08	—	319	319	< 0.005	0.01	0.50	322
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.01	0.01	0.02	0.23	0.00	0.00	0.06	0.06	0.00	0.01	0.01	—	52.7	52.7	< 0.005	< 0.005	0.08	53.4
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

5. Activity Data

5.1. Construction Schedule

Phase Name	Phase Type	Start Date	End Date	Days Per Week	Work Days per Phase	Phase Description
Pipeline	Building Construction	1/1/2025	6/30/2026	5.00	390	—

5.2. Off-Road Equipment

5.2.1. Unmitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Pipeline	Welders	Diesel	Average	4.00	8.00	48.0	0.45

Pipeline	Tractors/Loaders/Backhoes	Diesel	Average	3.00	8.00	67.0	0.37
Pipeline	Excavators	Diesel	Average	3.00	8.00	172	0.38
Pipeline	Cranes	Diesel	Average	4.00	8.00	300	0.29
Pipeline	Cranes	Diesel	Average	1.00	8.00	62.0	0.29
Pipeline	Other Construction Equipment	Diesel	Average	2.00	8.00	226	0.42
Pipeline	Other Construction Equipment	Diesel	Average	1.00	8.00	425	0.42
Pipeline	Rollers	Diesel	Average	1.00	8.00	33.0	0.38
Pipeline	Rubber Tired Loaders	Diesel	Average	1.00	8.00	232	0.36
Pipeline	Rubber Tired Loaders	Diesel	Average	1.00	8.00	125	0.36

5.2.2. Mitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Pipeline	Welders	Diesel	Average	4.00	8.00	48.0	0.45
Pipeline	Tractors/Loaders/Backhoes	Diesel	Average	3.00	8.00	67.0	0.37
Pipeline	Excavators	Diesel	Average	3.00	8.00	172	0.38
Pipeline	Cranes	Diesel	Average	4.00	8.00	300	0.29
Pipeline	Cranes	Diesel	Average	1.00	8.00	62.0	0.29
Pipeline	Other Construction Equipment	Diesel	Average	2.00	8.00	226	0.42
Pipeline	Other Construction Equipment	Diesel	Average	1.00	8.00	425	0.42
Pipeline	Rollers	Diesel	Average	1.00	8.00	33.0	0.38
Pipeline	Rubber Tired Loaders	Diesel	Average	1.00	8.00	232	0.36
Pipeline	Rubber Tired Loaders	Diesel	Average	1.00	8.00	125	0.36

5.3. Construction Vehicles

5.3.1. Unmitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Pipeline	—	—	—	—
Pipeline	Worker	29.0	45.0	LDA,LDT1,LDT2
Pipeline	Vendor	0.00	10.6	HHDT,MHDT
Pipeline	Hauling	0.00	20.0	HHDT
Pipeline	Onsite truck	—	—	HHDT

5.3.2. Mitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Pipeline	—	—	—	—
Pipeline	Worker	29.0	45.0	LDA,LDT1,LDT2
Pipeline	Vendor	0.00	10.6	HHDT,MHDT
Pipeline	Hauling	0.00	20.0	HHDT
Pipeline	Onsite truck	—	—	HHDT

5.4. Vehicles

5.4.1. Construction Vehicle Control Strategies

Non-applicable. No control strategies activated by user.

5.5. Architectural Coatings

Phase Name	Residential Interior Area Coated (sq ft)	Residential Exterior Area Coated (sq ft)	Non-Residential Interior Area Coated (sq ft)	Non-Residential Exterior Area Coated (sq ft)	Parking Area Coated (sq ft)

5.6. Dust Mitigation

5.6.1. Construction Earthmoving Activities

Phase Name	Material Imported (cy)	Material Exported (cy)	Acres Graded (acres)	Material Demolished (sq. ft.)	Acres Paved (acres)

5.6.2. Construction Earthmoving Control Strategies

Non-applicable. No control strategies activated by user.

5.7. Construction Paving

Land Use	Area Paved (acres)	% Asphalt
User Defined Industrial	0.00	0%

5.8. Construction Electricity Consumption and Emissions Factors

kWh per Year and Emission Factor (lb/MWh)

Year	kWh per Year	CO2	CH4	N2O
2025	0.00	204	0.03	< 0.005
2026	0.00	204	0.03	< 0.005

5.18. Vegetation

5.18.1. Land Use Change

5.18.1.1. Unmitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.2. Sequestration

5.18.2.1. Unmitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

5.18.2.2. Mitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

8. User Changes to Default Data

Screen	Justification
Land Use	Project acreage is 2,636 but disturbed land would be 40 acres per Applicant.
Construction: Construction Phases	Work Days per Phase provided by Applicant.
Construction: Off-Road Equipment	Construction equipment provided by Applicant.
Construction: Trips and VMT	Construction equipment provided by Applicant.

CCS - Distribution Pipeline Custom Report

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5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

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5.18.2. Sequestration

5.18.2.1. Unmitigated

5.18.2.2. Mitigated

8. User Changes to Default Data

1. Basic Project Information

1.1. Basic Project Information

Data Field	Value
Project Name	CCS - Distribution Pipeline
Construction Start Date	1/1/2025
Lead Agency	—
Land Use Scale	Project/site
Analysis Level for Defaults	County
Windspeed (m/s)	2.70
Precipitation (days)	16.2
Location	35.453174, -119.708967
County	Kern-San Joaquin
City	Unincorporated
Air District	San Joaquin Valley APCD
Air Basin	San Joaquin Valley
TAZ	2947
EDFZ	5
Electric Utility	Pacific Gas & Electric Company
Gas Utility	Southern California Gas
App Version	2022.1.1.14

1.2. Land Use Types

Land Use Subtype	Size	Unit	Lot Acreage	Building Area (sq ft)	Landscape Area (sq ft)	Special Landscape Area (sq ft)	Population	Description
User Defined Industrial	1.00	User Defined Unit	40.0	0.00	0.00	—	—	—

1.3. User-Selected Emission Reduction Measures by Emissions Sector

Sector	#	Measure Title
Construction	C-10-A	Water Exposed Surfaces
Construction	C-11	Limit Vehicle Speeds on Unpaved Roads

2. Emissions Summary

2.1. Construction Emissions Compared Against Thresholds

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Un/Mit.	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	5.69	4.77	36.7	38.7	0.07	2.22	0.73	2.95	2.04	0.17	2.21	—	7,908	7,908	0.32	0.08	2.89	7,943
Mit.	5.69	4.77	36.7	38.7	0.07	2.22	0.73	2.95	2.04	0.17	2.21	—	7,908	7,908	0.32	0.08	2.89	7,943
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	5.68	4.76	36.8	37.1	0.07	2.22	0.73	2.95	2.04	0.17	2.21	—	7,808	7,808	0.29	0.08	0.08	7,840
Mit.	5.68	4.76	36.8	37.1	0.07	2.22	0.73	2.95	2.04	0.17	2.21	—	7,808	7,808	0.29	0.08	0.08	7,840
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	4.05	3.39	26.2	26.7	0.05	1.58	0.52	2.10	1.46	0.12	1.58	—	5,582	5,582	0.21	0.06	0.89	5,606
Mit.	4.05	3.39	26.2	26.7	0.05	1.58	0.52	2.10	1.46	0.12	1.58	—	5,582	5,582	0.21	0.06	0.89	5,606

% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Annual (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	0.74	0.62	4.78	4.87	0.01	0.29	0.09	0.38	0.27	0.02	0.29	—	924	924	0.03	0.01	0.15	928
Mit.	0.74	0.62	4.78	4.87	0.01	0.29	0.09	0.38	0.27	0.02	0.29	—	924	924	0.03	0.01	0.15	928
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

2.2. Construction Emissions by Year, Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	5.69	4.77	36.7	38.7	0.07	2.22	0.73	2.95	2.04	0.17	2.21	—	7,908	7,908	0.32	0.08	2.89	7,943
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	5.68	4.76	36.8	37.1	0.07	2.22	0.73	2.95	2.04	0.17	2.21	—	7,808	7,808	0.29	0.08	0.08	7,840
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	4.05	3.39	26.2	26.7	0.05	1.58	0.52	2.10	1.46	0.12	1.58	—	5,582	5,582	0.21	0.06	0.89	5,606
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.74	0.62	4.78	4.87	0.01	0.29	0.09	0.38	0.27	0.02	0.29	—	924	924	0.03	0.01	0.15	928

2.3. Construction Emissions by Year, Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e

Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	5.69	4.77	36.7	38.7	0.07	2.22	0.73	2.95	2.04	0.17	2.21	—	7,908	7,908	0.32	0.08	2.89	7,943
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	5.68	4.76	36.8	37.1	0.07	2.22	0.73	2.95	2.04	0.17	2.21	—	7,808	7,808	0.29	0.08	0.08	7,840
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	4.05	3.39	26.2	26.7	0.05	1.58	0.52	2.10	1.46	0.12	1.58	—	5,582	5,582	0.21	0.06	0.89	5,606
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.74	0.62	4.78	4.87	0.01	0.29	0.09	0.38	0.27	0.02	0.29	—	924	924	0.03	0.01	0.15	928

3. Construction Emissions Details

3.1. Building Construction (2025) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	5.53	4.64	36.5	34.5	0.07	2.22	—	2.22	2.04	—	2.04	—	7,108	7,108	0.29	0.06	—	7,132
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	5.53	4.64	36.5	34.5	0.07	2.22	—	2.22	2.04	—	2.04	—	7,108	7,108	0.29	0.06	—	7,132

Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	3.94	3.30	26.0	24.5	0.05	1.58	—	1.58	1.46	—	1.46	—	5,063	5,063	0.21	0.04	—	5,080
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.72	0.60	4.75	4.48	0.01	0.29	—	0.29	0.27	—	0.27	—	838	838	0.03	0.01	—	841
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.16	0.14	0.22	4.21	0.00	0.00	0.73	0.73	0.00	0.17	0.17	—	800	800	0.03	0.02	2.89	811
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.15	0.12	0.27	2.65	0.00	0.00	0.73	0.73	0.00	0.17	0.17	—	701	701	0.01	0.02	0.08	708
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.11	0.09	0.18	2.14	0.00	0.00	0.52	0.52	0.00	0.12	0.12	—	519	519	< 0.005	0.02	0.89	525
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Worker	0.02	0.02	0.03	0.39	0.00	0.00	0.09	0.09	0.00	0.02	0.02	—	85.9	85.9	< 0.005	< 0.005	0.15	87.0
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.2. Building Construction (2025) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	5.53	4.64	36.5	34.5	0.07	2.22	—	2.22	2.04	—	2.04	—	7,108	7,108	0.29	0.06	—	7,132
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	5.53	4.64	36.5	34.5	0.07	2.22	—	2.22	2.04	—	2.04	—	7,108	7,108	0.29	0.06	—	7,132
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	3.94	3.30	26.0	24.5	0.05	1.58	—	1.58	1.46	—	1.46	—	5,063	5,063	0.21	0.04	—	5,080
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.72	0.60	4.75	4.48	0.01	0.29	—	0.29	0.27	—	0.27	—	838	838	0.03	0.01	—	841

Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.16	0.14	0.22	4.21	0.00	0.00	0.73	0.73	0.00	0.17	0.17	—	800	800	0.03	0.02	2.89	811
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.15	0.12	0.27	2.65	0.00	0.00	0.73	0.73	0.00	0.17	0.17	—	701	701	0.01	0.02	0.08	708
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.11	0.09	0.18	2.14	0.00	0.00	0.52	0.52	0.00	0.12	0.12	—	519	519	< 0.005	0.02	0.89	525
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.02	0.02	0.03	0.39	0.00	0.00	0.09	0.09	0.00	0.02	0.02	—	85.9	85.9	< 0.005	< 0.005	0.15	87.0
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

5. Activity Data

5.1. Construction Schedule

Phase Name	Phase Type	Start Date	End Date	Days Per Week	Work Days per Phase	Phase Description

Pipeline	Building Construction	1/1/2025	12/30/2025	5.00	260	—

5.2. Off-Road Equipment

5.2.1. Unmitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Pipeline	Cranes	Diesel	Average	1.00	8.00	62.0	0.29
Pipeline	Welders	Diesel	Average	3.00	8.00	48.0	0.45
Pipeline	Tractors/Loaders/Backhoes	Diesel	Average	2.00	7.00	67.0	0.37
Pipeline	Cranes	Diesel	Average	1.00	8.00	62.0	0.29
Pipeline	Excavators	Diesel	Average	3.00	8.00	172	0.38
Pipeline	Other Construction Equipment	Diesel	Average	1.00	8.00	232	0.42
Pipeline	Rubber Tired Loaders	Diesel	Average	1.00	8.00	232	0.36
Pipeline	Rollers	Diesel	Average	1.00	8.00	33.0	0.38
Pipeline	Rubber Tired Loaders	Diesel	Average	1.00	8.00	125	0.36
Pipeline	Other Construction Equipment	Diesel	Average	1.00	8.00	425	0.42

5.2.2. Mitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Pipeline	Cranes	Diesel	Average	1.00	8.00	62.0	0.29
Pipeline	Welders	Diesel	Average	3.00	8.00	48.0	0.45
Pipeline	Tractors/Loaders/Backhoes	Diesel	Average	2.00	7.00	67.0	0.37
Pipeline	Cranes	Diesel	Average	1.00	8.00	62.0	0.29
Pipeline	Excavators	Diesel	Average	3.00	8.00	172	0.38

Pipeline	Other Construction Equipment	Diesel	Average	1.00	8.00	232	0.42
Pipeline	Rubber Tired Loaders	Diesel	Average	1.00	8.00	232	0.36
Pipeline	Rollers	Diesel	Average	1.00	8.00	33.0	0.38
Pipeline	Rubber Tired Loaders	Diesel	Average	1.00	8.00	125	0.36
Pipeline	Other Construction Equipment	Diesel	Average	1.00	8.00	425	0.42

5.3. Construction Vehicles

5.3.1. Unmitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Pipeline	—	—	—	—
Pipeline	Worker	23.0	45.0	LDA,LDT1,LDT2
Pipeline	Vendor	0.00	10.6	HHDT,MHDT
Pipeline	Hauling	0.00	20.0	HHDT
Pipeline	Onsite truck	—	—	HHDT

5.3.2. Mitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Pipeline	—	—	—	—
Pipeline	Worker	23.0	45.0	LDA,LDT1,LDT2
Pipeline	Vendor	0.00	10.6	HHDT,MHDT
Pipeline	Hauling	0.00	20.0	HHDT
Pipeline	Onsite truck	—	—	HHDT

5.4. Vehicles

5.4.1. Construction Vehicle Control Strategies

Non-applicable. No control strategies activated by user.

5.5. Architectural Coatings

Phase Name	Residential Interior Area Coated (sq ft)	Residential Exterior Area Coated (sq ft)	Non-Residential Interior Area Coated (sq ft)	Non-Residential Exterior Area Coated (sq ft)	Parking Area Coated (sq ft)

5.6. Dust Mitigation

5.6.1. Construction Earthmoving Activities

Phase Name	Material Imported (cy)	Material Exported (cy)	Acres Graded (acres)	Material Demolished (sq. ft.)	Acres Paved (acres)

5.6.2. Construction Earthmoving Control Strategies

Non-applicable. No control strategies activated by user.

5.7. Construction Paving

Land Use	Area Paved (acres)	% Asphalt
User Defined Industrial	0.00	0%

5.8. Construction Electricity Consumption and Emissions Factors

kWh per Year and Emission Factor (lb/MWh)

Year	kWh per Year	CO2	CH4	N2O
2025	0.00	204	0.03	< 0.005

5.18. Vegetation

5.18.1. Land Use Change

5.18.1.1. Unmitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.2. Sequestration

5.18.2.1. Unmitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

5.18.2.2. Mitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

8. User Changes to Default Data

Screen	Justification
Land Use	Project acreage is 2,636 but disturbed land would be 40 acres per Applicant.

Construction: Construction Phases	Work Days per Phase provided by Applicant.
Construction: Off-Road Equipment	Construction equipment provided by Applicant.
Construction: Trips and VMT	Estimated Trip Length.

CCS - Electrical Transmission Line Custom Report

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5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

5.18.1.2. Mitigated

5.18.2. Sequestration

5.18.2.1. Unmitigated

5.18.2.2. Mitigated

8. User Changes to Default Data

1. Basic Project Information

1.1. Basic Project Information

Data Field	Value
Project Name	CCS - Electrical Transmission Line
Construction Start Date	4/24/2025
Lead Agency	—
Land Use Scale	Project/site
Analysis Level for Defaults	County
Windspeed (m/s)	2.70
Precipitation (days)	16.2
Location	35.453174, -119.708967
County	Kern-San Joaquin
City	Unincorporated
Air District	San Joaquin Valley APCD
Air Basin	San Joaquin Valley
TAZ	2947
EDFZ	5
Electric Utility	Pacific Gas & Electric Company
Gas Utility	Southern California Gas
App Version	2022.1.1.14

1.2. Land Use Types

Land Use Subtype	Size	Unit	Lot Acreage	Building Area (sq ft)	Landscape Area (sq ft)	Special Landscape Area (sq ft)	Population	Description
User Defined Industrial	1.00	User Defined Unit	40.0	0.00	0.00	—	—	—

1.3. User-Selected Emission Reduction Measures by Emissions Sector

Sector	#	Measure Title
Construction	C-10-A	Water Exposed Surfaces
Construction	C-11	Limit Vehicle Speeds on Unpaved Roads

2. Emissions Summary

2.1. Construction Emissions Compared Against Thresholds

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Un/Mit.	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	4.30	3.61	35.1	25.1	0.08	1.39	0.38	1.77	1.28	0.09	1.37	—	8,802	8,802	0.35	0.08	1.51	8,837
Mit.	4.30	3.61	35.1	25.1	0.08	1.39	0.38	1.77	1.28	0.09	1.37	—	8,802	8,802	0.35	0.08	1.51	8,837
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	0.71	0.59	5.77	4.03	0.01	0.23	0.06	0.29	0.21	0.01	0.22	—	1,441	1,441	0.06	0.01	0.11	1,446
Mit.	0.71	0.59	5.77	4.03	0.01	0.23	0.06	0.29	0.21	0.01	0.22	—	1,441	1,441	0.06	0.01	0.11	1,446
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Annual (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	0.13	0.11	1.05	0.74	< 0.005	0.04	0.01	0.05	0.04	< 0.005	0.04	—	239	239	0.01	< 0.005	0.02	239
Mit.	0.13	0.11	1.05	0.74	< 0.005	0.04	0.01	0.05	0.04	< 0.005	0.04	—	239	239	0.01	< 0.005	0.02	239

% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

2.2. Construction Emissions by Year, Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	4.30	3.61	35.1	25.1	0.08	1.39	0.38	1.77	1.28	0.09	1.37	—	8,802	8,802	0.35	0.08	1.51	8,837
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.71	0.59	5.77	4.03	0.01	0.23	0.06	0.29	0.21	0.01	0.22	—	1,441	1,441	0.06	0.01	0.11	1,446
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.13	0.11	1.05	0.74	< 0.005	0.04	0.01	0.05	0.04	< 0.005	0.04	—	239	239	0.01	< 0.005	0.02	239

2.3. Construction Emissions by Year, Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	4.30	3.61	35.1	25.1	0.08	1.39	0.38	1.77	1.28	0.09	1.37	—	8,802	8,802	0.35	0.08	1.51	8,837
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

2025	0.71	0.59	5.77	4.03	0.01	0.23	0.06	0.29	0.21	0.01	0.22	—	1,441	1,441	0.06	0.01	0.11	1,446
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.13	0.11	1.05	0.74	< 0.005	0.04	0.01	0.05	0.04	< 0.005	0.04	—	239	239	0.01	< 0.005	0.02	239

3. Construction Emissions Details

3.1. Building Construction (2025) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	4.21	3.54	35.0	23.0	0.08	1.39	—	1.39	1.28	—	1.28	—	8,385	8,385	0.34	0.07	—	8,414
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.69	0.58	5.75	3.77	0.01	0.23	—	0.23	0.21	—	0.21	—	1,378	1,378	0.06	0.01	—	1,383
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.13	0.11	1.05	0.69	< 0.005	0.04	—	0.04	0.04	—	0.04	—	228	228	0.01	< 0.005	—	229
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.08	0.07	0.12	2.19	0.00	0.00	0.38	0.38	0.00	0.09	0.09	—	418	418	0.01	0.01	1.51	423
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.01	0.01	0.02	0.26	0.00	0.00	0.06	0.06	0.00	0.01	0.01	—	62.5	62.5	< 0.005	< 0.005	0.11	63.2
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	< 0.005	< 0.005	< 0.005	0.05	0.00	0.00	0.01	0.01	0.00	< 0.005	< 0.005	—	10.3	10.3	< 0.005	< 0.005	0.02	10.5
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.2. Building Construction (2025) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	4.21	3.54	35.0	23.0	0.08	1.39	—	1.39	1.28	—	1.28	—	8,385	8,385	0.34	0.07	—	8,414

Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.69	0.58	5.75	3.77	0.01	0.23	—	0.23	0.21	—	0.21	—	1,378	1,378	0.06	0.01	—	1,383
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.13	0.11	1.05	0.69	< 0.005	0.04	—	0.04	0.04	—	0.04	—	228	228	0.01	< 0.005	—	229
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.08	0.07	0.12	2.19	0.00	0.00	0.38	0.38	0.00	0.09	0.09	—	418	418	0.01	0.01	1.51	423
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.01	0.01	0.02	0.26	0.00	0.00	0.06	0.06	0.00	0.01	0.01	—	62.5	62.5	< 0.005	< 0.005	0.11	63.2
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Worker	< 0.005	< 0.005	< 0.005	0.05	0.00	0.00	0.01	0.01	0.00	< 0.005	< 0.005	—	10.3	10.3	< 0.005	< 0.005	0.02	10.5
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

5. Activity Data

5.1. Construction Schedule

Phase Name	Phase Type	Start Date	End Date	Days Per Week	Work Days per Phase	Phase Description
Building Construction	Building Construction	4/24/2025	7/16/2025	5.00	60.0	—

5.2. Off-Road Equipment

5.2.1. Unmitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Building Construction	Rubber Tired Dozers	Diesel	Average	1.00	8.00	207	0.40
Building Construction	Off-Highway Trucks	Diesel	Average	1.00	8.00	407	0.38
Building Construction	Other Construction Equipment	Diesel	Average	1.00	8.00	226	0.42
Building Construction	Other Construction Equipment	Diesel	Average	4.00	8.00	180	0.42
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	210	0.42

5.2.2. Mitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Building Construction	Rubber Tired Dozers	Diesel	Average	1.00	8.00	207	0.40
Building Construction	Off-Highway Trucks	Diesel	Average	1.00	8.00	407	0.38

Building Construction	Other Construction Equipment	Diesel	Average	1.00	8.00	226	0.42
Building Construction	Other Construction Equipment	Diesel	Average	4.00	8.00	180	0.42
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	210	0.42

5.3. Construction Vehicles

5.3.1. Unmitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Building Construction	—	—	—	—
Building Construction	Worker	12.0	45.0	LDA,LDT1,LDT2
Building Construction	Vendor	0.00	10.6	HHDT,MHDT
Building Construction	Hauling	0.00	20.0	HHDT
Building Construction	Onsite truck	—	—	HHDT

5.3.2. Mitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Building Construction	—	—	—	—
Building Construction	Worker	12.0	45.0	LDA,LDT1,LDT2
Building Construction	Vendor	0.00	10.6	HHDT,MHDT
Building Construction	Hauling	0.00	20.0	HHDT
Building Construction	Onsite truck	—	—	HHDT

5.4. Vehicles

5.4.1. Construction Vehicle Control Strategies

Non-applicable. No control strategies activated by user.

5.5. Architectural Coatings

Phase Name	Residential Interior Area Coated (sq ft)	Residential Exterior Area Coated (sq ft)	Non-Residential Interior Area Coated (sq ft)	Non-Residential Exterior Area Coated (sq ft)	Parking Area Coated (sq ft)

5.6. Dust Mitigation

5.6.1. Construction Earthmoving Activities

Phase Name	Material Imported (cy)	Material Exported (cy)	Acres Graded (acres)	Material Demolished (sq. ft.)	Acres Paved (acres)

5.6.2. Construction Earthmoving Control Strategies

Non-applicable. No control strategies activated by user.

5.7. Construction Paving

Land Use	Area Paved (acres)	% Asphalt
User Defined Industrial	0.00	0%

5.8. Construction Electricity Consumption and Emissions Factors

kWh per Year and Emission Factor (lb/MWh)

Year	kWh per Year	CO2	CH4	N2O
2025	0.00	204	0.03	< 0.005

5.18. Vegetation

5.18.1. Land Use Change

5.18.1.1. Unmitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.2. Sequestration

5.18.2.1. Unmitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

5.18.2.2. Mitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

8. User Changes to Default Data

Screen	Justification
Land Use	Project acreage is 2,636 but disturbed land would be 40 acres per Applicant.
Construction: Construction Phases	Work Days per Phase provided by Applicant.

Construction: Off-Road Equipment	Construction equipment provided by Applicant.
Construction: Trips and VMT	Estimated trip length.

CCS - Intra-Field Electrical Distribution Custom Report

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5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

5.18.1.2. Mitigated

5.18.2. Sequestration

5.18.2.1. Unmitigated

5.18.2.2. Mitigated

8. User Changes to Default Data

1. Basic Project Information

1.1. Basic Project Information

Data Field	Value
Project Name	CCS - Intra-Field Electrical Distribution
Construction Start Date	2/12/2026
Lead Agency	—
Land Use Scale	Project/site
Analysis Level for Defaults	County
Windspeed (m/s)	2.70
Precipitation (days)	16.2
Location	35.453174, -119.708967
County	Kern-San Joaquin
City	Unincorporated
Air District	San Joaquin Valley APCD
Air Basin	San Joaquin Valley
TAZ	2947
EDFZ	5
Electric Utility	Pacific Gas & Electric Company
Gas Utility	Southern California Gas
App Version	2022.1.1.14

1.2. Land Use Types

Land Use Subtype	Size	Unit	Lot Acreage	Building Area (sq ft)	Landscape Area (sq ft)	Special Landscape Area (sq ft)	Population	Description
User Defined Industrial	1.00	User Defined Unit	40.0	0.00	0.00	—	—	—

1.3. User-Selected Emission Reduction Measures by Emissions Sector

Sector	#	Measure Title
Construction	C-10-A	Water Exposed Surfaces
Construction	C-11	Limit Vehicle Speeds on Unpaved Roads

2. Emissions Summary

2.1. Construction Emissions Compared Against Thresholds

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Un/Mit.	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	4.32	3.63	34.2	26.5	0.08	1.38	0.38	1.76	1.27	0.09	1.36	—	8,803	8,803	0.34	0.08	1.36	8,837
Mit.	4.32	3.63	34.2	26.5	0.08	1.38	0.38	1.76	1.27	0.09	1.36	—	8,803	8,803	0.34	0.08	1.36	8,837
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	4.31	3.62	34.2	25.7	0.08	1.38	0.38	1.76	1.27	0.09	1.36	—	8,752	8,752	0.34	0.08	0.04	8,785
Mit.	4.31	3.62	34.2	25.7	0.08	1.38	0.38	1.76	1.27	0.09	1.36	—	8,752	8,752	0.34	0.08	0.04	8,785
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	0.71	0.60	5.62	4.26	0.01	0.23	0.06	0.29	0.21	0.01	0.22	—	1,441	1,441	0.06	0.01	0.10	1,446
Mit.	0.71	0.60	5.62	4.26	0.01	0.23	0.06	0.29	0.21	0.01	0.22	—	1,441	1,441	0.06	0.01	0.10	1,446

% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Annual (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	0.13	0.11	1.03	0.78	< 0.005	0.04	0.01	0.05	0.04	< 0.005	0.04	—	239	239	0.01	< 0.005	0.02	239
Mit.	0.13	0.11	1.03	0.78	< 0.005	0.04	0.01	0.05	0.04	< 0.005	0.04	—	239	239	0.01	< 0.005	0.02	239
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

2.2. Construction Emissions by Year, Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2026	4.32	3.63	34.2	26.5	0.08	1.38	0.38	1.76	1.27	0.09	1.36	—	8,803	8,803	0.34	0.08	1.36	8,837
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2026	4.31	3.62	34.2	25.7	0.08	1.38	0.38	1.76	1.27	0.09	1.36	—	8,752	8,752	0.34	0.08	0.04	8,785
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2026	0.71	0.60	5.62	4.26	0.01	0.23	0.06	0.29	0.21	0.01	0.22	—	1,441	1,441	0.06	0.01	0.10	1,446
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2026	0.13	0.11	1.03	0.78	< 0.005	0.04	0.01	0.05	0.04	< 0.005	0.04	—	239	239	0.01	< 0.005	0.02	239

2.3. Construction Emissions by Year, Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e

Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2026	4.32	3.63	34.2	26.5	0.08	1.38	0.38	1.76	1.27	0.09	1.36	—	8,803	8,803	0.34	0.08	1.36	8,837
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2026	4.31	3.62	34.2	25.7	0.08	1.38	0.38	1.76	1.27	0.09	1.36	—	8,752	8,752	0.34	0.08	0.04	8,785
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2026	0.71	0.60	5.62	4.26	0.01	0.23	0.06	0.29	0.21	0.01	0.22	—	1,441	1,441	0.06	0.01	0.10	1,446
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2026	0.13	0.11	1.03	0.78	< 0.005	0.04	0.01	0.05	0.04	< 0.005	0.04	—	239	239	0.01	< 0.005	0.02	239

3. Construction Emissions Details

3.1. Building Construction (2026) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	4.24	3.56	34.1	24.5	0.08	1.38	—	1.38	1.27	—	1.27	—	8,394	8,394	0.34	0.07	—	8,423
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	4.24	3.56	34.1	24.5	0.08	1.38	—	1.38	1.27	—	1.27	—	8,394	8,394	0.34	0.07	—	8,423

Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.70	0.59	5.60	4.02	0.01	0.23	—	0.23	0.21	—	0.21	—	1,380	1,380	0.06	0.01	—	1,385
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.13	0.11	1.02	0.73	< 0.005	0.04	—	0.04	0.04	—	0.04	—	228	228	0.01	< 0.005	—	229
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.08	0.07	0.10	2.02	0.00	0.00	0.38	0.38	0.00	0.09	0.09	—	409	409	< 0.005	0.01	1.36	414
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.07	0.06	0.13	1.27	0.00	0.00	0.38	0.38	0.00	0.09	0.09	—	358	358	< 0.005	0.01	0.04	362
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.01	0.01	0.02	0.24	0.00	0.00	0.06	0.06	0.00	0.01	0.01	—	61.2	61.2	< 0.005	< 0.005	0.10	61.9
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Worker	< 0.005	< 0.005	< 0.005	0.04	0.00	0.00	0.01	0.01	0.00	< 0.005	< 0.005	—	10.1	10.1	< 0.005	< 0.005	0.02	10.2
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.2. Building Construction (2026) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	4.24	3.56	34.1	24.5	0.08	1.38	—	1.38	1.27	—	1.27	—	8,394	8,394	0.34	0.07	—	8,423
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	4.24	3.56	34.1	24.5	0.08	1.38	—	1.38	1.27	—	1.27	—	8,394	8,394	0.34	0.07	—	8,423
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.70	0.59	5.60	4.02	0.01	0.23	—	0.23	0.21	—	0.21	—	1,380	1,380	0.06	0.01	—	1,385
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.13	0.11	1.02	0.73	< 0.005	0.04	—	0.04	0.04	—	0.04	—	228	228	0.01	< 0.005	—	229

Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.08	0.07	0.10	2.02	0.00	0.00	0.38	0.38	0.00	0.09	0.09	—	409	409	< 0.005	0.01	1.36	414
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.07	0.06	0.13	1.27	0.00	0.00	0.38	0.38	0.00	0.09	0.09	—	358	358	< 0.005	0.01	0.04	362
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.01	0.01	0.02	0.24	0.00	0.00	0.06	0.06	0.00	0.01	0.01	—	61.2	61.2	< 0.005	< 0.005	0.10	61.9
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	< 0.005	< 0.005	< 0.005	0.04	0.00	0.00	0.01	0.01	0.00	< 0.005	< 0.005	—	10.1	10.1	< 0.005	< 0.005	0.02	10.2
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

5. Activity Data

5.1. Construction Schedule

Phase Name	Phase Type	Start Date	End Date	Days Per Week	Work Days per Phase	Phase Description

Building Construction	Building Construction	2/12/2026	5/6/2026	5.00	60.0	—

5.2. Off-Road Equipment

5.2.1. Unmitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Building Construction	Rubber Tired Dozers	Diesel	Average	1.00	8.00	207	0.40
Building Construction	Off-Highway Trucks	Diesel	Average	1.00	8.00	407	0.38
Building Construction	Other Construction Equipment	Diesel	Average	1.00	8.00	226	0.42
Building Construction	Other Construction Equipment	Diesel	Average	4.00	8.00	180	0.42
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	210	0.42

5.2.2. Mitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Building Construction	Rubber Tired Dozers	Diesel	Average	1.00	8.00	207	0.40
Building Construction	Off-Highway Trucks	Diesel	Average	1.00	8.00	407	0.38
Building Construction	Other Construction Equipment	Diesel	Average	1.00	8.00	226	0.42
Building Construction	Other Construction Equipment	Diesel	Average	4.00	8.00	180	0.42
Building Construction	Other Construction Equipment	Diesel	Average	3.00	8.00	210	0.42

5.3. Construction Vehicles

5.3.1. Unmitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Building Construction	—	—	—	—
Building Construction	Worker	12.0	45.0	LDA,LDT1,LDT2
Building Construction	Vendor	0.00	10.6	HHDT,MHDT
Building Construction	Hauling	0.00	20.0	HHDT
Building Construction	Onsite truck	—	—	HHDT

5.3.2. Mitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Building Construction	—	—	—	—
Building Construction	Worker	12.0	45.0	LDA,LDT1,LDT2
Building Construction	Vendor	0.00	10.6	HHDT,MHDT
Building Construction	Hauling	0.00	20.0	HHDT
Building Construction	Onsite truck	—	—	HHDT

5.4. Vehicles

5.4.1. Construction Vehicle Control Strategies

Non-applicable. No control strategies activated by user.

5.5. Architectural Coatings

Phase Name	Residential Interior Area Coated (sq ft)	Residential Exterior Area Coated (sq ft)	Non-Residential Interior Area Coated (sq ft)	Non-Residential Exterior Area Coated (sq ft)	Parking Area Coated (sq ft)

5.6. Dust Mitigation

5.6.1. Construction Earthmoving Activities

Phase Name	Material Imported (cy)	Material Exported (cy)	Acres Graded (acres)	Material Demolished (sq. ft.)	Acres Paved (acres)

5.6.2. Construction Earthmoving Control Strategies

Non-applicable. No control strategies activated by user.

5.7. Construction Paving

Land Use	Area Paved (acres)	% Asphalt
User Defined Industrial	0.00	0%

5.8. Construction Electricity Consumption and Emissions Factors

kWh per Year and Emission Factor (lb/MWh)

Year	kWh per Year	CO2	CH4	N2O
2026	0.00	204	0.03	< 0.005

5.18. Vegetation

5.18.1. Land Use Change

5.18.1.1. Unmitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.2. Sequestration

5.18.2.1. Unmitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

5.18.2.2. Mitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

8. User Changes to Default Data

Screen	Justification
Land Use	Project acreage is 2,636 but disturbed land would be 40 acres per Applicant.
Construction: Construction Phases	Work Days per Phase provided by Applicant.
Construction: Off-Road Equipment	Construction equipment provided by Applicant.
Construction: Trips and VMT	Estimated trip length.

CCS - Onsite Electrical Substation Custom Report

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5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

5.18.1.2. Mitigated

5.18.2. Sequestration

5.18.2.1. Unmitigated

5.18.2.2. Mitigated

8. User Changes to Default Data

1. Basic Project Information

1.1. Basic Project Information

Data Field	Value
Project Name	CCS - Onsite Electrical Substation
Construction Start Date	1/30/2025
Lead Agency	—
Land Use Scale	Project/site
Analysis Level for Defaults	County
Windspeed (m/s)	2.70
Precipitation (days)	16.2
Location	35.453174, -119.708967
County	Kern-San Joaquin
City	Unincorporated
Air District	San Joaquin Valley APCD
Air Basin	San Joaquin Valley
TAZ	2947
EDFZ	5
Electric Utility	Pacific Gas & Electric Company
Gas Utility	Southern California Gas
App Version	2022.1.1.14

1.2. Land Use Types

Land Use Subtype	Size	Unit	Lot Acreage	Building Area (sq ft)	Landscape Area (sq ft)	Special Landscape Area (sq ft)	Population	Description
User Defined Industrial	1.00	User Defined Unit	40.0	0.00	0.00	—	—	—

1.3. User-Selected Emission Reduction Measures by Emissions Sector

Sector	#	Measure Title
Construction	C-10-A	Water Exposed Surfaces
Construction	C-11	Limit Vehicle Speeds on Unpaved Roads

2. Emissions Summary

2.1. Construction Emissions Compared Against Thresholds

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Un/Mit.	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	4.98	2.58	23.5	24.6	0.03	1.19	0.57	1.77	1.10	0.13	1.24	—	4,083	4,083	0.18	0.05	2.27	4,104
Mit.	4.98	2.58	23.5	24.6	0.03	1.19	0.57	1.77	1.10	0.13	1.24	—	4,083	4,083	0.18	0.05	2.27	4,104
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	4.97	2.57	23.6	23.3	0.03	1.19	0.57	1.77	1.10	0.13	1.24	—	4,005	4,005	0.16	0.05	0.06	4,024
Mit.	4.97	2.57	23.6	23.3	0.03	1.19	0.57	1.77	1.10	0.13	1.24	—	4,005	4,005	0.16	0.05	0.06	4,024
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	1.77	0.91	8.39	8.41	0.01	0.43	0.20	0.63	0.39	0.05	0.44	—	1,434	1,434	0.06	0.02	0.35	1,441
Mit.	1.77	0.91	8.39	8.41	0.01	0.43	0.20	0.63	0.39	0.05	0.44	—	1,434	1,434	0.06	0.02	0.35	1,441

% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Annual (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	0.32	0.17	1.53	1.54	< 0.005	0.08	0.04	0.11	0.07	0.01	0.08	—	237	237	0.01	< 0.005	0.06	239
Mit.	0.32	0.17	1.53	1.54	< 0.005	0.08	0.04	0.11	0.07	0.01	0.08	—	237	237	0.01	< 0.005	0.06	239
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

2.2. Construction Emissions by Year, Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	4.98	2.58	23.5	24.6	0.03	1.19	0.57	1.77	1.10	0.13	1.24	—	4,083	4,083	0.18	0.05	2.27	4,104
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	4.97	2.57	23.6	23.3	0.03	1.19	0.57	1.77	1.10	0.13	1.24	—	4,005	4,005	0.16	0.05	0.06	4,024
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	1.77	0.91	8.39	8.41	0.01	0.43	0.20	0.63	0.39	0.05	0.44	—	1,434	1,434	0.06	0.02	0.35	1,441
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.32	0.17	1.53	1.54	< 0.005	0.08	0.04	0.11	0.07	0.01	0.08	—	237	237	0.01	< 0.005	0.06	239

2.3. Construction Emissions by Year, Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e

Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	4.98	2.58	23.5	24.6	0.03	1.19	0.57	1.77	1.10	0.13	1.24	—	4,083	4,083	0.18	0.05	2.27	4,104
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	4.97	2.57	23.6	23.3	0.03	1.19	0.57	1.77	1.10	0.13	1.24	—	4,005	4,005	0.16	0.05	0.06	4,024
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	1.77	0.91	8.39	8.41	0.01	0.43	0.20	0.63	0.39	0.05	0.44	—	1,434	1,434	0.06	0.02	0.35	1,441
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.32	0.17	1.53	1.54	< 0.005	0.08	0.04	0.11	0.07	0.01	0.08	—	237	237	0.01	< 0.005	0.06	239

3. Construction Emissions Details

3.1. Building Construction (2025) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	4.85	2.47	23.4	21.3	0.03	1.19	—	1.19	1.10	—	1.10	—	3,457	3,457	0.16	0.03	—	3,469
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	4.85	2.47	23.4	21.3	0.03	1.19	—	1.19	1.10	—	1.10	—	3,457	3,457	0.16	0.03	—	3,469

Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	1.73	0.88	8.32	7.57	0.01	0.43	—	0.43	0.39	—	0.39	—	1,231	1,231	0.06	0.01	—	1,236
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.32	0.16	1.52	1.38	< 0.005	0.08	—	0.08	0.07	—	0.07	—	204	204	0.01	< 0.005	—	205
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.13	0.11	0.17	3.29	0.00	0.00	0.57	0.57	0.00	0.13	0.13	—	626	626	0.02	0.02	2.27	635
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.12	0.10	0.21	2.07	0.00	0.00	0.57	0.57	0.00	0.13	0.13	—	548	548	< 0.005	0.02	0.06	554
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.04	0.03	0.07	0.84	0.00	0.00	0.20	0.20	0.00	0.05	0.05	—	203	203	< 0.005	0.01	0.35	206
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Worker	0.01	0.01	0.01	0.15	0.00	0.00	0.04	0.04	0.00	0.01	0.01	—	33.6	33.6	< 0.005	< 0.005	0.06	34.0
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.2. Building Construction (2025) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	4.85	2.47	23.4	21.3	0.03	1.19	—	1.19	1.10	—	1.10	—	3,457	3,457	0.16	0.03	—	3,469
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	4.85	2.47	23.4	21.3	0.03	1.19	—	1.19	1.10	—	1.10	—	3,457	3,457	0.16	0.03	—	3,469
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	1.73	0.88	8.32	7.57	0.01	0.43	—	0.43	0.39	—	0.39	—	1,231	1,231	0.06	0.01	—	1,236
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.32	0.16	1.52	1.38	< 0.005	0.08	—	0.08	0.07	—	0.07	—	204	204	0.01	< 0.005	—	205

Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.13	0.11	0.17	3.29	0.00	0.00	0.57	0.57	0.00	0.13	0.13	—	626	626	0.02	0.02	2.27	635
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.12	0.10	0.21	2.07	0.00	0.00	0.57	0.57	0.00	0.13	0.13	—	548	548	< 0.005	0.02	0.06	554
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.04	0.03	0.07	0.84	0.00	0.00	0.20	0.20	0.00	0.05	0.05	—	203	203	< 0.005	0.01	0.35	206
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.01	0.01	0.01	0.15	0.00	0.00	0.04	0.04	0.00	0.01	0.01	—	33.6	33.6	< 0.005	< 0.005	0.06	34.0
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

5. Activity Data

5.1. Construction Schedule

Phase Name	Phase Type	Start Date	End Date	Days Per Week	Work Days per Phase	Phase Description

Building Construction	Building Construction	1/30/2025	7/30/2025	5.00	130	—

5.2. Off-Road Equipment

5.2.1. Unmitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Building Construction	Tractors/Loaders/Backhoes	Diesel	Average	3.00	8.00	92.0	0.37
Building Construction	Bore/Drill Rigs	Diesel	Average	1.00	8.00	68.0	0.50
Building Construction	Rollers	Diesel	Average	1.00	8.00	8.00	0.38
Building Construction	Air Compressors	Diesel	Average	1.00	8.00	50.0	0.48
Building Construction	Other Construction Equipment	Diesel	Average	1.00	8.00	6.00	0.42
Building Construction	Cranes	Diesel	Average	1.00	8.00	250	0.29
Building Construction	Rough Terrain Forklifts	Diesel	Average	1.00	8.00	73.0	0.40
Building Construction	Skid Steer Loaders	Diesel	Average	1.00	8.00	45.0	0.37
Building Construction	Aerial Lifts	Diesel	Average	2.00	8.00	60.0	0.31
Building Construction	Cement and Mortar Mixers	Diesel	Average	1.00	8.00	7.00	0.56
Building Construction	Trenchers	Diesel	Average	1.00	8.00	80.0	0.50

5.2.2. Mitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Building Construction	Tractors/Loaders/Backhoes	Diesel	Average	3.00	8.00	92.0	0.37
Building Construction	Bore/Drill Rigs	Diesel	Average	1.00	8.00	68.0	0.50
Building Construction	Rollers	Diesel	Average	1.00	8.00	8.00	0.38
Building Construction	Air Compressors	Diesel	Average	1.00	8.00	50.0	0.48

Building Construction	Other Construction Equipment	Diesel	Average	1.00	8.00	6.00	0.42
Building Construction	Cranes	Diesel	Average	1.00	8.00	250	0.29
Building Construction	Rough Terrain Forklifts	Diesel	Average	1.00	8.00	73.0	0.40
Building Construction	Skid Steer Loaders	Diesel	Average	1.00	8.00	45.0	0.37
Building Construction	Aerial Lifts	Diesel	Average	2.00	8.00	60.0	0.31
Building Construction	Cement and Mortar Mixers	Diesel	Average	1.00	8.00	7.00	0.56
Building Construction	Trenchers	Diesel	Average	1.00	8.00	80.0	0.50

5.3. Construction Vehicles

5.3.1. Unmitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Building Construction	—	—	—	—
Building Construction	Worker	18.0	45.0	LDA,LDT1,LDT2
Building Construction	Vendor	0.00	10.6	HHDT,MHDT
Building Construction	Hauling	0.00	20.0	HHDT
Building Construction	Onsite truck	—	—	HHDT

5.3.2. Mitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Building Construction	—	—	—	—
Building Construction	Worker	18.0	45.0	LDA,LDT1,LDT2
Building Construction	Vendor	0.00	10.6	HHDT,MHDT
Building Construction	Hauling	0.00	20.0	HHDT
Building Construction	Onsite truck	—	—	HHDT

5.4. Vehicles

5.4.1. Construction Vehicle Control Strategies

Non-applicable. No control strategies activated by user.

5.5. Architectural Coatings

Phase Name	Residential Interior Area Coated (sq ft)	Residential Exterior Area Coated (sq ft)	Non-Residential Interior Area Coated (sq ft)	Non-Residential Exterior Area Coated (sq ft)	Parking Area Coated (sq ft)

5.6. Dust Mitigation

5.6.1. Construction Earthmoving Activities

Phase Name	Material Imported (cy)	Material Exported (cy)	Acres Graded (acres)	Material Demolished (sq. ft.)	Acres Paved (acres)

5.6.2. Construction Earthmoving Control Strategies

Non-applicable. No control strategies activated by user.

5.7. Construction Paving

Land Use	Area Paved (acres)	% Asphalt
User Defined Industrial	0.00	0%

5.8. Construction Electricity Consumption and Emissions Factors

kWh per Year and Emission Factor (lb/MWh)

Year	kWh per Year	CO2	CH4	N2O
2025	0.00	204	0.03	< 0.005

5.18. Vegetation

5.18.1. Land Use Change

5.18.1.1. Unmitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.2. Sequestration

5.18.2.1. Unmitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

5.18.2.2. Mitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

8. User Changes to Default Data

Screen	Justification
Land Use	Project acreage is 2,636 but disturbed land would be 40 acres per Applicant.
Construction: Construction Phases	Work Days per Phase provided by Applicant.
Construction: Off-Road Equipment	Construction equipment provided by Applicant.
Construction: Off-Road Equipment EF	CalEEMod Appendix D: Default Data Tables - Table 3.4 OFFROAD Equipment Emission Factors (g/bhp-hr)
Construction: Trips and VMT	Estimated trip length.

CCS - Water Pipeline Custom Report

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5.18.1. Land Use Change

5.18.1.1. Unmitigated

5.18.1.2. Mitigated

5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

5.18.1.2. Mitigated

5.18.2. Sequestration

5.18.2.1. Unmitigated

5.18.2.2. Mitigated

8. User Changes to Default Data

1. Basic Project Information

1.1. Basic Project Information

Data Field	Value
Project Name	CCS - Water Pipeline
Construction Start Date	1/30/2025
Lead Agency	—
Land Use Scale	Project/site
Analysis Level for Defaults	County
Windspeed (m/s)	2.70
Precipitation (days)	16.2
Location	35.453174, -119.708967
County	Kern-San Joaquin
City	Unincorporated
Air District	San Joaquin Valley APCD
Air Basin	San Joaquin Valley
TAZ	2947
EDFZ	5
Electric Utility	Pacific Gas & Electric Company
Gas Utility	Southern California Gas
App Version	2022.1.1.14

1.2. Land Use Types

Land Use Subtype	Size	Unit	Lot Acreage	Building Area (sq ft)	Landscape Area (sq ft)	Special Landscape Area (sq ft)	Population	Description
User Defined Industrial	1.00	User Defined Unit	40.0	0.00	0.00	—	—	—

1.3. User-Selected Emission Reduction Measures by Emissions Sector

Sector	#	Measure Title
Construction	C-10-A	Water Exposed Surfaces
Construction	C-11	Limit Vehicle Speeds on Unpaved Roads

2. Emissions Summary

2.1. Construction Emissions Compared Against Thresholds

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Un/Mit.	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	4.44	3.73	29.7	30.4	0.05	1.61	0.64	2.25	1.48	0.15	1.63	—	6,117	6,117	0.24	0.07	2.52	6,145
Mit.	4.44	3.73	29.7	30.4	0.05	1.61	0.64	2.25	1.48	0.15	1.63	—	6,117	6,117	0.24	0.07	2.52	6,145
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	4.43	3.71	29.7	29.1	0.05	1.61	0.64	2.25	1.48	0.15	1.63	—	6,031	6,031	0.22	0.07	0.07	6,056
Mit.	4.43	3.71	29.7	29.1	0.05	1.61	0.64	2.25	1.48	0.15	1.63	—	6,031	6,031	0.22	0.07	0.07	6,056
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	1.06	0.89	7.07	7.00	0.01	0.38	0.15	0.53	0.35	0.04	0.39	—	1,443	1,443	0.05	0.02	0.26	1,449
Mit.	1.06	0.89	7.07	7.00	0.01	0.38	0.15	0.53	0.35	0.04	0.39	—	1,443	1,443	0.05	0.02	0.26	1,449

% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Annual (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	0.19	0.16	1.29	1.28	< 0.005	0.07	0.03	0.10	0.06	0.01	0.07	—	239	239	0.01	< 0.005	0.04	240
Mit.	0.19	0.16	1.29	1.28	< 0.005	0.07	0.03	0.10	0.06	0.01	0.07	—	239	239	0.01	< 0.005	0.04	240
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

2.2. Construction Emissions by Year, Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	4.44	3.73	29.7	30.4	0.05	1.61	0.64	2.25	1.48	0.15	1.63	—	6,117	6,117	0.24	0.07	2.52	6,145
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	4.43	3.71	29.7	29.1	0.05	1.61	0.64	2.25	1.48	0.15	1.63	—	6,031	6,031	0.22	0.07	0.07	6,056
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	1.06	0.89	7.07	7.00	0.01	0.38	0.15	0.53	0.35	0.04	0.39	—	1,443	1,443	0.05	0.02	0.26	1,449
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.19	0.16	1.29	1.28	< 0.005	0.07	0.03	0.10	0.06	0.01	0.07	—	239	239	0.01	< 0.005	0.04	240

2.3. Construction Emissions by Year, Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e

Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	4.44	3.73	29.7	30.4	0.05	1.61	0.64	2.25	1.48	0.15	1.63	—	6,117	6,117	0.24	0.07	2.52	6,145
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	4.43	3.71	29.7	29.1	0.05	1.61	0.64	2.25	1.48	0.15	1.63	—	6,031	6,031	0.22	0.07	0.07	6,056
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	1.06	0.89	7.07	7.00	0.01	0.38	0.15	0.53	0.35	0.04	0.39	—	1,443	1,443	0.05	0.02	0.26	1,449
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.19	0.16	1.29	1.28	< 0.005	0.07	0.03	0.10	0.06	0.01	0.07	—	239	239	0.01	< 0.005	0.04	240

3. Construction Emissions Details

3.1. Building Construction (2025) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	4.30	3.61	29.5	26.8	0.05	1.61	—	1.61	1.48	—	1.48	—	5,421	5,421	0.22	0.04	—	5,440
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	4.30	3.61	29.5	26.8	0.05	1.61	—	1.61	1.48	—	1.48	—	5,421	5,421	0.22	0.04	—	5,440

Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	1.03	0.86	7.02	6.38	0.01	0.38	—	0.38	0.35	—	0.35	—	1,292	1,292	0.05	0.01	—	1,297
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.19	0.16	1.28	1.16	< 0.005	0.07	—	0.07	0.06	—	0.06	—	214	214	0.01	< 0.005	—	215
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.14	0.12	0.19	3.66	0.00	0.00	0.64	0.64	0.00	0.15	0.15	—	696	696	0.02	0.02	2.52	705
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.13	0.11	0.24	2.31	0.00	0.00	0.64	0.64	0.00	0.15	0.15	—	609	609	< 0.005	0.02	0.07	616
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.03	0.03	0.05	0.62	0.00	0.00	0.15	0.15	0.00	0.04	0.04	—	151	151	< 0.005	0.01	0.26	153
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Worker	0.01	< 0.005	0.01	0.11	0.00	0.00	0.03	0.03	0.00	0.01	0.01	—	25.0	25.0	< 0.005	< 0.005	0.04	25.3
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.2. Building Construction (2025) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	4.30	3.61	29.5	26.8	0.05	1.61	—	1.61	1.48	—	1.48	—	5,421	5,421	0.22	0.04	—	5,440
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	4.30	3.61	29.5	26.8	0.05	1.61	—	1.61	1.48	—	1.48	—	5,421	5,421	0.22	0.04	—	5,440
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	1.03	0.86	7.02	6.38	0.01	0.38	—	0.38	0.35	—	0.35	—	1,292	1,292	0.05	0.01	—	1,297
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.19	0.16	1.28	1.16	< 0.005	0.07	—	0.07	0.06	—	0.06	—	214	214	0.01	< 0.005	—	215

Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.14	0.12	0.19	3.66	0.00	0.00	0.64	0.64	0.00	0.15	0.15	—	696	696	0.02	0.02	2.52	705
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.13	0.11	0.24	2.31	0.00	0.00	0.64	0.64	0.00	0.15	0.15	—	609	609	< 0.005	0.02	0.07	616
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.03	0.03	0.05	0.62	0.00	0.00	0.15	0.15	0.00	0.04	0.04	—	151	151	< 0.005	0.01	0.26	153
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.01	< 0.005	0.01	0.11	0.00	0.00	0.03	0.03	0.00	0.01	0.01	—	25.0	25.0	< 0.005	< 0.005	0.04	25.3
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

5. Activity Data

5.1. Construction Schedule

Phase Name	Phase Type	Start Date	End Date	Days Per Week	Work Days per Phase	Phase Description

Pipeline	Building Construction	1/30/2025	5/30/2025	5.00	87.0	—

5.2. Off-Road Equipment

5.2.1. Unmitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Pipeline	Welders	Diesel	Average	3.00	8.00	48.0	0.45
Pipeline	Tractors/Loaders/Backhoes	Diesel	Average	2.00	8.00	67.0	0.37
Pipeline	Excavators	Diesel	Average	2.00	8.00	172	0.38
Pipeline	Other Construction Equipment	Diesel	Average	2.00	8.00	226	0.42
Pipeline	Rubber Tired Loaders	Diesel	Average	1.00	8.00	232	0.36
Pipeline	Rollers	Diesel	Average	1.00	8.00	33.0	0.38
Pipeline	Rubber Tired Loaders	Diesel	Average	1.00	8.00	125	0.36

5.2.2. Mitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Pipeline	Welders	Diesel	Average	3.00	8.00	48.0	0.45
Pipeline	Tractors/Loaders/Backhoes	Diesel	Average	2.00	8.00	67.0	0.37
Pipeline	Excavators	Diesel	Average	2.00	8.00	172	0.38
Pipeline	Other Construction Equipment	Diesel	Average	2.00	8.00	226	0.42
Pipeline	Rubber Tired Loaders	Diesel	Average	1.00	8.00	232	0.36
Pipeline	Rollers	Diesel	Average	1.00	8.00	33.0	0.38
Pipeline	Rubber Tired Loaders	Diesel	Average	1.00	8.00	125	0.36

5.3. Construction Vehicles

5.3.1. Unmitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Pipeline	—	—	—	—
Pipeline	Worker	20.0	45.0	LDA,LDT1,LDT2
Pipeline	Vendor	0.00	10.6	HHDT,MHDT
Pipeline	Hauling	0.00	20.0	HHDT
Pipeline	Onsite truck	—	—	HHDT

5.3.2. Mitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Pipeline	—	—	—	—
Pipeline	Worker	20.0	45.0	LDA,LDT1,LDT2
Pipeline	Vendor	0.00	10.6	HHDT,MHDT
Pipeline	Hauling	0.00	20.0	HHDT
Pipeline	Onsite truck	—	—	HHDT

5.4. Vehicles

5.4.1. Construction Vehicle Control Strategies

Non-applicable. No control strategies activated by user.

5.5. Architectural Coatings

Phase Name	Residential Interior Area Coated (sq ft)	Residential Exterior Area Coated (sq ft)	Non-Residential Interior Area Coated (sq ft)	Non-Residential Exterior Area Coated (sq ft)	Parking Area Coated (sq ft)

5.6. Dust Mitigation

5.6.1. Construction Earthmoving Activities

Phase Name	Material Imported (cy)	Material Exported (cy)	Acres Graded (acres)	Material Demolished (sq. ft.)	Acres Paved (acres)

5.6.2. Construction Earthmoving Control Strategies

Non-applicable. No control strategies activated by user.

5.7. Construction Paving

Land Use	Area Paved (acres)	% Asphalt
User Defined Industrial	0.00	0%

5.8. Construction Electricity Consumption and Emissions Factors

kWh per Year and Emission Factor (lb/MWh)

Year	kWh per Year	CO2	CH4	N2O
2025	0.00	204	0.03	< 0.005

5.18. Vegetation

5.18.1. Land Use Change

5.18.1.1. Unmitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.2. Sequestration

5.18.2.1. Unmitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

5.18.2.2. Mitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

8. User Changes to Default Data

Screen	Justification
Land Use	Project acreage is 2,636 but disturbed land would be 40 acres per Applicant.
Construction: Construction Phases	Work Days per Phase provided by Applicant.
Construction: Off-Road Equipment	Construction equipment provided by Applicant.
Construction: Trips and VMT	Construction equipment provided by Applicant.

CCS - CVR Gas Pipeline Custom Report

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5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

5.18.1.2. Mitigated

5.18.2. Sequestration

5.18.2.1. Unmitigated

5.18.2.2. Mitigated

8. User Changes to Default Data

1. Basic Project Information

1.1. Basic Project Information

Data Field	Value
Project Name	CCS - CVR Gas Pipeline
Construction Start Date	1/1/2025
Lead Agency	—
Land Use Scale	Project/site
Analysis Level for Defaults	County
Windspeed (m/s)	2.70
Precipitation (days)	16.2
Location	35.453174, -119.708967
County	Kern-San Joaquin
City	Unincorporated
Air District	San Joaquin Valley APCD
Air Basin	San Joaquin Valley
TAZ	2947
EDFZ	5
Electric Utility	Pacific Gas & Electric Company
Gas Utility	Southern California Gas
App Version	2022.1.1.14

1.2. Land Use Types

Land Use Subtype	Size	Unit	Lot Acreage	Building Area (sq ft)	Landscape Area (sq ft)	Special Landscape Area (sq ft)	Population	Description
User Defined Industrial	1.00	User Defined Unit	40.0	0.00	0.00	—	—	—

1.3. User-Selected Emission Reduction Measures by Emissions Sector

Sector	#	Measure Title
Construction	C-10-A	Water Exposed Surfaces
Construction	C-11	Limit Vehicle Speeds on Unpaved Roads

2. Emissions Summary

2.1. Construction Emissions Compared Against Thresholds

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Un/Mit.	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	4.43	3.71	29.7	29.1	0.05	1.61	0.64	2.25	1.48	0.15	1.63	—	6,031	6,031	0.22	0.07	0.07	6,056
Mit.	4.43	3.71	29.7	29.1	0.05	1.61	0.64	2.25	1.48	0.15	1.63	—	6,031	6,031	0.22	0.07	0.07	6,056
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	0.73	0.61	4.88	4.83	0.01	0.27	0.10	0.37	0.24	0.02	0.27	—	995	995	0.04	0.01	0.18	1,000
Mit.	0.73	0.61	4.88	4.83	0.01	0.27	0.10	0.37	0.24	0.02	0.27	—	995	995	0.04	0.01	0.18	1,000
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Annual (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	0.13	0.11	0.89	0.88	< 0.005	0.05	0.02	0.07	0.04	< 0.005	0.05	—	165	165	0.01	< 0.005	0.03	165
Mit.	0.13	0.11	0.89	0.88	< 0.005	0.05	0.02	0.07	0.04	< 0.005	0.05	—	165	165	0.01	< 0.005	0.03	165

% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

2.2. Construction Emissions by Year, Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	4.43	3.71	29.7	29.1	0.05	1.61	0.64	2.25	1.48	0.15	1.63	—	6,031	6,031	0.22	0.07	0.07	6,056
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.73	0.61	4.88	4.83	0.01	0.27	0.10	0.37	0.24	0.02	0.27	—	995	995	0.04	0.01	0.18	1,000
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.13	0.11	0.89	0.88	< 0.005	0.05	0.02	0.07	0.04	< 0.005	0.05	—	165	165	0.01	< 0.005	0.03	165

2.3. Construction Emissions by Year, Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	4.43	3.71	29.7	29.1	0.05	1.61	0.64	2.25	1.48	0.15	1.63	—	6,031	6,031	0.22	0.07	0.07	6,056
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

2025	0.73	0.61	4.88	4.83	0.01	0.27	0.10	0.37	0.24	0.02	0.27	—	995	995	0.04	0.01	0.18	1,000
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.13	0.11	0.89	0.88	< 0.005	0.05	0.02	0.07	0.04	< 0.005	0.05	—	165	165	0.01	< 0.005	0.03	165

3. Construction Emissions Details

3.1. Building Construction (2025) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	4.30	3.61	29.5	26.8	0.05	1.61	—	1.61	1.48	—	1.48	—	5,421	5,421	0.22	0.04	—	5,440
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.71	0.59	4.84	4.40	0.01	0.27	—	0.27	0.24	—	0.24	—	891	891	0.04	0.01	—	894
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.13	0.11	0.88	0.80	< 0.005	0.05	—	0.05	0.04	—	0.04	—	148	148	0.01	< 0.005	—	148
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.13	0.11	0.24	2.31	0.00	0.00	0.64	0.64	0.00	0.15	0.15	—	609	609	< 0.005	0.02	0.07	616
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.02	0.02	0.04	0.43	0.00	0.00	0.10	0.10	0.00	0.02	0.02	—	104	104	< 0.005	< 0.005	0.18	105
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	< 0.005	< 0.005	0.01	0.08	0.00	0.00	0.02	0.02	0.00	< 0.005	< 0.005	—	17.2	17.2	< 0.005	< 0.005	0.03	17.4
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.2. Building Construction (2025) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Off-Road Equipment	4.30	3.61	29.5	26.8	0.05	1.61	—	1.61	1.48	—	1.48	—	5,421	5,421	0.22	0.04	—	5,440
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.71	0.59	4.84	4.40	0.01	0.27	—	0.27	0.24	—	0.24	—	891	891	0.04	0.01	—	894
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.13	0.11	0.88	0.80	< 0.005	0.05	—	0.05	0.04	—	0.04	—	148	148	0.01	< 0.005	—	148
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.13	0.11	0.24	2.31	0.00	0.00	0.64	0.64	0.00	0.15	0.15	—	609	609	< 0.005	0.02	0.07	616
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.02	0.02	0.04	0.43	0.00	0.00	0.10	0.10	0.00	0.02	0.02	—	104	104	< 0.005	< 0.005	0.18	105
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	< 0.005	< 0.005	0.01	0.08	0.00	0.00	0.02	0.02	0.00	< 0.005	< 0.005	—	17.2	17.2	< 0.005	< 0.005	0.03	17.4

Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

5. Activity Data

5.1. Construction Schedule

Phase Name	Phase Type	Start Date	End Date	Days Per Week	Work Days per Phase	Phase Description
Pipeline	Building Construction	1/1/2025	3/25/2025	5.00	60.0	—

5.2. Off-Road Equipment

5.2.1. Unmitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Pipeline	Welders	Diesel	Average	3.00	8.00	48.0	0.45
Pipeline	Tractors/Loaders/Backhoes	Diesel	Average	2.00	8.00	67.0	0.37
Pipeline	Excavators	Diesel	Average	2.00	8.00	172	0.38
Pipeline	Other Construction Equipment	Diesel	Average	2.00	8.00	226	0.42
Pipeline	Rubber Tired Loaders	Diesel	Average	1.00	8.00	232	0.36
Pipeline	Rollers	Diesel	Average	1.00	8.00	33.0	0.38
Pipeline	Rubber Tired Loaders	Diesel	Average	1.00	8.00	125	0.36

5.2.2. Mitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Pipeline	Welders	Diesel	Average	3.00	8.00	48.0	0.45

Pipeline	Tractors/Loaders/Backhoes	Diesel	Average	2.00	8.00	67.0	0.37
Pipeline	Excavators	Diesel	Average	2.00	8.00	172	0.38
Pipeline	Other Construction Equipment	Diesel	Average	2.00	8.00	226	0.42
Pipeline	Rubber Tired Loaders	Diesel	Average	1.00	8.00	232	0.36
Pipeline	Rollers	Diesel	Average	1.00	8.00	33.0	0.38
Pipeline	Rubber Tired Loaders	Diesel	Average	1.00	8.00	125	0.36

5.3. Construction Vehicles

5.3.1. Unmitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Pipeline	—	—	—	—
Pipeline	Worker	20.0	45.0	LDA,LDT1,LDT2
Pipeline	Vendor	0.00	10.6	HHDT,MHDT
Pipeline	Hauling	0.00	20.0	HHDT
Pipeline	Onsite truck	—	—	HHDT

5.3.2. Mitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Pipeline	—	—	—	—
Pipeline	Worker	20.0	45.0	LDA,LDT1,LDT2
Pipeline	Vendor	0.00	10.6	HHDT,MHDT
Pipeline	Hauling	0.00	20.0	HHDT
Pipeline	Onsite truck	—	—	HHDT

5.4. Vehicles

5.4.1. Construction Vehicle Control Strategies

Non-applicable. No control strategies activated by user.

5.5. Architectural Coatings

Phase Name	Residential Interior Area Coated (sq ft)	Residential Exterior Area Coated (sq ft)	Non-Residential Interior Area Coated (sq ft)	Non-Residential Exterior Area Coated (sq ft)	Parking Area Coated (sq ft)

5.6. Dust Mitigation

5.6.1. Construction Earthmoving Activities

Phase Name	Material Imported (cy)	Material Exported (cy)	Acres Graded (acres)	Material Demolished (sq. ft.)	Acres Paved (acres)

5.6.2. Construction Earthmoving Control Strategies

Non-applicable. No control strategies activated by user.

5.7. Construction Paving

Land Use	Area Paved (acres)	% Asphalt
User Defined Industrial	0.00	0%

5.8. Construction Electricity Consumption and Emissions Factors

kWh per Year and Emission Factor (lb/MWh)

Year	kWh per Year	CO2	CH4	N2O
2025	0.00	204	0.03	< 0.005

5.18. Vegetation

5.18.1. Land Use Change

5.18.1.1. Unmitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.2. Sequestration

5.18.2.1. Unmitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

5.18.2.2. Mitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

8. User Changes to Default Data

Screen	Justification
Land Use	Project acreage is 2,636 but disturbed land would be 40 acres per Applicant.
Construction: Construction Phases	Work Days per Phase provided by Applicant.
Construction: Off-Road Equipment	Construction equipment provided by Applicant.
Construction: Trips and VMT	Construction equipment provided by Applicant.

CCS - Steam Pipeline Custom Report

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5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

5.18.1.2. Mitigated

5.18.2. Sequestration

5.18.2.1. Unmitigated

5.18.2.2. Mitigated

8. User Changes to Default Data

1. Basic Project Information

1.1. Basic Project Information

Data Field	Value
Project Name	CCS - Steam Pipeline
Construction Start Date	7/17/2025
Lead Agency	—
Land Use Scale	Project/site
Analysis Level for Defaults	County
Windspeed (m/s)	2.70
Precipitation (days)	16.2
Location	35.453174, -119.708967
County	Kern-San Joaquin
City	Unincorporated
Air District	San Joaquin Valley APCD
Air Basin	San Joaquin Valley
TAZ	2947
EDFZ	5
Electric Utility	Pacific Gas & Electric Company
Gas Utility	Southern California Gas
App Version	2022.1.1.14

1.2. Land Use Types

Land Use Subtype	Size	Unit	Lot Acreage	Building Area (sq ft)	Landscape Area (sq ft)	Special Landscape Area (sq ft)	Population	Description
User Defined Industrial	1.00	User Defined Unit	40.0	0.00	0.00	—	—	—

1.3. User-Selected Emission Reduction Measures by Emissions Sector

Sector	#	Measure Title
Construction	C-10-A	Water Exposed Surfaces
Construction	C-11	Limit Vehicle Speeds on Unpaved Roads

2. Emissions Summary

2.1. Construction Emissions Compared Against Thresholds

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Un/Mit.	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	4.44	3.73	29.7	30.4	0.05	1.61	0.64	2.25	1.48	0.15	1.63	—	6,117	6,117	0.24	0.07	2.52	6,145
Mit.	4.44	3.73	29.7	30.4	0.05	1.61	0.64	2.25	1.48	0.15	1.63	—	6,117	6,117	0.24	0.07	2.52	6,145
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	4.43	3.71	29.7	29.1	0.05	1.61	0.64	2.25	1.48	0.15	1.63	—	6,031	6,031	0.22	0.07	0.07	6,056
Mit.	4.43	3.71	29.7	29.1	0.05	1.61	0.64	2.25	1.48	0.15	1.63	—	6,031	6,031	0.22	0.07	0.07	6,056
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	1.07	0.90	7.16	7.08	0.01	0.39	0.15	0.54	0.36	0.04	0.39	—	1,460	1,460	0.05	0.02	0.26	1,466
Mit.	1.07	0.90	7.16	7.08	0.01	0.39	0.15	0.54	0.36	0.04	0.39	—	1,460	1,460	0.05	0.02	0.26	1,466

% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Annual (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	0.20	0.16	1.31	1.29	< 0.005	0.07	0.03	0.10	0.07	0.01	0.07	—	242	242	0.01	< 0.005	0.04	243
Mit.	0.20	0.16	1.31	1.29	< 0.005	0.07	0.03	0.10	0.07	0.01	0.07	—	242	242	0.01	< 0.005	0.04	243
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

2.2. Construction Emissions by Year, Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	4.44	3.73	29.7	30.4	0.05	1.61	0.64	2.25	1.48	0.15	1.63	—	6,117	6,117	0.24	0.07	2.52	6,145
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	4.43	3.71	29.7	29.1	0.05	1.61	0.64	2.25	1.48	0.15	1.63	—	6,031	6,031	0.22	0.07	0.07	6,056
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	1.07	0.90	7.16	7.08	0.01	0.39	0.15	0.54	0.36	0.04	0.39	—	1,460	1,460	0.05	0.02	0.26	1,466
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.20	0.16	1.31	1.29	< 0.005	0.07	0.03	0.10	0.07	0.01	0.07	—	242	242	0.01	< 0.005	0.04	243

2.3. Construction Emissions by Year, Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e

Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	4.44	3.73	29.7	30.4	0.05	1.61	0.64	2.25	1.48	0.15	1.63	—	6,117	6,117	0.24	0.07	2.52	6,145
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	4.43	3.71	29.7	29.1	0.05	1.61	0.64	2.25	1.48	0.15	1.63	—	6,031	6,031	0.22	0.07	0.07	6,056
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	1.07	0.90	7.16	7.08	0.01	0.39	0.15	0.54	0.36	0.04	0.39	—	1,460	1,460	0.05	0.02	0.26	1,466
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.20	0.16	1.31	1.29	< 0.005	0.07	0.03	0.10	0.07	0.01	0.07	—	242	242	0.01	< 0.005	0.04	243

3. Construction Emissions Details

3.1. Building Construction (2025) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	4.30	3.61	29.5	26.8	0.05	1.61	—	1.61	1.48	—	1.48	—	5,421	5,421	0.22	0.04	—	5,440
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	4.30	3.61	29.5	26.8	0.05	1.61	—	1.61	1.48	—	1.48	—	5,421	5,421	0.22	0.04	—	5,440

Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	1.04	0.87	7.10	6.45	0.01	0.39	—	0.39	0.36	—	0.36	—	1,307	1,307	0.05	0.01	—	1,311
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.19	0.16	1.30	1.18	< 0.005	0.07	—	0.07	0.07	—	0.07	—	216	216	0.01	< 0.005	—	217
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.14	0.12	0.19	3.66	0.00	0.00	0.64	0.64	0.00	0.15	0.15	—	696	696	0.02	0.02	2.52	705
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.13	0.11	0.24	2.31	0.00	0.00	0.64	0.64	0.00	0.15	0.15	—	609	609	< 0.005	0.02	0.07	616
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.03	0.03	0.05	0.63	0.00	0.00	0.15	0.15	0.00	0.04	0.04	—	153	153	< 0.005	0.01	0.26	155
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Worker	0.01	< 0.005	0.01	0.12	0.00	0.00	0.03	0.03	0.00	0.01	0.01	—	25.3	25.3	< 0.005	< 0.005	0.04	25.6
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.2. Building Construction (2025) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	4.30	3.61	29.5	26.8	0.05	1.61	—	1.61	1.48	—	1.48	—	5,421	5,421	0.22	0.04	—	5,440
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	4.30	3.61	29.5	26.8	0.05	1.61	—	1.61	1.48	—	1.48	—	5,421	5,421	0.22	0.04	—	5,440
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	1.04	0.87	7.10	6.45	0.01	0.39	—	0.39	0.36	—	0.36	—	1,307	1,307	0.05	0.01	—	1,311
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.19	0.16	1.30	1.18	< 0.005	0.07	—	0.07	0.07	—	0.07	—	216	216	0.01	< 0.005	—	217

Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.14	0.12	0.19	3.66	0.00	0.00	0.64	0.64	0.00	0.15	0.15	—	696	696	0.02	0.02	2.52	705
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.13	0.11	0.24	2.31	0.00	0.00	0.64	0.64	0.00	0.15	0.15	—	609	609	< 0.005	0.02	0.07	616
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.03	0.03	0.05	0.63	0.00	0.00	0.15	0.15	0.00	0.04	0.04	—	153	153	< 0.005	0.01	0.26	155
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.01	< 0.005	0.01	0.12	0.00	0.00	0.03	0.03	0.00	0.01	0.01	—	25.3	25.3	< 0.005	< 0.005	0.04	25.6
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

5. Activity Data

5.1. Construction Schedule

Phase Name	Phase Type	Start Date	End Date	Days Per Week	Work Days per Phase	Phase Description

Pipeline	Building Construction	7/17/2025	11/17/2025	5.00	88.0	—

5.2. Off-Road Equipment

5.2.1. Unmitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Pipeline	Welders	Diesel	Average	3.00	8.00	48.0	0.45
Pipeline	Tractors/Loaders/Backhoes	Diesel	Average	2.00	8.00	67.0	0.37
Pipeline	Excavators	Diesel	Average	2.00	8.00	172	0.38
Pipeline	Other Construction Equipment	Diesel	Average	2.00	8.00	226	0.42
Pipeline	Rubber Tired Loaders	Diesel	Average	1.00	8.00	232	0.36
Pipeline	Rubber Tired Loaders	Diesel	Average	1.00	8.00	125	0.36
Pipeline	Rollers	Diesel	Average	1.00	8.00	33.0	0.38

5.2.2. Mitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Pipeline	Welders	Diesel	Average	3.00	8.00	48.0	0.45
Pipeline	Tractors/Loaders/Backhoes	Diesel	Average	2.00	8.00	67.0	0.37
Pipeline	Excavators	Diesel	Average	2.00	8.00	172	0.38
Pipeline	Other Construction Equipment	Diesel	Average	2.00	8.00	226	0.42
Pipeline	Rubber Tired Loaders	Diesel	Average	1.00	8.00	232	0.36
Pipeline	Rubber Tired Loaders	Diesel	Average	1.00	8.00	125	0.36
Pipeline	Rollers	Diesel	Average	1.00	8.00	33.0	0.38

5.3. Construction Vehicles

5.3.1. Unmitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Pipeline	—	—	—	—
Pipeline	Worker	20.0	45.0	LDA,LDT1,LDT2
Pipeline	Vendor	0.00	10.6	HHDT,MHDT
Pipeline	Hauling	0.00	20.0	HHDT
Pipeline	Onsite truck	—	—	HHDT

5.3.2. Mitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Pipeline	—	—	—	—
Pipeline	Worker	20.0	45.0	LDA,LDT1,LDT2
Pipeline	Vendor	0.00	10.6	HHDT,MHDT
Pipeline	Hauling	0.00	20.0	HHDT
Pipeline	Onsite truck	—	—	HHDT

5.4. Vehicles

5.4.1. Construction Vehicle Control Strategies

Non-applicable. No control strategies activated by user.

5.5. Architectural Coatings

Phase Name	Residential Interior Area Coated (sq ft)	Residential Exterior Area Coated (sq ft)	Non-Residential Interior Area Coated (sq ft)	Non-Residential Exterior Area Coated (sq ft)	Parking Area Coated (sq ft)

5.6. Dust Mitigation

5.6.1. Construction Earthmoving Activities

Phase Name	Material Imported (cy)	Material Exported (cy)	Acres Graded (acres)	Material Demolished (sq. ft.)	Acres Paved (acres)

5.6.2. Construction Earthmoving Control Strategies

Non-applicable. No control strategies activated by user.

5.7. Construction Paving

Land Use	Area Paved (acres)	% Asphalt
User Defined Industrial	0.00	0%

5.8. Construction Electricity Consumption and Emissions Factors

kWh per Year and Emission Factor (lb/MWh)

Year	kWh per Year	CO2	CH4	N2O
2025	0.00	204	0.03	< 0.005

5.18. Vegetation

5.18.1. Land Use Change

5.18.1.1. Unmitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.2. Sequestration

5.18.2.1. Unmitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

5.18.2.2. Mitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

8. User Changes to Default Data

Screen	Justification
Land Use	Project acreage is 2,636 but disturbed land would be 40 acres per Applicant.
Construction: Construction Phases	Work Days per Phase provided by Applicant.
Construction: Off-Road Equipment	Construction equipment provided by Applicant.
Construction: Trips and VMT	Construction equipment provided by Applicant.

CCS - Demolition Custom Report

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5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

5.18.1.2. Mitigated

5.18.2. Sequestration

5.18.2.1. Unmitigated

5.18.2.2. Mitigated

8. User Changes to Default Data

1. Basic Project Information

1.1. Basic Project Information

Data Field	Value
Project Name	CCS - Demolition
Construction Start Date	1/30/2025
Lead Agency	—
Land Use Scale	Project/site
Analysis Level for Defaults	County
Windspeed (m/s)	2.70
Precipitation (days)	16.2
Location	35.453174, -119.708967
County	Kern-San Joaquin
City	Unincorporated
Air District	San Joaquin Valley APCD
Air Basin	San Joaquin Valley
TAZ	2947
EDFZ	5
Electric Utility	Pacific Gas & Electric Company
Gas Utility	Southern California Gas
App Version	2022.1.1.14

1.2. Land Use Types

Land Use Subtype	Size	Unit	Lot Acreage	Building Area (sq ft)	Landscape Area (sq ft)	Special Landscape Area (sq ft)	Population	Description
User Defined Industrial	1.00	User Defined Unit	40.0	0.00	0.00	—	—	—

1.3. User-Selected Emission Reduction Measures by Emissions Sector

Sector	#	Measure Title
Construction	C-10-A	Water Exposed Surfaces
Construction	C-11	Limit Vehicle Speeds on Unpaved Roads

2. Emissions Summary

2.1. Construction Emissions Compared Against Thresholds

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Un/Mit.	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	3.80	3.20	26.3	27.1	0.08	1.00	0.28	1.28	0.92	0.06	0.99	—	8,963	8,963	0.36	0.08	0.03	8,996
Mit.	3.80	3.20	26.3	27.1	0.08	1.00	0.28	1.28	0.92	0.06	0.99	—	8,963	8,963	0.36	0.08	0.03	8,996
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Average Daily (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	0.42	0.35	2.88	2.98	0.01	0.11	0.03	0.14	0.10	0.01	0.11	—	983	983	0.04	0.01	0.05	987
Mit.	0.42	0.35	2.88	2.98	0.01	0.11	0.03	0.14	0.10	0.01	0.11	—	983	983	0.04	0.01	0.05	987
% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Annual (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Unmit.	0.08	0.06	0.52	0.54	< 0.005	0.02	0.01	0.03	0.02	< 0.005	0.02	—	163	163	0.01	< 0.005	0.01	163
Mit.	0.08	0.06	0.52	0.54	< 0.005	0.02	0.01	0.03	0.02	< 0.005	0.02	—	163	163	0.01	< 0.005	0.01	163

% Reduced	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

2.2. Construction Emissions by Year, Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	3.80	3.20	26.3	27.1	0.08	1.00	0.28	1.28	0.92	0.06	0.99	—	8,963	8,963	0.36	0.08	0.03	8,996
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.42	0.35	2.88	2.98	0.01	0.11	0.03	0.14	0.10	0.01	0.11	—	983	983	0.04	0.01	0.05	987
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.08	0.06	0.52	0.54	< 0.005	0.02	0.01	0.03	0.02	< 0.005	0.02	—	163	163	0.01	< 0.005	0.01	163

2.3. Construction Emissions by Year, Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Year	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Daily - Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily - Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	3.80	3.20	26.3	27.1	0.08	1.00	0.28	1.28	0.92	0.06	0.99	—	8,963	8,963	0.36	0.08	0.03	8,996
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

2025	0.42	0.35	2.88	2.98	0.01	0.11	0.03	0.14	0.10	0.01	0.11	—	983	983	0.04	0.01	0.05	987
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
2025	0.08	0.06	0.52	0.54	< 0.005	0.02	0.01	0.03	0.02	< 0.005	0.02	—	163	163	0.01	< 0.005	0.01	163

3. Construction Emissions Details

3.1. Demolition (2025) - Unmitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	3.70	3.11	26.1	25.9	0.08	1.00	—	1.00	0.92	—	0.92	—	8,697	8,697	0.35	0.07	—	8,727
Demolition	—	—	—	—	—	—	0.00	0.00	—	0.00	0.00	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.41	0.34	2.86	2.84	0.01	0.11	—	0.11	0.10	—	0.10	—	953	953	0.04	0.01	—	956
Demolition	—	—	—	—	—	—	0.00	0.00	—	0.00	0.00	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Off-Road Equipment	0.07	0.06	0.52	0.52	< 0.005	0.02	—	0.02	0.02	—	0.02	—	158	158	0.01	< 0.005	—	158
Demolition	—	—	—	—	—	—	0.00	0.00	—	0.00	0.00	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.10	0.09	0.11	1.16	0.00	0.00	0.28	0.28	0.00	0.06	0.06	—	266	266	0.01	0.01	0.03	269
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.01	0.01	0.01	0.14	0.00	0.00	0.03	0.03	0.00	0.01	0.01	—	30.3	30.3	< 0.005	< 0.005	0.05	30.7
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	< 0.005	< 0.005	< 0.005	0.03	0.00	0.00	0.01	0.01	0.00	< 0.005	< 0.005	—	5.02	5.02	< 0.005	< 0.005	0.01	5.08
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

3.2. Demolition (2025) - Mitigated

Criteria Pollutants (lb/day for daily, ton/yr for annual) and GHGs (lb/day for daily, MT/yr for annual)

Location	TOG	ROG	NOx	CO	SO2	PM10E	PM10D	PM10T	PM2.5E	PM2.5D	PM2.5T	BCO2	NBCO2	CO2T	CH4	N2O	R	CO2e
Onsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	3.70	3.11	26.1	25.9	0.08	1.00	—	1.00	0.92	—	0.92	—	8,697	8,697	0.35	0.07	—	8,727
Demolition	—	—	—	—	—	—	0.00	0.00	—	0.00	0.00	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.41	0.34	2.86	2.84	0.01	0.11	—	0.11	0.10	—	0.10	—	953	953	0.04	0.01	—	956
Demolition	—	—	—	—	—	—	0.00	0.00	—	0.00	0.00	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Off-Road Equipment	0.07	0.06	0.52	0.52	< 0.005	0.02	—	0.02	0.02	—	0.02	—	158	158	0.01	< 0.005	—	158
Demolition	—	—	—	—	—	—	0.00	0.00	—	0.00	0.00	—	—	—	—	—	—	—
Onsite truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Offsite	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Summer (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Daily, Winter (Max)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

Worker	0.10	0.09	0.11	1.16	0.00	0.00	0.28	0.28	0.00	0.06	0.06	—	266	266	0.01	0.01	0.03	269
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Average Daily	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	0.01	0.01	0.01	0.14	0.00	0.00	0.03	0.03	0.00	0.01	0.01	—	30.3	30.3	< 0.005	< 0.005	0.05	30.7
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Annual	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Worker	< 0.005	< 0.005	< 0.005	0.03	0.00	0.00	0.01	0.01	0.00	< 0.005	< 0.005	—	5.02	5.02	< 0.005	< 0.005	0.01	5.08
Vendor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00
Hauling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	—	0.00	0.00	0.00	0.00	0.00	0.00

5. Activity Data

5.1. Construction Schedule

Phase Name	Phase Type	Start Date	End Date	Days Per Week	Work Days per Phase	Phase Description
Demolition	Demolition	1/30/2025	3/26/2025	5.00	40.0	—

5.2. Off-Road Equipment

5.2.1. Unmitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Demolition	Excavators	Diesel	Average	2.00	8.00	172	0.38
Demolition	Graders	Diesel	Average	1.00	8.00	259	0.41
Demolition	Off-Highway Trucks	Diesel	Average	1.00	8.00	407	0.38
Demolition	Rubber Tired Loaders	Diesel	Average	1.00	8.00	232	0.36

Demolition	Crawler Tractors	Diesel	Average	1.00	8.00	585	0.43
Demolition	Other Construction Equipment	Diesel	Average	1.00	8.00	425	0.42
Demolition	Generator Sets	Diesel	Average	2.00	8.00	18.0	0.74

5.2.2. Mitigated

Phase Name	Equipment Type	Fuel Type	Engine Tier	Number per Day	Hours Per Day	Horsepower	Load Factor
Demolition	Excavators	Diesel	Average	2.00	8.00	172	0.38
Demolition	Graders	Diesel	Average	1.00	8.00	259	0.41
Demolition	Off-Highway Trucks	Diesel	Average	1.00	8.00	407	0.38
Demolition	Rubber Tired Loaders	Diesel	Average	1.00	8.00	232	0.36
Demolition	Crawler Tractors	Diesel	Average	1.00	8.00	585	0.43
Demolition	Other Construction Equipment	Diesel	Average	1.00	8.00	425	0.42
Demolition	Generator Sets	Diesel	Average	2.00	8.00	18.0	0.74

5.3. Construction Vehicles

5.3.1. Unmitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Demolition	—	—	—	—
Demolition	Worker	22.5	17.3	LDA,LDT1,LDT2
Demolition	Vendor	—	10.6	HHDT,MHDT
Demolition	Hauling	0.00	20.0	HHDT
Demolition	Onsite truck	—	—	HHDT

5.3.2. Mitigated

Phase Name	Trip Type	One-Way Trips per Day	Miles per Trip	Vehicle Mix
Demolition	—	—	—	—
Demolition	Worker	22.5	17.3	LDA,LDT1,LDT2
Demolition	Vendor	—	10.6	HHDT,MHDT
Demolition	Hauling	0.00	20.0	HHDT
Demolition	Onsite truck	—	—	HHDT

5.4. Vehicles

5.4.1. Construction Vehicle Control Strategies

Non-applicable. No control strategies activated by user.

5.5. Architectural Coatings

Phase Name	Residential Interior Area Coated (sq ft)	Residential Exterior Area Coated (sq ft)	Non-Residential Interior Area Coated (sq ft)	Non-Residential Exterior Area Coated (sq ft)	Parking Area Coated (sq ft)

5.6. Dust Mitigation

5.6.1. Construction Earthmoving Activities

Phase Name	Material Imported (cy)	Material Exported (cy)	Acres Graded (acres)	Material Demolished (sq. ft.)	Acres Paved (acres)
Demolition	0.00	0.00	0.00	—	—

5.6.2. Construction Earthmoving Control Strategies

Non-applicable. No control strategies activated by user.

5.7. Construction Paving

Land Use	Area Paved (acres)	% Asphalt
User Defined Industrial	0.00	0%

5.8. Construction Electricity Consumption and Emissions Factors

kWh per Year and Emission Factor (lb/MWh)

Year	kWh per Year	CO2	CH4	N2O
2025	0.00	204	0.03	< 0.005

5.18. Vegetation

5.18.1. Land Use Change

5.18.1.1. Unmitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Vegetation Land Use Type	Vegetation Soil Type	Initial Acres	Final Acres

5.18.1. Biomass Cover Type

5.18.1.1. Unmitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.1.2. Mitigated

Biomass Cover Type	Initial Acres	Final Acres

5.18.2. Sequestration

5.18.2.1. Unmitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

5.18.2.2. Mitigated

Tree Type	Number	Electricity Saved (kWh/year)	Natural Gas Saved (btu/year)

8. User Changes to Default Data

Screen	Justification
Land Use	Project acreage is 2,636 but disturbed land would be 40 acres per Applicant.
Construction: Construction Phases	Work Days per Phase provided by Applicant.
Construction: Off-Road Equipment	Construction equipment provided by Applicant.

APPENDIX C. CARB 2020 AND 2025 ESTIMATED EMISSION INVENTORIES

2016 SIP Emission Projection Data

2020 Estimated Annual Average Emissions

KERN COUNTY

All emissions are represented in Tons per Day and reflect the most current data provided to ARB.

See detailed information.

Start a new query.

KERN COUNTY COUNTY - MOJAVE DESERT AIR BASIN

STATIONARY SOURCES	TOG	ROG	CO	NOX	SOX	PM	PM10	PM2.5	NH3
FUEL COMBUSTION	0.5	0.1	0.8	2.4	0.2	0.4	0.4	0.4	0.0
WASTE DISPOSAL	8.4	0.1	0.0	-	0.0	0.0	0.0	0.0	0.1
CLEANING AND SURFACE COATINGS	0.9	0.8	-	-	-	0.0	0.0	0.0	-
PETROLEUM PRODUCTION AND MARKETING	0.1	0.1	-	-	-	-	-	-	-
INDUSTRIAL PROCESSES	0.1	0.1	10.2	18.4	8.1	3.7	2.9	1.7	0.1
*** TOTAL STATIONARY SOURCES**	**10.2**	**1.3**	**11.0**	**20.8**	**8.3**	**4.1**	**3.3**	**2.1**	**0.1**
AREAWIDE SOURCES	**TOG**	**ROG**	**CO**	**NOX**	**SOX**	**PM**	**PM10**	**PM2.5**	**NH3**
SOLVENT EVAPORATION	1.6	1.4	-	-	-	-	-	-	1.3
MISCELLANEOUS PROCESSES	3.5	1.2	11.0	0.6	0.0	18.6	9.7	2.6	0.7
*** TOTAL AREAWIDE SOURCES**	**5.0**	**2.6**	**11.0**	**0.6**	**0.0**	**18.6**	**9.7**	**2.6**	**2.0**
MOBILE SOURCES	**TOG**	**ROG**	**CO**	**NOX**	**SOX**	**PM**	**PM10**	**PM2.5**	**NH3**
ON-ROAD MOTOR VEHICLES	1.1	1.1	7.2	4.1	0.0	0.3	0.3	0.1	0.1
OTHER MOBILE SOURCES	5.0	4.9	23.8	5.5	0.3	3.0	2.9	2.9	0.0
*** TOTAL MOBILE SOURCES**	**6.2**	**5.9**	**31.0**	**9.6**	**0.3**	**3.3**	**3.2**	**3.0**	**0.1**
TOTAL KERN COUNTY IN MOJAVE DESERT	**21.4**	**9.8**	**53.0**	**31.0**	**8.6**	**26.0**	**16.2**	**7.7**	**2.3**

KERN COUNTY COUNTY - SAN JOAQUIN VALLEY AIR BASIN

STATIONARY SOURCES	TOG	ROG	CO	NOX	SOX	PM	PM10	PM2.5	NH3
FUEL COMBUSTION	12.6	1.8	9.9	7.6	0.7	2.7	2.6	2.5	1.6
WASTE DISPOSAL	224.6	12.2	0.2	0.1	0.0	0.1	0.0	0.0	5.4
CLEANING AND SURFACE COATINGS	3.0	2.7	-	-	-	0.0	0.0	0.0	
PETROLEUM PRODUCTION AND MARKETING	46.2	11.8	0.9	0.3	0.4	0.2	0.1	0.1	0.0
INDUSTRIAL PROCESSES	2.4	2.3	0.1	0.1	0.1	3.7	1.6	0.6	0.2

* TOTAL STATIONARY SOURCES	288.8	30.7	11.1	8.0	1.1	6.7	4.4	3.3	7.2
AREAWIDE SOURCES	**TOG**	**ROG**	**CO**	**NOX**	**SOX**	**PM**	**PM10**	**PM2.5**	**NH3**
SOLVENT EVAPORATION	10.9	10.0	-	-	-	-	-	-	26.5
MISCELLANEOUS PROCESSES	63.6	9.9	5.2	1.2	0.0	61.8	30.9	5.7	17.1
* TOTAL AREAWIDE SOURCES	74.5	19.9	5.2	1.2	0.0	61.8	30.9	5.7	43.6
MOBILE SOURCES	**TOG**	**ROG**	**CO**	**NOX**	**SOX**	**PM**	**PM10**	**PM2.5**	**NH3**
ON-ROAD MOTOR VEHICLES	5.4	4.9	31.4	23.5	0.1	1.7	1.6	0.7	0.8
OTHER MOBILE SOURCES	4.0	3.5	27.2	10.8	0.0	0.6	0.5	0.5	0.0
* TOTAL MOBILE SOURCES	9.4	8.4	58.6	34.2	0.2	2.2	2.2	1.2	0.8
TOTAL KERN COUNTY IN SAN JOAQUIN VALLEY	372.7	59.0	74.9	43.5	1.4	70.7	37.4	10.2	51.7
GRAND TOTAL FOR KERN COUNTY	394.0	68.8	127.9	74.4	10.0	96.7	53.6	17.9	54.0

Start a new query.

CONTACT US

(800) 242-4450 | helpline@arb.ca.gov
1001 I Street, Sacramento, CA 95814
P.O. Box 2815, Sacramento, CA 95812

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2016 SIP Emission Projection Data

2020 Estimated Annual Average Emissions

SAN JOAQUIN VALLEY AIR BASIN

All emissions are represented in Tons per Day and reflect the most current data provided to ARB.

See detailed information.

Start a new query.

STATIONARY SOURCES	TOG	ROG	CO	NOX	SOX	PM	PM10	PM2.5	NH3
FUEL COMBUSTION	17.9	3.2	24.7	24.1	2.4	4.8	4.7	4.6	2.2
WASTE DISPOSAL	527.3	26.9	0.6	0.3	0.2	0.9	0.3	0.2	11.2
CLEANING AND SURFACE COATINGS	27.8	25.2	-	-	-	0.3	0.3	0.3	0.0
PETROLEUM PRODUCTION AND MARKETING	111.0	16.6	1.0	0.4	0.4	0.2	0.1	0.1	0.0
INDUSTRIAL PROCESSES	20.6	19.5	1.4	3.9	3.6	20.9	9.5	3.6	1.7
*** TOTAL STATIONARY SOURCES**	**704.7**	**91.3**	**27.7**	**28.6**	**6.5**	**27.2**	**14.9**	**8.7**	**15.2**
AREAWIDE SOURCES	**TOG**	**ROG**	**CO**	**NOX**	**SOX**	**PM**	**PM10**	**PM2.5**	**NH3**
SOLVENT EVAPORATION	55.0	49.9	-	-	-	-	-	-	113.1
MISCELLANEOUS PROCESSES	761.8	103.0	53.2	7.9	0.3	473.4	236.8	41.8	193.9
*** TOTAL AREAWIDE SOURCES**	**816.8**	**152.8**	**53.2**	**7.9**	**0.3**	**473.4**	**236.8**	**41.8**	**307.0**
MOBILE SOURCES	**TOG**	**ROG**	**CO**	**NOX**	**SOX**	**PM**	**PM10**	**PM2.5**	**NH3**
ON-ROAD MOTOR VEHICLES	27.3	24.9	167.9	96.9	0.6	7.8	7.6	3.4	3.6
OTHER MOBILE SOURCES	30.6	27.2	196.2	69.8	0.3	5.6	5.5	5.0	0.0
*** TOTAL MOBILE SOURCES**	**57.9**	**52.0**	**364.1**	**166.8**	**1.0**	**13.4**	**13.1**	**8.5**	**3.6**
GRAND TOTAL FOR SAN JOAQUIN VALLEY AIR BASIN	**1579.4**	**296.2**	**445.0**	**203.3**	**7.8**	**514.0**	**264.8**	**59.0**	**325.9**

Start a new query.

Secretary for Environmental Protection
Jared Blumenfeld
Visit his Website

Chair, California Air Resources Board
Liane M. Randolph
Visit her Website

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2016 SIP Emission Projection Data

2025 Estimated Annual Average Emissions

KERN COUNTY

All emissions are represented in Tons per Day and reflect the most current data provided to ARB.

See detailed information.

Start a new query.

KERN COUNTY COUNTY - MOJAVE DESERT AIR BASIN

STATIONARY SOURCES	TOG	ROG	CO	NOX	SOX	PM	PM10	PM2.5	NH3
FUEL COMBUSTION	0.5	0.1	0.8	2.5	0.2	0.4	0.4	0.4	0.0
WASTE DISPOSAL	9.3	0.1	0.0	-	0.0	0.0	0.0	0.0	0.1
CLEANING AND SURFACE COATINGS	1.0	0.9	-	-	-	0.0	0.0	0.0	-
PETROLEUM PRODUCTION AND MARKETING	0.1	0.1	-	-	-	-	-	-	-
INDUSTRIAL PROCESSES	0.1	0.1	11.0	19.7	8.6	3.9	3.2	1.9	0.1
*** TOTAL STATIONARY SOURCES**	**11.1**	**1.4**	**11.8**	**22.2**	**8.8**	**4.4**	**3.5**	**2.2**	**0.1**
AREAWIDE SOURCES	**TOG**	**ROG**	**CO**	**NOX**	**SOX**	**PM**	**PM10**	**PM2.5**	**NH3**
SOLVENT EVAPORATION	1.7	1.5	-	-	-	-	-	-	
MISCELLANEOUS PROCESSES	3.5	1.2	11.1	0.6	0.0	18.5	9.7	2.6	0.7
*** TOTAL AREAWIDE SOURCES**	**5.2**	**2.7**	**11.1**	**0.6**	**0.0**	**18.5**	**9.7**	**2.6**	**2.0**
MOBILE SOURCES	**TOG**	**ROG**	**CO**	**NOX**	**SOX**	**PM**	**PM10**	**PM2.5**	**NH3**
ON-ROAD MOTOR VEHICLES	0.9	0.8	5.0	2.3	0.0	0.3	0.3	0.1	0.1
OTHER MOBILE SOURCES	5.0	4.8	24.2	4.6	0.3	3.0	2.9	2.9	0.0
*** TOTAL MOBILE SOURCES**	**5.8**	**5.6**	**29.2**	**6.9**	**0.3**	**3.3**	**3.2**	**3.0**	**0.1**
TOTAL KERN COUNTY IN MOJAVE DESERT	**22.1**	**9.7**	**52.1**	**29.7**	**9.2**	**26.1**	**16.4**	**7.8**	**2.3**

KERN COUNTY COUNTY - SAN JOAQUIN VALLEY AIR BASIN

STATIONARY SOURCES	TOG	ROG	CO	NOX	SOX	PM	PM10	PM2.5	NH3
FUEL COMBUSTION	12.4	1.7	9.6	7.2	0.6	2.6	2.5	2.4	1.7
WASTE DISPOSAL	247.0	13.4	0.2	0.1	0.0	0.1	0.0	0.0	6.0
CLEANING AND SURFACE COATINGS	3.3	3.0	-	-	-	0.0	0.0	0.0	-
PETROLEUM PRODUCTION AND MARKETING	45.0	10.8	0.8	0.3	0.4	0.2	0.1	0.1	0.0
INDUSTRIAL PROCESSES	2.6	2.4	0.1	0.1	0.1	4.0	1.7	0.6	0.2

* TOTAL STATIONARY SOURCES	310.3	31.3	10.7	7.6	1.1	6.9	4.4	3.2	7.8
AREAWIDE SOURCES	**TOG**	**ROG**	**CO**	**NOX**	**SOX**	**PM**	**PM10**	**PM2.5**	**NH3**
SOLVENT EVAPORATION	11.4	10.3	-	-	-	-	-	-	25.1
MISCELLANEOUS PROCESSES	63.7	9.9	5.2	1.2	0.0	61.8	30.9	5.7	17.2
* TOTAL AREAWIDE SOURCES	75.0	20.3	5.2	1.2	0.0	61.8	30.9	5.7	42.3
MOBILE SOURCES	**TOG**	**ROG**	**CO**	**NOX**	**SOX**	**PM**	**PM10**	**PM2.5**	**NH3**
ON-ROAD MOTOR VEHICLES	4.3	3.9	23.7	12.7	0.1	1.7	1.7	0.7	0.8
OTHER MOBILE SOURCES	3.5	3.1	28.0	8.1	0.0	0.4	0.4	0.4	0.0
* TOTAL MOBILE SOURCES	7.8	7.0	51.6	20.8	0.2	2.1	2.1	1.1	0.8
TOTAL KERN COUNTY IN SAN JOAQUIN VALLEY	393.1	58.5	67.6	29.6	1.3	70.8	37.4	10.1	51.0
GRAND TOTAL FOR KERN COUNTY	415.2	68.2	119.7	59.3	10.5	97.0	53.8	17.8	53.2

Start a new query.

CONTACT US

(800) 242-4450 | helpline@arb.ca.gov
1001 I Street, Sacramento, CA 95814
P.O. Box 2815, Sacramento, CA 95812

California Governor
Gavin Newsom
Visit Governor's Website

Secretary for Environmental Protection
Jared Blumenfeld
Visit his Website

Chair, California Air Resources Board
Liane M. Randolph
Visit her Website

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2016 SIP Emission Projection Data

2025 Estimated Annual Average Emissions

SAN JOAQUIN VALLEY AIR BASIN

All emissions are represented in Tons per Day and reflect the most current data provided to ARB.

See detailed information.

Start a new query.

STATIONARY SOURCES	TOG	ROG	CO	NOX	SOX	PM	PM10	PM2.5	NH3
FUEL COMBUSTION	17.7	3.0	24.6	23.0	2.4	4.7	4.6	4.5	2.3
WASTE DISPOSAL	572.3	29.2	0.6	0.3	0.2	1.0	0.3	0.2	12.2
CLEANING AND SURFACE COATINGS	30.8	27.9	-	-	-	0.4	0.4	0.3	0.0
PETROLEUM PRODUCTION AND MARKETING	109.5	15.1	0.9	0.3	0.4	0.2	0.1	0.1	0.0
INDUSTRIAL PROCESSES	22.4	21.1	1.6	4.2	3.8	22.6	10.3	3.9	1.9
*** TOTAL STATIONARY SOURCES**	**752.7**	**96.4**	**27.7**	**27.7**	**6.8**	**28.9**	**15.7**	**9.0**	**16.4**
AREAWIDE SOURCES	**TOG**	**ROG**	**CO**	**NOX**	**SOX**	**PM**	**PM10**	**PM2.5**	**NH3**
SOLVENT EVAPORATION	57.5	52.0	-	-	-	-	-	-	109.9
MISCELLANEOUS PROCESSES	761.9	103.0	53.2	7.4	0.3	469.2	234.9	41.9	194.5
*** TOTAL AREAWIDE SOURCES**	**819.4**	**155.0**	**53.2**	**7.4**	**0.3**	**469.2**	**234.9**	**41.9**	**304.4**
MOBILE SOURCES	**TOG**	**ROG**	**CO**	**NOX**	**SOX**	**PM**	**PM10**	**PM2.5**	**NH3**
ON-ROAD MOTOR VEHICLES	20.5	18.8	118.9	54.2	0.6	7.9	7.7	3.2	3.4
OTHER MOBILE SOURCES	26.8	23.9	200.1	54.4	0.3	4.7	4.6	4.2	0.0
*** TOTAL MOBILE SOURCES**	**47.3**	**42.7**	**319.0**	**108.6**	**0.9**	**12.6**	**12.3**	**7.5**	**3.5**
GRAND TOTAL FOR SAN JOAQUIN VALLEY AIR BASIN	**1619.4**	**294.1**	**399.9**	**143.7**	**8.0**	**510.7**	**262.8**	**58.3**	**324.3**

Start a new query.

Secretary for Environmental Protection
Jared Blumenfeld
Visit his Website

Chair, California Air Resources Board
Liane M. Randolph
Visit her Website

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APPENDIX D. HEALTH RISK ASSESSMENT MODELING FILES

(Electronic Files)

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B.2 AQIA Addendum April 2024: Well Abandonment

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Trinity Consultants

MEMORANDUM

To: AERA Energy LLC

From: Matthew Daniel

Date: March 15, 2024

RE: Air Quality Impact Analysis CarbonFrontier Project – Well Re-abandonment

The Air Quality Impact Analysis (AQIA) associated with the proposed CarbonFrontier Project (Project) by Aera Energy LLC (Aera Energy) was completed in December 2023. A subsequent request has been made to add impacts from legacy well re-abandonments associated with the Project to the already analyzed Project. At the direction of the Kern County Planning and Natural Resources Department, the impacts of the well re-abandonments have been provided in this supplemental memo to the AQIA.

This memorandum provides the revised criteria pollutant emissions and health risk analysis (HRA) based on the additional impacts from well re-abandonments associated with the Project.

Construction Emissions Impacts

The AQIA analyzed the CO_2 capture facility and infrastructure construction occurring over a period of approximately three years, starting with the Pre-C facility construction at GP 32. The AQIA analyzed sequential construction occurring for construction of the Post-C facilities located at COGEN 32 and the two SGSs. The AQIA also analyzed other construction activities which would start concurrently with the facility construction and included pipeline construction, injection well pad construction, well drilling, well plugging and abandonment activities. Additionally, installation of CO_2 distribution pipelines, intra-field electrical distribution, and well hookups occurring throughout the three-year period was also analyzed.

The addition of the well re-abandonments would increase potential construction emissions from on-site equipment due to additional exhaust emissions. Criteria pollutant emissions were estimated using the California Emissions Estimator Model (CalEEMod) version 2020.4.0. There will be two types of re-abandonments, based on the scope of work to be performed – type A and type B. Type A re-abandonments will entail standard activities that can be performed with a workover rig and last approximately 19 days/well, while Type B re-abandonments will require a drilling rig to remove existing cement and casing from legacy wells and will last roughly 35 days/well. This analysis looks at 6 Type A and 26 Type B re-abandonments. Anticipated manpower, equipment and schedule associated with each type of re-abandonment is listed below.

<u>Type A Re-abandonments:</u>

- One shift per day with 10 workers per shift
- Workover Rig - 10 hours per day for 14 days
- Mud Pump - 10 hours per day for 14 days
- Power Swivel - 10 hours per day for 14 days
- Tool Truck - 10 hours per day for 14 days
- Coiled Tubing Unit – 10 hours per day for 5 days

4900 California Ave, Ste 420A, Bakersfield, CA 93309
P 661.282.2200 / F 661.427.0703

- Bulk Truck – 10 hours per day for 5 days
- Vac Truck - 10 hours per day for 5 days
- Cement Pump Truck - 10 hours per day for 5 days

Type B Reabandonments:

- Two shifts per day with 10 workers per shift
- Drilling Rig – 24 hours per day for 30 days
- Coiled Tubing Unit – 10 hours per day for 5 days
- Bulk Truck – 10 hours per day for 5 days
- Vac Truck - 10 hours per day for 5 days
- Cement Pump Truck - 10 hours per day for 5 days

Well re-abandonments are assumed to begin in January 2026. To be conservative, all well re-abandonment activities were analyzed as occurring within a one-year period; however, it is recognized that completion of all the well abandonments could take up to approximately three years. The proposed Project's construction emissions from the AQIA and well re-abandonments for the year 2026 are shown in **Table 1**. Two additional CalEEMod runs were conducted, one for each re-abandonment type. Emissions associated with each type were multiplied by the anticipated number of each re-abandonment type and summed together. The output from the additional CalEEMod runs for the well re-abandonment activities are available in Appendix A.

Table 1. Short-Term Project Emissions

Emissions Source	Pollutant (tons/year)					
	ROG	NO_X	CO	SO_2	PM_{10}	$PM_{2.5}$
Year 2026 - Total	***10.37***	***93.21***	***72.07***	***0.18***	***6.07***	***4.47***
Facilities Pad Grading - SGS2972	*0.06*	*0.56*	*0.47*	*0.00*	*0.07*	*0.04*
GP32 - CO2 Capture Facility	*2.30*	*16.24*	*14.41*	*0.03*	*1.41*	*1.03*
32 Cogen - CO2 Capture Facility	*2.30*	*16.24*	*14.41*	*0.03*	*1.41*	*1.03*
SGS2868 - CO2 Capture Facility	*2.30*	*16.24*	*14.41*	*0.03*	*1.41*	*1.03*
SGS2972 - CO2 Capture Facility	*1.86*	*13.13*	*11.64*	*0.02*	*1.14*	*0.83*
CO2 Main Pipeline	*0.44*	*3.51*	*3.43*	*0.01*	*0.25*	*0.19*
Intra-Field Electrical Distribution	*0.11*	*1.03*	*0.78*	*0.00*	*0.05*	*0.04*
Well Re-abandonments	*1.00*	*26.27*	*12.53*	*0.06*	*0.32*	*0.27*

Health Risk Impacts

The revised Project impacts would result in emission increases of Hazardous Air Pollutants (HAPs) of Deisel Particulate Matter (DPM) from on-site equipment over what was evaluated in the AQIA. The AQIA concluded that the health risk impacts of the Project from cancer and chronic risk were less than the significant threshold. The addition of the DPM emissions associated with the well re-abandonments have little effect on the overall maximum health risks associated with the Project. The location of the overall potential maximum impact (PMIs) did not change. Well re-abandonment emissions were equally divided amongst the potential location of the re-abandonments and were analyzed for a one-year exposure utilizing the same modeling parameters of the original HRA in the AQIA. Since the only additional HAP associated with well re-abandonments is DPM

only cancer and chronic risk was reevaluated. **Table 2** shows the risk impacts from the original Project and well re-abandonments of the PMIs.

Table2. Potential Maximum Impacts Predicted by HARP2

	Maximum Lifetime Excess Cancer Risk	Maximum Non-Cancer Chronic Hazard Index
AQIA	6.65E-06	1.55E-02
Well Re-abandonments	2.77E-08	2.81E-05
Total	6.68E-06	1.55E-02
UTM Easting (m)	251003.06	251950.08
UTM Northing (m)	3926087.12	3925329.29

Based on the conclusion of the HRA performed for the AQIA and the HRA from the increase in HAP emissions associated with the well re-abandonments it is concluded that the proposed Project would continue to have a *less than significant* health risk impact. Electronic modeling files can be found in Appendix B.

Ambient Air Quality Impacts

As stated in the GAMAQI (2015, p 96-97), SJVAPCD has developed screening levels for requiring an Ambient Air Quality Analysis (AAQA). The SJVAPCD recommends that an AAQA be performed for all criteria pollutants when emissions of any criteria pollutant resulting from project construction or operational activities exceed the 100 pounds per day screening level, after compliance with Rule 9510 requirements and implementation of all enforceable mitigation measures.

The Project will be entering into a VERA which will reduce average daily emissions for construction and operational activities associated with this Project to a no net increase level. Therefore, an AAQA is not required for this Project.

Impacts to Greenhouse Gases and Climate Change

The proposed Project will have GHG emissions from construction and operation. These GHG emissions include emissions from area, energy, mobile, water, and waste sources. New regulations and new technologies in the future, and phase out of old equipment over time, will lead to a reduction of GHG emissions, but the reduction is not currently quantifiable. Additionally, the Project, as proposed, has the capacity to capture and sequester up to roughly 1.6 million metric tons of CO_2 per year, with a total sequestration capacity up to 40 million metric tons of CO_2. The installed capture facilities will have a capture efficiency of 95% at the pre-combustion facility and 90% at the post-combustion facilities. Even with the addition of GHG emissions from well re-abandonment, the Project will continue to achieve net negative GHG emissions impact.

Conclusions

As demonstrated above the addition of 18 truck trips to the proposed Project would result in an increase of construction emissions for the year 2026, however, it would not significantly impact the health risk, ambient air quality impacts or GHG impacts associated with the proposed Project.

ATTACHMENT A: CALEEMOD EMISSION ESTIMATION

CarbonFrontier Complex Well Reabandoment Activities - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

CarbonFrontier Complex Well Reabandoment Activities

Kern-San Joaquin County, Annual

1.0 Project Characteristics

1.1 Land Usage

Land Uses	Size	Metric	Lot Acreage	Floor Surface Area	Population
User Defined Industrial	1.00	User Defined Unit	1.00	0.00	0

1.2 Other Project Characteristics

Urbanization	Rural	**Wind Speed (m/s)**	2.7	**Precipitation Freq (Days)**	32
Climate Zone	3			**Operational Year**	2026
Utility Company	Pacific Gas and Electric Company				
CO2 Intensity (lb/MWhr)	203.98	**CH4 Intensity (lb/MWhr)**	0.033	**N2O Intensity (lb/MWhr)**	0.004

1.3 User Entered Comments & Non-Default Data

Project Characteristics -

Land Use - X

Construction Phase - Number of Days for a Complex Well Reabandoment

Off-road Equipment - Estimated Equipment

Trips and VMT - 2 Shifts consisting of 10 workers each multiplied by 2 trips per worker with a distance of 45 miles

Vehicle Trips - Construction Run Only

Landscape Equipment - Construction Run Only

Construction Off-road Equipment Mitigation -

Table Name	Column Name	Default Value	New Value
tblConstDustMitigation	WaterUnpavedRoadVehicleSpeed	0	15
tblConstructionPhase	NumDays	100.00	30.00

CarbonFrontier Complex Well Reabandoment Activities - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

tblConstructionPhase	NumDaysWeek	5.00	7.00
tblLandscapeEquipment	NumberSummerDays	180	0
tblLandUse	LotAcreage	0.00	1.00
tblOffRoadEquipment	HorsePower	221.00	1,000.00
tblOffRoadEquipment	HorsePower	402.00	475.00
tblOffRoadEquipment	HorsePower	172.00	475.00
tblOffRoadEquipment	HorsePower	84.00	320.00
tblProjectCharacteristics	UrbanizationLevel	Urban	Rural
tblTripsAndVMT	WorkerTripLength	16.80	45.00

2.0 Emissions Summary

CarbonFrontier Complex Well Reabandoment Activities - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

2.1 Overall Construction

Unmitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	tons/yr										MT/yr					
2026	0.0324	0.9668	0.4340	2.1600e-003	0.0000	9.4800e-003	9.4800e-003	0.0000	8.7500e-003	8.7500e-003	0.0000	190.8178	190.8178	0.0597	0.0000	192.3094
Maximum	**0.0324**	**0.9668**	**0.4340**	**2.1600e-003**	**0.0000**	**9.4800e-003**	**9.4800e-003**	**0.0000**	**8.7500e-003**	**8.7500e-003**	**0.0000**	**190.8178**	**190.8178**	**0.0597**	**0.0000**	**192.3094**

Mitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	tons/yr										MT/yr					
2026	0.0324	0.9668	0.4340	2.1600e-003	0.0000	9.4800e-003	9.4800e-003	0.0000	8.7500e-003	8.7500e-003	0.0000	190.8176	190.8176	0.0597	0.0000	192.3091
Maximum	**0.0324**	**0.9668**	**0.4340**	**2.1600e-003**	**0.0000**	**9.4800e-003**	**9.4800e-003**	**0.0000**	**8.7500e-003**	**8.7500e-003**	**0.0000**	**190.8176**	**190.8176**	**0.0597**	**0.0000**	**192.3091**

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio-CO2	Total CO2	CH4	N20	CO2e
Percent Reduction	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

CarbonFrontier Complex Well Reabandoment Activities - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

Quarter	Start Date	End Date	Maximum Unmitigated ROG + NOX (tons/quarter)	Maximum Mitigated ROG + NOX (tons/quarter)
1	1-5-2026	4-4-2026	0.9992	0.9992
		Highest	0.9992	0.9992

2.2 Overall Operational

Unmitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Area	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Energy	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Mobile	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Waste						0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Water						0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**

CarbonFrontier Complex Well Reabandoment Activities - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

2.2 Overall Operational

Mitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Area	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Energy	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Mobile	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Waste						0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Water						0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio-CO2	Total CO2	CH4	N20	CO2e
Percent Reduction	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

3.0 Construction Detail

Construction Phase

Phase Number	Phase Name	Phase Type	Start Date	End Date	Num Days Week	Num Days	Phase Description
1	Complex Well Reabandoments	Building Construction	1/5/2026	2/3/2026	7	30	

Acres of Grading (Site Preparation Phase): 0

CarbonFrontier Complex Well Reabandoment Activities - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

Acres of Grading (Grading Phase): 0

Acres of Paving: 0

Residential Indoor: 0; Residential Outdoor: 0; Non-Residential Indoor: 0; Non-Residential Outdoor: 0; Striped Parking Area: 0 (Architectural Coating – sqft)

OffRoad Equipment

Phase Name	Offroad Equipment Type	Amount	Usage Hours	Horse Power	Load Factor
Complex Well Reabandoments	Bore/Drill Rigs	1	24.00	1000	0.50
Complex Well Reabandoments	Off-Highway Trucks	1	1.70	475	0.38
Complex Well Reabandoments	Other Construction Equipment	2	1.70	475	0.42
Complex Well Reabandoments	Pumps	1	1.70	320	0.74

Trips and VMT

Phase Name	Offroad Equipment Count	Worker Trip Number	Vendor Trip Number	Hauling Trip Number	Worker Trip Length	Vendor Trip Length	Hauling Trip Length	Worker Vehicle Class	Vendor Vehicle Class	Hauling Vehicle Class
Complex Well Reabandoments	5	0.00	0.00	0.00	45.00	6.60	20.00	LD_Mix	HDT_Mix	HHDT

3.1 Mitigation Measures Construction

Water Exposed Area

Reduce Vehicle Speed on Unpaved Roads

CarbonFrontier Complex Well Reabandoment Activities - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

3.2 Complex Well Reabandoments - 2026

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Off-Road	0.0324	0.9668	0.4340	2.1600e-003		9.4800e-003	9.4800e-003		8.7500e-003	8.7500e-003	0.0000	190.8178	190.8178	0.0597	0.0000	192.3094
Total	**0.0324**	**0.9668**	**0.4340**	**2.1600e-003**		**9.4800e-003**	**9.4800e-003**		**8.7500e-003**	**8.7500e-003**	**0.0000**	**190.8178**	**190.8178**	**0.0597**	**0.0000**	**192.3094**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Worker	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**

CarbonFrontier Complex Well Reabandoment Activities - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

3.2 Complex Well Reabandoments - 2026

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Off-Road	0.0324	0.9668	0.4340	2.1600e-003		9.4800e-003	9.4800e-003		8.7500e-003	8.7500e-003	0.0000	190.8176	190.8176	0.0597	0.0000	192.3091
Total	**0.0324**	**0.9668**	**0.4340**	**2.1600e-003**		**9.4800e-003**	**9.4800e-003**		**8.7500e-003**	**8.7500e-003**	**0.0000**	**190.8176**	**190.8176**	**0.0597**	**0.0000**	**192.3091**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Worker	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**

CarbonFrontier Normal Well Reabandoment Activities - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

CarbonFrontier Normal Well Reabandoment Activities

Kern-San Joaquin County, Annual

1.0 Project Characteristics

1.1 Land Usage

Land Uses	Size	Metric	Lot Acreage	Floor Surface Area	Population
User Defined Industrial	1.00	User Defined Unit	1.00	0.00	0

1.2 Other Project Characteristics

Urbanization	Rural	**Wind Speed (m/s)**	2.7	**Precipitation Freq (Days)**	32
Climate Zone	3			**Operational Year**	2026
Utility Company	Pacific Gas and Electric Company				
CO2 Intensity (lb/MWhr)	203.98	**CH4 Intensity (lb/MWhr)**	0.033	**N2O Intensity (lb/MWhr)**	0.004

1.3 User Entered Comments & Non-Default Data

Project Characteristics -

Land Use - X

Construction Phase - Number of Days for a Normal Well Reabandoment

Off-road Equipment - Estimated Equipment

Trips and VMT - 1 Shift consisting of 10 workers each multiplied by 2 trips per worker with a distance of 45 miles

Vehicle Trips - Construction Run Only

Landscape Equipment - Construction Run Only

Construction Off-road Equipment Mitigation -

Off-road Equipment - Esitmated Equipment

Table Name	Column Name	Default Value	New Value
tblConstDustMitigation	WaterUnpavedRoadVehicleSpeed	0	15

CarbonFrontier Normal Well Reabandoment Activities - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

tblConstructionPhase	NumDays	100.00	14.00
tblConstructionPhase	NumDaysWeek	5.00	7.00
tblConstructionPhase	PhaseEndDate	6/10/2026	1/18/2026
tblConstructionPhase	PhaseStartDate	1/22/2026	1/5/2026
tblLandscapeEquipment	NumberSummerDays	180	0
tblLandUse	LotAcreage	0.00	1.00
tblOffRoadEquipment	HorsePower	221.00	430.00
tblOffRoadEquipment	HorsePower	84.00	416.00
tblOffRoadEquipment	HorsePower	172.00	156.00
tblOffRoadEquipment	HorsePower	172.00	360.00
tblOffRoadEquipment	HorsePower	172.00	475.00
tblOffRoadEquipment	HorsePower	402.00	475.00
tblOffRoadEquipment	HorsePower	84.00	320.00
tblOffRoadEquipment	OffRoadEquipmentType	Cranes	Bore/Drill Rigs
tblOffRoadEquipment	OffRoadEquipmentType	Forklifts	Pumps
tblOffRoadEquipment	OffRoadEquipmentType	Tractors/Loaders/Backhoes	Other Construction Equipment
tblOffRoadEquipment	OffRoadEquipmentType		Other Construction Equipment
tblOffRoadEquipment	OffRoadEquipmentType		Other Construction Equipment
tblOffRoadEquipment	OffRoadEquipmentType		Off-Highway Trucks
tblOffRoadEquipment	OffRoadEquipmentType		Pumps
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	0.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	0.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	0.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	0.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	0.00	2.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	0.00	1.00
tblOffRoadEquipment	OffRoadEquipmentUnitAmount	0.00	1.00
tblOffRoadEquipment	PhaseName		Normal Well Reabandoments
tblOffRoadEquipment	PhaseName		Normal Well Reabandoments

CarbonFrontier Normal Well Reabandoment Activities - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

tblOffRoadEquipment	PhaseName		Normal Well Reabandoments
tblOffRoadEquipment	PhaseName		Normal Well Reabandoments
tblOffRoadEquipment	PhaseName		Normal Well Reabandoments
tblOffRoadEquipment	PhaseName		Normal Well Reabandoments
tblOffRoadEquipment	PhaseName		Normal Well Reabandoments
tblOnRoadDust	PhaseName	Complex Well Reabandoments	Normal Well Reabandoments
tblProjectCharacteristics	UrbanizationLevel	Urban	Rural
tblTripsAndVMT	PhaseName	Complex Well Reabandoments	Normal Well Reabandoments
tblTripsAndVMT	WorkerTripLength	16.80	45.00
tblTripsAndVMT	WorkerTripNumber	0.00	20.00

2.0 Emissions Summary

CarbonFrontier Normal Well Reabandoment Activities - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

2.1 Overall Construction

Unmitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	tons/yr										MT/yr					
2026	0.0256	0.1893	0.2078	8.2000e-004	4.7000e-003	6.8700e-003	0.0116	1.2500e-003	6.4600e-003	7.7000e-003	0.0000	76.9816	76.9816	0.0145	7.0000e-005	77.3640
Maximum	**0.0256**	**0.1893**	**0.2078**	**8.2000e-004**	**4.7000e-003**	**6.8700e-003**	**0.0116**	**1.2500e-003**	**6.4600e-003**	**7.7000e-003**	**0.0000**	**76.9816**	**76.9816**	**0.0145**	**7.0000e-005**	**77.3640**

Mitigated Construction

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Year	tons/yr										MT/yr					
2026	0.0256	0.1893	0.2078	8.2000e-004	4.7000e-003	6.8700e-003	0.0116	1.2500e-003	6.4600e-003	7.7000e-003	0.0000	76.9815	76.9815	0.0145	7.0000e-005	77.3639
Maximum	**0.0256**	**0.1893**	**0.2078**	**8.2000e-004**	**4.7000e-003**	**6.8700e-003**	**0.0116**	**1.2500e-003**	**6.4600e-003**	**7.7000e-003**	**0.0000**	**76.9815**	**76.9815**	**0.0145**	**7.0000e-005**	**77.3639**

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio-CO2	Total CO2	CH4	N20	CO2e
Percent Reduction	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

CarbonFrontier Normal Well Reabandoment Activities - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

Quarter	Start Date	End Date	Maximum Unmitigated ROG + NOX (tons/quarter)	Maximum Mitigated ROG + NOX (tons/quarter)
1	1-5-2026	4-4-2026	0.2150	0.2150
		Highest	0.2150	0.2150

2.2 Overall Operational

Unmitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Area	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Energy	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Mobile	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Waste						0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Water						0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**

CarbonFrontier Normal Well Reabandoment Activities - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

2.2 Overall Operational

Mitigated Operational

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Area	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Energy	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Mobile	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Waste						0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Water						0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio-CO2	Total CO2	CH4	N20	CO2e
Percent Reduction	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

3.0 Construction Detail

Construction Phase

Phase Number	Phase Name	Phase Type	Start Date	End Date	Num Days Week	Num Days	Phase Description
1	Normal Well Reabandoments	Building Construction	1/5/2026	1/18/2026	7	14	

Acres of Grading (Site Preparation Phase): 0

CarbonFrontier Normal Well Reabandoment Activities - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

Acres of Grading (Grading Phase): 0

Acres of Paving: 0

Residential Indoor: 0; Residential Outdoor: 0; Non-Residential Indoor: 0; Non-Residential Outdoor: 0; Striped Parking Area: 0 (Architectural Coating – sqft)

OffRoad Equipment

Phase Name	Offroad Equipment Type	Amount	Usage Hours	Horse Power	Load Factor
Normal Well Reabandoments	Other Construction Equipment	1	10.00	360	0.42
Normal Well Reabandoments	Other Construction Equipment	2	3.60	475	0.42
Normal Well Reabandoments	Off-Highway Trucks	1	3.60	475	0.38
Normal Well Reabandoments	Bore/Drill Rigs	1	10.00	430	0.50
Normal Well Reabandoments	Pumps	1	10.00	416	0.74
Normal Well Reabandoments	Pumps	1	3.60	320	0.74
Normal Well Reabandoments	Other Construction Equipment	1	10.00	156	0.42

Trips and VMT

Phase Name	Offroad Equipment Count	Worker Trip Number	Vendor Trip Number	Hauling Trip Number	Worker Trip Length	Vendor Trip Length	Hauling Trip Length	Worker Vehicle Class	Vendor Vehicle Class	Hauling Vehicle Class
Normal Well Reabandoments	7	20.00	0.00	0.00	45.00	6.60	20.00	LD_Mix	HDT_Mix	HHDT

3.1 Mitigation Measures Construction

Water Exposed Area

Reduce Vehicle Speed on Unpaved Roads

CarbonFrontier Normal Well Reabandoment Activities - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

3.2 Normal Well Reabandoments - 2026

Unmitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Off-Road	0.0247	0.1886	0.1986	7.9000e-004		6.8500e-003	6.8500e-003		6.4400e-003	6.4400e-003	0.0000	73.6313	73.6313	0.0145	0.0000	73.9930
Total	**0.0247**	**0.1886**	**0.1986**	**7.9000e-004**		**6.8500e-003**	**6.8500e-003**		**6.4400e-003**	**6.4400e-003**	**0.0000**	**73.6313**	**73.6313**	**0.0145**	**0.0000**	**73.9930**

Unmitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Worker	9.1000e-004	6.6000e-004	9.1500e-003	4.0000e-005	4.7000e-003	2.0000e-005	4.7200e-003	1.2500e-003	2.0000e-005	1.2700e-003	0.0000	3.3503	3.3503	4.0000e-005	7.0000e-005	3.3710
Total	**9.1000e-004**	**6.6000e-004**	**9.1500e-003**	**4.0000e-005**	**4.7000e-003**	**2.0000e-005**	**4.7200e-003**	**1.2500e-003**	**2.0000e-005**	**1.2700e-003**	**0.0000**	**3.3503**	**3.3503**	**4.0000e-005**	**7.0000e-005**	**3.3710**

CarbonFrontier Normal Well Reabandoment Activities - Kern-San Joaquin County, Annual

EMFAC Off-Model Adjustment Factors for Gasoline Light Duty Vehicle to Account for the SAFE Vehicle Rule Not Applied

3.2 Normal Well Reabandoments - 2026

Mitigated Construction On-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Off-Road	0.0247	0.1886	0.1986	7.9000e-004		6.8500e-003	6.8500e-003		6.4400e-003	6.4400e-003	0.0000	73.6312	73.6312	0.0145	0.0000	73.9929
Total	**0.0247**	**0.1886**	**0.1986**	**7.9000e-004**		**6.8500e-003**	**6.8500e-003**		**6.4400e-003**	**6.4400e-003**	**0.0000**	**73.6312**	**73.6312**	**0.0145**	**0.0000**	**73.9929**

Mitigated Construction Off-Site

	ROG	NOx	CO	SO2	Fugitive PM10	Exhaust PM10	PM10 Total	Fugitive PM2.5	Exhaust PM2.5	PM2.5 Total	Bio- CO2	NBio- CO2	Total CO2	CH4	N2O	CO2e
Category	tons/yr										MT/yr					
Hauling	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Vendor	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Worker	9.1000e-004	6.6000e-004	9.1500e-003	4.0000e-005	4.7000e-003	2.0000e-005	4.7200e-003	1.2500e-003	2.0000e-005	1.2700e-003	0.0000	3.3503	3.3503	4.0000e-005	7.0000e-005	3.3710
Total	**9.1000e-004**	**6.6000e-004**	**9.1500e-003**	**4.0000e-005**	**4.7000e-003**	**2.0000e-005**	**4.7200e-003**	**1.2500e-003**	**2.0000e-005**	**1.2700e-003**	**0.0000**	**3.3503**	**3.3503**	**4.0000e-005**	**7.0000e-005**	**3.3710**

ATTACHMENT B: ELECTRONIC MODELING FILES

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B.3 Failure Investigation Report

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DOT	US Department of Transportation
PHMSA	Pipeline and Hazardous Materials Safety Administration
OPS	Office of Pipeline Safety – Accident Investigation Division

Principal Investigator	Wesley Mathews
Acting Accident Investigation Director	Chris Ruhl
Date of Report	May 26, 2022
Subject	Failure Investigation Report - Denbury Gulf Coast Pipelines, LLC – Pipeline Rupture/ Natural Force Damage

Operator, Location, & Consequences

Date of Failure	February 22, 2020
Commodity Released	Carbon Dioxide
City, County and State	Satartia, Yazoo County, MS
OpID and Operator Name	32545, Denbury Gulf Coast Pipelines, LLC
Unit # and Unit Name	75379 – MS-2
WMS Activity ID	20-176125
Milepost (MP) / Location	MP 6.6 / Pipeline Stationing 348+63
Type of Failure	Natural Force Damage
Fatalities	None
Injuries	None
Description of Area Impacted	Rural, “Could Affect” High Consequence Area (HCA) - Other Populated Area
Total Costs	$ 3,947,009

Key Points

- On February 22, 2020, a carbon dioxide (CO_2) pipeline operated by Denbury Gulf Coast Pipelines LLC (Denbury) ruptured in proximity to the community of Satartia, Mississippi. The rupture followed heavy rains that resulted in a landslide, creating excessive axial strain on a pipeline weld.
- Carbon dioxide is considered minimally toxic by inhalation and is classified as an asphyxiant, displacing the oxygen in air. Symptoms of CO_2 exposure may include headache and drowsiness. Individuals exposed to higher concentrations may experience rapid breathing, confusion, increased cardiac output, elevated blood pressure, and increased arrhythmias. Extreme CO_2 concentrations can lead to death by asphyxiation.
- When CO_2 in a super-critical phase (which is common for CO_2 pipelines) releases into open air, it naturally vaporizes into a heavier than air gas and dissipates. During the February 22 event, atmospheric conditions and unique topographical features of the accident site significantly delayed dissipation of the heavier-than-air vapor cloud. Pipeline operators are required to establish atmospheric models to prepare for emergencies—Denbury's model did not contemplate a release that could affect the Village of Satartia.
- Local emergency responders were not informed by Denbury of the rupture and the nature of the unique safety risks of the CO_2 pipeline. As a result, responders had to guess the nature of the risk, in part making assumptions based on reports of a "green gas" and "rotten egg smell" and had to contemplate appropriate mitigative actions. Fortunately, responders decided to quickly isolate the affected area by shutting down local highways and evacuating people in proximity to the release. Denbury reported on its PHMSA F 7000.1 accident report that 200 residents surrounding the rupture location were evacuated, and forty-five people were taken to the hospital. Denbury also reported that to the company's knowledge, one individual was admitted to the hospital for reasons unrelated to the pipeline failure. No fatalities were reported.
- This event demonstrated the need for:
    - Pipeline company awareness and mitigation efforts directed at addressing integrity threats due to changing climate, geohazards, and soil stability issues.
    - Improved public engagement efforts to ensure public and emergency responder awareness of nearby CO_2 pipeline and pipeline facilities and what to do if a CO_2 release occurs. This is especially important for communities in low-lying areas, with certain topographical features such as rivers and valleys.

Executive Summary

On February 22, 2020, at 7:06 p.m. Central Standard Time (CST[1]), Denbury's 24-inch Delhi (Delhi) Pipeline ruptured, releasing liquid CO_2 that immediately began to vaporize at atmospheric conditions. The site of the rupture was on the northeast side of Highway 433 (HWY 433), approximately one mile southeast of Satartia, Mississippi. Denbury subsequently reported the rupture released an estimated total of 31,405[2] barrels of CO_2. Following the accident, investigators from the Pipeline and Hazardous Material Safety Administration's (PHMSA's) Accident Investigation Division (AID) and Southwest Regional Office, conducted an investigation, including an onsite investigation.

Liquid CO_2 vaporizes when released to the atmosphere. Carbon dioxide vapor is 1.53 times heavier than air, and displaces oxygen, so it can act as an asphyxiant to humans and animals. The National Institute for Occupational Safety and Health has established that concentrations of 40,000 parts per million (ppm) are immediately dangerous to life and health. The Occupational Safety and Health Administration has established 5000 ppm as a permissible exposure limit, which is an 8-hour time-weighted average. The weather conditions and unique topography of the accident site prevented the CO_2 vapor from rapidly dispersing and allowing a plume to form that migrated toward Satartia. Upon learning of the pipeline rupture, Yazoo County Office of Emergency Management (Yazoo County OEM) shut down HWY 433 to all traffic and evacuated the area. Local authorities evacuated approximately 200 people near the rupture, including the entire town of Satartia (around 50 residents), and three homes across the Yazoo River. According to Denbury's PHMSA F 7000.1 accident report, forty-five people sought medical attention at local hospitals, including individuals who were caught in the vapor cloud while driving a vehicle. One individual was admitted to the hospital for reasons unrelated to the pipeline failure. There were no fatalities.

The pipeline failed on a steep embankment adjacent to HWY 433, which had recently subsided. Heavy rains are believed to have led to a landslide, which created axial strain on the pipeline and resulted in a full circumferential girth weld failure. After the accident, Denbury, under PHMSA's oversight, cut out the failed sections of pipe and sent them to Det Norske Veritas' (DNV) Columbus, Ohio laboratory for metallurgical analysis. DNV confirmed the initial onsite observations of a girth weld failure.

PHMSA's investigation also revealed several contributing factors to the accident, including but not limited to, Denbury not addressing the risks of geohazards in its plans and procedures, underestimating the potential affected areas that could be impacted by a release in its CO_2 dispersion model, and not notifying local responders to advise them of a potential failure.

System Details

Denbury's Delhi Pipeline, on which the failure occurred, consists of 77 miles of 24-inch diameter pipeline, the majority of which is located within Mississippi. The entire Delhi Pipeline system flows east to west, beginning at the Jackson Dome in Mississippi and terminating in Delhi, Louisiana. Denbury primarily uses the CO_2 for enhanced oil recovery (EOR) for Denbury Resources Inc. onshore oil wells. The pipeline is controlled from the Denbury control room located in Plano, Texas.

[1] All times are reported in CST unless otherwise noted.

[2] Denbury reported a total release volume of 31,405 barrels in Form PHMSA F-7000.1, Accident Report – Hazardous Liquid Pipeline Systems, dated November 25, 2020. The actual release volume likely exceeded this amount due to a valve operation error, however, Denbury has not confirmed and reported any new release volume to PHMSA.

Following the Delhi Pipeline rupture, two of Denbury's local oilfields were cut off from its CO_2 supply and assumed non-EOR operation while the pipeline remained out of service. One oilfield returned to full EOR operation before repairs were made to the Delhi Pipeline as the oilfield had an alternate supply of CO_2. The other oilfield conducted non-EOR operations until the pipeline was repaired and returned to service in October 2020.

Stupp Corporation manufactured the pipe in 2007 and Denbury installed it in 2009. The pipe was manufactured to API 5L X80 grade, with an electric resistance welded (ERW) longitudinal weld seam, a 0.469-inch wall thickness on the mainline pipe, 0.540-inch wall thickness on the bored pipe section under roads, which was 240 feet in length and more than 30 feet below HWY 433. The pipe is coated with fusion bonded epoxy (FBE) and was installed by horizontal directional drill. During construction, Denbury welded the pipe joints using an API 1104 qualified welding procedure. The procedure specified using an E6010 electrode root pass, followed by an E9018 electrode hot pass, then E10045 electrode for subsequent passes.

The maximum operating pressure of the Delhi Pipeline is 2160 pounds per square inch gauge (psig). At the time of the rupture, Denbury was operating the Delhi Pipeline at an estimated pressure of 1400 psig, which was above the 1070 psig needed to maintain CO_2 in a supercritical state.

Denbury's control room isolated the failed pipeline section by remotely operating the mainline block valves (MLBVs) at Redwood, Satartia, and Tinsley. There is approximately 9.55 miles of pipe between the Tinsley and Satartia MLBVs, which are the two MLBVs closest to the rupture.

Events Leading up to the Failure

According to the National Weather Service (NWS), accumulated rainfall data between January 1, 2020, through February 29, 2020 (60 days) for each of the cities of Greenville, Greenwood, Vicksburg, and Jackson, Mississippi – which form a relative square (Figure 1) around Satartia and Yazoo County[3] – was 17.43 inches, 19.41 inches, 23.2 inches, and 23.36 inches of rain, respectively. The amount of rain recorded in these four cities was between 7.44 and 13.63 inches above the annual historical average for the same 60-day timespan. Significant variations in environmental/climate conditions such as ambient temperatures and rainfall can impact soil stability and erosion patterns. Landslides are typically associated with periods of heavy rain, particularly in susceptible areas with the right combination of slope and soil-type. On May 26, 2022, PHMSA issued an updated Advisory Bulletin to remind operators of gas and hazardous liquid pipelines of the importance of identifying and mitigating risks caused by changes in environmental and geological conditions on their pipeline facilities.

[3] Neither Yazoo City, Satartia, nor Yazoo County had historic NWS data for the desired date range.

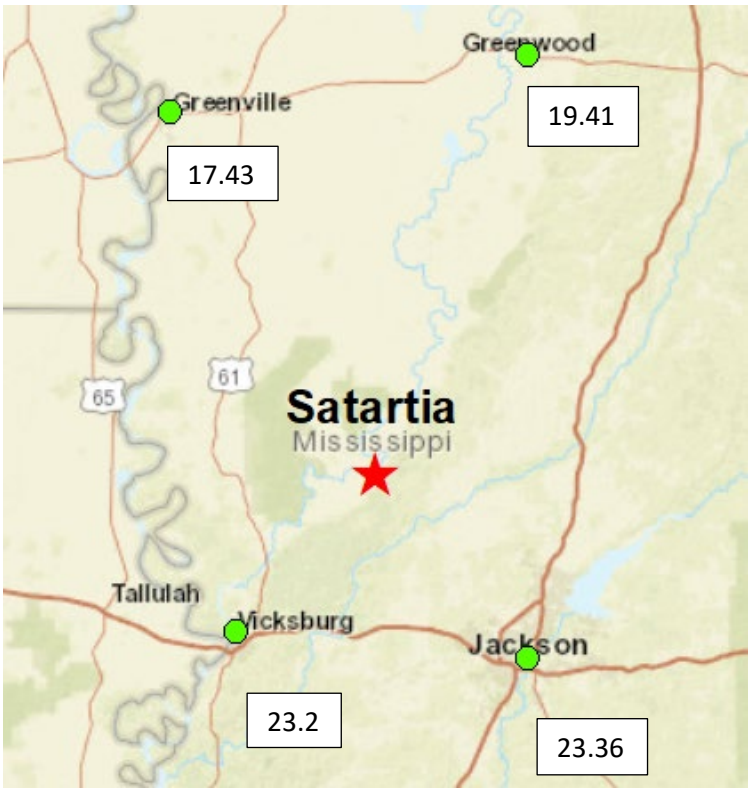


Figure 1: Map of Cities Relative to Satartia and Their Respective Rain Totals Between January 1, 2020, and February 29, 2020

On November 9, 2018, the Delhi Pipeline experienced a girth weld rupture at a valve location during pipeline reloading activities, and not attributed to natural force damage. Laboratory analysis indicated the release was the result of large thermal differential stresses being exerted on the pipeline from CO_2 loading at two different locations at the same time. The pipe between the two loading points shrank due to chilling from the CO_2, causing the girth weld connecting the pipeline to the valve body to rupture. The report found no evidence of inadequate mechanical properties or chemical composition anomalies in the ruptured weld. Denbury updated their procedure to prevent similar occurrences.

Prior to the accident, on November 8, 2019, Yazoo County first responders practiced a full-scale county response during a drill for a rail accident, however Denbury was not a participant in the drill. Local responders believe that the drill prepared them to respond to this event. Denbury had not conducted any drills with local responders since Denbury's modeling had not identified that Satartia would be impacted by a rupture of the pipeline.

Emergency Response

The Delhi Pipeline was operating normally prior to the February 22, 2020 accident.

Approximated Timeline

The following timeline was developed utilizing information provided by the Yazoo County OEM, [4] Denbury, and PHMSA investigator notes.

On February 22, 2020:

- 7:06 p.m. – Denbury's 24-inch pipeline ruptured.
- 7:07 p.m. – Denbury's control room was alerted by its supervisory control and data acquisition (SCADA) system of a pressure drop.
- 7:14 p.m. – Denbury control room remotely closed three MLBVs (one MLBV at Tinsley Station, which is upstream of the rupture site, and two MLBVs at Satartia and Redwood, which are downstream of the rupture).
- 7:15 p.m. – Denbury control room received SCADA confirmation that the MLBVs were closed.
- 7:15 p.m. – Yazoo County OEM dispatcher received an initial report of a "foul smell and green fog across the highway." Based on that information, responders responded under the assumption there was a possible chlorine leak and began contacting people from the local water utility company.
- 7:17 p.m. – Yazoo County OEM dispatcher received a call regarding a person possibly having a seizure. Responders began contacting personnel responsible for a nearby water well as the description of the report indicated chlorine gas.
- 7:19 p.m. – Denbury dispatched personnel to attempt to confirm MLBVs were closed successfully and to identify the location of the release.
- 7:26 p.m. – HWY 433 was ordered closed by local officials due to belief a chlorine leak was occurring.
- 7:30 p.m. – A responder commented that it sounded like a gas line had erupted. It was around this same time that another responder fielded a call from someone in the area who could hear a loud roar. This led the responders to believe that the accident was not chlorine gas related. First responders redirected their efforts to a possible CO_2 and hydrogen sulfide release, based on the initial first-hand reports from community members.
- 7:30 p.m. – First responders accessed a plume model generated by the NWS correlating local meteorological data with product type which indicated the CO_2 would move from the release site directly toward Satartia. Responders then called for the evacuation of Satartia. The scope of the response expanded as the CO_2 cloud dispersed, requiring an Incident Command (IC), commanded by the Chief of the District Three Volunteer Fire Department.
- 7:39 p.m. – Yazoo County OEM closed Highway 3 to traffic (intersection with HWY 433 is about 2/3-mile northwest of the rupture site).
- 7:43 p.m. – IC confirmed Denbury's CO_2 pipeline had ruptured; however, no one could get close to the release site due to the ongoing release of CO_2.
- 7:48 p.m. – Denbury's Tinsley Station Manager was contacted by IC and informed that Denbury's pipeline had ruptured. IC made Denbury aware of the response measures being taken. Denbury informed the IC that the Jackson Dome formation was shut down and that company personnel had been dispatched to check that the MLBVs were closed.

[4] The events entered in the Yazoo County OEM recording system are time stamped upon entry and may be delayed by seconds or minutes from the actual time of the event.

- 7:57 p.m. – Yazoo County OEM blocked off Mechanicsburg Road (around two miles southeast of the rupture site; intersects with HWY 433).
- 7:58 p.m. – According to Yazoo County OEM records, the Mississippi Department of Environmental Quality (MDEQ) contacted the Center for Toxicology & Environmental Health (CTEH) requesting technicians be dispatched to the rupture site with air monitoring equipment.
- 8:06 p.m. – The first Denbury representative arrived near the rupture site after confirming MLBV closures.
- 8:24 p.m. – Yazoo County OEM dispatch confirmed the second Denbury representative arrived near the rupture site.
- 9:06 p.m. – A Denbury representative from the Plano, Texas office called the National Response Center (NRC) to report their Delhi Pipeline had ruptured, releasing an estimated 222 barrels of liquid carbon dioxide (Report No. 1271847).
- 9:25 p.m. – Representatives from the CTEH and Denbury's environmental contractor E3 Environmental (E3) arrived on scene to conduct air monitoring to support the IC.
- 10:25 p.m. – Tinsley MLBV was completely closed.[5]
- 10:30 p.m. – CTEH initiated real-time air monitoring.

On February 23, 2020:

- 1:49 a.m. – The IC established a warming shelter at a local middle school for evacuees.
- 8:00 a.m. – Evacuees were allowed to return home. Air monitoring services were extended to anyone who requested the service. Evacuees were encouraged to vent their homes by opening doors and windows. The closure of HWY 433 was lifted after heavy equipment was used to clear mud that was deposited by the rupture.
- 11:34 a.m. – Real-time air monitoring concluded.

On February 24, 2020:

- 6:56 p.m., Denbury called the NRC and made the PHMSA required 48-hour update (Report No. 1272001). The update stated 21,873 barrels of liquid CO_2 had been released.[5]

Personnel from the Vicksburg Fire Department, including paramedics, District Three Volunteer Fire Department, Pafford EMS, Mississippi Emergency Management Agency, CF Industries, MDEQ, Madison County Fire Department, Warren County Fire Department, NWS, Local Police Departments, Yazoo County OEM, CTEH, E3, and Denbury participated in the emergency response efforts.

Local emergency responders utilized regular media, social media posts, phone calls, and door-to-door checks to notify homeowners and affected individuals of the CO_2 release.

A total of approximately 200 people were evacuated, which included those who were evacuated out of the area and those who were not allowed to pass through the area. During post-accident interviews, PHMSA learned that individuals on HWY 433 and in the area nearest to the migrating CO_2 vapor cloud experienced vehicle engine issues. This included individuals in a vehicle off of HWY 433, who succumbed to the effects of exposure to the released CO_2 and required emergency assistance to be evacuated. PHMSA also learned that one of two residents living in a dwelling in closest proximity to the pipeline rupture

[5] Denbury reported an updated estimate of 31,405 barrels to PHMSA on November 25, 2020.

passed out upon investigating the cloud. She later came-to and was able to evacuate to safety with her partner. Denbury reported a total of forty-five people sought medical attention at local hospitals.

Emergency Response Air Monitoring Plan

CTEH (Denbury's third-party contractor) in consultation with the IC developed an air monitoring plan to ensure the safety of response personnel, the community, and site characterization. CTEH implemented the plan to monitor for concentrations of CO_2, hydrogen-sulfide (H_2S), and oxygen (O_2) using handheld real-time instrumentation throughout the community and within homes of residents who requested monitoring. Air monitoring was conducted from 10:30 p.m. on February 22, 2020, until approximately 11:30 a.m. on February 23, 2020. Monitoring was performed using calibrated RAE Systems instruments made by Honeywell.

Carbon dioxide is considered minimally toxic by inhalation, unless in higher concentrations. CO_2 is classified as an asphyxiant, displacing the oxygen in breathing air. Symptoms of CO_2 exposure may include headache and drowsiness. Those exposed to higher concentrations may experience rapid breathing, confusion, increased cardiac output, elevated blood pressure, and increased arrhythmias. Extreme CO_2 concentrations can lead to death by asphyxiation.

In the hours after the rupture, after outdoor ambient air CO_2 levels continuously measured below 5,000 ppm, responders performed initial indoor assessment monitoring within residences and church buildings potentially impacted by the accident. During initial indoor assessments, CO_2 concentrations ranged from 200 through 28,000 ppm, with six detections exceeding 5,000 ppm. In these instances, occupants of these structures were advised to open doors and windows to allow ventilation to dissipate the concentration of CO_2 and not to enter prior to re-assessment. No subsequent CO_2 readings in the hours after the accident were recorded above 3,500 ppm during re-assessments.

According to firsthand accounts, as well as secondhand accounts from first responders, there was a "rotten eggs" odor associated with the CO_2 release and gas plume. A rotten eggs odor can be attributed to the presence of H_2S, which is naturally occurring in the geologic formation that serves as a source of the CO_2 in the pipeline. PHMSA reviewed the CTEH air monitoring results and did not identify any observed readings of H_2S by monitoring equipment. The monitoring equipment's detection limit for H_2S was 0.1 ppm.

Summary of Return-to-Service

Prior to repairing the pipeline, Denbury contracted an engineering firm to develop plans to cutout the failed section of pipe and to mitigate potential future land movement. Denbury installed soil shoring along HWY 433 to stabilize the area. PHMSA evaluated the repair plan and monitored its execution.

On September 1, 2020, Denbury began replacing the failed pipe section, and on September 26, Denbury welded the new sections of pipe into the pipeline at the accident location. Mannesmann Line Pipe manufactured the newly installed 80-foot section of 24-inch nominal diameter pipe in 2019. The pipe is API 5L X70 grade, has 0.562-inch wall thickness and an ERW longitudinal weld seam, and is coated with FBE.

Denbury restarted the pipeline on October 26, 2020. Prior to the restart of the pipeline, Denbury provided PHMSA with a proposed restart plan for review and approval. Concurrently with Denbury's repair and restart efforts, PHMSA conducted an inspection of Denbury's pipeline operations, which resulted in the

issuance of various enforcement actions, including a Notice of Probable Violation in connection with this accident.[6]

Investigation Details

On February 23, 2020, at 10:09 a.m., a PHMSA AID investigator from Oklahoma City arrived at the intersection of HWY 433 and Highway 3 to meet with Denbury representatives and emergency response organizations. The group then proceeded to the site of the rupture (Figure 2). By that time, the IC had demobilized, and roadblocks had been removed. Denbury crews were in the process of setting up caution fencing and slowing traffic on HWY 433 for public and worker safety. The rupture crater was on the northeast side of HWY 433 (Figure 2).



Figure 2: Vehicle is Parked on HWY 433 - The White is Ice Generated by the Release of CO_2 - The Blue Arrow Points North (Aerial Drone Photograph Courtesy of the Mississippi Emergency Management Agency)

[6] CPF 4-2022-017-NOPV, dated May 26, 2022.

The topography along the pipeline right-of-way (ROW) in this area is a steep hill that rises from the valley containing the Big Black River to the east, goes relatively flat across the crest of the hill containing HWY 433, and then slopes downward toward the valley containing the Yazoo River to the west.



Figure 3: Crater Created by the Rupture Containing Fallen Debris (dry ice, and the failed pipe sections) (Blue Arrow is Pointing at the Pipeline Separation)

The pipeline separated at a girth weld. The pipeline self-excavated due to the discharge of CO_2. The auto refrigeration generated by the CO_2 discharge and accompanying chance in phase covered the area with a thick layer of ice (Figures 2, 3, and 4). The upstream section of pipe was not covered in ice, and a slightly jagged edge was observed on the rupture edge (Figure 4). The crater was an estimated 40-feet-deep on the downstream (HWY 433) side and about four-feet-deep on the upstream side.



Figure 4: The failed pipe sections shown separated by a few inches.

Upon release, the CO_2 transitioned from a liquid to a gaseous phase resulting in a refrigeration effect. Although the pipeline was shut down by 7:15 pm, the remaining contents of the pipe continued to vent to the atmosphere for several hours. The CO_2 was heavier than air[7] and followed a path downhill. CO_2 moved down the slope to the east and remained in the bowl of the crater. As the discharged volume increased, and without significant winds to disperse the CO_2, the CO_2 moved over the crest of the hill then west into the valley, reaching Satartia.

Plume Model

First responders utilized a plume model generated by the NWS to base the decision to evacuate Satartia (Figure 5).

[7] CO_2 has a density approximately 1.53 times that of air in standard atmospheric conditions.

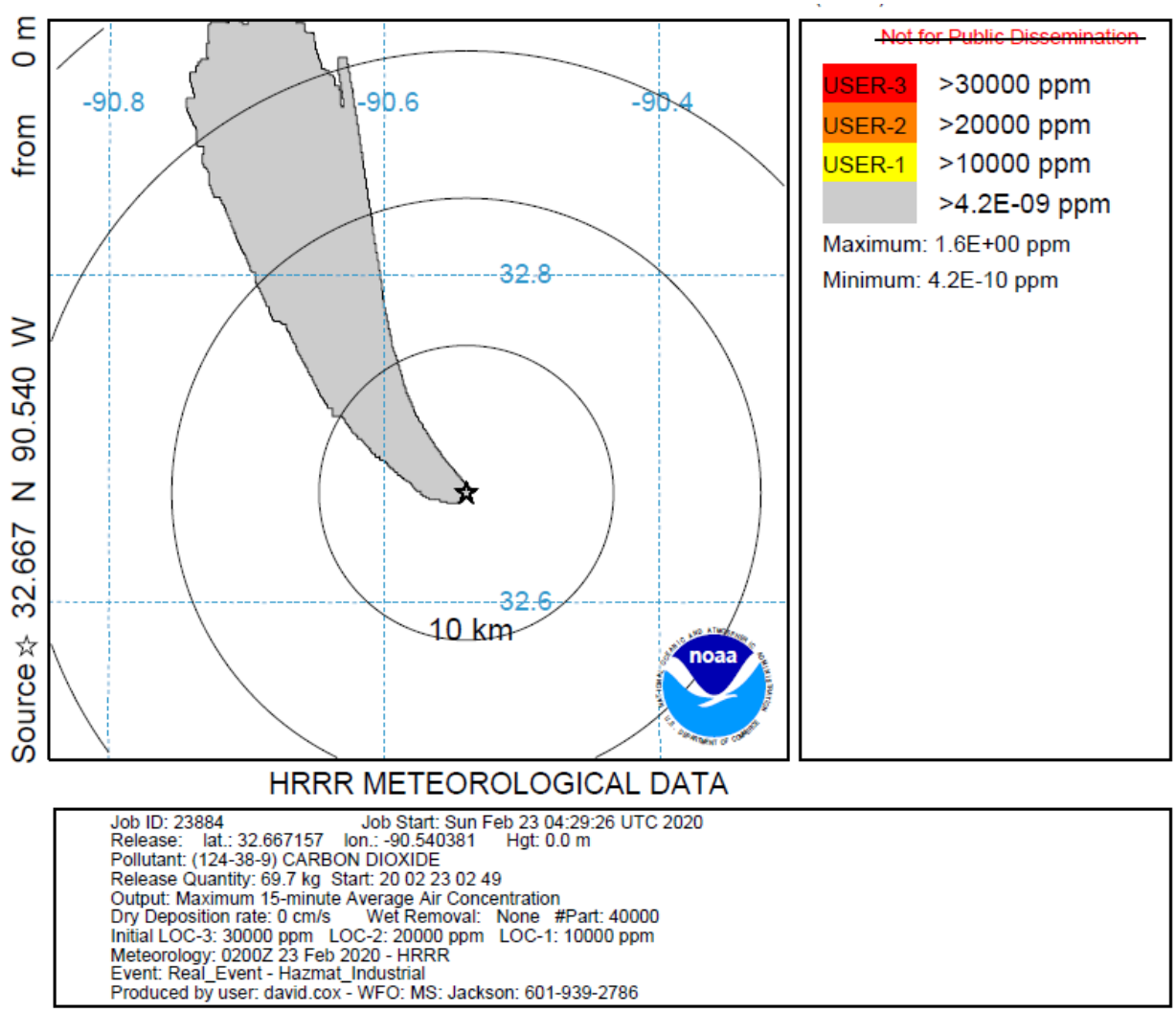


Figure 5: This Chart Shows the Plume Model Data Generated by the National Weather Service/NOAA - The Model Indicates the Direction a Plume or Cloud of CO_2 Would Have Followed from Ground Level While Dissipating, According to Atmospheric Data at the Time of the Release - Each Ring is 10 Kilometers (Satartia is Less Than Two Kilometers Northwest of Release Site, Indicated by the Star)[8]

Prior to the accident in 2011, Denbury had contracted a third-party company to generate an affected radius model for a potential CO_2 release. Denbury used the model to generate a zone along the pipeline ROW to identify pipeline segments which were within or "could affect" an HCA and to develop its Public Awareness Program (PAP).[9] The model established a zone for the Delhi Pipeline (Figure 6) that left Satartia outside of the affected radius, and therefore the pipeline segment was not identified by Denbury as a "could affect" HCA. Additionally, Satartia was not included in Denbury's PAP or considered in any local

[8] The NWS approved inclusion of the chart within this report and clarified that "Not for Public Dissemination" (in the upper right-hand corner) pertains to real-time emergency response utilization, due to inherent uncertainties with several variables.
[9] Required by 49 CFR § 195.440.

emergency response plans. The rupture location was one mile from the center of Satartia, where the entire town was evacuated.



Figure 6: Topographical Map Showing the Delhi Pipeline (Green) and Denbury's Buffer Zone (Red) on Either Side of the Pipeline and the Proximity to Satartia (Blue Star Indicates the Rupture Site)

Soil and Geohazards

The soil at the failure location is identified as a loess soil typical to the area and was relatively saturated due to the recent heavy rainfall. Dry patches of the soil observed later were powdery, confirming the loess to be silty and clayey, indicating the soil would be prone to absorb water as well as collapse or slump under the right conditions.[10] Vertical erosion of the steeply sloped hillside, made heavier by water saturation, produced enough axial loading on the pipeline to cause the girth weld to fail.

On February 23, 2020, representatives from the Mississippi Department of Transportation assessed the condition of the crater's edge along HWY 433. They determined the highway was at risk of further land movement due to current and future soil saturation from rainfall, the weight of the trees at the edge of the crater, and the HWY 433 ROW was impinged upon by the rupture. Crews were dispatched to cut down the trees and mitigate the risk of additional land movement. Soil instability along roads is not unusual in the region. The PHMSA AID investigator observed road damage from unstable soil slumping away from a road along roadways leading to the accident site. Denbury representatives mentioned that, along the Delhi pipeline, they experience two to three issues per year involving land movement. Denbury's Integrity Management Program (IMP)[11] identified "geo-technical hazards" (geohazards) as a potential risk to its pipelines but lacked additional details concerning threat assessment or preventative/mitigative measures for its operational pipelines such as: using in-line inspection tools with inertial measurement unit sensors, conducting bending strain analysis, or conducting geohazard assessments. Denbury's operations and

[10] Loess soil has a relatively high porosity (typically around 50-55%) and often contains vertical capillaries that allow the sediment to fracture and form vertical bluffs. The loess bluffs tend to erode vertically.
[11] Required by 49 CFR § 195.452.

maintenance (O&M) procedures also lacked substantive information regarding geohazard identification, assessment, remediation, and training for employees. Additionally, Denbury's pipeline patrolling program to address federal regulations[12] was commonly performed by aerial patrol. Records indicate that patrols were made at regular intervals, but no geohazards were identified at the rupture location.

In response to this rupture, PHMSA initiated a specialized review of Denbury's IMP and O&M activities. PHMSA's investigation identified that Denbury did not address the risk of geohazards to the pipeline and take adequate preventive and mitigative measures prior to the accident. PHMSA has made specific recommendations for the development of the company's geohazards program, which the company has initiated.

Welding Procedure

Denbury hired DNV prior to the construction of the pipeline to develop its welding procedure. The welding procedure was developed to API 1104, 20th edition and was qualified. The procedure utilized an E6010 electrode root pass, an E9018G electrode hot pass and E10045 electrode filler and cap pass. In 2009, a welding procedure utilizing an E10045 electrode was a pipeline construction industry leading development. Prior industry practice was to utilize cellulosic-type electrodes.

Laboratory and Root Cause Analyses

Once shoring was installed at the rupture site, the upstream pipe was excavated, and two failed pipe sections were cut out. On March 11, 2020, the two failure samples were secured and shipped to DNV's laboratory in Columbus, Ohio for metallurgical analysis. Denbury worked with Mears to provide DNV with a testing protocol to facilitate analysis. Mott MacDonald performed a site-specific soil movement analysis to estimate soil loading on the pipeline and perform a stress analysis. Mears performed a Root Cause Analysis utilizing the above information, coupled with information from original construction documentation, site observations, operating and maintenance records, and related information.

Denbury reported the results of the metallurgical findings and stress evaluations in a written accident report on the PHMSA Form 7000.1 and indicated soil movement upstream of the failure location induced axial stresses sufficient to cause an overload condition, and the soil movement was promoted by unusually heavy rainfall. There were no material defects observed with the pipe or the failed weld which could have contributed to the failure.

PHMSA notes the failed girth weld exhibited both ductile and brittle fracture appearances. A typical overload condition in these circumstances is expected to be ductile, unless the grain structure of the steel is susceptible to brittle failure, or the material has been chilled below its transition temperature from ductile to brittle behavior. A failure scenario whereby a leak initiates, and the refrigeration effect associated with vaporization of the liquid CO_2 results in a brittle failure is plausible, although a distinct failure origin within the girth weld was not identified.

Findings and Contributing Factors

PHMSA has determined that the failure of the Delhi Pipeline was a result of soil movement which caused excessive axial loading leading to failure at the girth weld. Area topography, soil type, and large amounts of rain over the preceding months saturated and vertically eroded the loess soil on the side of the hill above the pipeline. It is unclear whether prevalent warmer temperatures in the two months preceding the heavy rainfall could have contributed to the soil instability as well.

[12] Required by 49 CFR § 195.412.

Contributing factors include:

- Denbury's O&M procedures did not appear to address the potential for pipeline damage due to soil instability despite having prior experience with and knowledge of land movement risks.
- Denbury's IMP did not appear to address integrity threat identification and/or assessment for geohazards or preventative or mitigative measures.
- Denbury's aerial patrols did not identify a geohazard at the failure location prior to the accident.
- Denbury's CO_2 dispersion model underestimated the potential affected area that could be impacted by a release. As a result, the pipeline segment was not identified as a "could affect" HCA, and Satartia was not included in Denbury's PAP.
- Denbury did not notify local responders advising them of a potential failure. Local responders contacted Denbury approximately 40-minutes after the rupture. This led to confusion in understanding circumstances associated with the emergency and hindered the ability of first responders and community members to safely navigate the emergency.

Appendices

Appendix A Map

Appendix B NRC Reports Nos. 1271847 and 1272001

Appendix C PHMSA 7000.1 Final Report

Appendix D Mears Metallurgical and Root Cause Failure Analysis

Appendix E CTEH Air Monitoring Summary Report

Appendix A Map



Figure 7: An ArcGIS-generated Satellite Map with the Site of the Rupture Marked by the Red Star (the Insert Map on the Bottom Right Shows the Rupture Site Location Within the State of Mississippi)

Appendix B NRC Report No. 1271847

Mathews, Wesley (PHMSA)

From: HQS-SMB-NRC@uscg.mil
Sent: Thursday, May 21, 2020 12:28 PM
To: Mathews, Wesley (PHMSA)
Subject: NRC#1271847

NATIONAL RESPONSE CENTER 1-800-424-8802
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Information released to a third party shall comply with any
applicable federal and/or state Freedom of Information and Privacy Laws

Incident Report # 1271847

INCIDENT DESCRIPTION

*Report taken by NRC on 22-FEB-20 at 22:06 ET.
Incident Type: PIPELINE
Incident Cause: UNKNOWN
Affected Area:
Incident was discovered on 22-FEB-20 at 19:07 local incident time.
Affected Medium: AIR / ATMOSPHERE

SUSPECTED RESPONSIBLE PARTY

Organization: DENBURY GULF COAST PIPELINE

PLANO, TX 75024

Type of Organization: PRIVATE ENTERPRISE

INCIDENT LOCATION

32.658 County: YAZOO
-90.537
City: SATARTIA State: MS
Distance from City: 1 MILES
Direction from City: SE
OFF HWY 433

RELEASED MATERIAL(S)

CHRIS Code: CDO Official Material Name: CARBON DIOXIDE
Also Known As:
Qty Released: 222 BARREL(S)

DESCRIPTION OF INCIDENT

CARBON DIOXIDE RELEASED FROM A 24 INCH PIPELINE DUE TO AN UNKNOWN CAUSE AT THIS TIME. CALLER STATES THE CONTROL ROOM NOTICED A PRESSURE DROP AT 1907 AND PERSONNEL VERIFIED LEAK AT 2046. CALLER ALSO STATES THERE WERE EMERGENCY RESPONDERS ONSITE AS WELL WHEN THEIR PERSONNEL ARRIVED ONSCENE.

INCIDENT DETAILS

Pipeline Type: TRANSMISSION
DOT Regulated: YES
Pipeline Above/Below Ground: BELOW
Exposed or Under Water: NO
Pipeline Covered: UNKNOWN

IMPACT

Fire Involved: NO Fire Extinguished: UNKNOWN

INJURIES: NO Sent to Hospital: Empl/Crew: Passenger:
FATALITIES: NO Empl/Crew: Passenger: Occupant:
EVACUATIONS:NO Who Evacuated: Radius/Area:

Damages: UNKNOWN

Closure Type	Description of Closure	Hours Closed	Direction of Closure

Air: NO

Road: YES HWY 3; HWY 433; EAGLE BEND RD; PERRY CREEK RD — Major Artery:YES
Waterway:NO

Track: NO

Passengers Transferred: NO
Environmental Impact: UNKNOWN
Media Interest: NONE

REMEDIAL ACTIONS

VALVES WERE IMMEDIATELY SHUT AFTER IDENTIFICATION OF PRESSURE DROP.
Release Secured: YES
Release Rate:
Estimated Release Duration:

WEATHER

ADDITIONAL AGENCIES NOTIFIED

Federal:
State/Local:
State/Local On Scene:
State Agency Number:

NOTIFICATIONS BY NRC

CENTERS FOR DISEASE CONTROL (GRASP)
22-FEB-20 22:14

DEPT OF HEALTH AND HUMAN SERVICES (SECRETARY'S OPERATION CENTER (SOC))
22-FEB-20 22:14
AZ OFFIC OF INTEL AND ANALYSIS (FIELD INTELLIGENCE AND INTEGRATION DIVISION)
22-FEB-20 22:14
DHS DEFENSE THREAT REDUCTION AGENCY (CHEMICAL AND BIOLOGICAL TECHNOLOGIES DEPARTMENT)
22-FEB-20 22:14
MS DEPT OF HOMELAND SECURITY (I&A FIELD OPS)
22-FEB-20 22:14
DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)
22-FEB-20 22:14
U.S. EPA IV (MAIN OFFICE)
22-FEB-20 22:17
U.S. EPA IV (EPA RRT4)
22-FEB-20 22:14
GULF STRIKE TEAM (MAIN OFFICE)
22-FEB-20 22:14
JFO-LA (COMMAND CENTER)
22-FEB-20 22:14
MS ANALYSIS AND INFORMATION CENTER (FUSION CENTER)
22-FEB-20 22:14
NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)
22-FEB-20 22:14
NOAA RPTS FOR MS (MAIN OFFICE)
22-FEB-20 22:14
NTSB PIPELINE (MAIN OFFICE)
22-FEB-20 22:14
PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY (AUTO))
22-FEB-20 22:14
PIPELINE & HAZMAT SAFETY ADMIN (HAZARDOUS MATERIAL ACCIDENT INVESTIGATION)
22-FEB-20 22:14
DOI FOR REGION 4 (MAIN OFFICE)
22-FEB-20 22:14
REPORTING PARTY (RP SUBMITTER)
22-FEB-20 22:14
SECTOR LOWER MISSISSIPPI RIVER (AUTO NRC NOTIFICATIONS)
22-FEB-20 22:14
SHELBY SHERIFF'S OFFICE (CRIMINAL INTELLIGENCE UNIT)
22-FEB-20 22:14
MS EMERGENCY MANAGEMENT AGENCY (MAIN OFFICE)
22-FEB-20 22:14
TEXAS FUSION CENTER (COUNTER TERRORISM)
22-FEB-20 22:14
USCG DISTRICT 8 (MAIN OFFICE)
22-FEB-20 22:14
USCG DISTRICT 8 (PLANNING)
22-FEB-20 22:14

ADDITIONAL INFORMATION

THE ROAD CLOSURES ARE STILL ONGOING.

*** END INCIDENT REPORT #1271847 ***

Report any problems by calling 1-800-424-8802

PLEASE VISIT OUR WEB SITE AT

https://gcc01.safelinks.protection.outlook.com/?url=http%3A%2F%2Fnrc.uscg.mil%2F&data=02%7C01%7Cwesley.mathews%40dot.gov%7Cb811754707c84b89d3e308d7fdabecad%7Cc4cd245b44f04395a1aa3848d258f78b%7C0%7C0%7C637256787161489692&sdata=MzcfYqeN1ZIbmwqa6VXKF9L%2FqieIW0kTmcl30E8JTvk%3D&reserved=0

Appendix B NRC Report No. 1272001

Mathews, Wesley (PHMSA)

From: HQS-SMB-NRC@uscg.mil
Sent: Thursday, May 21, 2020 12:30 PM
To: Mathews, Wesley (PHMSA)
Subject: NRC#1272001

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Information released to a third party shall comply with any
applicable federal and/or state Freedom of Information and Privacy Laws

Incident Report # 1272001

INCIDENT DESCRIPTION

*Report taken by NRC on 24-FEB-20 at 19:56 ET.
Incident Type: PIPELINE
Incident Cause: UNKNOWN
Affected Area:
Incident was discovered on 22-FEB-20 at 22:06 local incident time.
Affected Medium: AIR / ATMOSPHERE

SUSPECTED RESPONSIBLE PARTY

Organization: DENBURY GULF COAST PIPELINE

PLANO, TX 75024

Type of Organization: PRIVATE ENTERPRISE

INCIDENT LOCATION
OFF HWY 433 County: YAZOO
City: SATARTIA State: MS
Distance from City: 1 MILES
Direction from City: Latitude: 32° 39' 28" N

Longitude: 090° 32' 13" W

RELEASED MATERIAL(S)
CHRIS Code: CDO Official Material Name: CARBON DIOXIDE
Also Known As:
Qty Released: 21873 BARREL(S)

DESCRIPTION OF INCIDENT
///THIS IS A PHMSA 48HR UPDATE TO NRC REPORT 1271847///

UPDATE: THE CORRECT LAT/LONG FOR THE INCIDENT IS 32.65785 NORTH AND
-90.53695 WEST.
TWO HUNDRED PRIVATE CITIZENS WERE EVACUATED FROM THEIR HOMES IN THE

AREA OF THE RELEASE.
FORTY FIVE PEOPLE WERE TAKEN TO A HOSPITAL. THE NUMBER OF PEOPLE TAKEN TO A HOSPITAL DUE TO INJURIES IS UNKNOWN
TWO PEOPLE ARE STILL AT THE HOSPITAL AS OF 24-FEB-20. THE RELEASE WAS COMPLETELY SECURED AT 23:08HRS ON SATURDAY THE 22-FEB-20. ROAD CLOSURES AND EVACUATION ORDER WAS LIFTED AT 08:00AM ON SUNDAY FEBRUARY 23RD. THE TOTAL AMOUNT OF THE RELEASE WAS DETERMINED TO BE 21,873 BARRELS OF CARBON DIOXIDE GAS. THE EVACUATION RADIUS WAS .25 MILES. TV NEWS AND POSSIBLY NEWSPAPERS IN THE LOCAL AREA AS WELL AS NATIONAL NEWS REPORTED THE INCIDENT. RELEASE DURATION WAS 4 HOURS. PHMSA, MS OIL AND GAS, MS DEQ WERE NOTIFIED. MS DEQ, STATE POLICE, LOCAL FD, LOCAL PD, EMS AND HWY PATROL WERE ALL ON SCENE.

ORIGINAL REPORT: CARBON DIOXIDE RELEASED FROM A 24 INCH PIPELINE DUE TO AN UNKNOWN CAUSE AT THIS TIME. CALLER STATES THE CONTROL ROOM NOTICED A PRESSURE DROP AT 1907 AND PERSONNEL VERIFIED LEAK AT 2046. CALLER ALSO STATES THERE WERE EMERGENCY RESPONDERS ONSITE AS WELL WHEN THEIR PERSONNEL ARRIVED ONSCENE.

INCIDENT DETAILS

Pipeline Type: TRANSMISSION
DOT Regulated: YES
Pipeline Above/Below Ground: BELOW
Exposed or Under Water: NO
Pipeline Covered: UNKNOWN

IMPACT

Fire Involved: NO Fire Extinguished: UNKNOWN

INJURIES: YES 45 Sent to Hospital:45 Empl/Crew: Passenger:
FATALITIES: NO Empl/Crew: Passenger: Occupant:
EVACUATIONS:YES 200 Who Evacuated: EVERYONE Radius/Area:.25 Mile(s)

Damages: NO

Closure Type	Description of Closure	Hours Closed	Direction of Closure

Air: NO

Road: YES HWY 3; HWY 433; EAGLE BEND RD; PERRY CREEK RD Major Artery:YES

Waterway:NO

Track: NO

Passengers Transferred: NO
Environmental Impact: UNKNOWN
Media Interest: HIGH

REMEDIAL ACTIONS

VALVES WERE IMMEDIATELY SHUT AFTER IDENTIFICATION OF PRESSURE DROP
Release Secured: YES
Release Rate:
Estimated Release Duration:

WEATHER

ADDITIONAL AGENCIES NOTIFIED

Federal: PHMSA
State/Local: MS DEQ, MS OIL AND GAS, SATATE POLICE
State/Local On Scene: MS DEQ, STATE POLICE, PD, FD, EMS
State Agency Number:

NOTIFICATIONS BY NRC

AGCY TOXIC SUBST & DISEASE REGISTRY (HHS)
24-FEB-20 20:22
CENTERS FOR DISEASE CONTROL (GRASP)
24-FEB-20 20:22
DEPT OF HEALTH AND HUMAN SERVICES (SECRETARY'S OPERATION CENTER (SOC))
24-FEB-20 20:22
AZ OFFIC OF INTEL AND ANALYSIS (FIELD INTELLIGENCE AND INTEGRATION DIVISION)
24-FEB-20 20:22
DHS DEFENSE THREAT REDUCTION AGENCY (CHEMICAL AND BIOLOGICAL TECHNOLOGIES DEPARTMENT)
24-FEB-20 20:22
MS DEPT OF HOMELAND SECURITY (I&A FIELD OPS)
24-FEB-20 20:22
DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)
24-FEB-20 20:22
EPA HQ EMERGENCY OPERATIONS CENTER (MAIN OFFICE (AUTO))
24-FEB-20 20:22
EPA HQ EMERGENCY OPERATIONS CENTER (AFTER HOURS SECONDARY)
24-FEB-20 20:36
U.S. EPA IV (MAIN OFFICE)
24-FEB-20 20:32
U.S. EPA IV (EPA RRT4)
24-FEB-20 20:22
GULF STRIKE TEAM (MAIN OFFICE)
24-FEB-20 20:22
INFO ANALYSIS AND INFRA PROTECTION (MAIN OFFICE)
24-FEB-20 20:22
JFO-LA (COMMAND CENTER)
24-FEB-20 20:22
MS ANALYSIS AND INFORMATION CENTER (FUSION CENTER)
24-FEB-20 20:22
NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)
24-FEB-20 20:22
NOAA RPTS FOR MS (MAIN OFFICE)
24-FEB-20 20:22
NRC COMMAND DUTY OFFICER (MAIN OFFICE)

24-FEB-20 20:50
NTSB PIPELINE (MAIN OFFICE)
24-FEB-20 20:22
OCCUPATIONAL SAFETY & HEALTH ADMIN (MAIN OFFICE)
24-FEB-20 20:22
PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY (AUTO))
24-FEB-20 20:22
PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY WEEKDAYS (VERBAL))
24-FEB-20 20:34
PIPELINE & HAZMAT SAFETY ADMIN (HAZARDOUS MATERIAL ACCIDENT INVESTIGATION)
24-FEB-20 20:22
DOI FOR REGION 4 (MAIN OFFICE)
24-FEB-20 20:22
REPORTING PARTY (RP SUBMITTER)
24-FEB-20 20:22
SECTOR LOWER MISSISSIPPI RIVER (AUTO NRC NOTIFICATIONS)
24-FEB-20 20:22
SHELBY SHERIFF'S OFFICE (CRIMINAL INTELLIGENCE UNIT)
24-FEB-20 20:22
MS EMERGENCY MANAGEMENT AGENCY (MAIN OFFICE)
24-FEB-20 20:22
TEXAS FUSION CENTER (COUNTER TERRORISM)
24-FEB-20 20:22
USCG DISTRICT 8 (MAIN OFFICE)
24-FEB-20 20:22
USCG DISTRICT 8 (PLANNING)
24-FEB-20 20:22

ADDITIONAL INFORMATION
///THIS IS A PHMSA 48HR UPDATE TO NRC REPORT 1271847///

*** END INCIDENT REPORT #1272001 ***
Report any problems by calling 1-800-424-8802
PLEASE VISIT OUR WEB SITE AT
https://gcc01.safelinks.protection.outlook.com/?url=http%3A%2F%2Fnrc.uscg.mil%2F&data=02%7C01%7Cwesley.mathews%40dot.gov%7Cb126276307c640ca447f08d7fdab7b17%7Cc4cd245b44f04395a1aa3848d258f78b%7C0%7C0%7C637256785273758601&sdata=wEB2Wbm6RWfQw9nm5l8g20CXFahn0HprioWivv3i1Uo%3D&reserved=0

Appendix C PHMSA 7000.1 Final Report

NOTICE: This report is required by 49 CFR Part 195. Failure to report can result in a civil penalty not to exceed $100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122.		OMB NO: 2137-0047 EXPIRATION DATE: 8/31/2020
U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Original Report Date:**	03/21/2020
	No.	20200087 - 34574 --- (DOT Use Only)

ACCIDENT REPORT - HAZARDOUS LIQUID PIPELINE SYSTEMS

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0047. All responses to the collection of information are mandatory. Send comments regarding this burden or any other aspect of this collection of information, including suggestions for reducing the burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

INSTRUCTIONS

Important: *Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the PHMSA Pipeline Safety Community Web Page at http://www.phmsa.dot.gov/pipeline/library/forms.*

PART A - KEY REPORT INFORMATION

Report Type: *(select all that apply)*	**Original:**	**Supplemental:**	**Final:**
		Yes	**Yes**
Last Revision Date:	11/25/2020		
1. Operator's OPS-issued Operator Identification Number (OPID):	32545		
2. Name of Operator	DENBURY GULF COAST PIPELINES, LLC		
3. Address of Operator:			
3a. Street Address	5851 LEGACY CIRCLE SUITE 1200		
3b. City	PLANO		
3c. State	Texas		
3d. Zip Code	75024		
4. Local time *(24-hr clock)* and date of the Accident:	02/22/2020 19:07		
5. Location of Accident:			
Latitude / Longitude	32.65785, -90.53695		
6. National Response Center Report Number (if applicable):	1271847		
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	02/22/2020 20:51		
8. Commodity released: *(select only one, based on predominant volume released)*	CO2 (Carbon Dioxide)		
- Specify Commodity Subtype:			
- If "Other" Subtype, Describe:			
- If Biofuel/Alternative Fuel and Commodity Subtype is Ethanol Blend, then % Ethanol Blend:			
- If Biofuel/Alternative Fuel and Commodity Subtype is Biodiesel, then Biodiesel Blend e.g. B2, B20, B100			
9. Estimated volume of commodity released unintentionally (Barrels):	9,532.00		
10. Estimated volume of intentional and/or controlled release/blowdown (Barrels):	21,873.00		
11. Estimated volume of commodity recovered (Barrels):			
12. Were there fatalities?	No		
- If Yes, specify the number in each category:			
12a. Operator employees			
12b. Contractor employees working for the Operator			
12c. Non-Operator emergency responders			
12d. Workers working on the right-of-way, but NOT associated with this Operator			
12e. General public			
12f. Total fatalities (sum of above)			
13. Were there injuries requiring inpatient hospitalization?	No		
- If Yes, specify the number in each category:			
13a. Operator employees			
13b. Contractor employees working for the Operator			
13c. Non-Operator emergency responders			
13d. Workers working on the right-of-way, but NOT associated with this Operator			
13e. General public			
13f. Total injuries (sum of above)			

14. Was the pipeline/facility shut down due to the Accident?	Yes
- If No, Explain:	
- If Yes, complete Questions 14a and 14b: *(use local time, 24-hr clock)*	
14a. Local time and date of shutdown:	02/22/2020 19:15
14b. Local time pipeline/facility restarted:	10/26/2020 12:30
- Still shut down? (* Supplemental Report Required)	
15. Did the commodity ignite?	No
16. Did the commodity explode?	No
17. Number of general public evacuated:	200
18. Time sequence *(use local time, 24-hour clock)*:	
18a. Local time Operator identified Accident - effective 7- 2014 changed to "Local time Operator identified failure":	02/22/2020 20:20
18b. Local time Operator resources arrived on site:	02/22/2020 20:20

PART B - ADDITIONAL LOCATION INFORMATION

1. Was the origin of the Accident onshore?	Yes
If Yes, Complete Questions (2-12)	
If No, Complete Questions (13-15)	
- If Onshore:	
2. State:	Mississippi
3. Zip Code:	39194
4. City	Not Within a Municipality
5. County or Parish	Yazoo County
6. Operator-designated location:	Milepost/Valve Station
Specify:	6.6
7. Pipeline/Facility name:	Delhi
8. Segment name/ID:	Delhi
9. Was Accident on Federal land, other than the Outer Continental Shelf (OCS)?	No
10. Location of Accident:	Pipeline Right-of-way
11. Area of Accident (as found):	Underground
Specify:	Under soil
- If Other, Describe:	
Depth-of-Cover (in):	360
12. Did Accident occur in a crossing?	No
- If Yes, specify type below:	
- If Bridge crossing –	
Cased/ Uncased:	
- If Railroad crossing –	
Cased/ Uncased/ Bored/drilled	
- If Road crossing –	
Cased/ Uncased/ Bored/drilled	
- If Water crossing –	
Cased/ Uncased	
- Name of body of water, if commonly known:	
- Approx. water depth (ft) at the point of the Accident:	
- Select:	
- If Offshore:	
13. Approximate water depth (ft) at the point of the Accident:	
14. Origin of Accident:	
- In State waters - Specify:	
- State:	
- Area:	
- Block/Tract #:	
- Nearest County/Parish:	
- On the Outer Continental Shelf (OCS) - Specify:	
- Area:	
- Block #:	
15. Area of Accident:	

PART C - ADDITIONAL FACILITY INFORMATION

1. Is the pipeline or facility:	Interstate
2. Part of system involved in Accident:	Onshore Pipeline, Including Valve Sites
- If Onshore Breakout Tank or Storage Vessel, Including Attached Appurtenances, specify:	
3. Item involved in Accident:	Weld, including heat-affected zone
- If Pipe, specify:	
3a. Nominal diameter of pipe (in):	24
3b. Wall thickness (in):	.540

3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	80,000
3d. Pipe specification:	API 5L
3e. Pipe Seam , specify:	Longitudinal ERW - High Frequency
- If Other, Describe:	
3f. Pipe manufacturer:	Stupp Corporation
3g. Year of manufacture:	2007
3h. Pipeline coating type at point of Accident, specify:	Field Applied Epoxy
- If Other, Describe:	
- If Weld, including heat-affected zone, specify. If Pipe Girth Weld, 3a through 3h above are required:	Pipe Girth Weld
- If Other, Describe:	
- If Valve, specify:	
- If Mainline, specify:	
- If Other, Describe:	
3i. Manufactured by:	
3j. Year of manufacture:	
- If Tank/Vessel, specify:	
- If Other - Describe:	
- If Other, describe:	
4. Year item involved in Accident was installed:	2009
5. Material involved in Accident:	Carbon Steel
- If Material other than Carbon Steel, specify:	
6. Type of Accident Involved:	Other
- If Mechanical Puncture – Specify Approx. size:	
in. (axial) by	
in. (circumferential)	
- If Leak - Select Type:	
- If Other, Describe:	
- If Rupture - Select Orientation:	
- If Other, Describe:	
Approx. size: in. (widest opening) by	
in. (length circumferentially or axially)	
- If Other – Describe:	Guillotine Type Failure

PART D - ADDITIONAL CONSEQUENCE INFORMATION

1. Wildlife impact:	No
1a. If Yes, specify all that apply:	
- Fish/aquatic	
- Birds	
- Terrestrial	
2. Soil contamination:	No
3. Long term impact assessment performed or planned:	No
4. Anticipated remediation:	No
4a. If Yes, specify all that apply:	
- Surface water	
- Groundwater	
- Soil	
- Vegetation	
- Wildlife	
5. Water contamination:	No
5a. If Yes, specify all that apply:	
- Ocean/Seawater	
- Surface	
- Groundwater	
- Drinking water: *(Select one or both)*	
- Private Well	
- Public Water Intake	
5b. Estimated amount released in or reaching water (Barrels):	
5c. Name of body of water, if commonly known:	
6. At the location of this Accident, had the pipeline segment or facility been identified as one that "could affect" a High Consequence Area (HCA) as determined in the Operator's Integrity Management Program?	No
7. Did the released commodity reach or occur in one or more High Consequence Area (HCA)?	Yes
7a. If Yes, specify HCA type(s): *(Select all that apply)*	
- Commercially Navigable Waterway:	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	

- High Population Area:	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Other Populated Area	Yes
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	No
- Unusually Sensitive Area (USA) - Drinking Water	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Unusually Sensitive Area (USA) - Ecological	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
8. Estimated cost to Operator – effective 12-2012, changed to "Estimated Property Damage":	
8a. Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator – effective 12-2012, "paid/reimbursed by the Operator" removed	$ 225,899
8b. Estimated cost of commodity lost	$ 11,130
8c. Estimated cost of Operator's property damage & repairs	$ 3,504,518
8d. Estimated cost of Operator's emergency response	$ 205,462
8e. Estimated cost of Operator's environmental remediation	$ 0
8f. Estimated other costs	$ 0
Describe:	
8g. Estimated total costs (sum of above) – effective 12-2012, changed to "Total estimated property damage (sum of above)"	$ 3,947,009

PART E - ADDITIONAL OPERATING INFORMATION

1. Estimated pressure at the point and time of the Accident (psig):	1,402.00
2. Maximum Operating Pressure (MOP) at the point and time of the Accident (psig):	2,160.00
3. Describe the pressure on the system or facility relating to the Accident (psig):	Pressure did not exceed MOP
4. Not including pressure reductions required by PHMSA regulations (such as for repairs and pipe movement), was the system or facility relating to the Accident operating under an established pressure restriction with pressure limits below those normally allowed by the MOP?	No
- If Yes, Complete 4.a and 4.b below:	
4a. Did the pressure exceed this established pressure restriction?	
4b. Was this pressure restriction mandated by PHMSA or the State?	
5. Was "Onshore Pipeline, Including Valve Sites" OR "Offshore Pipeline, Including Riser and Riser Bend" selected in PART C, Question 2?	Yes
- If Yes - (*Complete 5a. – 5f below)* effective 12-2012, changed to *"(Complete 5.a – 5.e below)"*	
5a. Type of upstream valve used to initially isolate release source:	Remotely Controlled
5b. Type of downstream valve used to initially isolate release source:	Remotely Controlled
5c. Length of segment isolated between valves (ft):	50,406
5d. Is the pipeline configured to accommodate internal inspection tools?	Yes
- If No, Which physical features limit tool accommodation? (*select all that apply)*	
- Changes in line pipe diameter	
- Presence of unsuitable mainline valves	
- Tight or mitered pipe bends	
- Other passage restrictions (i.e. unbarred tee's, projecting instrumentation, etc.)	
- Extra thick pipe wall (applicable only for magnetic flux leakage internal inspection tools)	
- Other -	
- If Other, Describe:	
5e. For this pipeline, are there operational factors which significantly complicate the execution of an internal inspection tool run?	Yes
- If Yes, Which operational factors complicate execution? (*select all that apply*)	
- Excessive debris or scale, wax, or other wall buildup	

- Low operating pressure(s)	
- Low flow or absence of flow	Yes
- Incompatible commodity	
- Other -	
- If Other, Describe:	
5f. Function of pipeline system:	> 20% SMYS Regulated Trunkline/Transmission
6. Was a Supervisory Control and Data Acquisition (SCADA)-based system in place on the pipeline or facility involved in the Accident?	Yes
If Yes -	
6a. Was it operating at the time of the Accident?	Yes
6b. Was it fully functional at the time of the Accident?	Yes
6c. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	Yes
6d. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	Yes
7. Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	No
- If Yes:	
7a. Was it operating at the time of the Accident?	
7b. Was it fully functional at the time of the Accident?	
7c. Did CPM leak detection system information (such as alarm (s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	
7d. Did CPM leak detection system information (such as alarm (s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	
8. How was the Accident initially identified for the Operator?	CPM leak detection system or SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations)
- If Other, Specify:	
8a. If "Controller", "Local Operating Personnel", including contractors", "Air Patrol", or "Ground Patrol by Operator or its contractor" is selected in Question 8, specify:	
9. Was an investigation initiated into whether or not the controller(s) or control room issues were the cause of or a contributing factor to the Accident?	Yes, specify investigation result(s): (select all that apply)
- If No, the Operator did not find that an investigation of the controller(s) actions or control room issues was necessary due to: *(provide an explanation for why the operator did not investigate)*	
- If Yes, specify investigation result(s): *(select all that apply)*	
- Investigation reviewed work schedule rotations, continuous hours of service (while working for the Operator), and other factors associated with fatigue	Yes
- Investigation did NOT review work schedule rotations, continuous hours of service (while working for the Operator), and other factors associated with fatigue	
Provide an explanation for why not:	
- Investigation identified no control room issues	Yes
- Investigation identified no controller issues	Yes
- Investigation identified incorrect controller action or controller error	
- Investigation identified that fatigue may have affected the controller(s) involved or impacted the involved controller(s) response	
- Investigation identified incorrect procedures	
- Investigation identified incorrect control room equipment operation	
- Investigation identified maintenance activities that affected control room operations, procedures, and/or controller response	
- Investigation identified areas other than those above:	
Describe:	

PART F - DRUG & ALCOHOL TESTING INFORMATION

1. As a result of this Accident, were any Operator employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?	No
- If Yes:	
1a. Specify how many were tested:	

1b. Specify how many failed:	
2. As a result of this Accident, were any Operator contractor employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?	No
- If Yes:	
2a. Specify how many were tested:	
2b. Specify how many failed:	

PART G – APPARENT CAUSE

Select only one box from PART G in shaded column on left representing the APPARENT Cause of the Accident, and answer the questions on the right. Describe secondary, contributing or root causes of the Accident in the narrative (PART H).

Apparent Cause:	G2 - Natural Force Damage

G1 - Corrosion Failure - only one **sub-cause** can be picked from shaded left-hand column

Corrosion Failure – Sub-Cause:	
- If External Corrosion:	
1. Results of visual examination:	
- If Other, Describe:	
2. Type of corrosion: *(select all that apply)*	
- Galvanic	
- Atmospheric	
- Stray Current	
- Microbiological	
- Selective Seam	
- Other:	
- If Other, Describe:	
3. The type(s) of corrosion selected in Question 2 is based on the following: *(select all that apply)*	
- Field examination	
- Determined by metallurgical analysis	
- Other:	
- If Other, Describe:	
4. Was the failed item buried under the ground?	
- If Yes :	
4a. Was failed item considered to be under cathodic protection at the time of the Accident?	
If Yes - Year protection started:	
4b. Was shielding, tenting, or disbonding of coating evident at the point of the Accident?	
4c. Has one or more Cathodic Protection Survey been conducted at the point of the Accident?	
If "Yes, CP Annual Survey" – Most recent year conducted:	
If "Yes, Close Interval Survey" – Most recent year conducted:	
If "Yes, Other CP Survey" – Most recent year conducted:	
- If No:	
4d. Was the failed item externally coated or painted?	
5. Was there observable damage to the coating or paint in the vicinity of the corrosion?	
- If Internal Corrosion:	
6. Results of visual examination:	
- Other:	
7. Type of corrosion *(select all that apply)*: -	
- Corrosive Commodity	
- Water drop-out/Acid	
- Microbiological	
- Erosion	
- Other:	
- If Other, Describe:	
8. The cause(s) of corrosion selected in Question 7 is based on the following *(select all that apply)*: -	
- Field examination	
- Determined by metallurgical analysis	
- Other:	
- If Other, Describe:	
9. Location of corrosion *(select all that apply)*: -	
- Low point in pipe	
- Elbow	
- Other:	

- If Other, Describe:	
10. Was the commodity treated with corrosion inhibitors or biocides?	
11. Was the interior coated or lined with protective coating?	
12. Were cleaning/dewatering pigs (or other operations) routinely utilized?	
13. Were corrosion coupons routinely utilized?	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Tank/Vessel.	
14. List the year of the most recent inspections:	
14a. API Std 653 Out-of-Service Inspection	
- No Out-of-Service Inspection completed	
14b. API Std 653 In-Service Inspection	
- No In-Service Inspection completed	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
15. Has one or more internal inspection tool collected data at the point of the Accident?	
15a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: -	
- Magnetic Flux Leakage Tool	
Most recent year:	
- Ultrasonic	
Most recent year:	
- Geometry	
Most recent year:	
- Caliper	
Most recent year:	
- Crack	
Most recent year:	
- Hard Spot	
Most recent year:	
- Combination Tool	
Most recent year:	
- Transverse Field/Triaxial	
Most recent year:	
- Other	
Most recent year:	
Describe:	
16. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
If Yes -	
Most recent year tested:	
Test pressure:	
17. Has one or more Direct Assessment been conducted on this segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident::	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
18. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
18a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	

G2 - Natural Force Damage - only one **sub-cause** can be picked from shaded left-handed column

Natural Force Damage – Sub-Cause:	Heavy Rains/Floods
- If Earth Movement, NOT due to Heavy Rains/Floods:	
1. Specify:	

- If Other, Describe:	
- If Heavy Rains/Floods:	
2. Specify:	Other
- If Other, Describe:	,Soil movement, promoted by unusually high rainfall averages and not a singular event, induced axial stresses sufficient to cause an overload condition.,,
- If Lightning:	
3. Specify:	
- If Temperature:	
4. Specify:	
- If Other, Describe:	
- If Other Natural Force Damage:	
5. Describe:	
Complete the following if any Natural Force Damage sub-cause is selected.	
6. Were the natural forces causing the Accident generated in conjunction with an extreme weather event?	No
6a. If Yes, specify: *(select all that apply)*	
- Hurricane	
- Tropical Storm	
- Tornado	
- Other	
- If Other, Describe:	
G3 - Excavation Damage - only one **sub-cause** can be picked from shaded left-hand column	
Excavation Damage – Sub-Cause:	
- If Previous Damage due to Excavation Activity: Complete Questions 1-5 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
1. Has one or more internal inspection tool collected data at the point of the Accident?	
1a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: -	
- Magnetic Flux Leakage	
Most recent year conducted:	
- Ultrasonic	
Most recent year conducted:	
- Geometry	
Most recent year conducted:	
- Caliper	
Most recent year conducted:	
- Crack	
Most recent year conducted:	
- Hard Spot	
Most recent year conducted:	
- Combination Tool	
Most recent year conducted:	
- Transverse Field/Triaxial	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
2. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
3. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
4. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident:	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
5. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
5a. If Yes, for each examination, conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	

Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
Complete the following if Excavation Damage by Third Party is selected as the sub-cause.	
6. Did the operator get prior notification of the excavation activity?	
6a. If Yes, Notification received from: *(select all that apply)* -	
- One-Call System	
- Excavator	
- Contractor	
- Landowner	
Complete the following mandatory CGA-DIRT Program questions if any Excavation Damage sub-cause is selected.	
7. Do you want PHMSA to upload the following information to CGA-DIRT (www.cga-dirt.com)?	
8. Right-of-Way where event occurred: *(select all that apply)* -	
- Public	
- If "Public", Specify:	
- Private	
- If "Private", Specify:	
- Pipeline Property/Easement	
- Power/Transmission Line	
- Railroad	
- Dedicated Public Utility Easement	
- Federal Land	
- Data not collected	
- Unknown/Other	
9. Type of excavator:	
10. Type of excavation equipment:	
11. Type of work performed:	
12. Was the One-Call Center notified?	
12a. If Yes, specify ticket number:	
12b. If this is a State where more than a single One-Call Center exists, list the name of the One-Call Center notified:	
13. Type of Locator:	
14. Were facility locate marks visible in the area of excavation?	
15. Were facilities marked correctly?	
16. Did the damage cause an interruption in service?	
16a. If Yes, specify duration of the interruption (hours)	
17. Description of the CGA-DIRT Root Cause *(select only the one predominant first level CGA-DIRT Root Cause and then, where available as a choice, the one predominant second level CGA-DIRT Root Cause as well):*	
Root Cause:	
- If One-Call Notification Practices Not Sufficient, specify:	
- If Locating Practices Not Sufficient, specify:	
- If Excavation Practices Not Sufficient, specify:	
- If Other/None of the Above, explain:	
G4 - Other Outside Force Damage - *only one **sub-cause** can be selected from the shaded left-hand column*	
Other Outside Force Damage – Sub-Cause:	
- If Damage by Car, Truck, or Other Motorized Vehicle/Equipment NOT Engaged in Excavation:	
1. Vehicle/Equipment operated by:	
- If Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equipment or Vessels Set Adrift or Which Have Otherwise Lost Their Mooring:	
2. Select one or more of the following IF an extreme weather event was a factor:	
- Hurricane	
- Tropical Storm	
- Tornado	
- Heavy Rains/Flood	
- Other	
- If Other, Describe:	
- If Previous Mechanical Damage NOT Related to Excavation: Complete Questions 3-7 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	

3. Has one or more internal inspection tool collected data at the point of the Accident?	
3a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	
Most recent year conducted:	
- Ultrasonic	
Most recent year conducted:	
- Geometry	
Most recent year conducted:	
- Caliper	
Most recent year conducted:	
- Crack	
Most recent year conducted:	
- Hard Spot	
Most recent year conducted:	
- Combination Tool	
Most recent year conducted:	
- Transverse Field/Triaxial	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
4. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
5. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
6. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident:	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
7. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
7a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
- If Intentional Damage:	
8. Specify:	
- If Other, Describe:	
- If Other Outside Force Damage:	
9. Describe:	

G5 - Material Failure of Pipe or Weld - only one **sub-cause** can be selected from the shaded left-hand column

Use this section to report material failures ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is "Pipe" or "Weld."	
Material Failure of Pipe or Weld – Sub-Cause:	
1. The sub-cause shown above is based on the following: *(select all that apply)*	
- Field Examination	
- Determined by Metallurgical Analysis	
- Other Analysis	
- If "Other Analysis", Describe:	
- Sub-cause is Tentative or Suspected; Still Under Investigation	

(Supplemental Report required)	
- If Construction, Installation, or Fabrication-related:	
2. List contributing factors: *(select all that apply)*	
- Fatigue or Vibration-related	
Specify:	
- If Other, Describe:	
- Mechanical Stress:	
- Other	
- If Other, Describe:	
- If Environmental Cracking-related:	
3. Specify:	
- If Other - Describe:	
Complete the following if any Material Failure of Pipe or Weld sub-cause is selected.	
4. Additional factors: (*select all that apply*):	
- Dent	
- Gouge	
- Pipe Bend	
- Arc Burn	
- Crack	
- Lack of Fusion	
- Lamination	
- Buckle	
- Wrinkle	
- Misalignment	
- Burnt Steel	
- Other:	
- If Other, Describe:	
5. Has one or more internal inspection tool collected data at the point of the Accident?	
5a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	
Most recent year run:	
- Ultrasonic	
Most recent year run:	
- Geometry	
Most recent year run:	
- Caliper	
Most recent year run:	
- Crack	
Most recent year run:	
- Hard Spot	
Most recent year run:	
- Combination Tool	
Most recent year run:	
- Transverse Field/Triaxial	
Most recent year run:	
- Other	
Most recent year run:	
Describe:	
6. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
7. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident -	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site -	
Most recent year conducted:	
8. Has one or more non-destructive examination(s) been conducted at the point of the Accident since January 1, 2002?	
8a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted: -	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	

Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
G6 – Equipment Failure - only one **sub-cause** can be selected from the shaded left-hand column	
Equipment Failure – Sub-Cause:	
- If Malfunction of Control/Relief Equipment:	
1. Specify: *(select all that apply)* -	
- Control Valve	
- Instrumentation	
- SCADA	
- Communications	
- Block Valve	
- Check Valve	
- Relief Valve	
- Power Failure	
- Stopple/Control Fitting	
- ESD System Failure	
- Other	
- If Other – Describe:	
- If Pump or Pump-related Equipment:	
2. Specify:	
- If Other – Describe:	
- If Threaded Connection/Coupling Failure:	
3. Specify:	
- If Other – Describe:	
- If Non-threaded Connection Failure:	
4. Specify:	
- If Other – Describe:	
- If Other Equipment Failure:	
5. Describe:	
Complete the following if any Equipment Failure sub-cause is selected.	
6. Additional factors that contributed to the equipment failure: *(select all that apply)*	
- Excessive vibration	
- Overpressurization	
- No support or loss of support	
- Manufacturing defect	
- Loss of electricity	
- Improper installation	
- Mismatched items (different manufacturer for tubing and tubing fittings)	
- Dissimilar metals	
- Breakdown of soft goods due to compatibility issues with transported commodity	
- Valve vault or valve can contributed to the release	
- Alarm/status failure	
- Misalignment	
- Thermal stress	
- Other	
- If Other, Describe:	
G7 - Incorrect Operation - only one **sub-cause** can be selected from the shaded left-hand column	
Incorrect Operation – Sub-Cause:	
- If Tank, Vessel, or Sump/Separator Allowed or Caused to Overfill or Overflow	
1. Specify:	
- If Other, Describe:	

- If Other Incorrect Operation	
2. Describe:	
Complete the following if any Incorrect Operation sub-cause is selected.	
3. Was this Accident related to *(select all that apply)*: -	
- Inadequate procedure	
- No procedure established	
- Failure to follow procedure	
- Other:	
- If Other, Describe:	
4. What category type was the activity that caused the Accident?	
5. Was the task(s) that led to the Accident identified as a covered task in your Operator Qualification Program?	
5a. If Yes, were the individuals performing the task(s) qualified for the task(s)?	

G8 - Other Accident Cause - only one **sub-cause** can be selected from the shaded left-hand column

Other Accident Cause – Sub-Cause:	
- If Miscellaneous:	
1. Describe:	
- If Unknown:	
2. Specify:	

PART H - NARRATIVE DESCRIPTION OF THE ACCIDENT

On 2/22/2020 at 19:07, the Denbury Control Center (DCC) observed a low-pressure alarm at the Satartia motor operated valve (MOV) location on the Delhi segment. The Control Center Supervisor was notified and at 19:15 the upstream MOV, downstream MOV, and the Satartia MOV were closed by the DCC. Denbury operations personnel were immediately notified by the DCC of low-pressure alarms and valve closures and were mobilized to the area in addition to emergency response contractors. While mobilization of personnel occurred, the DCC closed all CO2 sources to Delhi segment between 19:26 and 19:28. At 19:54, a Denbury representative contacted the Tri-Community Fire Chief, who was on-site and identified himself as the Incident Commander on location acknowledging the incident was being managed in the Unified Command. Denbury personnel arrived on-site at 20:20 to confirm the Delhi segment had experienced a pipeline failure upstream of the Hwy 433 road crossing. At 20:21, a Denbury representative contacted the Yazoo County EMA, who was directing the Yazoo County Sheriffs Department, MS Highway Patrol, and MDOT. The Yazoo County EMA confirmed that they began facilitating the evacuation of residence near Satartia, MS at approximately 19:20. MSDEQ was notified at 19:58. Both MSDEQ and MEMA were on-scene and performing supporting agency roles during the emergency phase of the response (4 hours). At 20:51, the NRC was notified, and the CO2 leak was reported (NRC #1271847). At 21:36 emergency response contractors arrived on-site and began conducting preliminary air-monitoring for response personnel. At 21:55 additional emergency response contractors arrived on-site and began conducting community air monitoring and atmospheric testing in and around the failure site and the City of Satartia and the surrounding area. Air monitoring and atmospheric testing continued throughout the night. At 23:06, Denbury personnel observed no product coming from the failure location. At 0:00 on 2/23/2020, an Operation Period Briefing was conducted by the Unified Command. During the briefing, the incident command team instructed responders to continue air monitoring, conduct reconnaissance within the evacuated areas to ensure no people were left behind, clear the debris and soil off of HWY 433, and begin developing a plan to lift the evacuation. At 06:00 a planning meeting was conducted by the Unified Command. The recon team confirmed all personnel had been evacuated and reported seeing live cows, dogs, and cats throughout the evacuated area. The air monitoring team also reported that CO2 levels were down to ambient levels and the evacuation could be lifted. At 08:00 the Unified Command gave the All Clear, and the roads were opened and residents in the surrounding area were allowed to return to their homes. Personnel and a toxicologist from CTEH were made available to inspect homes prior to the residence re-entry. At 18:39 on 2/24/2020, the NRC was contacted and given a 48-hour update report (NRC #1272001). A total of 200 residents were evacuated and 45 residents were taken to the hospital. To Denburys knowledge, one individual was admitted to the hospital for reasons unrelated to the pipeline failure.

On 3/9/2020 pipeline samples of the failure location were removed, prepared for shipment, and sent to a testing laboratory on 3/11/2020. The results from the laboratory testing were received and shared with PHMSA on 6/26/2020.

Based on the findings of metallurgical and stress evaluations and the evidence of a code compliant pipeline, it is concluded that soil movement upstream of the failure location induced axial stresses sufficient to cause an overload condition and resulted in the pipeline rupture. Soil movement was promoted by unusually high rainfall averages and not a singular rainfall event.

The pipeline segment was repaired and on 10/26/2020 at 12:30 the pipeline was restarted with no issues.

PART I - PREPARER AND AUTHORIZED SIGNATURE

Preparer's Name	Chad Docekal
Preparer's Title	Regulatory Compliance Specialist
Preparer's Telephone Number	9726732734
Preparer's E-mail Address	chad.docekal@denbury.com
Preparer's Facsimile Number	
Authorized Signer Name	David Sheppard
Authorized Signer Title	Senior Vice President - Operations
Authorized Signer Telephone Number	9726732038
Authorized Signer Email	david.sheppard@denbury.com
Date	11/24/2020

Appendix D Mears Metallurgical and Root Cause Failure Analysis



4500 N. Mission Road

Rosebush, MI 48878

PHONE 989.433.2929

WEB mears.net

Study of Root Cause and Contributing Factors

Denbury – Yazoo County

Failure Investigation

Final Report

Revised 9/02/2021

Prepared for:

Denbury Resources Inc.

Prepared by:

Mears Group, Inc.

[redacted]

September 2, 2021

Denbury Resources Inc.
5320 Legacy Drive
Plano, TX 75024
(214) 662-2536
chad.docekal@denbury.com

Attention: Chad Docekal

Subject: Denbury Delhi 24-inch Transmission Line failure Root Cause Analysis – Final Report, Revised 9/02/2021

Thank you for the opportunity to provide Denbury Resources with root cause investigation and analysis for the Denbury Delhi 24-inch transmission line near Satartia, Mississippi. This revision includes additional appendices providing supporting information and responses to questions provided to Mears 4/7/2021. If you have any questions or comments, please call me at (614) 832-3896.

Sincerely,

Kevin Garrity
Executive Vice President

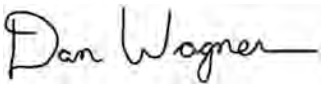
Cc: Dan Wagner
Aida Lopez-Garrity
Kurt Lawson

mears
A QUANTA SERVICES COMPANY

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Study of Root Cause and Contributing Factors
Denbury – Yazoo County
Failure Investigation
Final Report

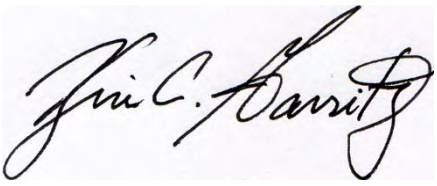
Prepared by:



Dan Wagner – Principal Technical Advisor — 9/02/2021 Date



Aida Lopez-Garrity – Executive Director – Special Projects — 9/2/2021 Date



Kevin C. Garrity, P.E., FNACE – Executive Vice President — 9/2/2021

Executive Summary

Mears Group, Inc. (Mears) was retained by Denbury Resources (Denbury) to support investigation efforts and provide a Root Cause Analysis (RCA) in coordination with their response to a pipeline failure on the Delhi 24-inch Transmission Line near Satartia, Mississippi. The failure is reported to have occurred February 22, 2020, with a rupture approximately 6.59 miles (stationing 348+26) downstream of the Tinsley, MS station.

The investigation into the cause and contributing factors to the Delhi 24-inch failure has been undertaken through the following activities:

- In-Situ investigations at the incident location,
- Corrosion and coating related assessments,
- A review of available documents and information associated with the design, specification, construction, operation and maintenance of the pipeline infrastructure, and
- Laboratory Analysis of the Failure.

Metallurgical Testing and Failure Analysis was performed on three samples of pipe from the failure site. The metallurgical testing laboratory completed the following tests and examinations:

- Physical examination,
- Photographic documentation and videography,
- Magnetic Particle Inspection,
- Scanning electron microscopy,
- Metallographic analysis,
- Hardness testing,
- Mechanical testing, and
- Chemical analysis.

The results of the metallurgical testing have been analyzed for the purposes of this report and are relied upon in the formulation of the opinions and conclusions expressed in this report.

□□□□d □□ □□□ □□d□□□□ □r□□□□□d□□□□ pipeline failure occurred at the girth weld due to an overload of axial stress on the weld. A possible contributing factor to the failure may have been axial stresses introduced by movement. These □□d□□□□ □r□ □□□□□r□d □□ □□□ □□□□□ □□□□

1. The brittle failure originated at a girth weld. The presence of soft regions with dimples (ductile mode) and cleavage facets (brittle mode) are characteristics typical of a failure from overload conditions.
2. The failure occurred due to axial stresses. There was no indication of a pre-existing defect and a specific failure initiation site was not apparent.
3. The weld metal for both the failed girth weld and the intact weld was found to have lower hardness values than the surrounding pipe materials indicating the weld metal was weaker than the pipe material and thus, more susceptible to overload under axial stress conditions. The findings do not suggest the failure resulted from a welding quality issue.
4. There was no evidence of internal or external corrosion that may have contributed to the failure mode.
5. The mechanical and chemical testing results were in accordance with the requirements for API 5L X-80M PSL 2 line pipe.
6. The microstructure of the pipe material U/S and D/S of the failed girth weld are consistent with modern X-80M PSL 2 line pipe steel.

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Acronyms and Abbreviations

API	American Petroleum Institute
ARO	Abrasion Resistant Overlay
CP	Cathodic Protection
CVN	Charpy V-Notch
D/S	Downstream
EDS	Energy-Dispersive Spectroscopy
ERW	Electric Resistance Welding
FATT	Fracture Appearance Transition Temperature
FBE	Fusion Bonded Epoxy
GW	Girth Weld
HAZ	Heat Affected Zone
HDD	Horizontal Directional Drilling
HF-ERW	High Frequency Electric Resistance Welding
HV	Hardness Value
ID	Inside Diameter
MAOP	Maximum Allowable Operating Pressure
MPI	Magnetic Particle Inspection
NWT	Nominal Wall Thickness
OD	Outside Diameter
PS	Pipe Sample
PSIG	Pounds per Square Inch Gauge
PSL	Product Specification Levels
RCA	Root Cause Analysis
SEM	Scanning Electron Microscope
SMYS	Specified Minimum Yield Strength
TS	Tensile Strength
U/S	Upstream
UTS	Ultimate Tensile Strength

WT	Wall Thickness
YS	Yield Strength

1.0 INTRODUCTION

Mears Group, Inc. (Mears) was retained by Denbury Resources (Denbury) to support investigation efforts and provide a Root Cause Analysis (RCA) in coordination with their response to a pipeline failure on the Delhi 24-inch Transmission Line near Satartia, Mississippi. The incident is reported to have occurred on February 22, 2020, when a failure occurred on the 24-inch Delhi Transmission Line, resulting a rupture of the pipeline.

The information, material and documentation reviewed and relied upon in the formation of the findings expressed include:

- Pipe and coating data,
- Alignment Sheets,
- Indirect inspection results,
- Google Earth™ imagery,
- As-built drawings and sketches,
- Onsite inspections,
- Field and laboratory test results,
- Metallurgical examination reports,
- Welding Procedures,
- Stress Analysis Report, and
- Personnel interviews.

The findings expressed are based upon the information reviewed to date and analyses performed to date and may be modified as new or additional information/analysis are considered.

2.0 BACKGROUND

The Delhi 24-inch Transmission Line serves as a carrier of carbon dioxide and is approximately 77.4 miles in length. The pipeline segment begins at the Denbury Tinsley Station in Yazoo County, Mississippi and continues to a meter station near Delhi, Louisiana. An overview of the pipeline segment is provided in Figure 1.

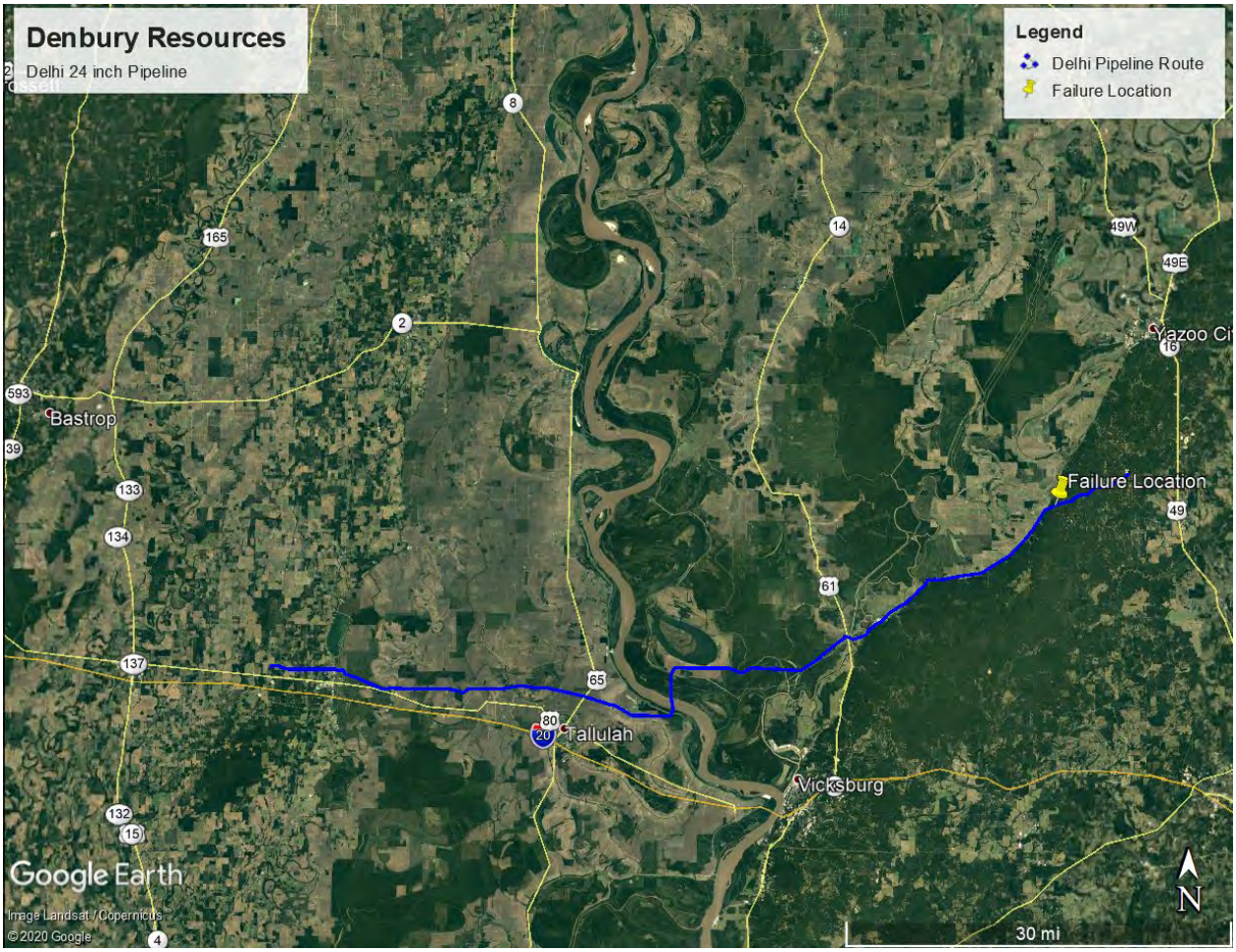


Figure 1. Delhi 24-inch Transmission Pipeline Route

2.1 Pipeline Construction Data

The Delhi 24-inch Transmission Line is documented as installed in 2009, primarily of 0.469-inch wall thickness, API 5L Grade X-80M PSL 2 piping, with a high frequency electric resistance welded (HF-ERW) seam, coated with fusion-bonded epoxy (FBE). Sections of piping installed using slick bore were constructed of 0.540-inch X-80 coated with FBE and an additional layer of abrasion-resistant overcoat (ARO). The pipeline has a diameter of 24 inches. A simplified overview of the pipeline segment is provided in Figure 2.

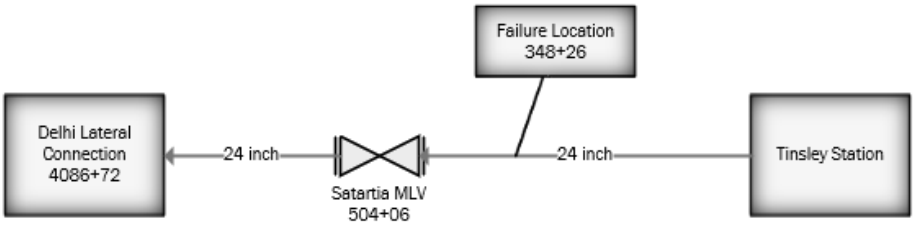


Figure 2. Simplified Delhi 24-inch Transmission Line Diagram

A summary of pipeline information for the Delhi 24-inch Transmission Line in included in Table 1.

Table 1. Pipeline Data

Pipeline Information	Delhi 24-inch Transmission Line
Line Length (miles)	77.4
Pipe Outside Diameter (inches)	24
Pipe Wall Thickness (inches)	0.469, 0.540
Pipe Grade	X-80
Maximum Allowable Operating Pressure (MAOP, psi)	2,160
Normal Operating Stress Level (psi)	1,200-1,450
Pressure at Time of Failure (psi)	1,336
Pipe Seam Type	ERW
Product Carried	Carbon Dioxide (dry)
Pipe Construction Date	2009
Pipe Coatings (type/thickness)	FBE 14-16 mils and ARO 40 mils
Girth Weld Coatings	Liquid Epoxy – SPC-2888

A post-construction hydrostatic pressure test was reported to have been conducted on the piping in January 2009 to a minimum test pressure of 2,908 psig at the Dead Weight Location for 8 hours.

The pipeline is reported to have had impressed current cathodic protection applied since the date of construction with no interference bonds and two continuity bonds at the start and end of the pipeline section.

2.2 Incident Summary

The incident is reported to have occurred after 7:00 p.m. local time, based on resident reports and an evacuation order, on February 22, 2020 near Satartia Mississippi, when a failure occurred at a girth weld, resulting in a rupture of the pipe near a crossing of Mississippi Highway 433 approximately 1 mile southeast of Satartia. The line was shut down and valves closed at approximately 7:17 p.m. as reported by Denbury.

The failure occurred on a pipe section consisting of 24-inch diameter by 0.540-inch wall thickness API 5L Grade X-80M PSL 2 line pipe with a high frequency electric resistance welded (HF ERW) seam. The pipe at the site of the failure was installed using slick bore, coated with FBE/ARO on the pipe and liquid epoxy coating applied on the girth welds. The failure occurred at approximate stationing 348+26, about 6.59 miles downstream of the Tinsley Station at the base of a hill, significantly lower in elevation than the surface of Highway 433. The pipeline normally operates between 1,200 psig and 1,450 psig. At the time of the failure, the pressure at the Tinsley Meter Station (0+00) was 1,336 psig.

A Google Earth™ overview of the failure location is provided in Figure 3.



Figure 3. Delhi 24-inch Transmission Failure Location

A photo of the failure location post-incident is included in Figure 4.



Figure 4. Post-Incident Photo of Failure Location (Downstream to Upstream)

3.0 ROOT CAUSE ANALYSIS PROCESS

A failure action sequence was used for the purposes of performing the Root Cause Analysis.

The basic role of a root cause analysis is as follows:

- Collect information.
- Understand what happened.
- Identify the problems that caused the incident.
- Analyze each problem's root causes.
- Look beyond root causes for systemic, cultural, and organizational factors.
- Develop recommendations for remediation to improve performance and prevent repeat incidents.

Since root cause analyses are normally associated with incidents or accidents, much of the existing terminology in use refers to "incidents".

A typical Failure Action Response Sequence adapted from Guidance for Plant Personnel on Gathering Data and Samples for Materials Failure Analysis MTI catalog MTI 9539 is shown in Figure 5.

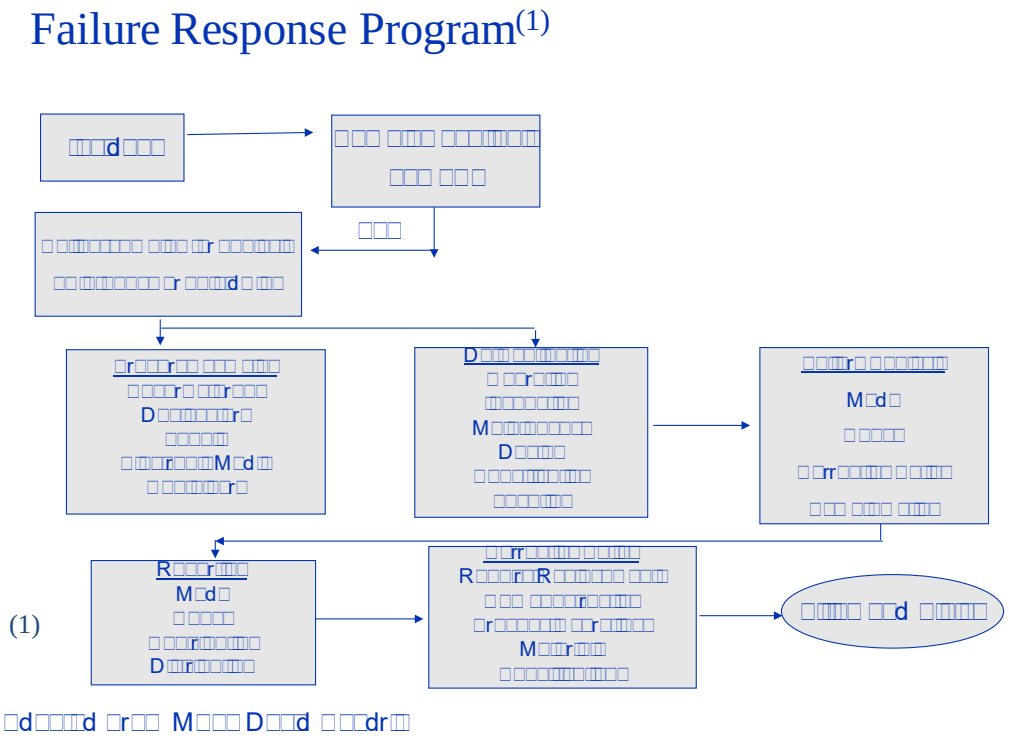


Figure 5. Failure Response Sequence

The root cause analysis focused on identifying the root cause(s) of the pipeline failure and contributing factors.

4.0 DESCRIPTION OF INVESTIGATIVE PROCESS

The investigation into the cause and contributing factors to the Delhi 24-inch Transmission line failure has been undertaken through the following activities:

1. In-Situ investigations at the release location,
2. Corrosion and coating related assessments,
3. A review of available documents and information associated with the design, specification, construction, operation and maintenance of the pipeline infrastructure, and
4. Laboratory failure analysis of the failure.

Metallurgical testing and a failure analysis were performed on three samples of pipe from the release site. The metallurgical testing lab completed the following tests and examinations:

- Physical examination,
- Photographic documentation and videography,
- Magnetic Particle Inspection,
- Scanning electron microscopy,
- Metallographic analysis,
- Hardness testing,
- Mechanical testing, and
- Chemical analysis.

The results of the metallurgical testing have been analyzed for the purposes of this report and are relied upon in the formulation of the opinions and conclusions expressed in this report.
The available information related to construction, prior integrity assessments and cathodic protection was analyzed to assist in establishing the root cause and contributing factors of the failure.

4.1 In-Situ Investigation Findings

On February 27, Mears mobilized to the release location to secure the failed pipe sections for laboratory investigation, perform initial site investigations, and collect information to support the root cause analysis.

Upon arrival, significant response and operational activities had been undertaken to secure the site and prepare for excavation and removal of the pipe section.

From initial visual examination, the failure appeared to have occurred at least 40 feet in elevation below the roadway, with indications of soil subsidence in the vicinity of the failure. The release crater included trees and root debris, but based on the pipeline alignment sheet elevation profile, a significant volume of soil in the slick bore section between the failure and MS Highway 433 had collapsed. The soil in the vicinity of the failure appeared to be extremely wet.

Figure 6 and Figure 7 show the view of the release location as-found on February 27, 2020.



Figure 6. Failure Location (Upstream to Downstream)



Figure 7. Failure Location (Upstream to Downstream)

Personnel were unable to access the pipe at the failure location due to the depth of the crater and instability of the soil on the downstream side of the crater.

In-situ visual inspection of the exterior surface of the pipe identified a separation of the piping at a girth weld of approximately 8 inches, with slight misalignment between the upstream and downstream joints. Figure 8 provides a close-up of the as-found pipe and coating condition at the separation.



Figure 8. Delhi 24-inch Transmission Line Failure - As-Found Condition at Girth Weld

A protocol was developed for removal of pipe samples in the vicinity of the failure, to include the upstream and downstream sections of the failure and an intact girth weld near the failure location. A copy of the Pipe Collection Protocol is provided in Appendix A.

Removal of the samples began on March 9, 2020. Excavation and removal of an upstream section of piping included the upstream half of the failure and the intact girth weld noted above. This section was approximately 68 feet 5 ½ inches in length.

Figure 9 shows the upstream pipe section being removed from the site.



Figure 9. Upstream Pipe Section During Removal

Following removal of the upstream section, limited excavation and backfill was conducted to allow access to the downstream side of the failure. A section of pipe containing the downstream section of the failure was then removed using a magnesium torch attached to the bucket of an excavator.

Once moved to an accessible location, the pipe sections were documented, samples were cut and prepared for shipment to the laboratory. Figure 10 provides an overview of the pipe sections as removed and prepared for shipment.

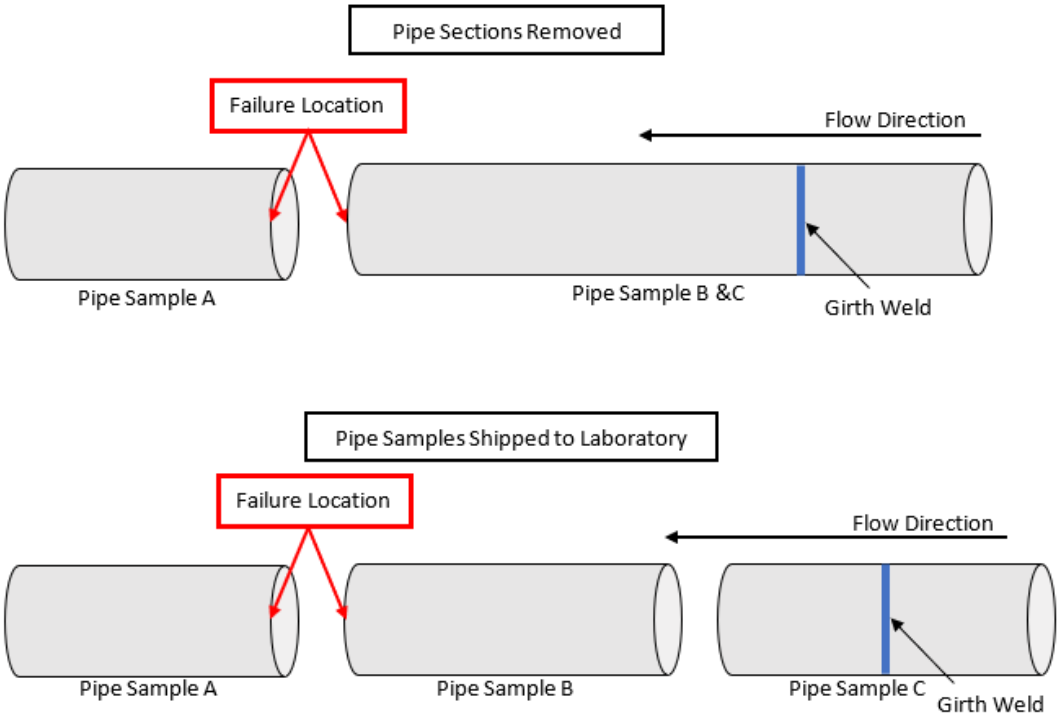


Figure 10. Overview of Pipe Sections and Samples

Visual inspection of the external surface of the pipe sections identified an area of coating damage near the failure, which appeared to have occurred as a result of the failure (no pitting, attached solids, and apparent adhesive failure). No external corrosion was observed and the pipe coating on the remainder of the section appeared to be in excellent condition.

Initial visual inspection of the internal surface of the piping showed no accumulated solids or liquids in the pipe sample and no indications of pitting or corrosion. A view of the internal condition of the pipe section containing samples B & C after removal is provided in Figure 11.



Figure 11. Internal Condition of Pipe Sample During Removal

Soil samples were collected from the area around the pipe for chemical and microbiological analysis, the failure surfaces were protected with foam insulation, then the pipe samples were wrapped, crated and shipped to the laboratory for metallurgical testing on March 10, 2020. The approximate lengths of the pipe samples were PS A – 6 feet, PS B – 6 feet and PS C – 8 feet.

5.0 LABORATORY INVESTIGATION FINDINGS

Metallurgical Testing and a Failure Analysis was performed on a multiple pipe samples from the release site. The work was conducted under Mears direction by a third-party independent laboratory (DNV GL). The metallurgical testing consisted of the following tests and examinations:

- Physical Examination,
- Photographic documentation and videography,
- Scanning electron microscopy
- Metallographic Analysis,

- Hardness testing, and
- Chemical analysis.

The metallurgical sampling and testing protocol utilized for the laboratory investigations is included in Appendix B.

5.1 Visual and Nondestructive Examination

The pipe sections were removed from the shipping crates, visually inspected and photographed. As noted above, some of the pipe coating adjacent to the failed girth weld was missing on PS A and PS B. This may be due to the fact that CO2 is in a supercritical state at about 1,000 psig and about 60°F during the transportation before the rupture. The release of CO2 after the rupture from the actual operating conditions to the atmospheric conditions commonly results in an accumulation and flow of dry ice (i.e. -70°F or colder) which may have impacted adhesion to the pipe.

The mill-applied pipe coating (FBE/ARO) was brown in color, with a light blue liquid epoxy applied to the girth welds. Black residue was found adjacent to ends of the pipe samples cut in the field using an acetylene torch. Figure 12, Figure 13 and Figure 14 show the as-received pipe samples after removal from the crates and protective wrappings.

The pipe adjacent to the fracture surfaces and failed girth weld were visually inspected. The fractured surface was flat and generally at a 180-degree angle with no thinning and/or reduction of the affected area. The fracture path traversed or crossed over the weld at various locations.

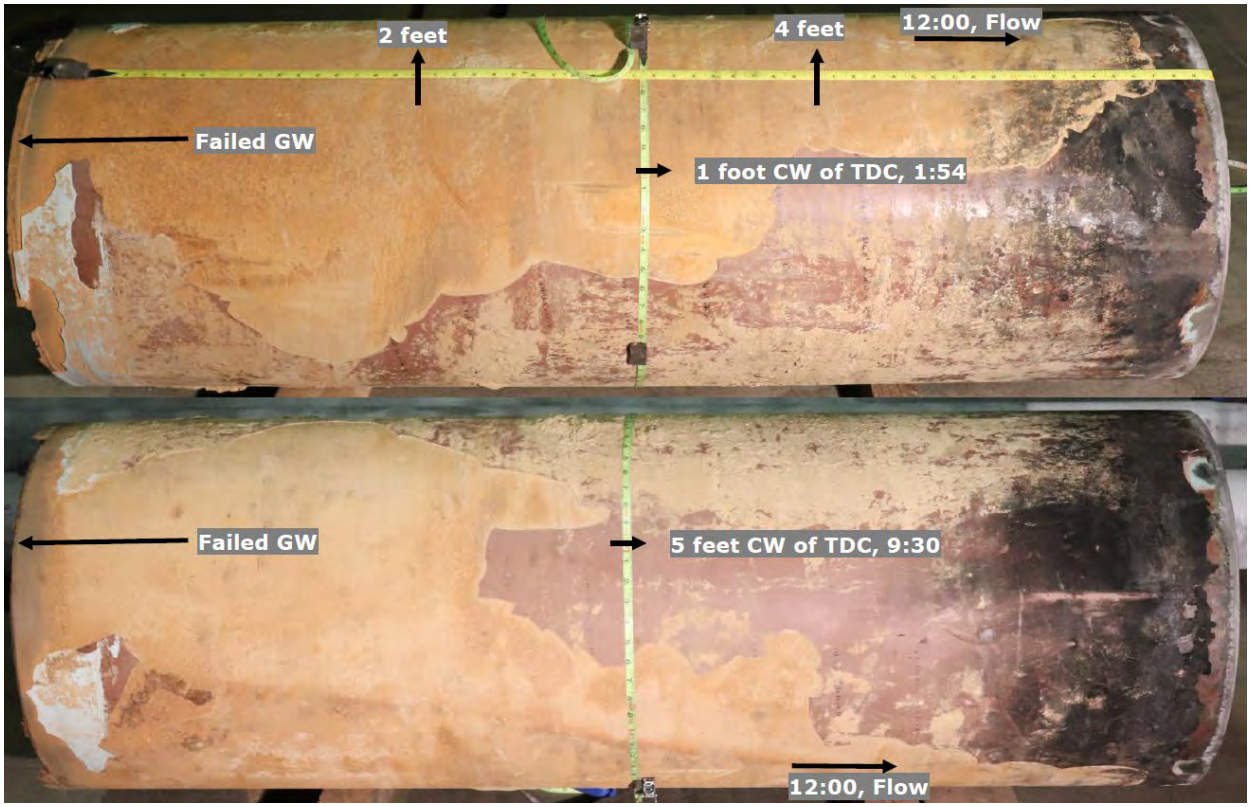


Figure 12. Pipe Sample A (PS A)



Figure 13. Pipe Sample B (PS B)



Figure 14. Pipe Sample C (PS C)

A photograph of the fracture surface of PS A is provided in Figure 15.



Figure 15. PS A Fracture Surface (Upstream to Downstream)

Pipe circumferences and diameters were measured at the field-cut ends of the pipe sections, finding no measurable ovality and diameters meeting API 5L tolerances for the 24-inch diameter pipe. Wall thicknesses were between 0.530 inches and 0.540 inches, which meet API 5L tolerances for pipe with a nominal wall thickness (NWT) of 0.540 inches.

The intact girth weld (PS C) was grit blasted and MPI was conducted on the external and internal surfaces. No crack-like indications were identified.

After detailed visual inspection and measurements were collected, the pipe samples were aligned and evaluated to identify locations for further sampling and metallurgical analyses. An overview of the locations selected for metallography (M, MU), fractography (S), mechanical and chemical analyses is provided in Figure 16.

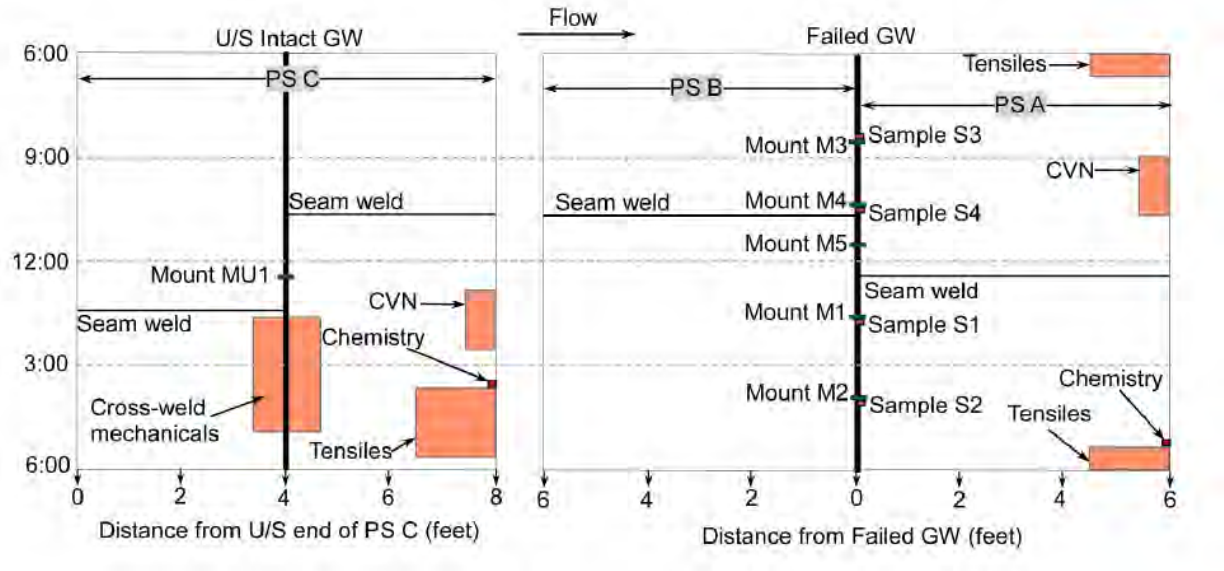


Figure 16. Laboratory Testing and Sample Schematic

5.2 Defect Examination

The internal and external surfaces of the failed girth weld were cleaned with a soft bristle brush to for more detailed examination. Five areas were selected for metallurgical analyses of the failed girth weld (PS A, PS B) and one area from the intact girth weld in PS C. The fracture surface consisted of smooth regions and rougher surfaces that varied in thickness throughout the rupture face. An example of these regions is provided in Figure 17. There was no evidence of pre-existing manufacturing flaws. It was not possible to determine the exact location of the failure initiation process due to the lack of chevrons on the fracture surface.

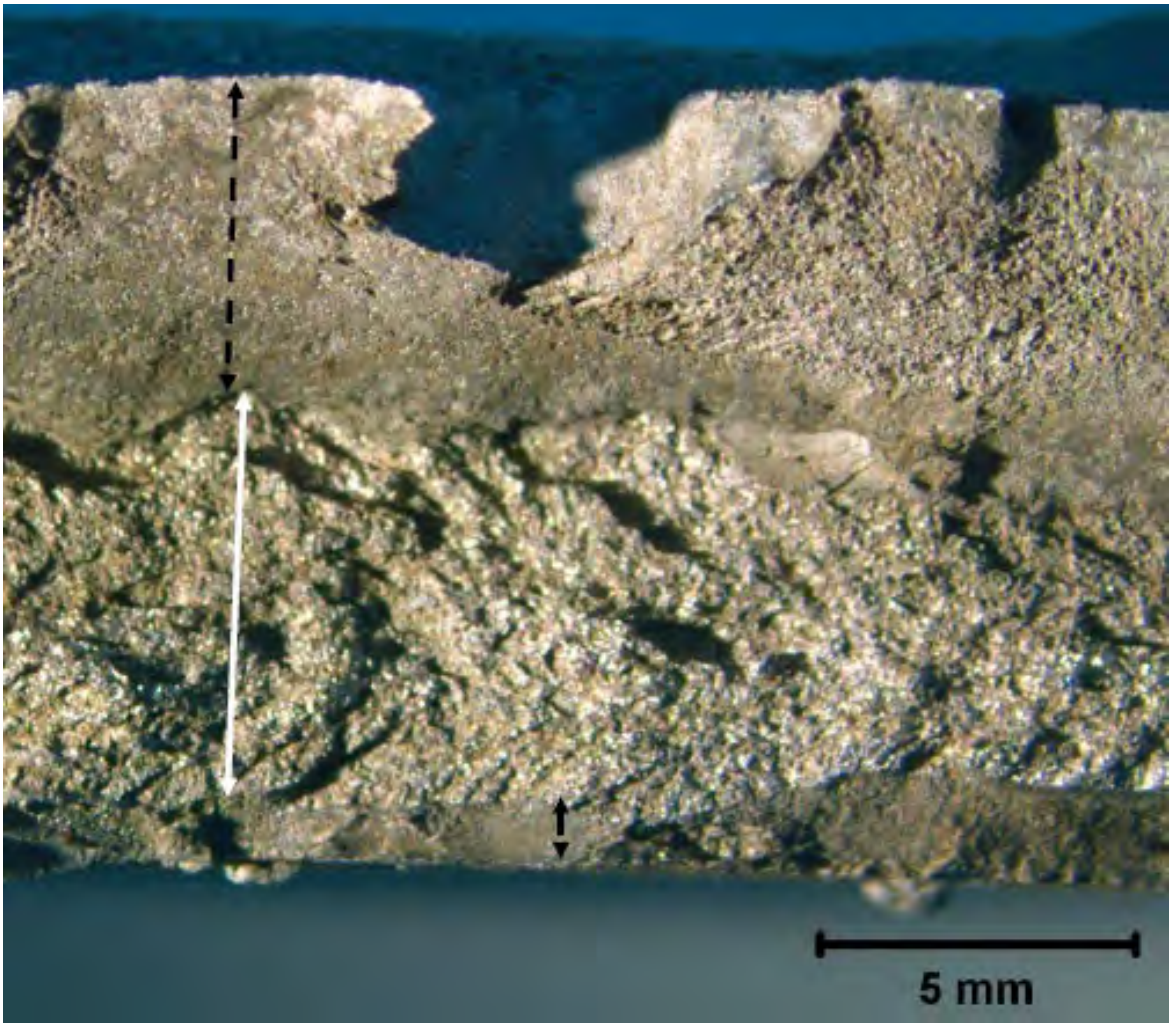


Figure 17. Image of Sample S2 - Smooth (Black Arrow) and Rough (White Arrow) Regions

5.3 Metallography and Fractographic Examination

Upon removal of the samples discussed above, the samples were evaluated utilizing standard microscopy techniques including stereographic evaluations, microscopic evaluation and scanning electron microscopy. Five (5) axial and cross-sections were removed from the failed girth weld and one (1) from the intact weld for metallographic analysis. Some of the samples contain fracture paths at a shear angle (fracture path through the smooth surfaces) and other show the fracture path perpendicular to the free surface and regions of shear failure (fracture surface is rough).

These samples are shown in Figure 18.

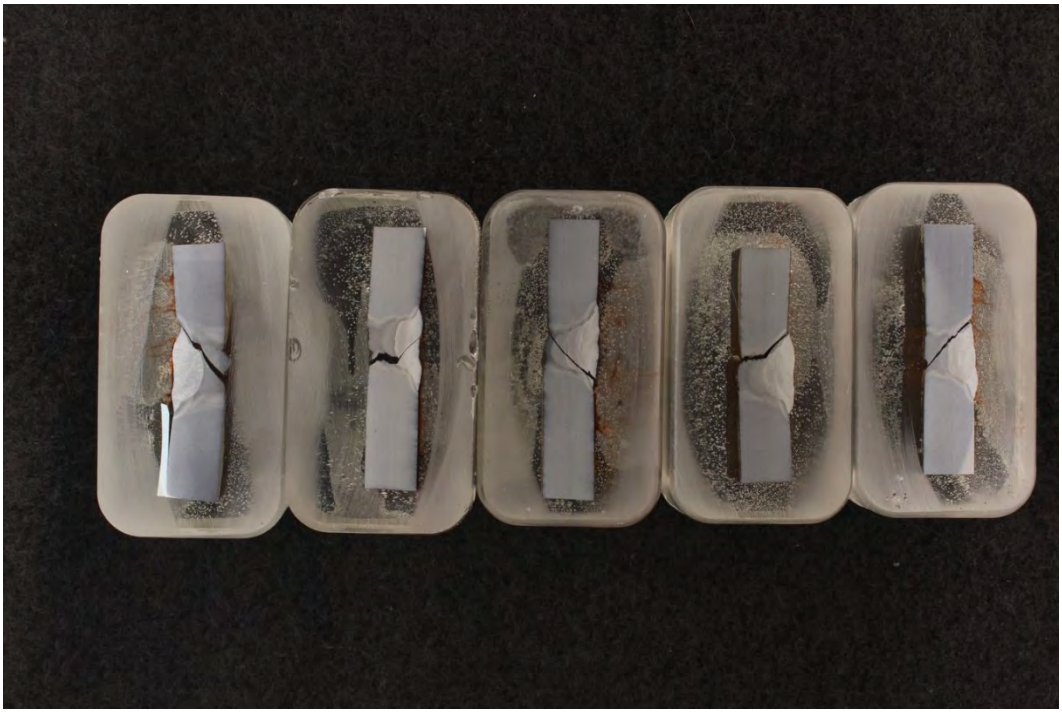


Figure 18. Metallurgical samples M1 through M5

5.3.1 Metallurgical Sample 1

Sample M1 contains a fracture path at a shear angle. This sample was removed from the girth weld at the 1:35 o'clock orientation (see Figure 19).

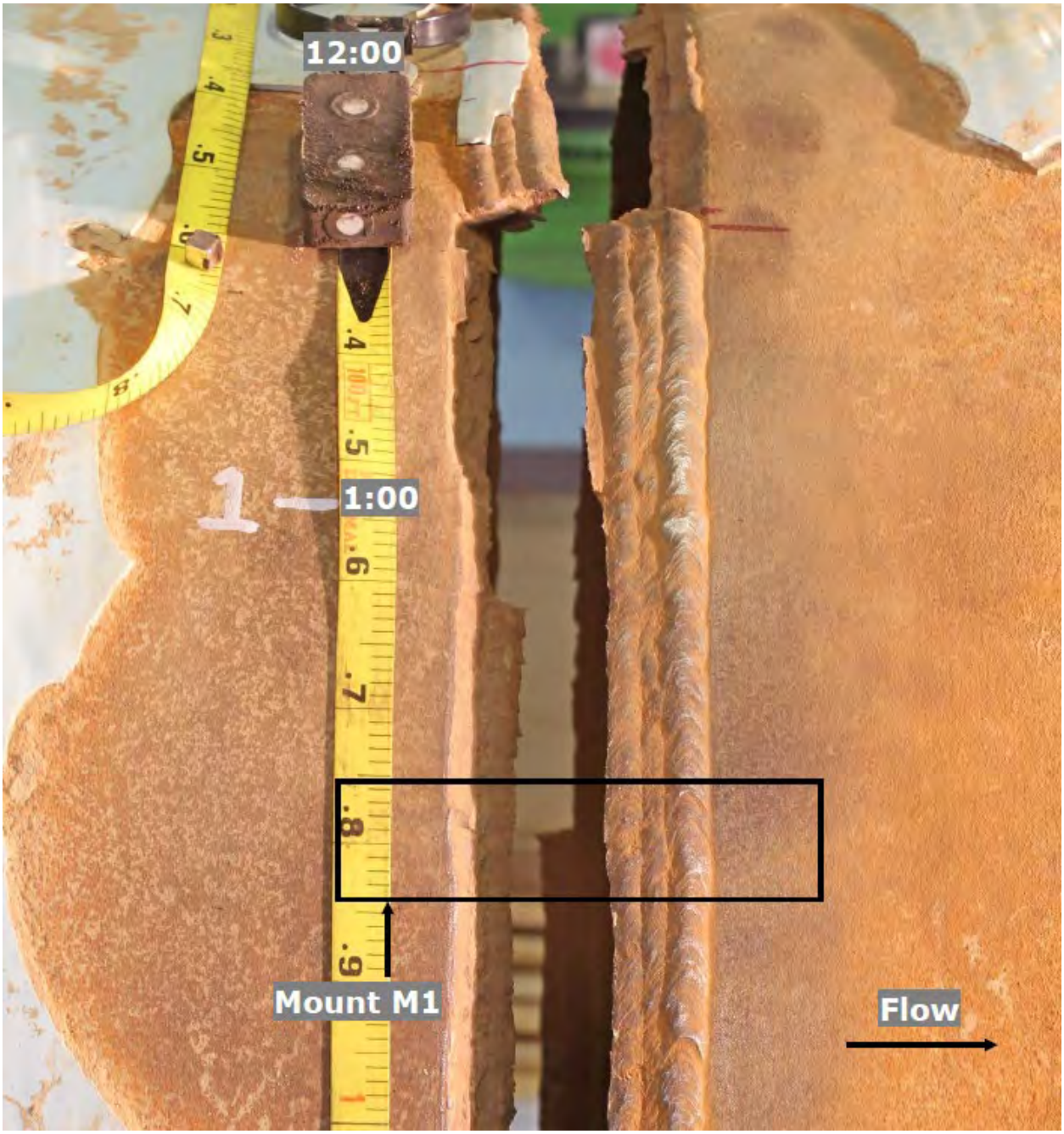


Figure 19. Overview of Mount M1

The fracture path of this sample is located in the HAZ near the toe of the weld at the OD surface. An image of the cross section of sample M1 is provided in Figure 20.

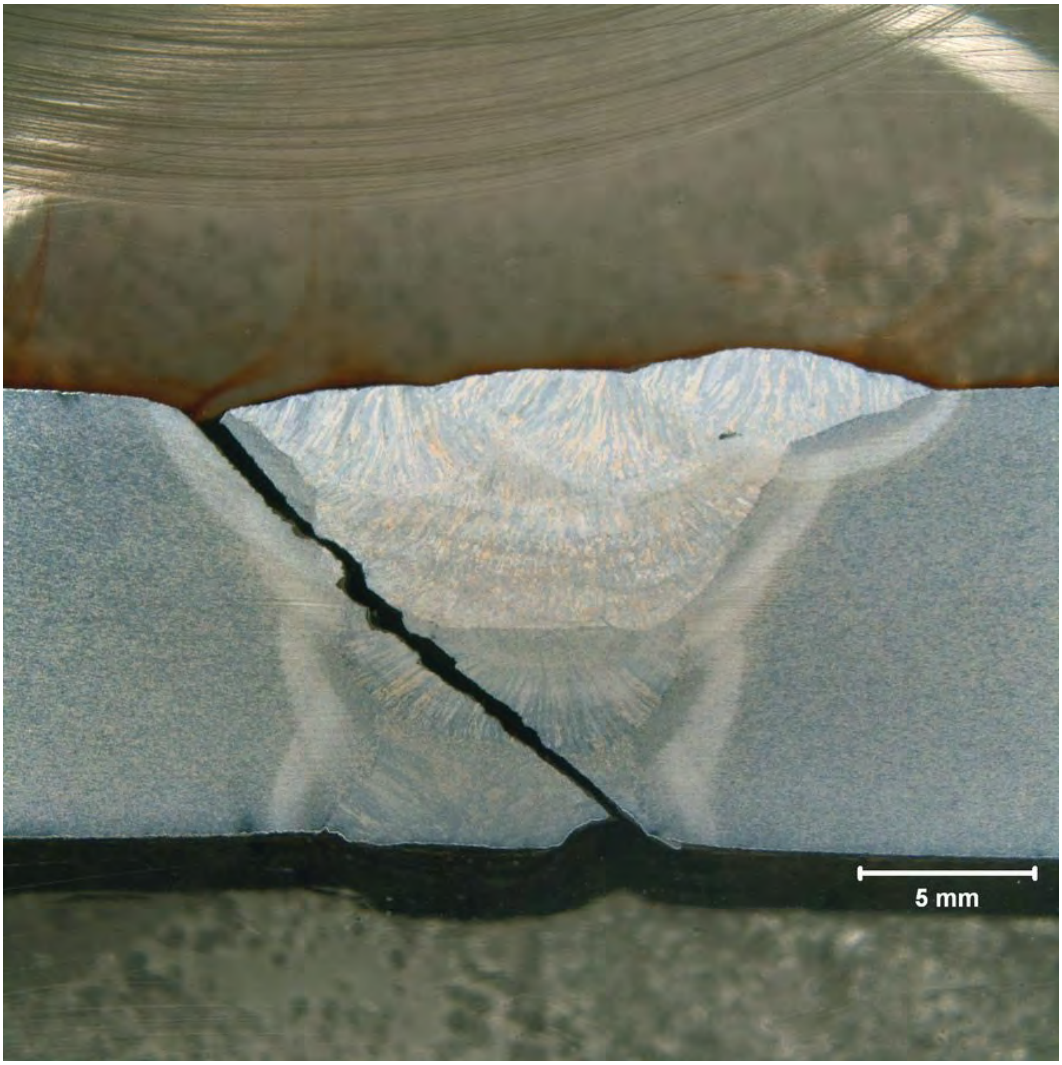


Figure 20. Representative Cross-Section from Sample M1

There is no indication of excessive porosity and/or inclusions. It shows a slight misalignment of the high-low weld of approximately 4.3% of the NWT. Higher magnifications are provided in the laboratory report which show grain elongation due to the cold work that took place during the rupture process. This is consistent with ductile overloading. The microstructure is typical of modern X80 line pipe. A close-up of sample M1 is provided in Figure 21.

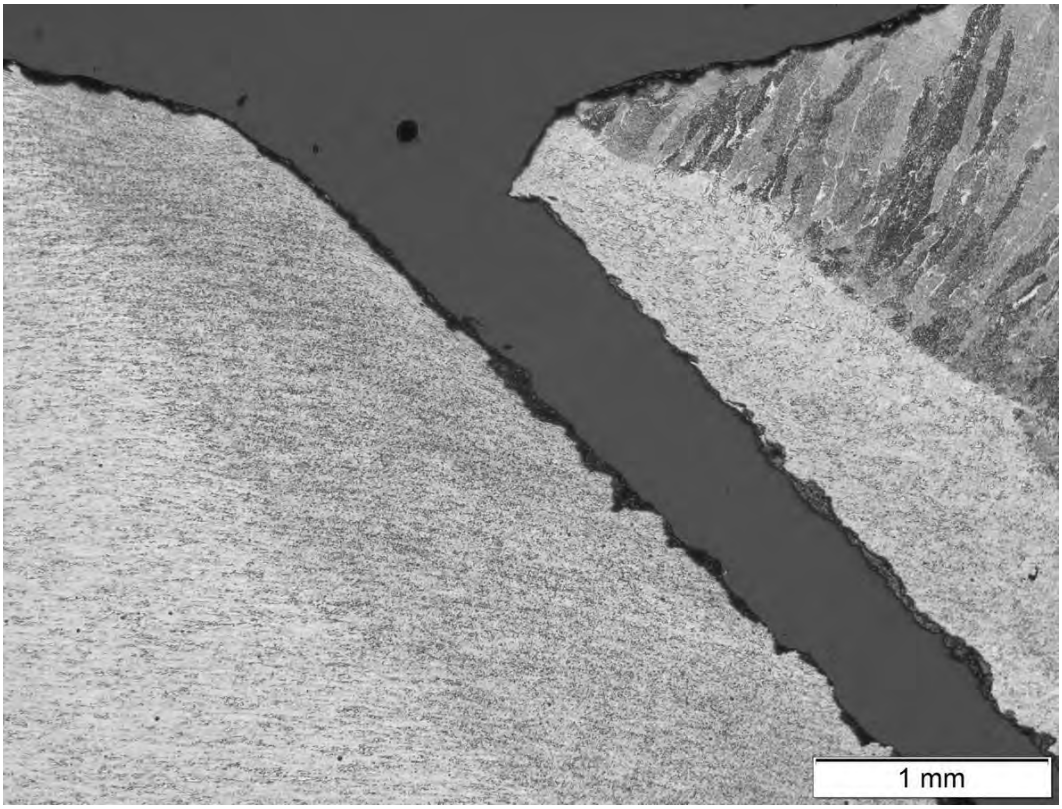


Figure 21. Close-Up of Sample M1

5.3.2 Metallurgical Sample 2

Sample 2 contains regions where the fracture path is perpendicular to the free surface and regions of shear failure. This sample was taken from the GW at the 3:55 o'clock orientation (see Figure 22).

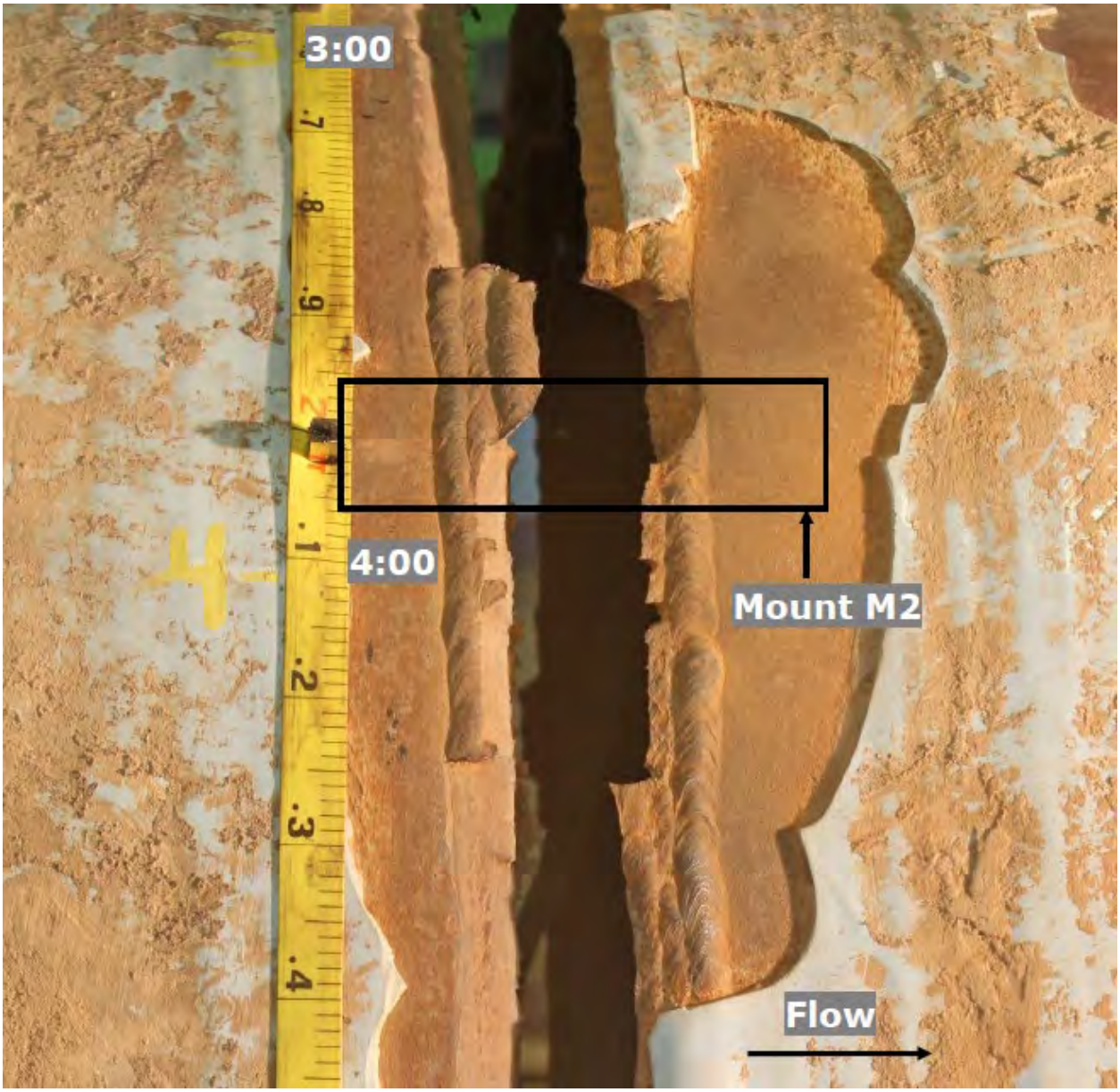


Figure 22. Overview of Mount M2

The cross section of M2 includes both the weld metal and HAZ. The cross section of sample M2 is provided in Figure 23.

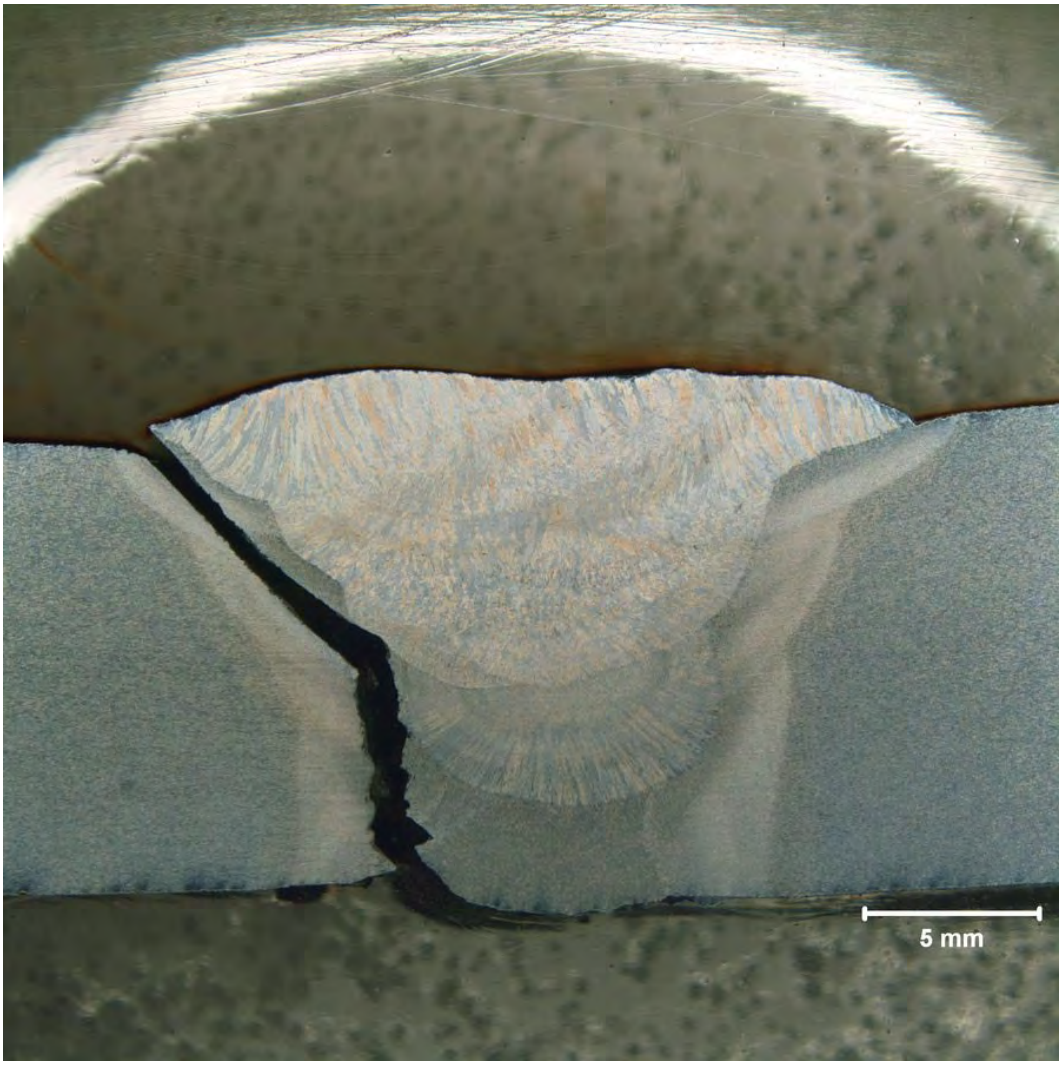


Figure 23. Representative Cross-Section from Sample M2

There are both smooth and rough regions in this sample. The high-low weld misalignment at this location is approximately 6.9% of the NWT. The fracture path at this location was mainly located at the HAZ. Fractography in the SEM shows the presence of a smooth region containing dimples (typical of ductile behavior) and cleavage facets (typical of brittle behavior) in the rough region. Some fissures were also found in the area where cleavage facets were located. These fissures are usually seen in girth weld overload areas (see Figure 24).

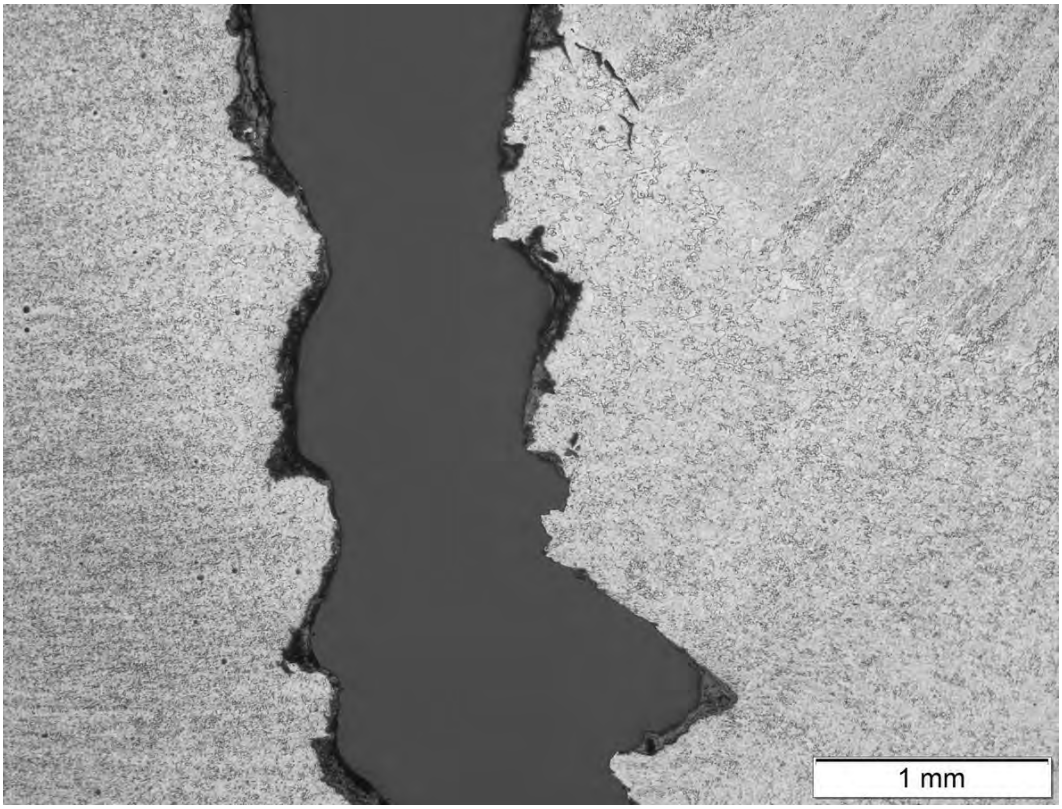


Figure 24. Close-Up of Sample M2

5.3.3 Metallurgical Sample 3

This sample was removed from the failed GW at the 8:35 o'clock orientation (Figure 25).

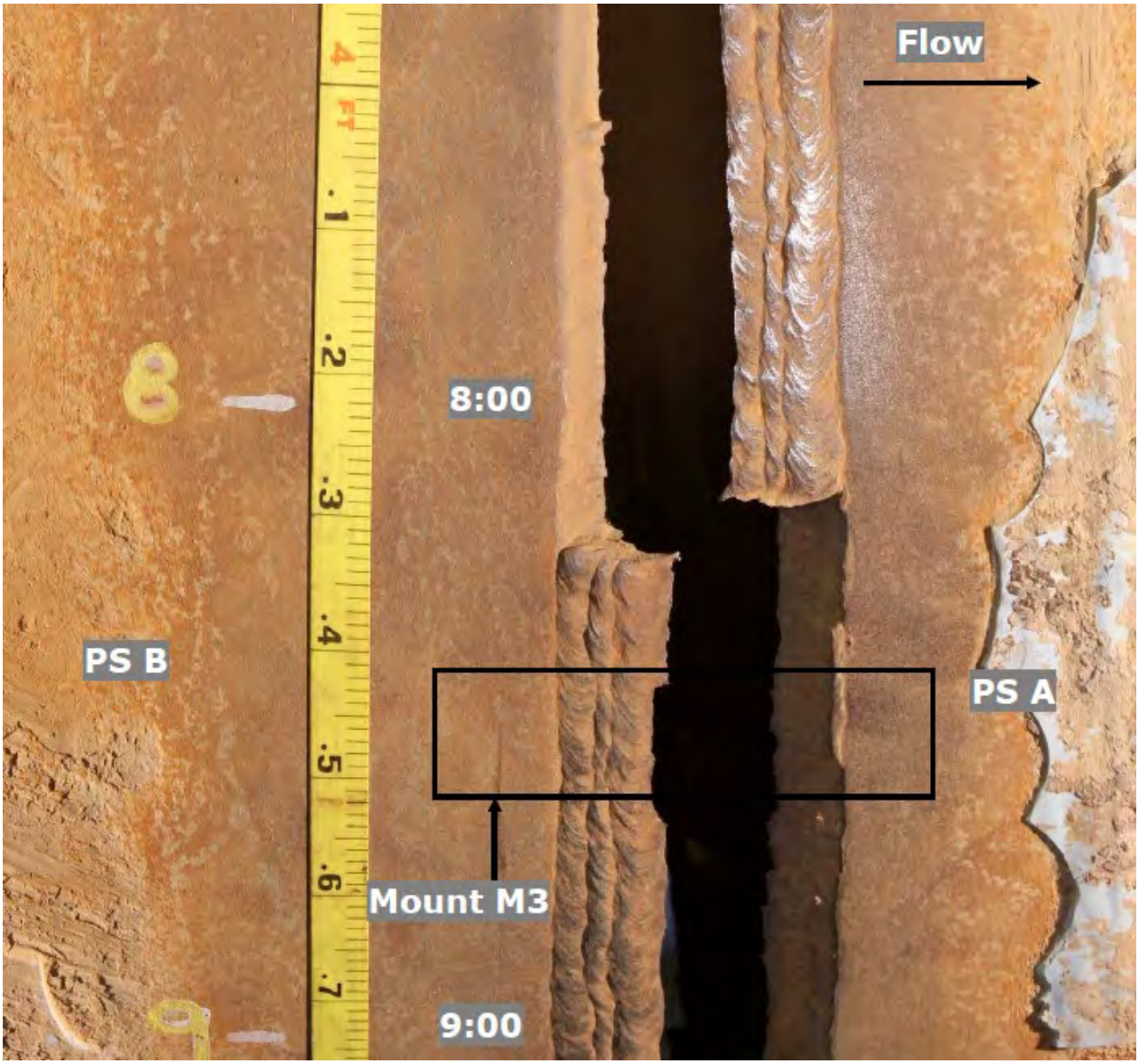


Figure 25. Overview of Mount M3

The fracture path is at a shear angle and mainly located in the weld metal. The morphology of the weld is similar to samples M1 and M2. The high-low weld misalignment at this location was approximately 2.6% of the NWT. The microstructure is consistent with the findings in samples M1 and M2 (see Figure 26 and Figure 27).

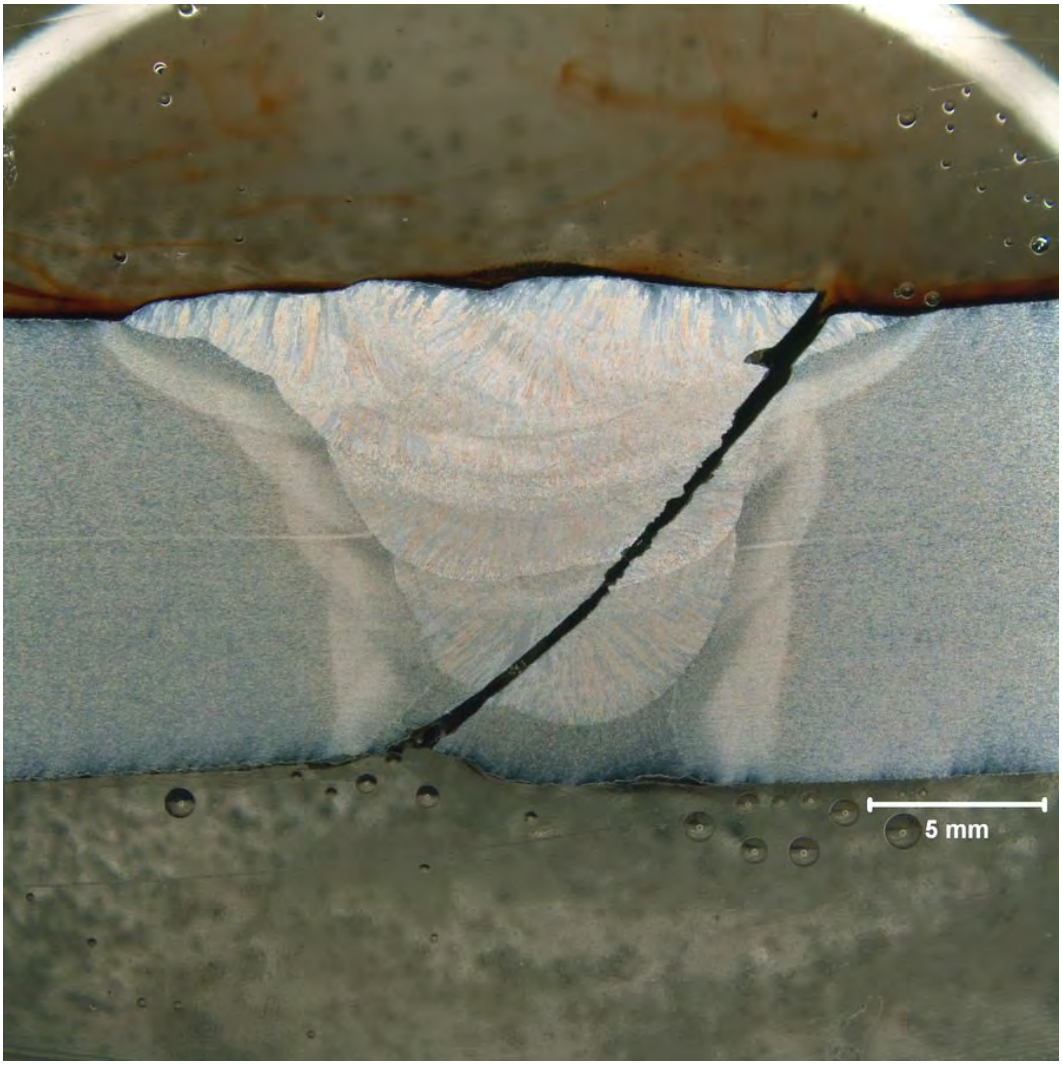


Figure 26. Location of Mount M3

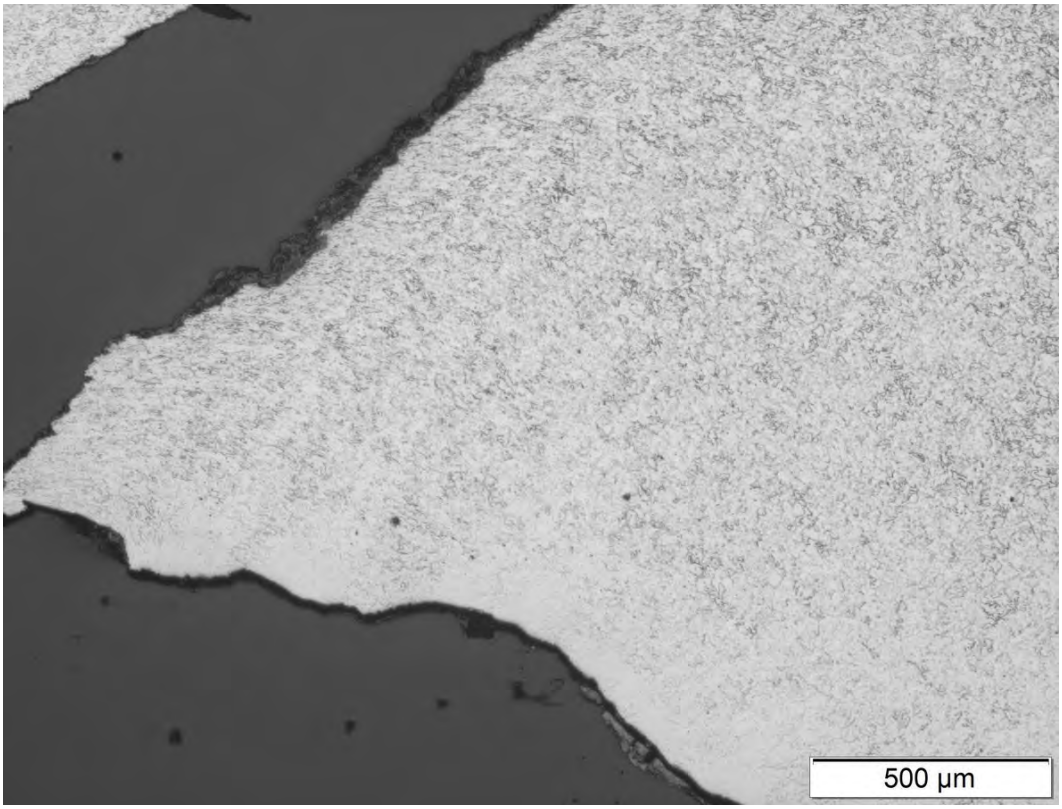


Figure 27. Close-Up of Sample M3

5.3.4 Metallurgical Sample 4

Sample M4 was removed from the failed GW at the 10:24 o'clock orientation. An overview of sample M4 is provided in Figure 28.

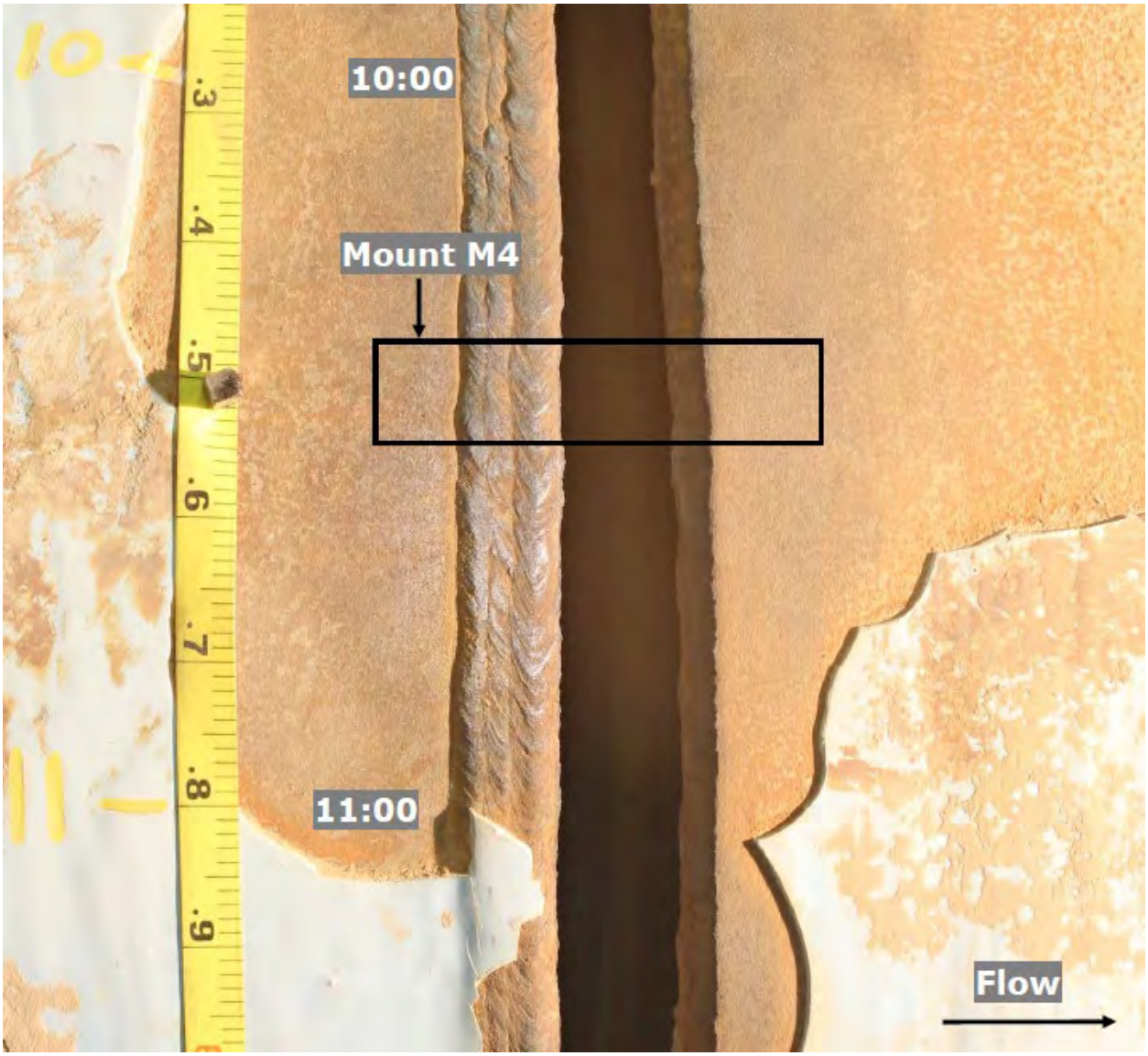


Figure 28. Overview of Mount M4

There is a smooth shear angle region and a rough region. The fracture path at this location is mainly in the HAZ. (see Figure 29).

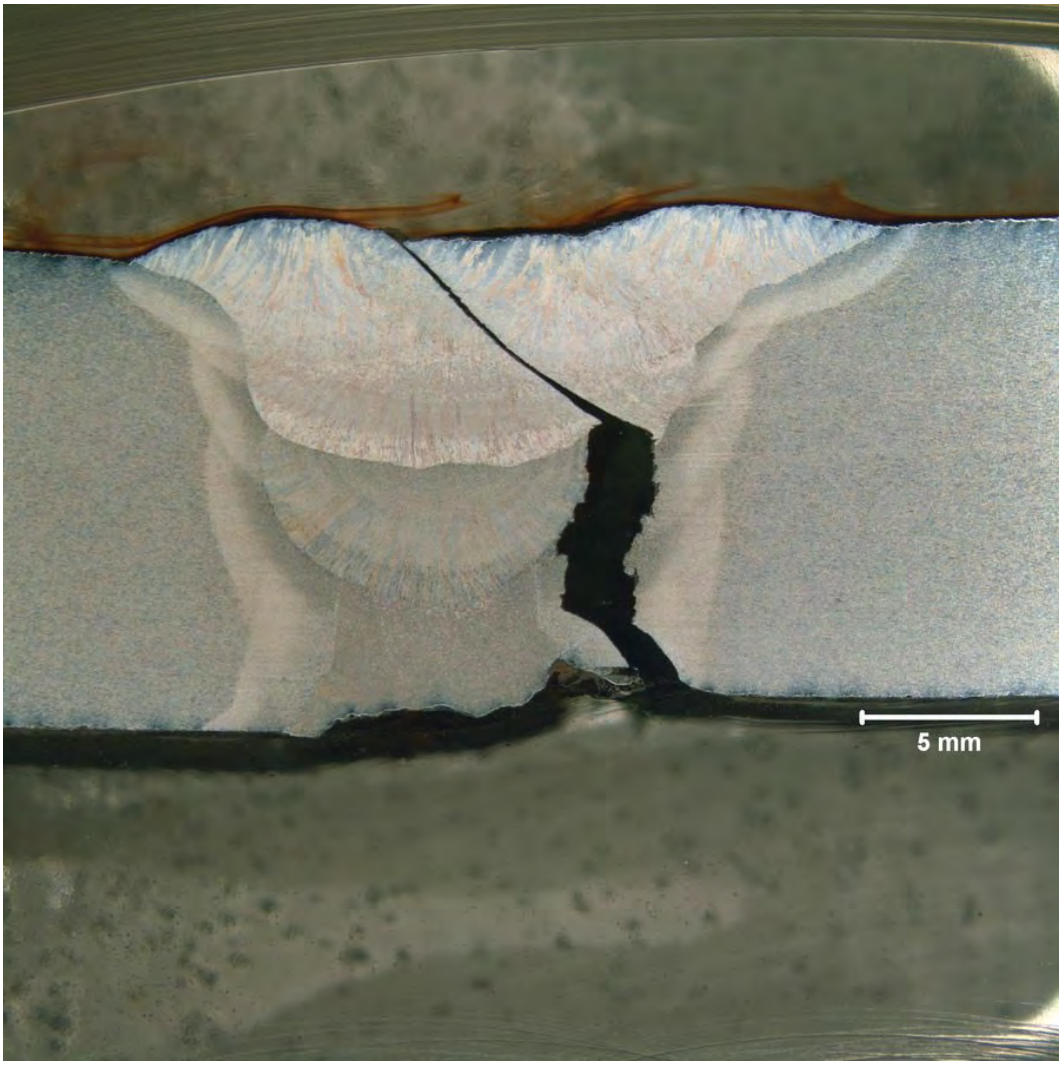


Figure 29. Representative Cross-Section from Sample M4

The sample shows grain elongation and an inclusion orientated parallel to the fracture surface which is consistent with ductile overload. There are also fissures in this sample that have the same morphology shown in M2 sample. A close-up of the M4 sample is provided in Figure 30.

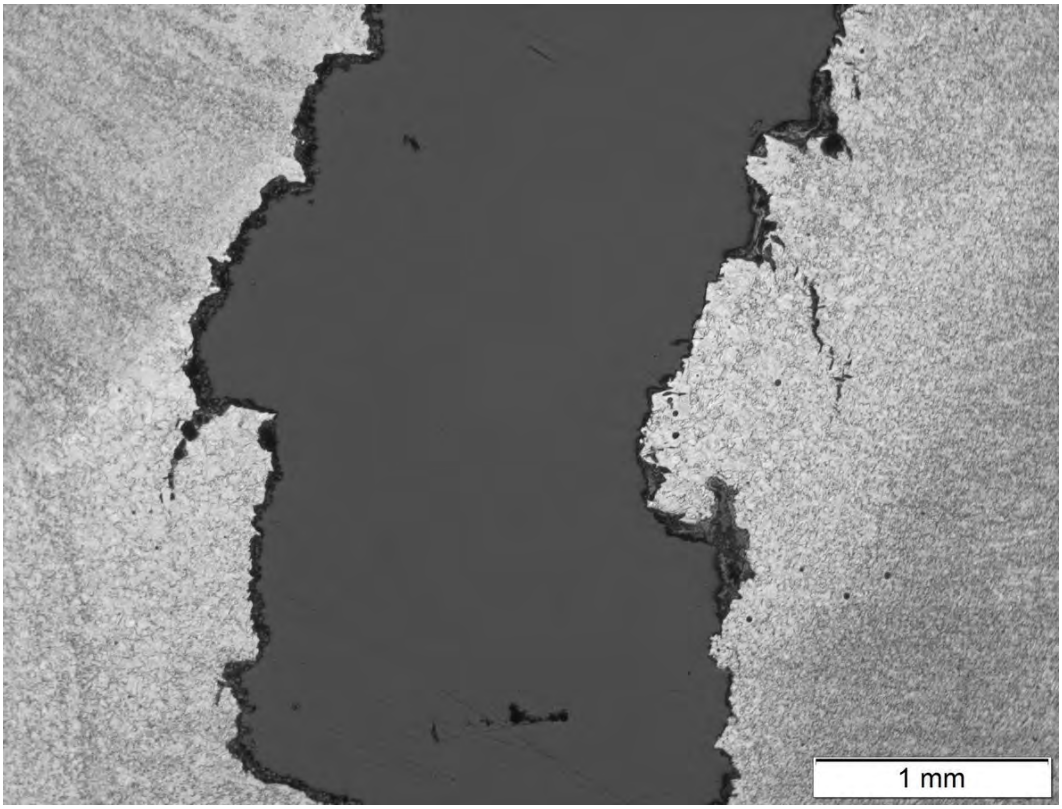


Figure 30. Close-Up of Sample M4

5.3.5 Metallurgical Sample 5

Sample 5 was removed from the failed GW at the 11:37 o'clock orientation (see Figure 31).

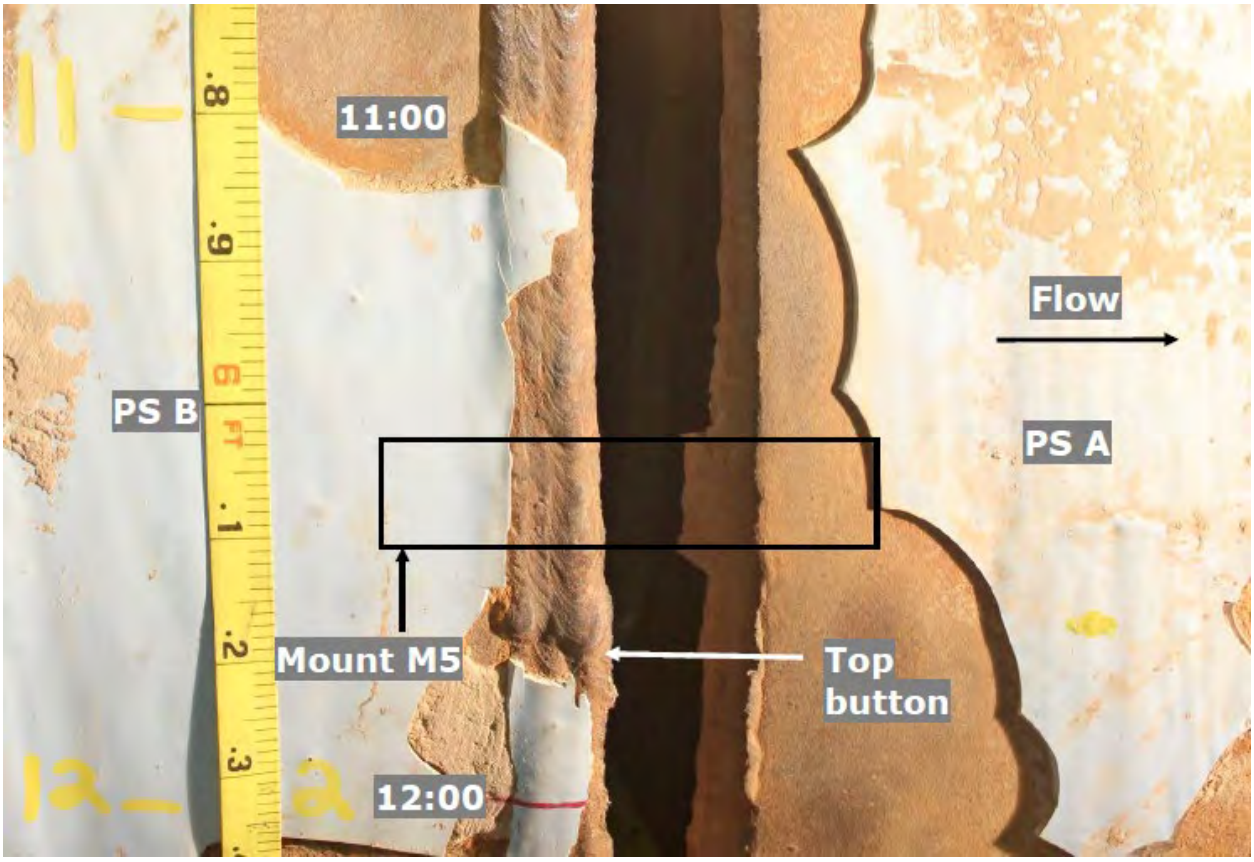


Figure 31. Overview of Mount M5

This sample has a smooth shear region on most of the fracture surface, located in both the weld metal and base metal. There is a shallow flaw between the weld metal and HAZ which is consistent with incomplete fusion. The high-low weld misalignment at this location was approximately 4.6% of the NWT. There is no evidence of crack extension at the flaw in this sample. A view of the cross section of sample M5 is provided in Figure 32.

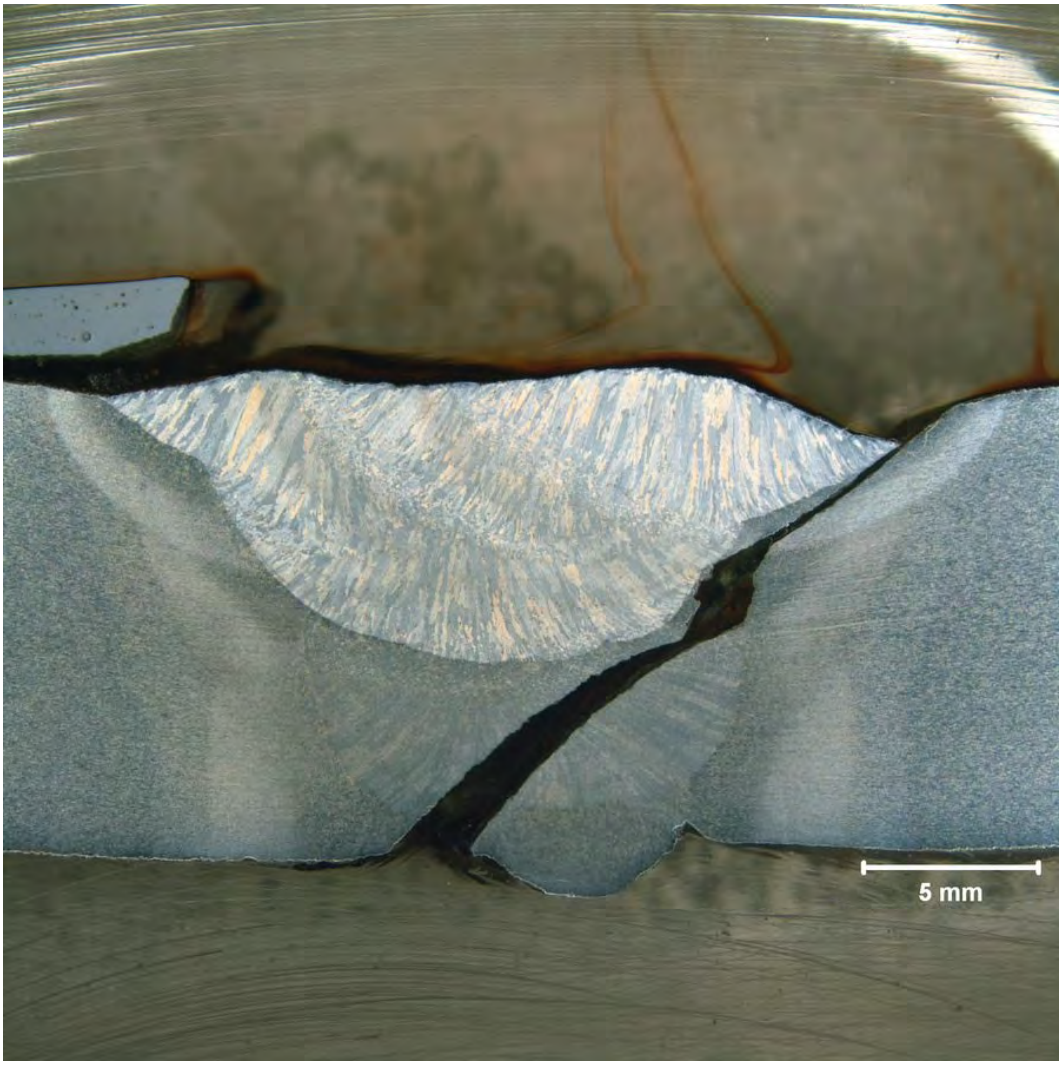


Figure 32. Representative Cross-Section from Sample M5

5.3.6 Metallurgical Sample MU1

Sample MU1 was removed from the intact girth weld. An overview of this sample is provided in Figure 33.

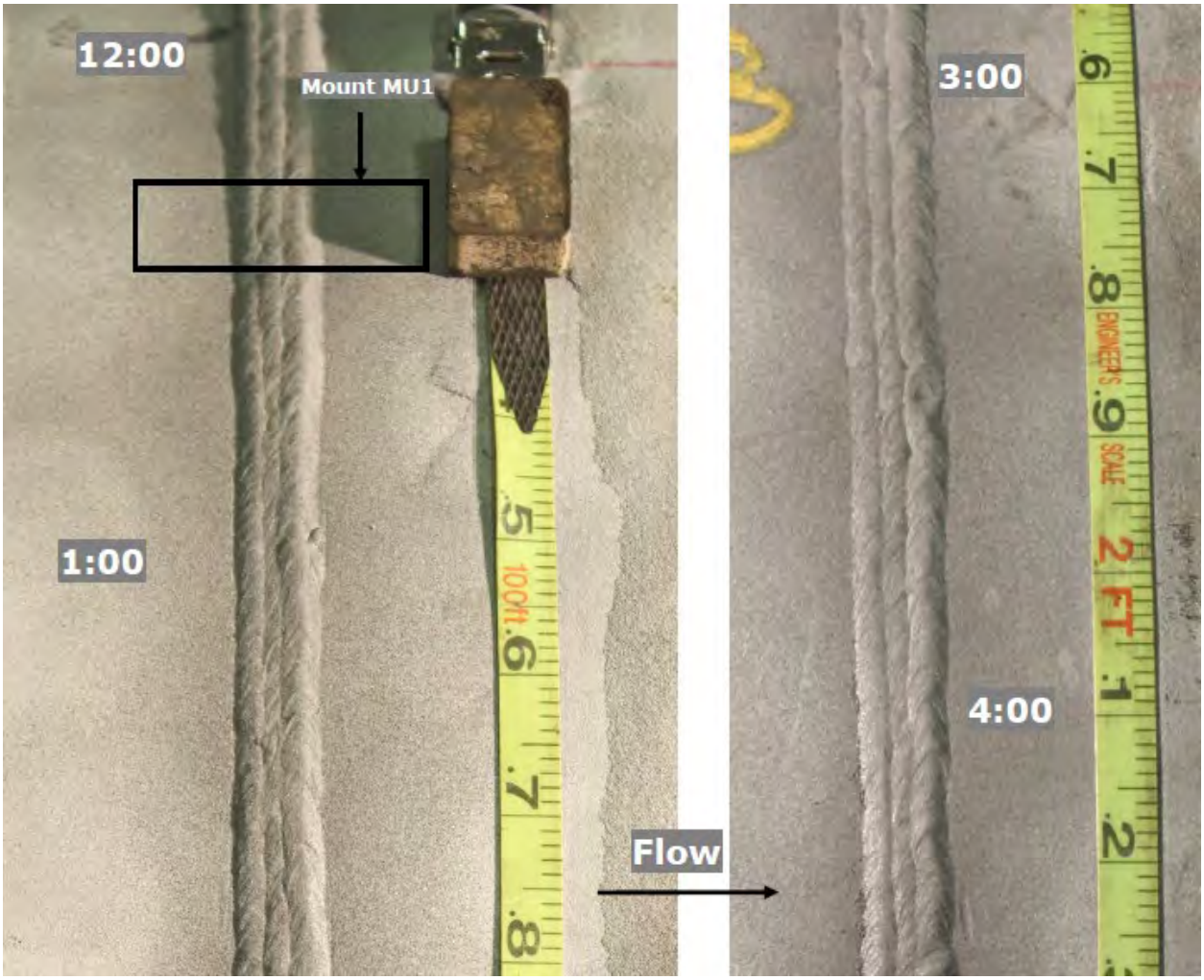


Figure 33. Overview of Mount MU1

This sample was removed from the intact GW at the 12:24 o'clock position. The morphology is similar to the previous mounts. The high-low weld misalignment at this location is approximately 4.6% of the NWT. The figure shows a shallow incomplete fusion flaw (1.9% of the NWT) between the weld metal and the HAZ. An image of the cross section of sample MU1 is provided in Figure 34.

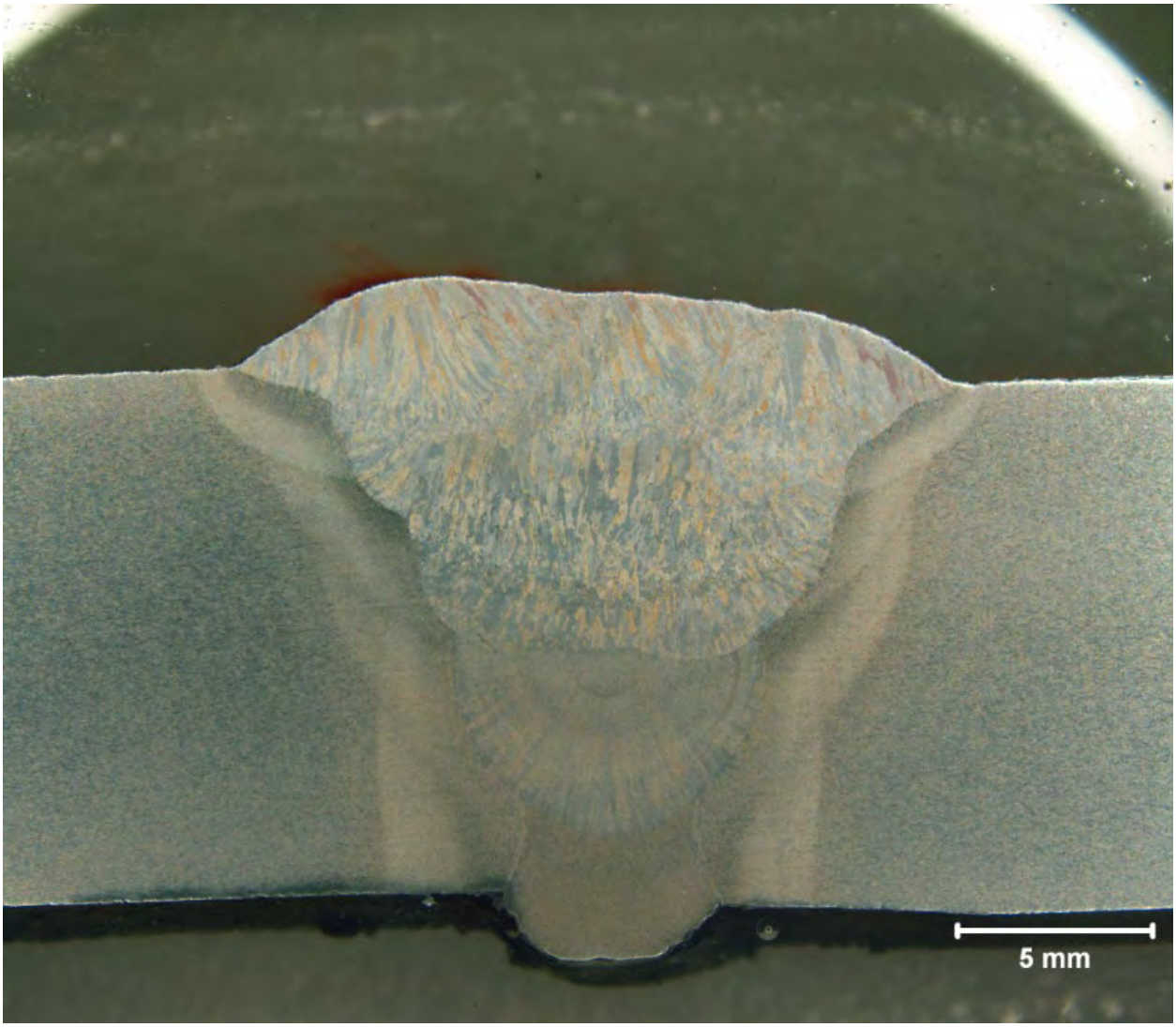


Figure 34. Cross Section of Mount MU1

A shallow flaw was identified between the weld metal and HAZ, with no evidence of cracking or extension of the flaw. A close up view of the flaw is provided in Figure 35.

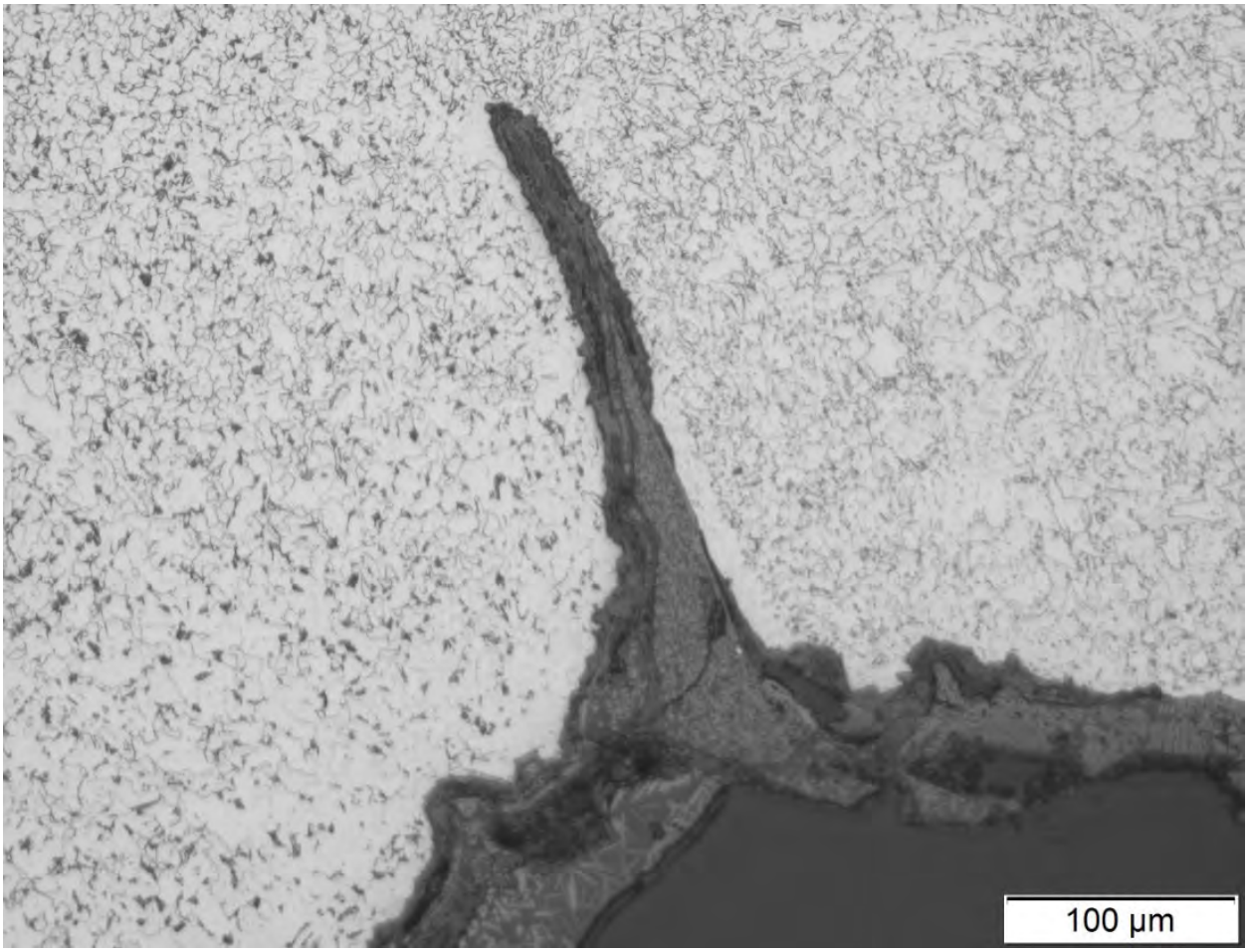


Figure 35. Close Up View of Sample MU1 Flaw

5.4 Scanning Electron Microscopy

As noted above, 4 samples were removed from PS A adjacent to the metallographic samples. No evidence of pre-existing flaws or fatigue were identified. SEM images (Figure 36, Figure 37, Figure 38) provide examples of dimples and mid-wall tears associated with ductile fracture, and cleavage facets associated with brittle fracture.

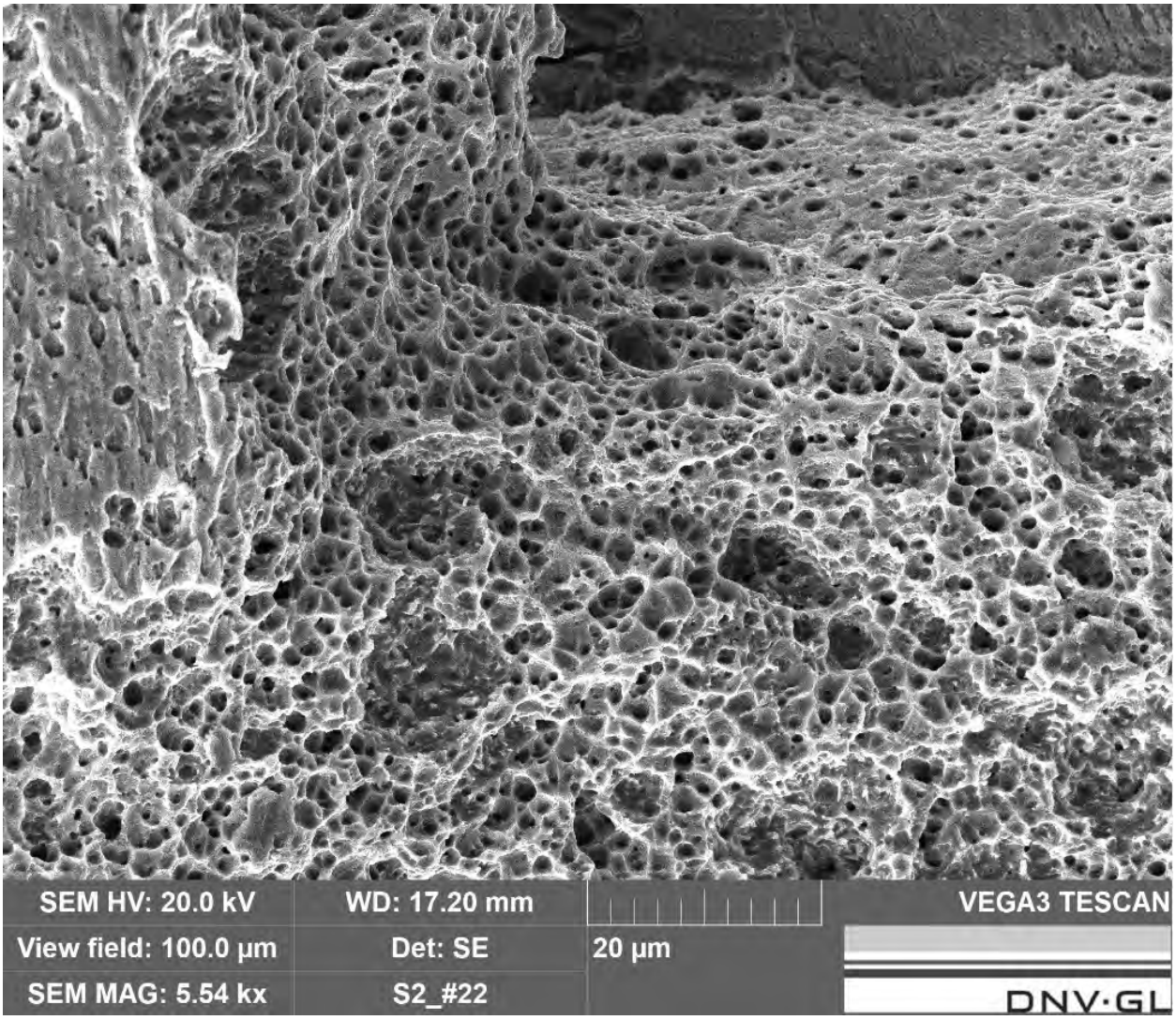


Figure 36. Sample S2 – Dimples Associated with Ductile Fracture

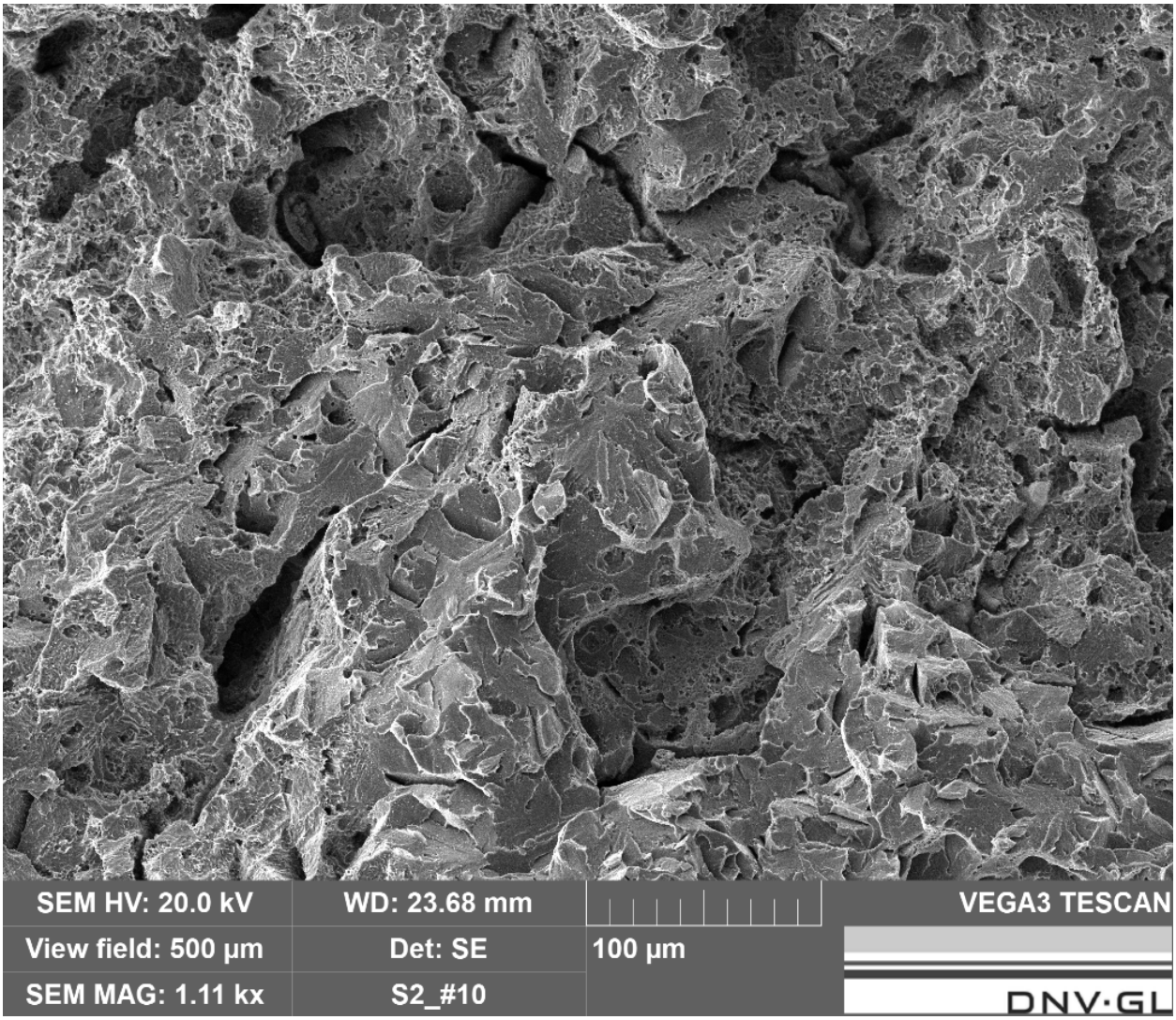


Figure 37. Sample S2 – Facets Associated with Brittle Fracture

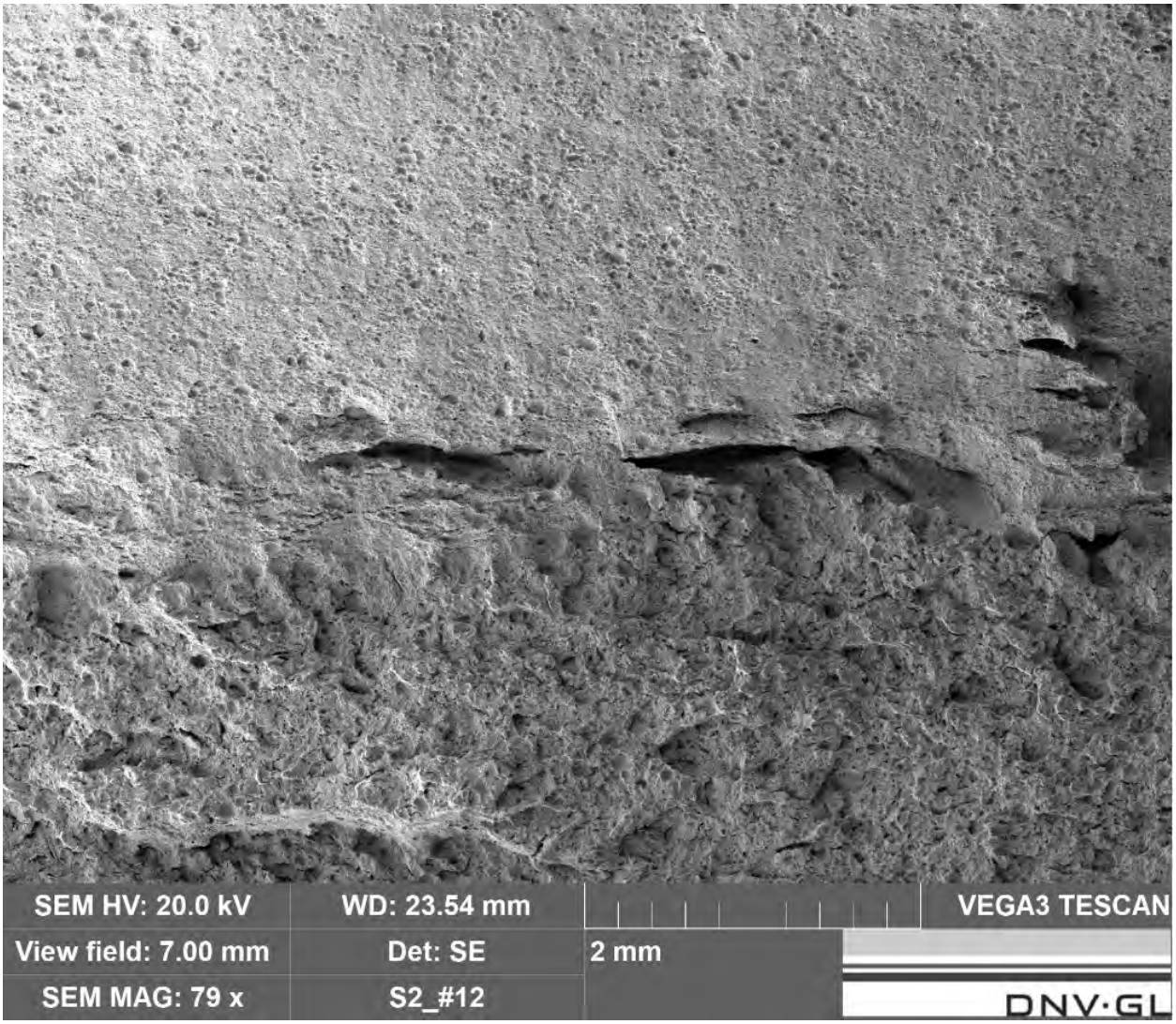


Figure 38. Sample S2 – Tears Mid-Wall (Smooth Region)

5.5 Hardness Testing

Vickers hardness testing was conducted on all six metallographic cross sections. No areas of unusually high hardness were identified. Hardness testing of the failed girth weld exhibit variability that is likely associated with cold work sustained during the failure. The hardness testing of the intact weld are the best representation of the base hardness of the welds preceding the failure. The results indicate a lower hardness of the weld metal compared to the pipe metal, which indicating that the weld metal is softer than the parent metal. Typically, the parent metal

is harder than the weld metal. The axial tensile tests on the intact girth weld show similar failure to the actual fracture, further indicating that the lower hardness typical of the weld was the preferred location for the overload failure under applied axial stress. Hardness levels at varying points on sample M2 from the failed girth weld are shown in Figure 39.

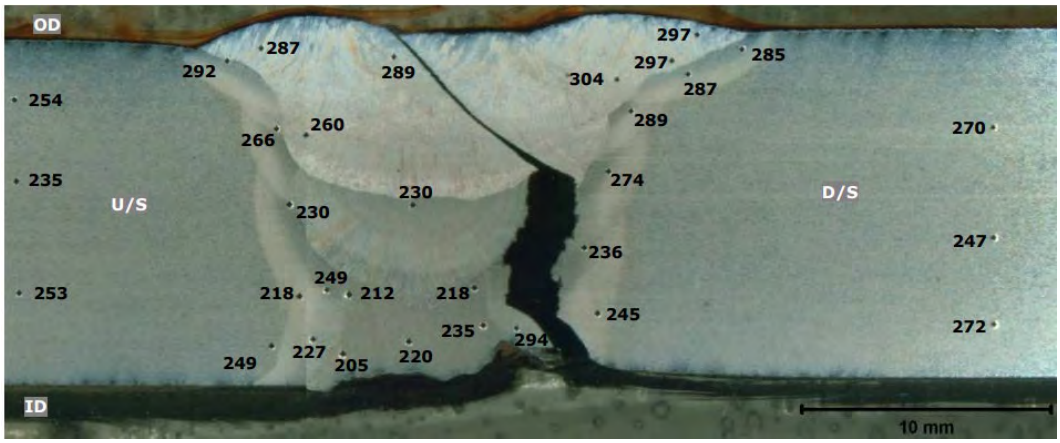


Figure 39: Light Photomicrograph of M2 Axial Cross-Section Showing Hardness Levels in HV

5.6 Mechanical Testing

A summary of mechanical testing results for the Delhi 24-inch pipeline samples is provided below. Additional detail is included in Appendix C.

5.6.1 Tensile Testing

Tensile testing of duplicate circumferential base metal specimens indicates the average yield strength (YS) and ultimate tensile strength (UTS) meet the requirements for API 5L X80M PSL 2 line pipe at the time of construction. The average UTS of duplicate axial specimens taken from the intact girth weld was 103.3 ksi. Both specimens failed in the girth weld, similar to the in-service pipeline failure. The average axial YS and UTS value across the weld meets the tensile requirements for API 5L X80M PSL 2 line pipe at the time of construction.

5.6.2 Charpy V-Notch Testing

The results of CVN testing of the base metal samples indicate impact values all exceeding the specified values for the specified minimum value for API 5L X80M PSL 2 line pipe at the time of construction. Test results of the girth weld samples taken from PS C indicate acceptable values, with the 85% Fracture Appearance Transition Temperature (FATT) 59.9ºF.

5.6.3 Chemical Analyses

The results of the chemical analysis indicate that the steels meet the compositional requirements of API 5L Grade X80M PSL 2 line pipe. The carbon equivalent (CE) values were calculated for the base metal samples PS A and PS C and are 0.17 and 0.16 respectively. These values compare favorably to the maximum allowable 0.25 according to API 5L specification at the time of construction.

6.0 CONCLUSIONS

The combined results of this investigation indicate that the root cause of the 24-inch Delhi pipeline failure was overload at a field girth weld due to axial stresses sufficient to cause an overload condition. Movement is considered to be a possible contributing factor. Based on the results of this investigation, we provide the following conclusions:

1. The brittle failure originated at a girth weld. The presence of soft regions with dimples (ductile mode) and cleavage facets (brittle mode) are characteristics typical of a failure from overload conditions.
2. The failure occurred due to axial stresses. There was no indication of a pre-existing defect and a specific failure initiation site was not apparent.
3. The weld metal for both the failed girth weld and the intact weld was found to have lower hardness values than the surrounding pipe materials indicating the weld metal was weaker than the pipe material and thus, more susceptible to overload under axial stress conditions. The findings do not suggest the failure resulted from a welding quality issue.

4. There was no evidence of internal or external corrosion that may have contributed to the failure mode.
5. The mechanical and chemical testing results were in accordance with the requirements for API 5L X80M PSL 2 line pipe.
6. The microstructure of the pipe material U/S and D/S of the failed girth weld are consistent with modern X-80M PSL 2 line pipe steel.

7.0 APPENDICES

Appendix A – Denbury Yazoo County Pipe Sample Collection Protocol

Appendix B - Denbury Yazoo County Metallurgical Sampling & Testing Protocol

Appendix C - DNV-GL Metallurgical Analysis Report

Appendix D - Responses to Questions Provided by PHMSA 4/7/2021

Appendix E - Chain of Custody Documentation

Appendix F - Welding Procedure Development and Qualification for X80 Line Pipe

Appendix G - Welding Procedure Specification WPS 14 6/18/2008

Appendix H - Stress Analysis Report Denbury Delta Pipeline Repair 7/28/2021

Appendix A

Denbury Yazoo County Pipe Sample Collection Protocol

Pipe Sample Collection Protocol

Denbury Yazoo County Pipeline

1. Each pipe sample location will be identified and documented according to Mears procedures.

2. The as-found condition of the site will be documented and photographed, and the areas previously identified will be excavated to uncover the pipeline.

3. Any welded sleeves or temporary repair clamps covering the area of interest are to be left in place for removal after delivery of the sample to the laboratory.

4. If any bolted connections are disconnected or removed, fasteners and gaskets will be marked for identification purposes, photographed and retained for further analysis (if applicable).

5. If the pipeline is encased at the area of interest:

    a. The exterior of the casing will be visually inspected, condition documented, and a section of the casing will be selected and marked for identification purposes.
    b. The identified casing section will then be removed in a manner that preserves the condition of the pipeline and casing in the area of interest to provide access for inspection of the pipeline in the area of interest.
    c. The interior surface of the casing will be visually inspected, documented and photographed.
    d. If applicable, samples of the casing or materials inside the casing will be selected and collected for detailed analysis.

6. The as-found condition of the carrier pipe will be documented and photographed. Labeling will include the 12:00 position of the pipe and direction of flow, prior to coating removal and pipe inspection.

7. Prior to disturbing or removing the pipe coating, samples of any liquids or solids deposits located between the carrier pipe and coating or adhered to the pipe surface located in the area of interest will be collected in duplicate. Liquid samples will be retrieved using a syringe. Solids samples will be collected using a wooden spatula/tongue depressor. All samples will be placed in sealed enclosures (test tubes or sample bags). Samples will then be labeled and photographed. Duplicate samples will be transferred to designated representatives of IPL or shall be retained for future transfer.

8. If no liquids are present, pH paper may be used to evaluate any moisture present on the pipe section.

9. The pipeline in the area of interest will then be evaluated to determine if pipe samples are required for further detailed analysis.

10. If temporary repairs are required at the area of interest in order to allow future removal of a pipe sample, the repair will be installed preserving the condition of the area of interest and will be left in place for removal after delivery to the laboratory.

11. Sample(s) to be removed for detailed analysis and testing from the pipe section cut out of the pipeline will be identified:

    a. The sample(s) will be marked for identification, including the 12:00 position of the pipe and direction of flow.
    b. The identified sample(s) will be photographed prior to removal from the pipeline.
    c. Coating removal and cuts will be made at least 12" from the identified defect/damage location, with care taken not to disturb the area of interest.
    d. If welded sleeves or temporary repair clamps cover the area of interest, cuts will be performed at least six inches from the edges of the sleeve or clamp.

12. After removal, the pipe sample(s) will be photographed prior to packaging for shipment:

    a. The pipe sample(s) will be wrapped in hydrophobic material like polyethylene to prevent contamination.
    b. The pipe sample(s) will then be crated for shipment, along with any other portable evidence identified for further testing.
    c. The pipe sample(s) will be immobilized within the container.

13. Transport documentation and chain of custody will then be initiated.

14. The pipe sample will then be shipped to DNV GL, Columbus, OH or Plain City, OH receiving yard.

Appendix B

Denbury Yazoo County Metallurgical Sampling & Testing Protocol

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Appendix C

DNV GL Metallurgical Analysis Report

DNV·GL

Draft Report

Metallurgical Analysis of 24-Inch Diameter Delhi Pipeline Failure (02/22/20)

Mears Group, Inc.
Plain City, Ohio

Report No.: O-AP-FINV / GTQU (10206282)
June 4, 2020



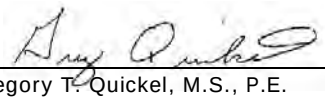
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Customer:	Mears Group, Inc.
Contact Person:	Aida Garrity
Date of Issue:	June 4, 2020
Project No.:	10206282
Organization Unit:	Incident Investigation
Report No.:	O-AP-FINV / GTQU

DNV GL USA, INC. (OIL & GAS
Pipeline Services Department
Incident Investigation
5777 Frantz Road
Dublin, OH 43017-1886
United States
Tel: (614) 761-1214
Fax: (614) 761-1633
www.dnvgl.com

Task and Objective:

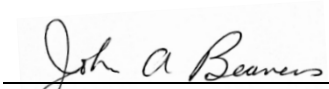
Please see Executive Summary.

Prepared by

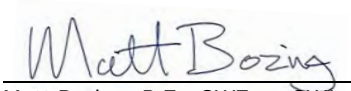


Gregory T. Quickel, M.S., P.E.
Principal Engineer

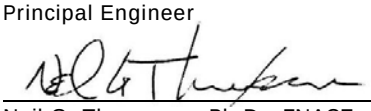
Reviewed and Verified by



John A. Beavers, Ph.D., FNACE
Senior Principal Engineer



Matt Boring, P.E., CWEng, CWI
Principal Engineer



Neil G. Thompson, Ph.D., FNACE
Senior Vice President

Approved by

David M. Norfleet, Ph.D., P.E.
Head of Section –
Incident Investigation

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Keywords

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Rev. No.	Date	Reason for Issue:	Prepared by:	Verified by:	Approved by:
0	2020-05-27	Draft			
1	2020-06-04	Revised Draft			

Executive Summary

Mears Groups, Inc. (Mears) retained DNV GL USA, Inc. (*DNV·GL*) to perform a metallurgical analysis on a portion of the Delhi 24-inch diameter carbon dioxide (CO_2, dry) transmission pipeline, that failed at a girth weld while in service, resulting in full separation. The failure occurred on February 22, 2020 in Satartia, Mississippi at Stationing 348+26, 6.59 miles from the nearest upstream (U/S) pump station.

The segment of the pipeline that failed is comprised of 24-inch diameter by 0.540-inch wall, API 5L Grade X80M PSL 2 line pipe steel that contains a high frequency electric resistance welded (HF ERW) seam. The maximum allowable operating pressure (MAOP) is 2,160-psig, which corresponds to 59.6% of the specified minimum yield strength (SMYS). The pressure at the Tinsley Meter Station (Stationing 0+00) at the time of the failure was 1,336-psig (36.9% of SMYS). The pipeline normally operates between 1,200 and 1,450-psig (33.1 and 40.0% of SMYS, respectively).

The pipeline was installed in 2009 and is externally coated with a factory applied fusion bonded epoxy (FBE) and abrasion resistant overlay (ARO) coating. A liquid epoxy coating was applied to the pipeline at the girth welds in the field. Following construction, a hydrostatic pressure test was performed on January 14, 2009 to a minimum pressure at the dead weight gage of 2,908 psig (80.3% of SMYS). The pipeline has an impressed current cathodic protection (CP) system that was commissioned in 2009, directly following pipeline installation.

Three pipe sections (Pipe Sections [PSs] A, B, and C) were delivered to DNV GL for analysis. Pipe Section A was 5.99 feet long and contained the downstream (D/S) portion of the failed girth weld. Pipe Section B was 6.08 feet long and contained U/S portion of the failed girth weld. Pipe Section C was 8.00 feet long and contained an adjacent U/S intact girth weld. The objectives of the analysis were to determine the metallurgical cause of the failure and identify any contributing factors.

The results of the metallurgical analysis indicate that the failure initiated at a field girth weld, due to axial stresses sufficient to produce overload failure. No pre-existing flaws were present on the fracture surface. A contributing factor to the failure was that the pipe steel was stronger than the girth weld.

The scope of the work consisted of:

- Visual inspection and photography
- Magnetic particle inspection
- Fractography
- Scanning electron microscopy
- Metallography
- Energy dispersive spectroscopy

- Hardness testing
- Mechanical testing
- Chemical analysis

The results of the metallurgical analysis indicate that the failure initiated at a field girth weld, completely separating the girth weld. The exact location of the initiation could not be determined due to a lack of chevrons on the fracture surfaces and the fact that no significant pre-existing (prior to failure) cracks were identified. Microscopically, the fracture surface contained regions with dimples (ductile fracture) and cleavage facets (brittle fracture). The dimples were located where the fracture surface was at a shear angle and macroscopically smooth, and the cleavage facets were located where the fracture surface was perpendicular to the free surfaces and macroscopically rough. Both fractographic features are an indication of the overload nature on the fracture surface.

The failure occurred due to axial stresses sufficient to produce an overload failure. Supporting evidence for the presence of large axial stresses include 1) a relatively large opening between the failed ends and 2) cracked and missing epoxy coating U/S of the failed girth weld indicating a high strain prior/during fracture. A possible contributing factor to relatively large axial stresses includes stresses associated with movement.

No excessively high hardness areas were identified in the girth weld cross-sections. The weld metal of the intact girth weld had a lower hardness than the surrounding pipe material, indicating that the weld metal is weaker than the surrounding pipe material. This trend was somewhat followed for the failed girth weld, although cold work from the failure likely skewed some of the data. The softest regions in all the mounts was the weld metal root pass. The lower overall hardness values of the weld metal compared to the surrounding pipe material is consistent with the axial tensile results. The ultimate tensile strength for the girth weld of 103.3 ksi is less than the axial tensile strength of 109.7 ksi and 106 ksi for the joint's D/S and U/S, respectively, of the failed girth weld. The axial tensile tests across the intact GW failed in the GW, similar to the actual failure. Therefore, a contributing factor to the failure was that the pipe steel was stronger than the girth weld.

Below is a summary of additional conclusions:

- There was no evidence of notable internal or external corrosion.
- The tensile and toughness properties of the joint's U/S and D/S of the failed girth weld meet requirements for API 5L X80M PSL 2 line pipe at the time of construction.
- The chemical compositions of the joint's U/S and D/S of the failed girth weld meet the requirements for API 5L X80M PSL 2 line pipe at the time of construction.

- The microstructures of the joint's U/S and D/S of the failed girth are consistent with modern API 5L X80 line pipe steel.
- An analysis of the Charpy V-notch impact testing data for the intact girth weld indicates that the 85% fracture appearance transition temperature (FATT) is 59.9°F and upper shelf Charpy energy is 114 ft lbs.

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1.0 BACKGROUND

Mears Groups, Inc. (Mears) retained DNV GL USA, Inc. (*DNV·GL*) to perform a metallurgical analysis on a portion of the Delhi 24-inch diameter carbon dioxide (CO_2, dry) transmission pipeline, that failed at a girth weld while in service, resulting in full separation. The failure occurred on February 22, 2020 in Satartia, Mississippi at Stationing 348+26, 6.59 miles from the nearest upstream (U/S) pump station.

The segment of the pipeline that failed is comprised of 24-inch diameter by 0.540-inch wall, API 5L Grade X80M PSL 2 line pipe steel that contains a high frequency electric resistance welded (HF ERW) seam. The maximum allowable operating pressure (MAOP) is 2,160-psig, which corresponds to 59.6% of the specified minimum yield strength (SMYS). The pressure at the Tinsley Meter Station (Stationing 0+00) at the time of the failure was 1,336-psig (36.9% of SMYS). The pipeline normally operates between 1,200 and 1,450-psig (33.1 and 40.0% of SMYS, respectively).

The pipeline was installed in 2009 and is externally coated with a factory applied fusion bonded epoxy (FBE) and abrasion resistant overlay (ARO) coating. A liquid epoxy coating was applied to the pipeline at the girth welds in the field. Following construction, a hydrostatic pressure test was performed on January 14, 2009 to a minimum pressure at the dead weight gage of 2,908 psig (80.3% of SMYS). The pipeline has an impressed current cathodic protection (CP) system that was commissioned in 2009, directly following pipeline installation.

Three pipe sections (Pipe Sections [PSs] A, B, and C) were delivered to DNV GL for analysis. Pipe Section A was 5.99 feet long and contained the downstream (D/S) portion of the failed girth weld. Pipe Section B was 6.08 feet long and contained U/S portion of the failed girth weld. Pipe Section C was 8.00 feet long and contained an adjacent U/S intact girth weld. The objectives of the analysis were to determine the metallurgical cause of the failure and identify any contributing factors.

2.0 TECHNICAL APPROACH

The procedures used in the analysis were in accordance with industry-accepted standards. Five of the general standards governing terminology, specific metallographic procedures, mechanical testing, and chemical analysis used are as follows:

- ASTM E7, “Standard Terminology Relating to Metallography.”
- ASTM E3, “Standard Methods of Preparation of Metallographic Specimens.”
- ASTM E8, “Test Methods for Tension Testing of Metallic Materials.”

- ASTM E23, “Standard Test Methods for Notched Bar Impact Testing of Metallic Materials.”
- ASTM A751, “Standard Test Methods, Practices, and Terminology for Chemical Analysis of Steel Products.”

The following steps were performed for the analysis. The pipe sections were removed from the wooden shipping crates and visually inspected and photographed. Wall thicknesses, outside diameters (ODs), and circumferences were measured at the field cut ends of the pipe sections. The external and internal surfaces of the pipe sections at the failed girth weld were cleaned with a Scotch-Brite™ pad, followed by photography of the surfaces. The fracture surfaces were then cleaned with a soft bristle brush, followed by photography at one hour o’clock increments. The external surface of PS C was grit blasted at the intact girth weld, followed by magnetic particle inspection (MPI) of the grit blasted surface. Samples were removed from PS A and C for mechanical testing and steel chemical analysis.

Axial (cross girth weld) cross-sections were removed from the failed girth weld (five total) and intact girth weld (one total) for metallographic analysis. The cross-sections were mounted, polished, and etched. Light photomicrographs were taken to document the morphology of any flaws and the microstructures of the pipe steel and welds. Hardness testing was performed on the six mounted cross-sections to document the hardness values at and away from the girth welds. Fracture surface samples (four total) were removed from PS A, cleaned in ENPREP® 214, examined optically at low magnification with a stereomicroscope, and imaged at high magnification in a scanning electron microscope (SEM) to document the fracture morphologies.

Magnetic particle inspection was performed on the internal surfaces of the intact and failed girth welds. Chemical analyses were performed on the steel samples removed from the joints U/S and D/S of the failed girth weld to determine the compositions. Tensile (duplicates) testing was performed on transverse and axial specimens removed from the joints U/S and D/S of the failed girth weld, and on axial (cross-girth weld) specimens removed from the intact girth weld, to document the tensile properties. Charpy V-notch (CVN, triplicates) testing was performed on transverse specimens removed from the joints U/S and D/S of the failed girth weld to document the base metal toughness. Charpy V-notch (CVN) impact testing (full curve, 10 specimens per curve) was performed on axial (cross-girth weld, heat affected zone [HAZ] notch) specimens removed from the intact girth weld and an upper shelf impact energy and 85% fracture appearance transition temperature (FATT) was determined.

Figure 1 is a schematic of PSs A, B, and C showing the locations of the girth welds and seam welds, and where samples for metallography (Mount M1, M2, M3, M4, M5, and MU1),

fractography (Sample S1, S2, S3, and S4), mechanical testing, and chemical analysis were removed.

3.0 RESULTS AND DISCUSSION

3.1 Optical Examination

Figure 2 is a photograph of the wooden shipping crate that contained PS A as received at DNV GL. The crate is approximately 10 feet long and was in good condition. Figure 3 is a photograph of PS A after removal from the wooden crate. The figure shows that the ends of the pipe were wrapped in clear plastic that was secured with duct tape. Foam insulation was secured to the U/S end of the pipe to cover the fracture surface of the failed girth weld. Figure 4 are photographs of PS A after removal of the clear plastic and foam insulation. Flow direction and o'clock orientation were marked (prior to shipment to DNV GL) on the pipe section. The pipe section is 5.99 feet long, contains a longitudinal seam weld at the 12:26 orientation, has portions of a field applied liquid epoxy coating (light blue appearance) at the girth weld, and portions of a factory applied FBE coating (reddish brown appearance) on the remainder of the pipe section. The figure shows a large portion of the coating is not present. The coating is not present between approximately 0 and 5.70 feet D/S of the girth weld, from the 8:00 to 4:00 orientations. Field personnel indicated that following failure the product flow was toward PS A, which may have contributed to the lack of coating. Additionally, the figure shows some residual soil is present on the pipe section.

Figure 5 is a photograph of the wooden shipping crate that contained PS B as received at DNV GL. The crate also is approximately 10 feet long and was in good condition. Figure 6 is a photograph of PS B after removal from the wooden crate. The figure shows that the ends of this pipe also were wrapped in clear plastic that was secured with duct tape. Foam insulation was secured to the D/S end of the pipe to cover the fracture surface of the failed girth weld. Figure 7 is a photograph of PS B after removal of the clear plastic and foam insulation. Flow direction and o'clock orientation were marked (prior to shipment to DNV GL) on the pipe section. The pipe section is 6.08 feet long, contains a longitudinal seam weld at the 10:37 orientation, has portions of a field applied liquid epoxy coating (light blue appearance) at the girth weld, and a factory applied FBE coating (reddish brown appearance) on the remainder of the pipe section. Some of the field applied coating was not present adjacent to the girth weld, for the entire circumference. Additionally, the figure shows some residual soil is present on the pipe section.

Figure 8 is a photograph of the wooden shipping crate that contained PS C. The crate also is approximately 10 feet long and was in good condition. Figure 9 is a photograph of PS C after removal from the wooden crate. The figure shows that the ends of the pipe also were wrapped in clear plastic that was secured with duct tape. Figure 10 is a photograph of PS C

after removal of the clear plastic. Flow direction and o'clock orientation were marked (prior to shipment to DNV GL) on the pipe section. The pipe section is 8.00 feet long and contains longitudinal seam welds at the 1:24 orientation (U/S joint) and at the 10:37 orientation (D/S joint). An intact girth weld, that is the girth weld just U/S of the failed girth weld, is indicated in the figure. A field applied liquid epoxy coating (light blue appearance) is located at the girth weld and a factory applied FBE coating (reddish brown appearance) on the remainder of the pipe section. The field and factory applied coatings were intact. Additionally, the figure shows some residual soil is present on the pipe section. There was no evidence of notable internal or external corrosion of the three pipe sections.

Figure 11 through Figure 14 are photographs of the external surface of PSs A and B adjacent to the fracture surfaces/failed girth weld. The figures are sequential photographs taken around the circumference of the girth weld and show the morphology of the weld pattern and where coating is present. The lack of coating adjacent to the girth weld on the PS B side (U/S of the failed girth weld) suggests that large strains were present prior to/during the failure. The figures shows that the fracture path traversed (crossed over) the weld at various locations. The external appearance of the weld ripple pattern is indicative of low hydrogen electrodes deposited in the vertical-down direction, with a triple pass wide weave cap pass. Even though downhill welding progression with low-hydrogen electrodes is not common in the pipeline industry, electrode manufactures do provide low-hydrogen electrodes specifically designed to weld down, which are classified as EXX45 type electrodes. The morphology of the weld ripple pattern also indicates that the top button (start of welding) is located near the marked 12:00 orientation; see Figure 14.

Figure 15 and Figure 16 contain photographs of the internal pipe surface adjacent to the fracture surface of PS B. Each photograph shows approximately 3 o'clock hours of the internal surface at the girth weld adjacent to the fracture surface. The figures show that the root pass is located on the PS A side of the failure opening between approximately the 6 and 9 o'clock orientations and a majority of the root pass is located on the PS B side of the failure opening elsewhere. The top button is indicated in Figure 16, near the marked 12:00 orientation.

Circumferences and ODs were measured at the four field cut ends of the pipe sections. Table 1 summarizes the results of the measurements. The ODs calculated from the circumference measurement were between 24.1 and 24.2 inches at the field cut ends. The diameters meet API 5L tolerance requirements for 24-inch diameter pipe. The ODs were measured with a tape measure from the 3 to 9 o'clock and 12 to 6 o'clock orientations to check for ovality. The ODs at the ends of PSs B and C, and both orientations, were 24.0 inches, indicating no measurable ovality. The ODs at the end of PSs A, and both orientations, were 24.1 inches, indicating no measurable ovality.

Wall thicknesses were measured at the 12, 3, 6, and 9 o'clock orientations at the four field cut ends. The external coating was ground prior to the measurements. The wall thickness values were between 0.530 and 0.540 inches, as shown in Table 2, and meet API 5L tolerance requirements for pipe with a nominal wall thickness (NWT) of 0.540 inches.

3.2 Magnetic Particle Inspection

The intact girth weld on PS C was grit blasted and MPI was performed. Figure 17 and Figure 18 contain photographs of the external surface at the girth weld following MPI. No crack-like indications were identified. A metallographic cross-section (Mount MU1) was removed from the 12:24 orientation. The weld ripple pattern of the weld is consistent with PS A and PS B and with the use of a low hydrogen electrode and a vertical-down progression. The top button (Figure 18) is just above (counter-clockwise of) the 12:00 orientation.

Note that MPI of the internal surface of the intact weld also was performed following mechanical testing, as was MPI of the internal surface of at the failed GW, following metallography. No crack-like indications were identified.

3.3 Fractography

3.3.1 Optical

Figure 19 is a photograph of the fracture surface and internal surface of PS A following cleaning with a soft bristle brush. Each o'clock hour is indicated and located at the twelve grey magnets. Figure 20 through Figure 31 are sequential photographs of the PS A side of the fracture surface of the failed girth weld, in 1 hour o'clock increments, starting at the 12:00 orientation. The fracture surface mainly consists of fairly smooth surfaces (*smooth regions*) at a shear (~45°) angle with respect to the free surfaces, and rougher surfaces (*rough* surfaces) that are perpendicular to the free surfaces. Some examples of the smooth surfaces are in Figure 21 through Figure 23, between the 1:00 and 3:45 orientations. The fracture surface between the 3:45 and 4:15 orientations contains smooth and rough regions. Some other examples of the rough regions are in Figure 29 through Figure 31, between the 9:15 and 12:00 orientations, where the rough regions are mainly ID surface breaking, with some midwall portions. The differences in these appearances is related to the fracture mode (ductile vs brittle), as described in Section 3.3.2, and both regions formed as a result of overload. There was no evidence of gross pre-existing flaws on the fracture surface that would have been rejected if detected by radiographic inspection. The exact location of the initiation could not be determined due to a lack of chevrons on the fracture surfaces and the fact that no significant pre-existing (prior to failure) cracks were identified.

3.3.2 Optical and Scanning Electron Microscopy

Four fracture surface samples (Samples S1, S2, S3, and S4) were removed from the PS A side of the failed girth weld, adjacent to the metallographic cross-sections. The results of examinations of Samples S2 and S3 are below.

Figure 32 is a light photomicrograph of the fracture surface of Sample S2, following cleaning in ENPREP® 214. Sample S2 was removed near the 4:00 orientation. The figure shows smooth regions (black dashed double arrows) adjacent to the OD and ID surfaces, and a rougher region (white double arrow) midwall. There is no evidence of any pre-existing (present prior to the failure) flaws on the facture surface. Figure 33 is an SEM image of Sample S2 adjacent to the ID surface. The figure shows a smooth region (adjacent to the ID surface) and a rough region of the fracture surface. Figure 34 is an SEM image of Sample S2 at the interface of a smooth and rough region. The black box in the figure is just below the interface and the figure shows dimples in the smooth region. Dimples indicate ductile (overload) fracture, which occurred during the failure. Figure 35 is a high magnification SEM image of Sample S2 in the smooth region. The figure clearly shows the dimples. Figure 36 and Figure 37 are SEM images of Sample S2 in a rough region. The fracture surface contains cleavage facets, which indicates brittle (overload) fracture, which occurred during the failure.

Figure 38 is an SEM image of Sample S2, midwall at a second interface of the smooth and rough regions. The figure shows what appear to be some tears in the smooth region, above the rough region. Figure 39 and Figure 40 are SEM images in the smooth region. The figures shows dimples, consistent with ductile (overload) fracture.

Figure 41 and Figure 42 are SEM images of Sample S2 in a smooth region adjacent to the OD surface. The figures show dimples, which is very clear in the high magnification SEM image. Again, the dimples indicate ductile (overload) fracture and are consistent with ductile fracture in the smooth region.

Figure 43 is a light photomicrograph of the fracture surface of Sample S3, following cleaning in ENPREP® 214. Sample S3 was removed near the 8:30 orientation. Figure 44 is an SEM image of Sample S3. The fracture surface is macroscopically smooth and at a shear angle to the free surfaces, and consists of mainly, if not entirely, smooth regions. Figure 45 is an SEM image of Sample S3 midwall. The figure shows small and larger dimples. Figure 46 is a high magnification SEM image of Sample S3 in the smooth region. The figure clearly shows the dimples.

Examination of Samples S1 and S4 showed similar fractographic features that formed as a result of overload failure. There was no evidence of obvious pre-existing flaws or fatigue growth on the fracture surfaces examined.

3.4 Metallography

Axial (cross girth weld) cross-sections were removed from the failed girth weld (five total) and the intact girth weld (one total) for metallographic analysis. Figure 47 is a photograph of the mounts that were removed from across the failed girth weld. The figure shows that Mounts M1 and M3 contain fracture paths at a shear angle, which is indicative of ductile overload failure. Mounts M2 and M4 (and a small portion of M5) contain regions where the fracture path is perpendicular to the free surface and regions of shear failure. The perpendicular portions are where the fracture surfaces are rough and the shear angle portions are where the fracture surfaces are smooth.

Figure 48 is a light photomicrograph of the axial metallographic cross-section (Mount M1), which was removed from the failed GW at the 1:35 o'clock orientation; refer to Figure 1 and Figure 11 for the location. The sequence of the welding is typical of a pipeline girth weld consisting of a root pass, a hot pass, several fill passes (depending on o'clock orientation), and cap passes. There is no evidence of excessive porosity or slag inclusions in the weld. The fracture path is at a shear angle and mainly located in the weld metal. The high-low weld misalignment at this location is approximately 0.023 inches (4.3% of NWT); note the misalignment is difficult to measure on the fracture cross-section and is an approximation.

Figure 49 is light photomicrograph of Mount M1 adjacent to the OD surface. The figure shows the fracture path is located in the HAZ, near the toe of the weld at the OD surface. Figure 50 is a light photomicrograph of Mount M1 adjacent to the fracture surface, near the OD surface. The figure shows inclusions aligned at an oblique angle with the fracture surface. The orientation of the inclusions is a result of cold work from the failure. Figure 51 is a high magnification light photomicrograph of Mount M1 adjacent to the fracture surface. The figure shows some grain elongation adjacent to the fracture surface and inclusions. The presence of the grain elongation from cold work and orientation of the inclusions is consistent with ductile overload. Figure 52 is a high magnification light photomicrograph of Mount M1 midwall adjacent to the fracture surface. The figure clearly shows the change in the grain orientation and thus more grain elongation adjacent to the fracture surface.

Figure 53 and Figure 54 are light photomicrographs showing the microstructures of the U/S and D/S Joints, respectively. The microstructures of the joints consist mainly of ferrite (white areas), which is consistent with modern X80 line pipe.

Figure 55 is a light photomicrograph of the axial metallographic cross-section (Mount M2), which was removed from the failed GW at the 3:55 o'clock orientation; refer to Figure 1 and Figure 12 for the location. The morphology of the weld similar to Mount M1. The high-low weld misalignment at this location is approximately 0.037 inches (6.9% of the NWT). The figure clearly illustrates the smooth and rough regions examined near SEM Sample S2, such

that the smooth regions are surface breaking and the rough region is midwall. The fracture path at this location is in both the weld metal and HAZ, such that smooth region near the OD surface is in the weld metal, and the rough region midwall and smooth region near the ID surface are in the HAZ. Fractography in the SEM demonstrated that the smooth region contains dimples and the rough region contains cleavage facets.

Figure 56 is a light photomicrograph of Mount M2 adjacent to the ID surface. The figure shows that the fracture surface is relatively smooth. Figure 57 is a high magnification light photomicrograph of Mount M2 adjacent to the ID surface. The figure shows grain elongation adjacent to the fracture surface. The presence of the grain elongation from cold work is consistent with ductile overload. Figure 58 is a light photomicrograph of Mount M2 midwall, in a rough region. The fracture surface is clearly rougher here than the previous figure, and the fracture path is mainly located in the HAZ, if not entirely. Figure 59 is a light photomicrograph of Mount M2 adjacent to the fracture, midwall. The figure shows some fissures. Figure 60 is a high magnification light photomicrograph of Mount M2 at fissures. The fissures are located where cleavage facets (brittle fracture) were present on the fracture surface. These fissures are commonly seen in girth weld overload failures, adjacent to fractures surfaces, or pipe (body or seam weld) failures that involve axially running fracture.

Figure 61 is a light photomicrograph of the axial metallographic cross-section (Mount M3), which was removed from the failed GW at the 8:35 o'clock orientation; refer to Figure 1 and Figure 13 for the location. The morphology of the weld is similar to Mounts M1 and M2. The fracture path is at a shear angle and mainly located in the weld metal. The high-low weld misalignment at this location is approximately 0.014 inches (2.6% of the NWT). The figure clearly illustrates the smooth region examined near SEM Sample S3.

Figure 62 is light photomicrograph of Mount M3 adjacent to the fracture surface, near the ID surface. The figure shows grain elongation adjacent to the fracture surface that is consistent with ductile overload.

Figure 63 is a light photomicrograph of the axial metallographic cross-section (Mount M4), which was removed from the failed GW at the 10:24 o'clock orientation; refer to Figure 1 and Figure 14 for the location. The morphology of the weld is similar to the previous mounts. The high-low weld misalignment at this location is minimal. The figure shows both a smooth shear angle region and a rough region oriented perpendicular to the free surfaces. The fracture path at this location is mainly in the HAZ.

Figure 64 is light photomicrograph of Mount M4 adjacent to the OD surface. The figure clearly shows the fracture path is located in the HAZ. Figure 65 is a high magnification light photomicrograph of Mount M4 adjacent to the OD surface. The figure shows grain

elongation, and an inclusion orientated parallel to the fracture surface, both observations consistent with ductile overload. Figure 66 is a light photomicrograph of Mount M4 midwall, mainly in a rough region. The figure shows some fissures. Figure 67 is a high magnification light photomicrograph of Mount M4 at some fissures. The fissure have the same morphology as shown in Mount M2. Figure 68 is a high magnification light photomicrograph of Mount M4 near the ID surface. The figure shows grain elongation adjacent to the fracture surface.

Figure 69 is a light photomicrograph of the axial metallographic cross-section (Mount M5), which was removed from the failed GW at the 11:37 o'clock orientation; refer to Figure 1 and Figure 14 for the location. The morphology of the weld is similar to the previous mounts. The high-low weld misalignment at this location is approximately 0.025 inches (4.6% of the NWT). The figure shows a smooth shear angle region for a majority of the fracture surface, and a rough region oriented perpendicular to the free surfaces midwall. The fracture path at this location is located in both the weld metal and base metal.

Figure 70 is a light photomicrograph of the axial metallographic cross-section (Mount MU1), which was removed from the intact GW at the 12:24 o'clock orientation; refer to Figure 1 and Figure 17 for the location. The morphology of the weld is similar to the previous mounts. The high-low weld misalignment at this location is approximately 0.011 inches (2.0% of the NWT). Figure 71 is a light photomicrograph of Mount MU1 adjacent to the ID surface. The figure shows a shallow (0.01 inches [1.9% of NWT] deep) flaw between the weld metal and HAZ. The location of the flaw is consistent with incomplete fusion (IF). Figure 72 is a high magnification light photomicrograph of Mount MU1 at the tip of the shallow IP flaw. The figure shows there is no evidence of crack extension at the flaw.

3.5 Hardness Testing

Vickers hardness testing was performed on all six mounts in the base metal, HAZ, and weld metal. A 1 kg load was used on Mounts M1, M4, and MU1 and approximately 1500 indents with approximately 0.5 mm spacing were performed. Figure 73, Figure 76, and Figure 78 are hardness map overlays showing the locations of the indents and color coded maps indicating the hardness values. The hardness values for the two mounts from the failed girth weld are between 208 and 317 HV, and the values for the mount from the intact girth weld are between 167 and 268 HV. The average hardness for Mount M1, M4, and MU1 are 266, 253, and 228 HV, respectively. There was a larger variation in the hardness values, and less of a consistent pattern of hardness values, for the mounts from the failed GW compared to the intact girth weld. Overall for the mounts from the failed girth weld, the weld metal in the root pass was the softest, the weld metal in the cap pass was higher than the fill passes, and the base metal was somewhere in between. The highest values for the

mounts from the failed girth weld was adjacent to the shear fracture surface, between midwall and the OD surface.

The hardness of the intact girth weld (Figure 78) is a better representation of the hardness of all the welds prior to the failure. For the intact girth weld, the values appeared to follow a more consistent pattern. Figure 78 clearly shows that the root pass of the weld metal is the softest and the surrounding base metal (adjacent to the HAZ) is harder than the weld metal. Hardness typically correlates with ultimate tensile strength (UTS) fairly well, thus the data indicates that the weld metal is weaker than the surrounding pipe material. The higher hardnesses measured in the failed welds, and the large variation and lack of a consistent pattern, is a byproduct of the cold work the material experienced during the failure.

A 10 kg load was used on Mounts M2, M3, and M5 (all from the failed girth weld) and indents were performed at approximately 20 to 30 locations. Figure 74, Figure 75, and Figure 77 are light photomicrographs of the mounts showing the indents and hardness values. The hardness values are between 205 and 304HV. The lowest values are at the ID weld metal (root pass, similar to the hardness maps), and the highest values are in the weld metal cap pass. The base metal is generally harder than the root and fill passes, and similar to or sometimes less than the cap pass.

Overall no areas of unusually high hardness area were found. The hardness results show that the softest region is located in the weld metal root pass, suggesting a lower grade electrode was used for the root pass compared to the other passes.

3.6 Mechanical Testing

3.6.1 Tensile Testing

The results of tensile testing of duplicate circumferential base metal specimens removed from PS A (Joint D/S of failed GW) are shown in Table 3. The average yield strength (YS) and ultimate tensile strength (UTS) of the circumferential specimens were 93.5 ksi and 112.4 ksi, respectively. The results of tensile testing of axial base metal specimens also are shown in the table and YS values for the axial specimens are quite a bit higher than those of the circumferential specimens (by 8 ksi). The YS and UTS of the circumferential base metal specimens meet the requirements for API 5L X80M PSL 2 line pipe at the time of construction.

The results of tensile testing of duplicate circumferential base metal specimens removed from PS C (Joint U/S of failed GW) are shown in Table 4. The average YS and UTS of the circumferential specimens were 91.0 ksi and 104.8 ksi, respectively, which is slightly less than the values for PS A. The results of tensile testing of axial base metal specimens also

are shown in the table and the YS values for the axial specimens also are higher than those of the circumferential specimens (by 6.7 ksi). The YS and UTS of the circumferential base metal specimens meet the requirements for API 5L X80M PSL 2 line pipe at the time of construction.

The average UTS of duplicate axial specimens removed across the intact girth weld was 103.3 ksi. Both cross-girth weld specimens failed in the girth weld, similar to the actual failure. YS values across the girth weld are not reliable and not specified in API 1104. The average UTS value across the weld meets the tensile requirements API 5L X80M PSL 2 line pipe at the time of construction. Note that the value of 103.3 ksi is less than the axial tensile strength of 109.7 ksi and 106 ksi for the joints D/S and U/S, respectively, of the failed girth weld.

3.6.2 CVN Testing of Base Metal Specimens

The results of CVN testing of triplicate transverse base metal specimens removed from PSs A (Joint D/S of failed GW) and C (Joint U/S of failed GW) are shown in Table 5. The specimens were tested at 32°F. The impact values are relatively high, i.e. full-size values all above 93 ft·lbs for PS A and above 148 ft·lbs for PS C. The shear % values are all 100% (indicating fully ductile behavior). The impact values all exceed the specified minimum value of 30 ft·lbs (at 32°F) for API 5L X80 PSL 2 line pipe, and the average of shear % values are greater than 85 %.

3.6.3 CVN Testing of Girth Weld Specimens

Table 6 shows the results of CVN testing for axial specimens removed from the intact girth weld (notch in the HAZ from PS C), while Figure 79 and Figure 80 show the Charpy percent shear and impact energy curves. An analysis of the data for the girth weld specimens indicates that the 85% FATT is 59.9°F and upper shelf Charpy energy is 114 ft lbs, as shown in Table 7. Both values are good for line pipe steel.

3.7 Chemical Analysis

The results of the chemical analyses conducted on steel samples removed from PSs A (Joint D/S of failed GW) and C (Joint U/S of failed GW) are summarized in Table 8. The results of the chemical analyses indicate that the steels meet the chemical composition requirements for API 5L Grade X80M PSL 2 line pipe steel at the time of construction. Carbon equivalent (CE) values were calculated for the base metal samples. The calculated CE_{Pcm} values for the PSs A and C are 0.17 and 0.16, respectively, compared to a maximum allowed CE_{Pcm} of 0.25 per the API 5L spec at the time of construction. These values for the joints are relatively low and indicate a very good resistance to HACC in the HAZ.

4.0 CONCLUSIONS

The results of the metallurgical analysis indicate that the failure initiated at a field girth weld, completely separating the girth weld. The exact location of the initiation could not be determined due to a lack of chevrons on the fracture surfaces and the fact that no significant pre-existing (prior to failure) cracks were identified. Microscopically, the fracture surface contained regions with dimples (ductile fracture) and cleavage facets (brittle fracture). The dimples were located where the fracture surface was at a shear angle and macroscopically smooth, and the cleavage facets were located where the fracture surface was perpendicular to the free surfaces and macroscopically rough. Both fractographic features are an indication of the overload nature on the fracture surface.

The failure occurred due to axial stresses sufficient to produce an overload failure. Supporting evidence for the presence of large axial stresses include 1) a relatively large opening between the failed ends and 2) cracked and missing epoxy coating U/S of the failed girth weld indicating a high strain prior/during fracture. A possible contributing factor to relatively large axial stresses include stresses associated with movement.

No excessively high hardness areas were identified in the girth weld cross-sections. The weld metal of the intact girth weld had a lower hardness than the surrounding pipe material, indicating that the weld metal is weaker than the surrounding pipe material. This trend was somewhat followed for the failed girth weld, although cold work from the failure likely skewed some of the data. The softest regions in all the mounts was the weld metal root pass. The lower overall hardness values of the weld metal compared to the surrounding pipe material is consistent with the axial tensile results. The ultimate tensile strength for the girth weld of 103.3 ksi is less than the axial tensile strength of 109.7 ksi and 106 ksi for the joints D/S and U/S, respectively, of the failed girth weld. The axial tensile tests across the intact GW failed in the GW, similar to the actual failure. Therefore, a contributing factor to the failure was that the pipe steel was stronger than the girth weld.

Below is a summary of additional conclusions:

- There was no evidence of notable internal or external corrosion.
- The tensile and toughness properties of the joints U/S and D/S of the failed girth weld meet requirements for API 5L X80M PSL 2 line pipe at the time of construction.
- The chemical compositions of the joints U/S and D/S of the failed girth weld meet the requirements for API 5L X80M PSL 2 line pipe at the time of construction.
- The microstructures of the joints U/S and D/S of the failed girth are consistent with modern API 5L X80 line pipe steel.

- An analysis of the Charpy V-notch impact testing data for the intact girth weld indicates that the 85% FATT is 59.9°F and upper shelf Charpy energy is 114 ft lbs.

Table 1. Results of circumference and diameter measurements performed at the field cut ends of Pipe Sections (PS) A, B, and C.

□i□e□ □e□tion	□i□e□ □e□tion□ □nd□	Cir□□□ □eren□e□ □eet□□	Dia□ eter□in□□e□□□		
			Fro□ □ Cir□□□ □eren□e□ Mea□□re□ ent□	□to□□□o□□□o□□□	□to□□□o□□□o□□□
□	D□□	□□□□□	□□□□	□□□□	□□□□
□	□ □□	□□□□□	□□□□	□□□□	□□□□
□	D□□	□□□□□	□□□□	□□□□	□□□□
□	□ □□	□□□□□	□□□□	□□□□	□□□□

Table 2. Results of wall thickness measurements performed at the field cut ends of PS A, B, and C.

O□□□o□□□ Orientation□	□ a□□T□i□□ne□□□□in□□e□□□			
	□□□A□D□□□nd□	□□□B□□□□□nd□	□□□C□D□□□nd□	□□□C□□□□□nd□
□□	□□5□□	□□5□□	□□5□□	□□5□□
□	□□5□□	□□5□□	□□5□□	□□5□□
□	□□5□□	□□5□5	□□5□□	□□5□□
□	□□5□□	□□5□□	□□5□□	□□5□□
□□□r□□□□	□□5□5	□□5□□	□□5□□	□□5□□

Table 3. Results of tensile tests performed on circumferential specimens from PS A (Joint D/S of failed GW) compared with requirements for API 5L X80M PSL 2 line pipe steel, and axial base metal specimens from Pipe Section A.

	Cir□□□ □erentia□□	A□l□□□□□□□M□ □ine□□i□e□□tee□□□□	A□ia□□
□□□d □r□□□□□□□□□□□	□□□5	□□□5 □ □□□□□□	□□□□5
□□□□□□□ □□r□□□□□□□□□□□	□□□□□□	□□□□ □ □□□□□□	□□□□□□
□□□□□□□□□□□ □□ □ □□□□□□□□□□	□□□5	□□□□ □□ □□□	□□□□
R□d□□□□□□ □□□r□□□□	□□□□	□	□□□□

1 – Average of duplicate tests.
2 – API 5L 44th Edition, October 1, 2007.

Table 4. Results of tensile tests performed on circumferential specimens from PS C (Joint U/S of failed GW) compared with requirements for API 5L X80M PSL 2 line pipe steel and axial base metal specimens and axial/cross-girth weld specimens from Pipe Section C.

	Cir[illegible] erentia[illegible]	A[illegible] M[illegible] ine[illegible] i[illegible] e[illegible] tee[illegible]	A[illegible] ia[illegible]	Cro[illegible] irt[illegible] [illegible] e[illegible]
[illegible] r[illegible]	[illegible]	[illegible] 5 [illegible]	[illegible]	[illegible]
[illegible] r[illegible]	[illegible]	[illegible] [illegible]	[illegible]	[illegible]
[illegible] [illegible]	[illegible]	[illegible] [illegible]	[illegible]	[illegible]
R[illegible] r[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

1 – Average of duplicate tests.
2 – API 5L 44th Edition, October 1, 2007.

Table 5. Results of Charpy V-notch impact tests for circumferential base metal specimens removed from the PS A (Joint D/S of failed GW) and PS C (Joint U/S of failed GW). Specimens were tested at 32F.

Sample ID	Absorbed Energy (ft-lb)	Percent Shear	Lateral Expansion (mils)
[illegible]			
[illegible]	[illegible]	[illegible]	5[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]5	[illegible]5	[illegible]
Average	[illegible]	[illegible]	[illegible]5
[illegible]			
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]55	[illegible]55	[illegible]
Average	[illegible]5[illegible]	[illegible]5[illegible]	[illegible]5
API 5L[illegible]	[illegible]	[illegible]	[illegible]5

1 – API 5L 44th Edition, October 1, 2007.

Table 6. Results of Charpy V-notch impact tests performed on axial/cross-girth weld (heat affected zone [HAZ] notch) specimens removed from PS C.

Sample ID	Test Temperature °F	Absorbed Energy, Fraction 1 (ft-lb)	Absorbed Energy, Fraction 2 (ft-lb)	Shear (%)	Lateral Expansion (mils)
[illegible]	[illegible]	[illegible]	[illegible]	5	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	5[illegible]	5[illegible]	5[illegible]	[illegible]
5	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]5
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]5	[illegible]5	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Table 7. Results of analyses of Charpy V-notch impact energy and percent shear plots for axial/cross-girth weld (HAZ notch) specimens removed from PS C (Joint U/S of failed GW).

[illegible]	[illegible]
[illegible]	[illegible]
[illegible]5[illegible]	5[illegible]

Table 8. Results of chemical analyses of base metal samples removed from PS A (Joint D/S of failed GW) and PS C (Joint U/S of failed GW), compared with composition requirements for API 5L X80M PSL 2 line pipe steel. The highlighted CE values are the ones that are applicable based on carbon wt%.

Element	Composition (wt%)		
	PS A Joint D/S of failed GW	PS C Joint U/S of failed GW	API 5L X80M PSL 2 Requirements
C	0.05	0.05	0.18 max
Mn	1.66	1.65	1.90 max
P	0.010	0.010	0.020 max
S	0.002	0.001	0.008 max
Si	0.20	0.20	0.45 max
Cu	0.01	0.01	0.25 max
Ni	0.01	0.01	0.25 max
Cr	0.02	0.02	0.25 max
Mo	0.01	0.01	0.15 max
Nb	0.06	0.06	0.06 max
V	0.01	0.01	0.05 max
Ti	0.01	0.01	0.06 max
Al	0.03	0.03	0.06 max
B	0.0001	0.0001	0.0005 max
N	0.0045	0.0045	0.012 max
Ca	0.0020	0.0020	0.0035 max
CE$_{IIW}$ [2]	0.31	0.31	0.43 max
CE$_{Pcm}$ [3]	0.16	0.16	0.25 max

1 – API 5L 44th Edition, October 1, 2007.

2 – $CE_{IIW} = C + Mn/6 + (Cu + Ni)/15 + (Cr + Mo + V)/5$

3 – $CE_{Pcm} = C + Si/30 + Mn/20 + Cu/20 + Ni/60 + Cr/20 + Mo/15 + V/10 + 5B$.

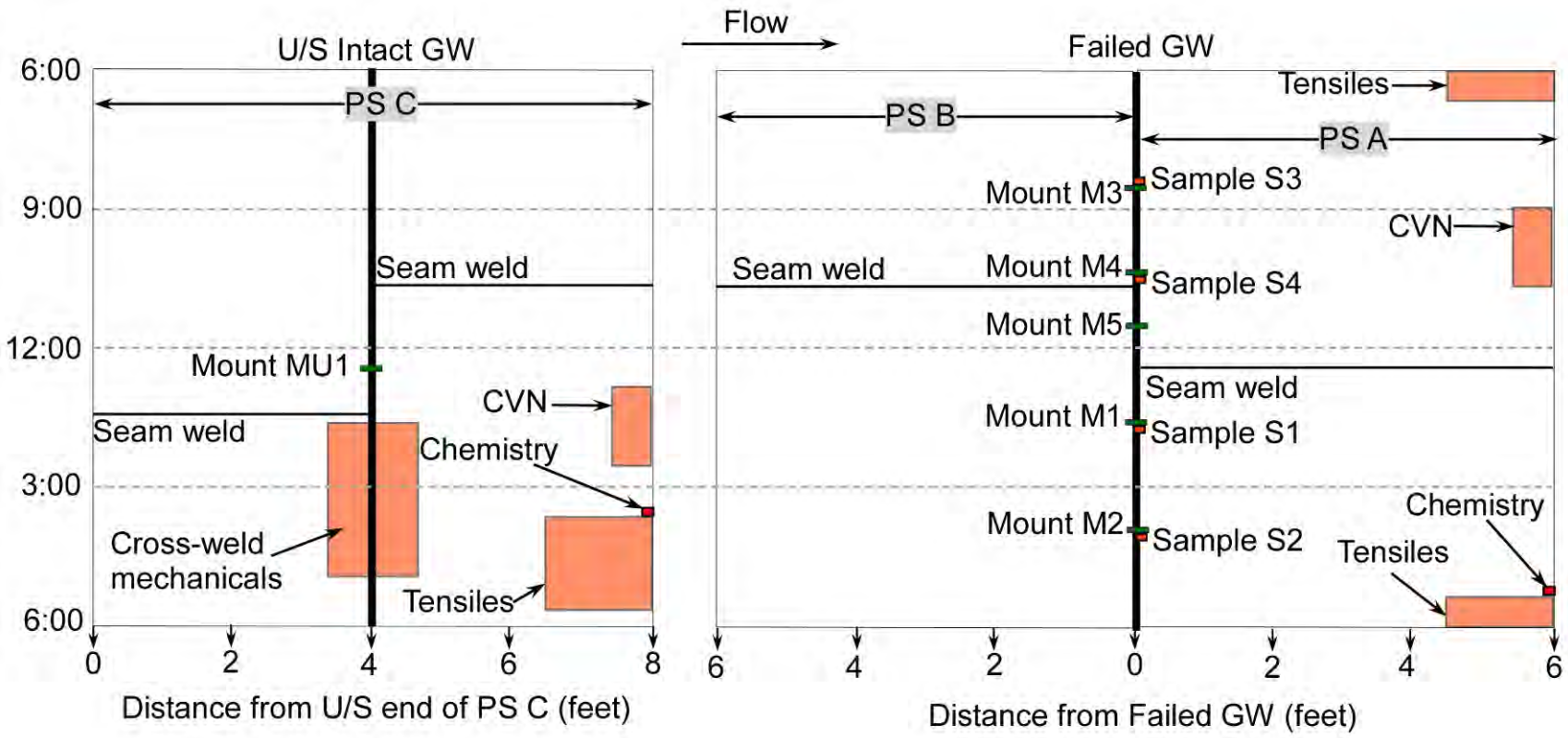


Figure 1. Schematic of Pipe Sections (PSs) A, B, and C showing the locations of the girth welds and seam welds, and where samples for metallography (Mounts M1, M2, M3, M4, M5, and MU1), fractography (Sample S1, S2, S3, and S4), mechanical testing (CVN, cross-weld mechanicals, and tensiles), and chemical analyses (chemistry) were removed.



Figure 2. Photograph of the wooden crate that contained PS A, as received at DNV GL.

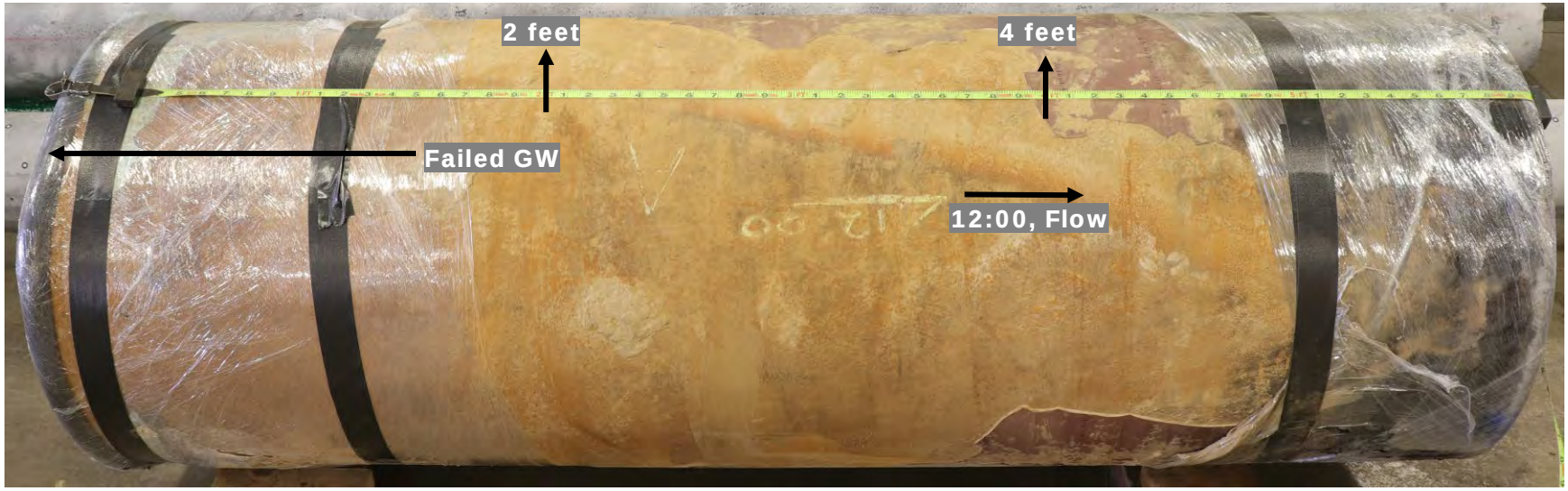


Figure 3. Photograph of PS A after removal from the wooden crate. The tape measure indicates the distance from the U/S end of PS A.

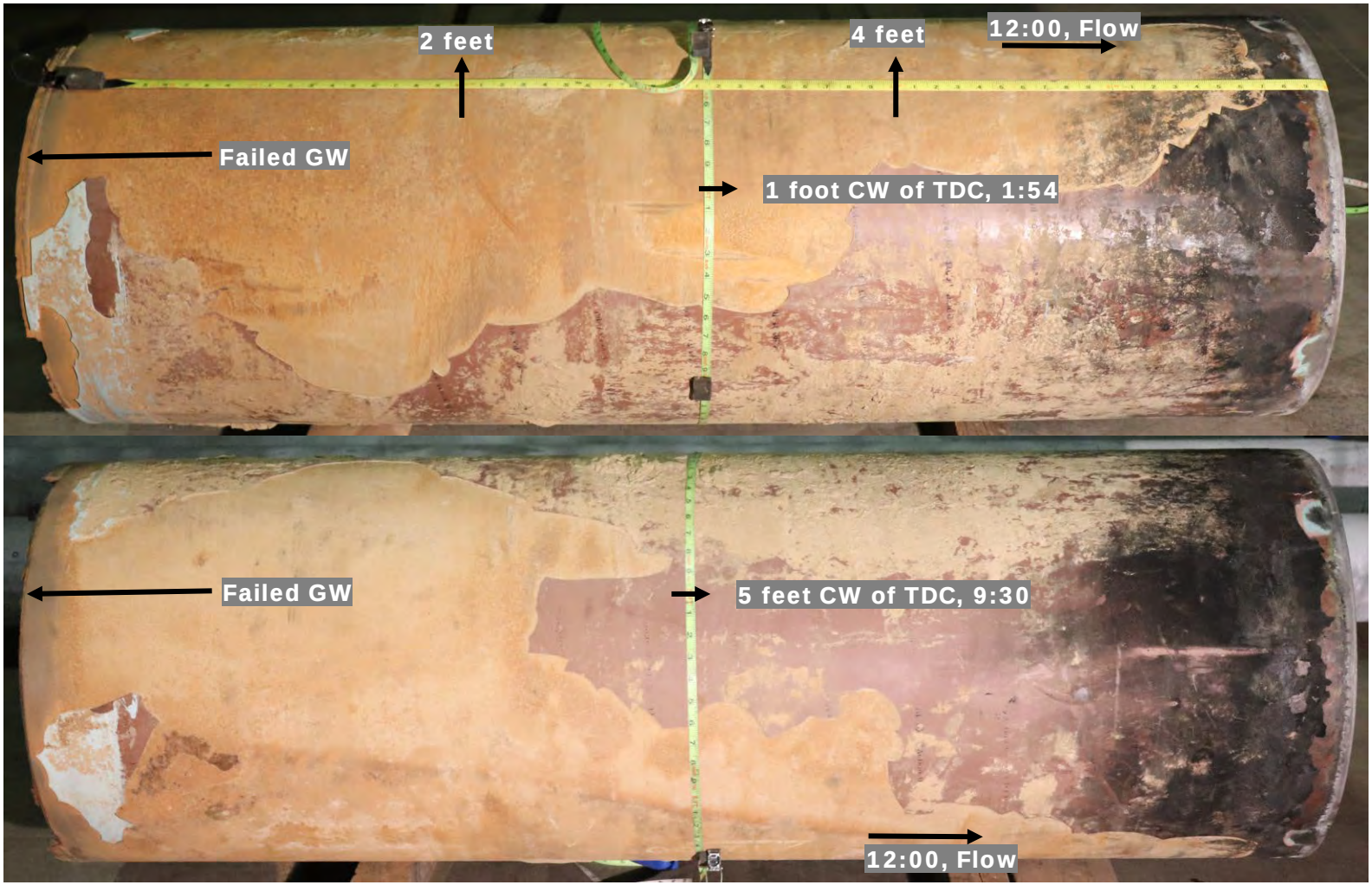


Figure 4. Photographs of PS A after removal of the protective wrappings. The horizontal tape measure indicates the distance from the U/S end of PS A, and circumferential tape measure indicates the distance clockwise (CW) of top-dead-center (TDC) looking downstream (D/S).



Figure 5. Photograph of the wooden crate that contained PS B, as received at DNV GL.

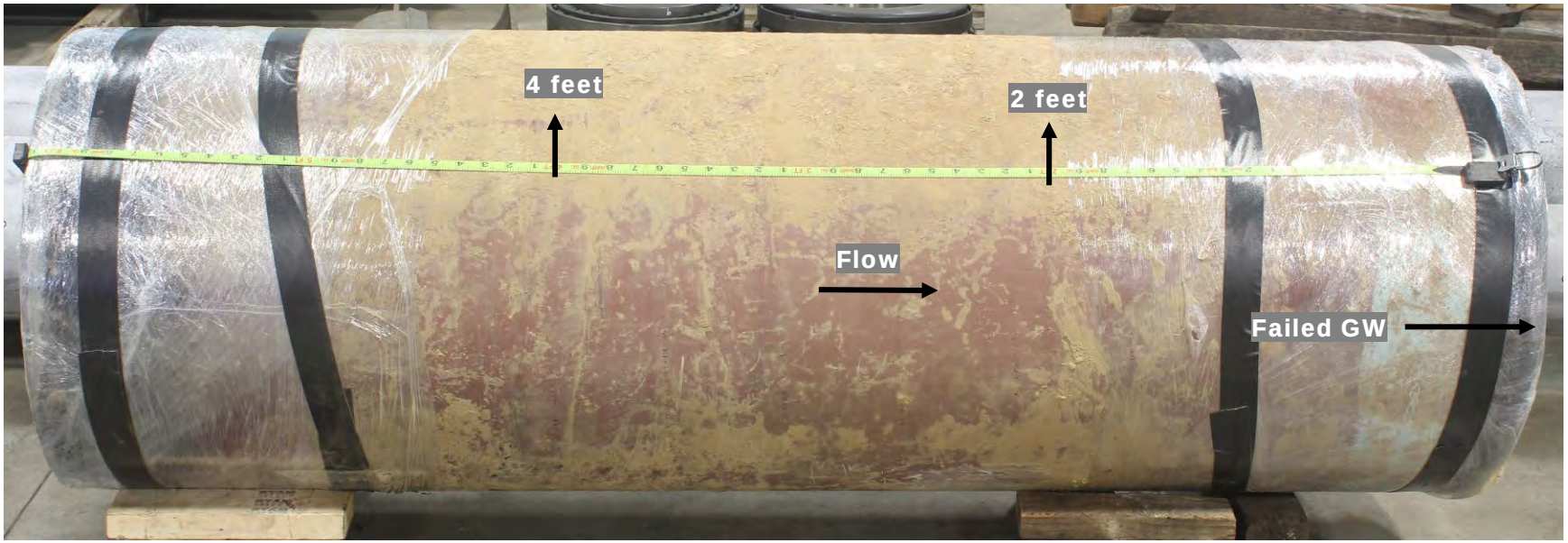


Figure 6. Photograph of PS B after removal from the wooden crate. The tape measure indicates the distance from the D/S end of PS B.



Figure 7. Photograph of PS B after removal of the protective wrappings. The tape measure indicates the distance from the D/S end of PS B.



Figure 8. Photograph of the wooden crate that contained PS C, as received at DNV GL.

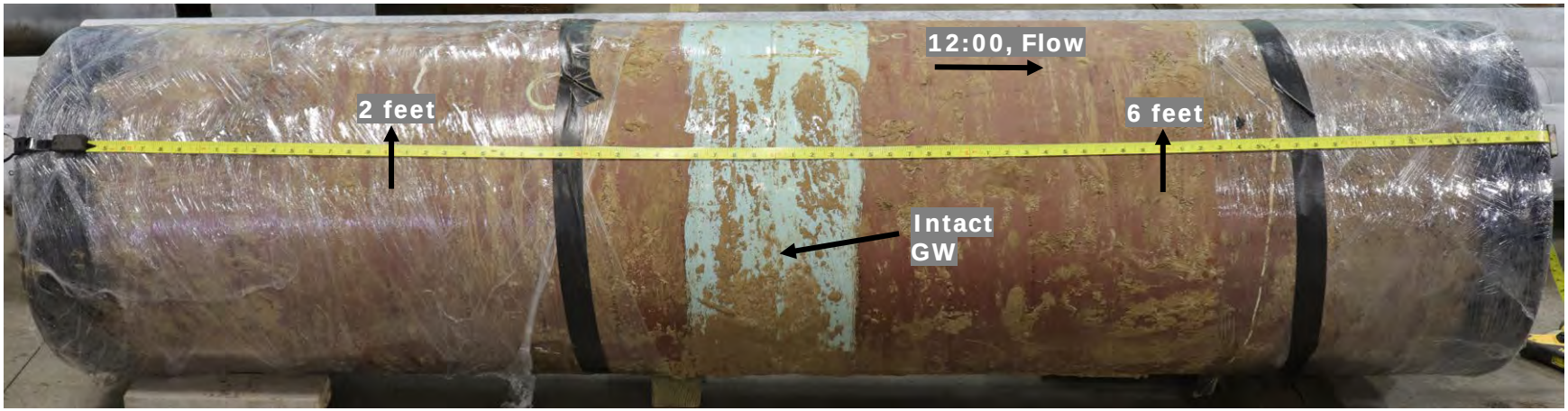


Figure 9. Photograph of PS C after removal from the wooden crate. The tape measure indicates the distance from the U/S end of PS C.

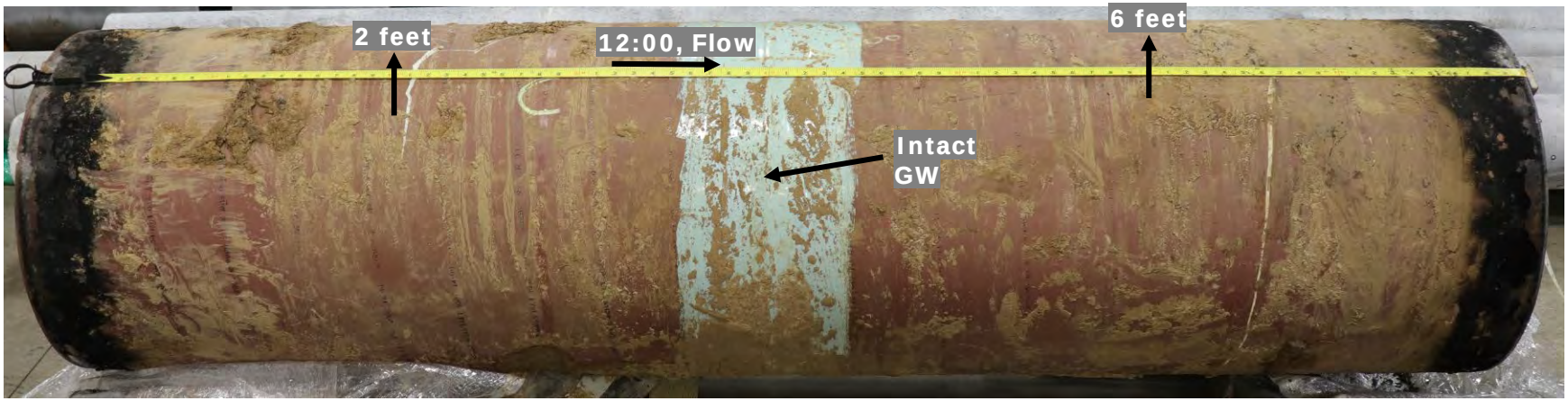


Figure 10. Photograph of PS C after removal of the protective wrappings. The tape measure indicates the distance from the U/S end of PS C.

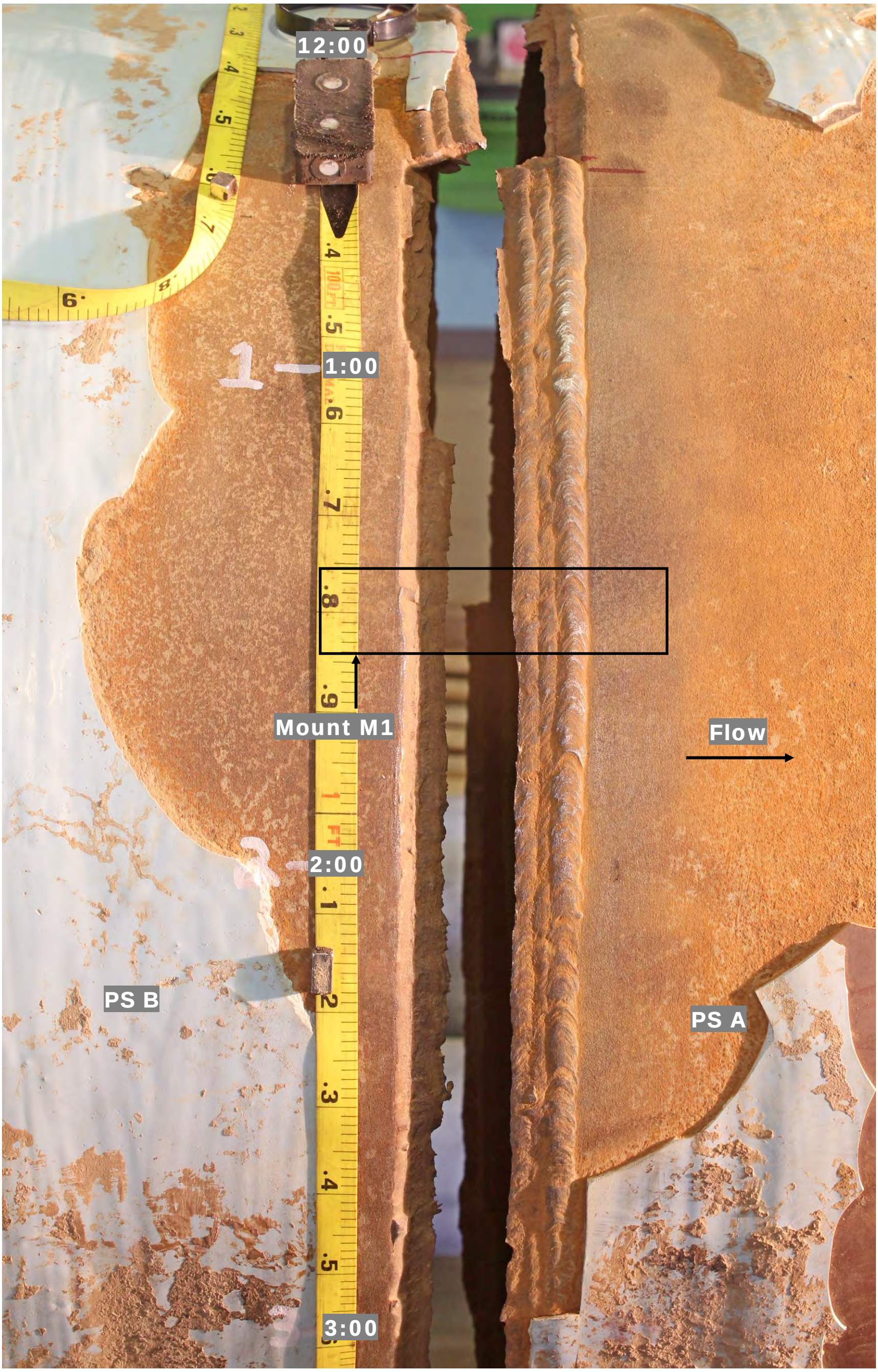


Figure 11. Photograph of the external of surfaces of PSs A and B adjacent to the fracture surfaces, between the 12 and 3 o'clock orientations, showing the failed girth weld and the morphology of the coating. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).

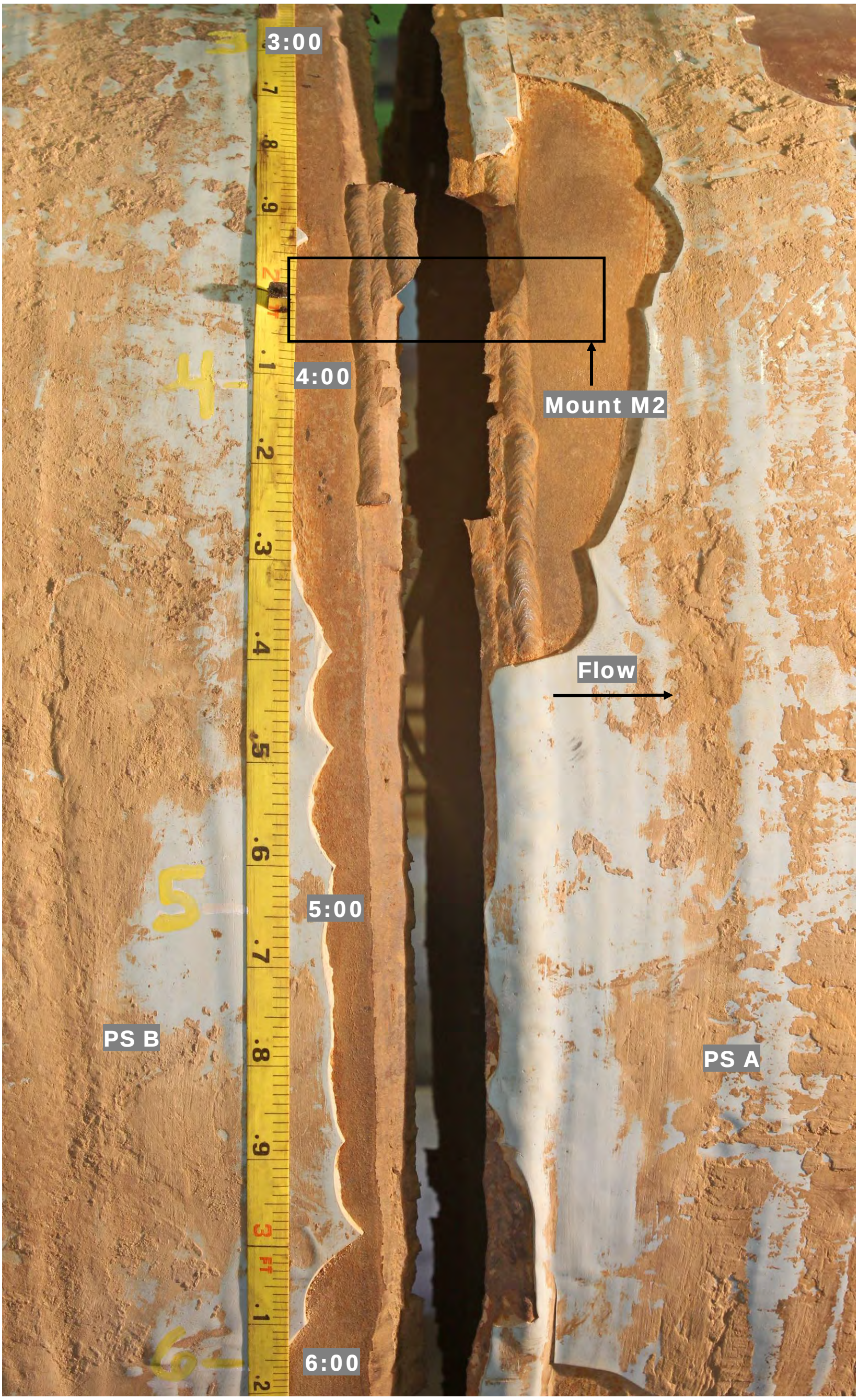


Figure 12. Photograph of the external of surfaces of PSs A and B adjacent to the fracture surfaces, between the 3 and 6 o'clock orientations, showing the failed girth weld and the morphology of the coating. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).

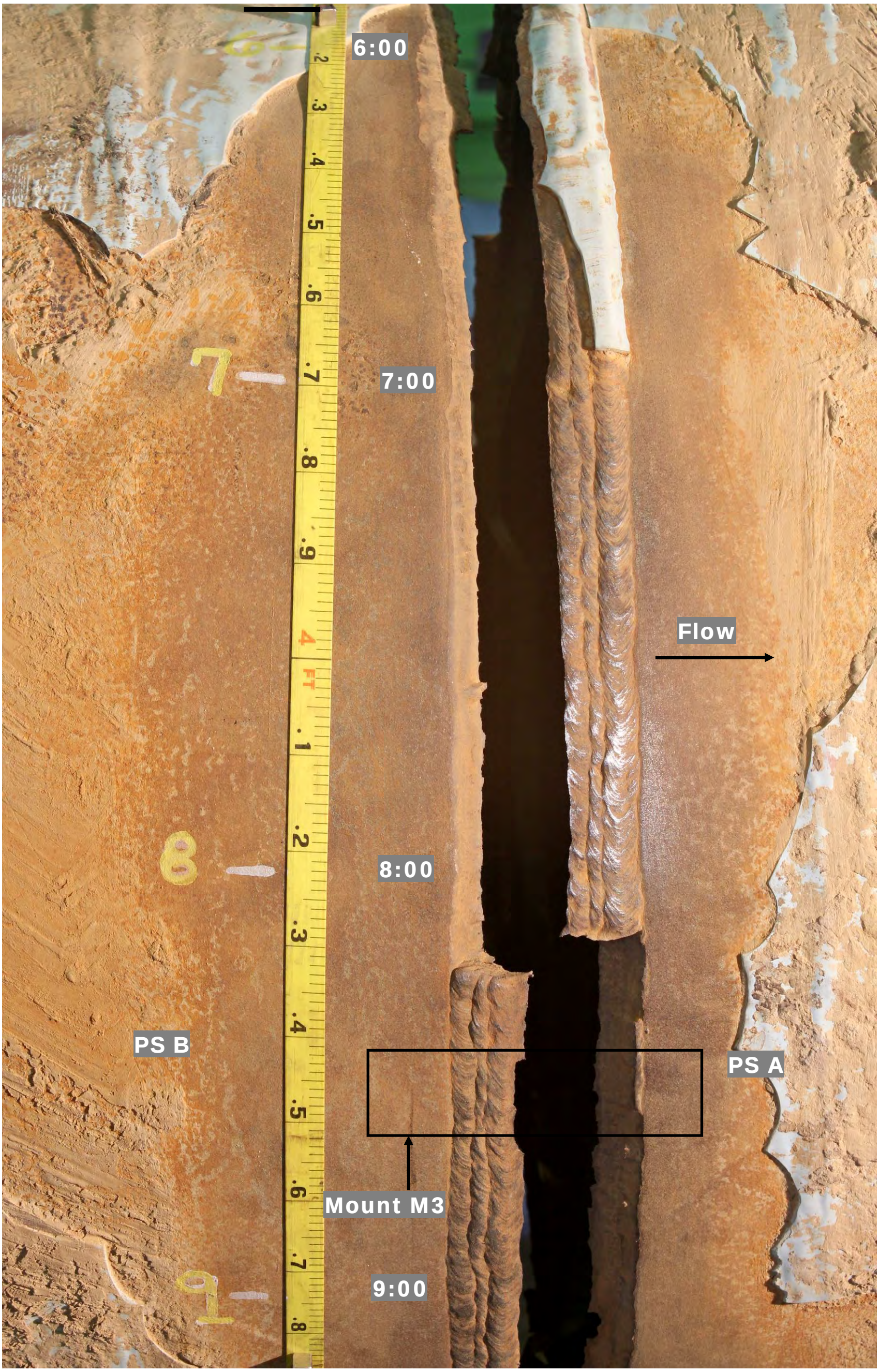


Figure 13. Photograph of the external of surfaces of PSs A and B adjacent to the fracture surfaces, between the 6 and 9 o'clock orientations, showing the failed girth weld and the morphology of the coating. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).

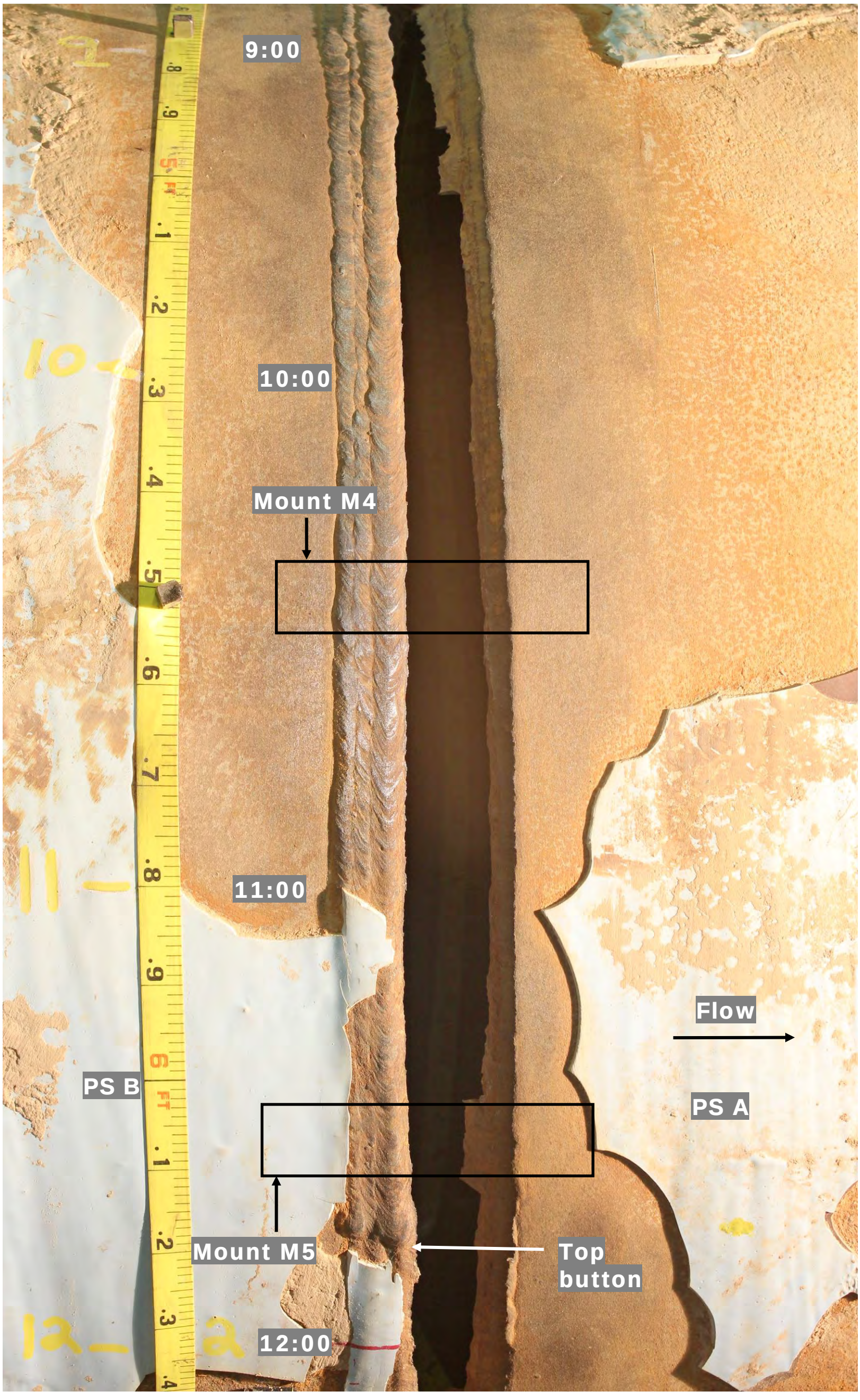


Figure 14. Photograph of the external of surfaces of PSs A and B adjacent to the fracture surfaces, between the 9 and 12 o'clock orientations, showing the failed girth weld and the morphology of the coating. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).

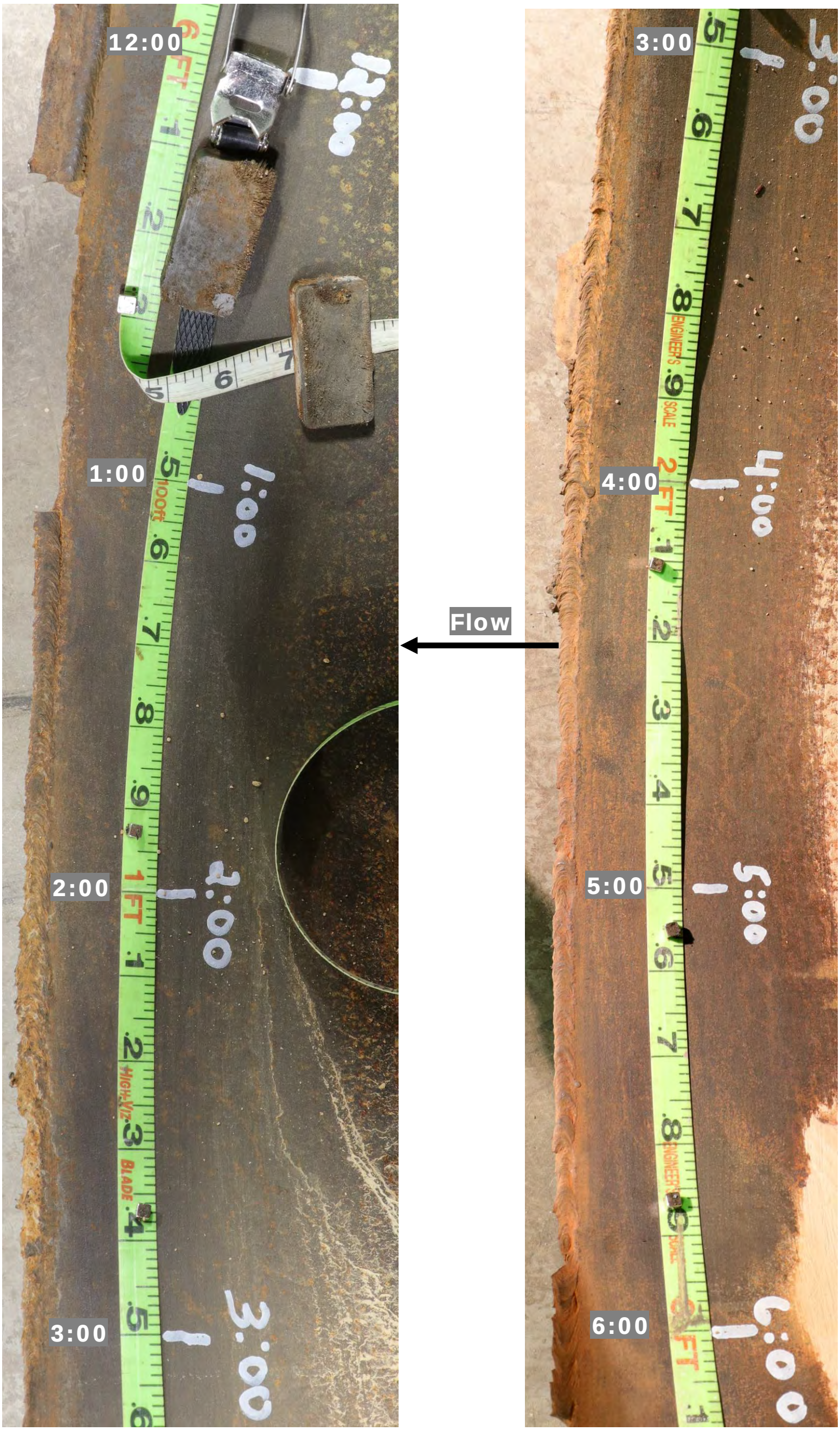


Figure 15. Photograph of the internal pipe surface adjacent to the fracture surface of PS B, between the 12 and 6 o'clock orientations. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).

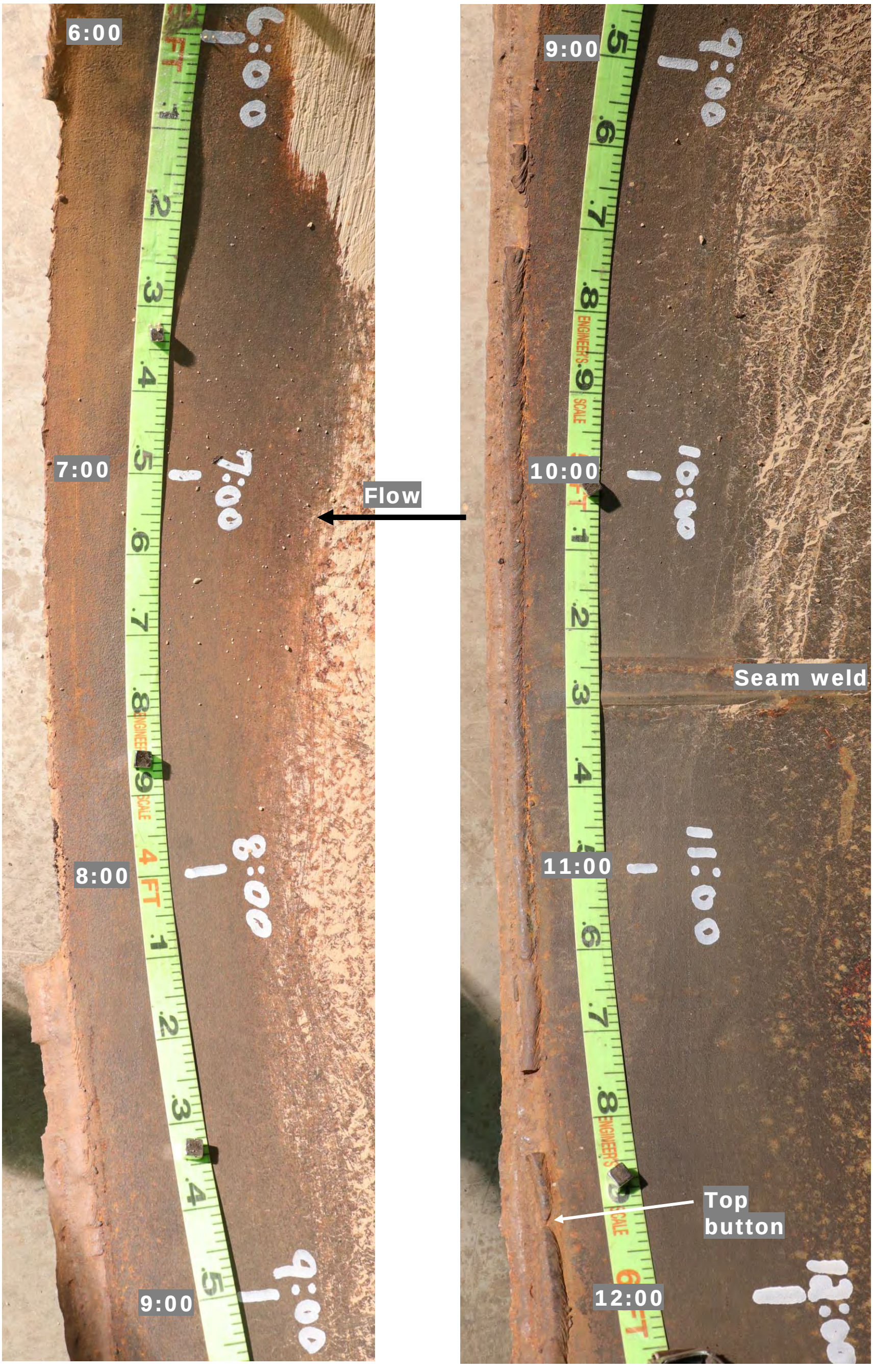


Figure 16. Photographs of the internal pipe surface adjacent to the fracture surface of PS B, between the 6 and 12 o'clock orientations. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).

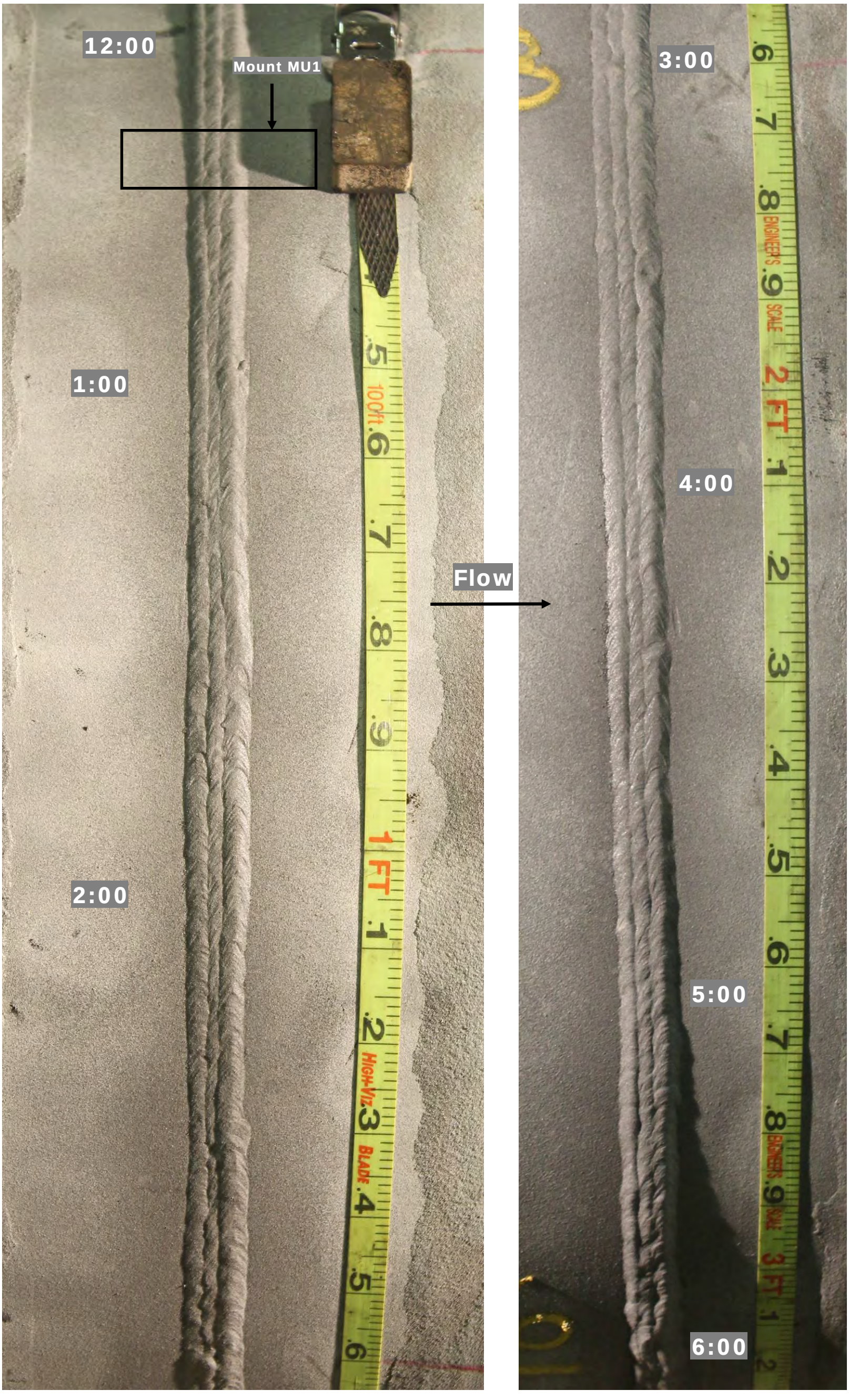


Figure 17. Photograph of the external pipe surface at the intact girth weld following grit blasting and MPI, between the 12:00 and 6:00 orientations. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).

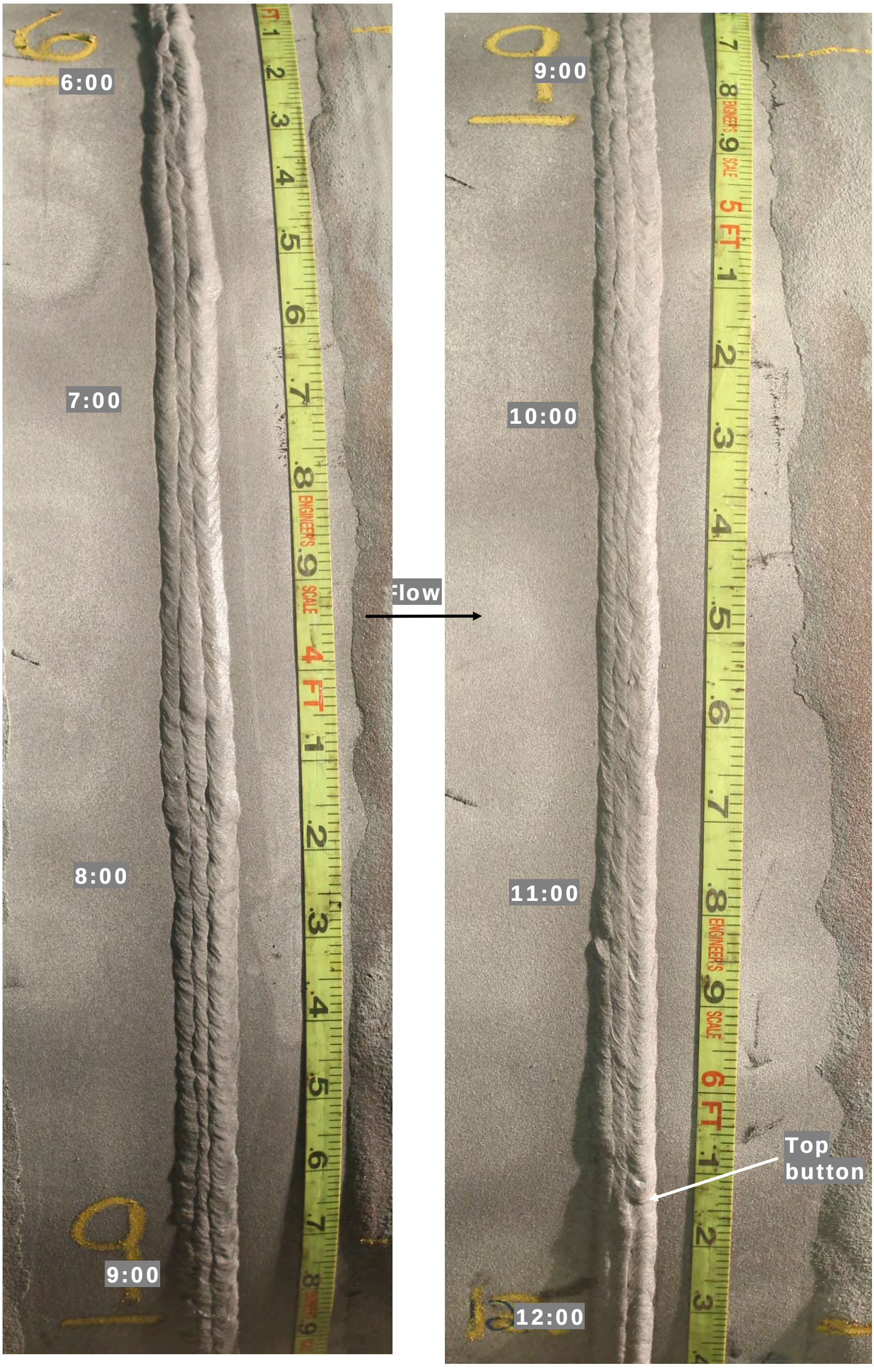


Figure 18. Photograph of the external pipe surface at the intact girth weld following grit blasting and MPI, between the 6:00 and 12:00 orientations. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).



Figure 19. Photograph of the fracture surface and internal pipe surface of PS A. Flow direction is into the photograph. Labels on magnets indicate o'clock orientations.



Figure 20. Photograph of the fracture surface of PS A between the 12 and 1 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.



Figure 21. Photograph of the fracture surface of PS A between the 1 and 2 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.

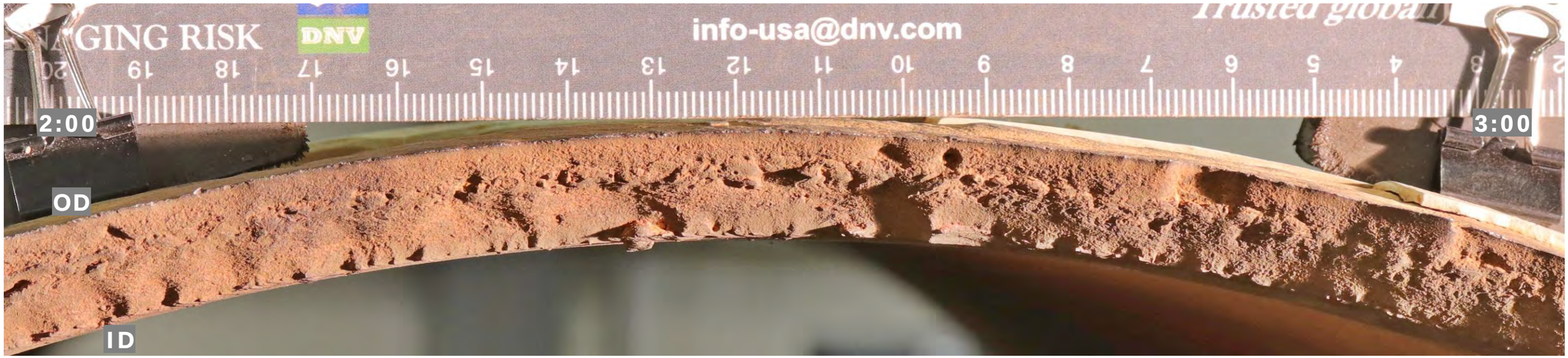


Figure 22. Photograph of the fracture surface of PS A between the 2 and 3 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.



Figure 23. Photograph of the fracture surface of PS A between the 3 and 4 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.

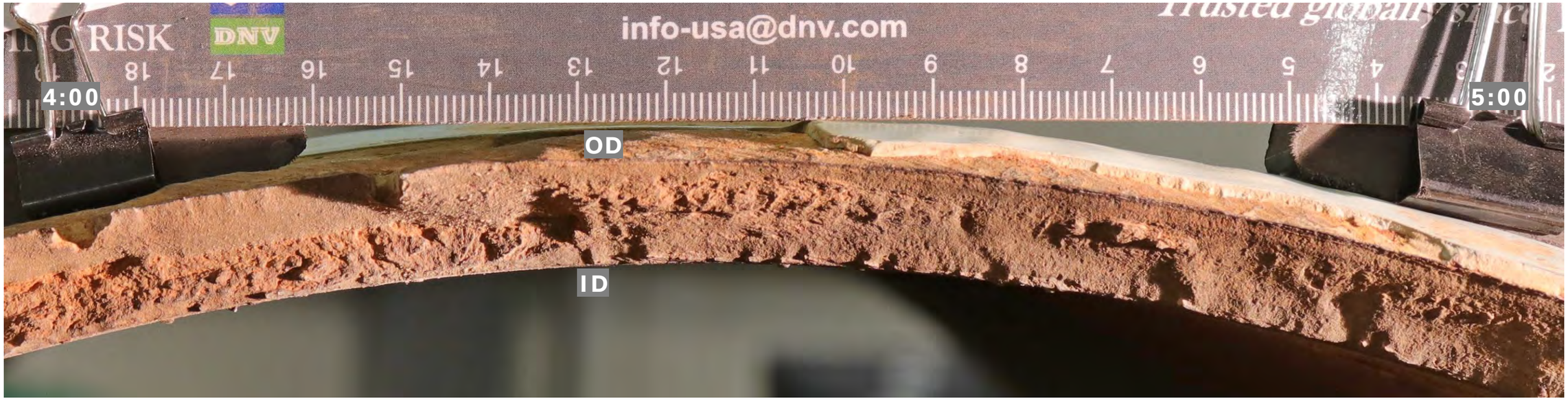


Figure 24. Photograph of the fracture surface of PS A between the 4 and 5 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.



Figure 25. Photograph of the fracture surface of PS A between the 5 and 6 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.



Figure 26. Photograph of the fracture surface of PS A between the 6 and 7 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.



Figure 27. Photograph of the fracture surface of PS A between the 7 and 8 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.



Figure 28. Photograph of the fracture surface of PS A between the 8 and 9 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.



Figure 29. Photograph of the fracture surface of PS A between the 9 and 10 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.



Figure 30. Photograph of the fracture surface of PS A between the 10 and 11 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.

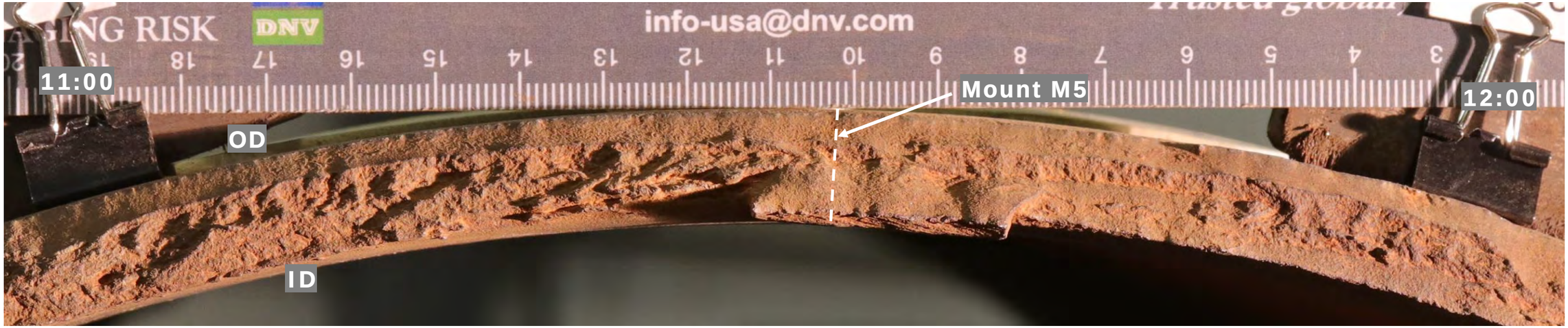


Figure 31. Photograph of the fracture surface of PS A between the 11 and 12 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.

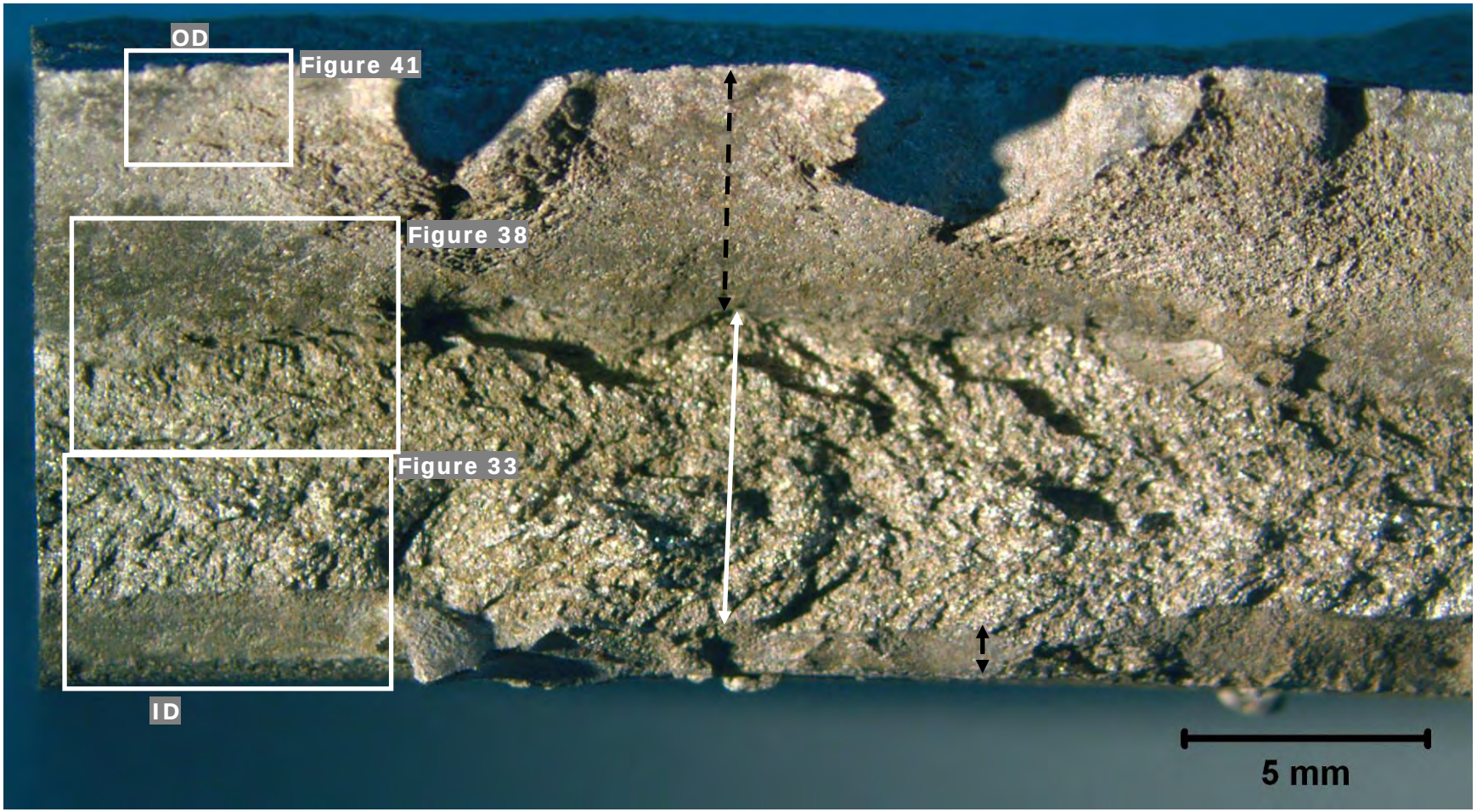


Figure 32. Light photomicrograph of the fracture surface of Sample S2, following cleaning in ENPREP® 214. The sample was removed near the 4:00 orientation from PSA; area indicated in Figure 23. The black, dashed double arrows indicate smooth regions and the white double arrow indicates a rough region.

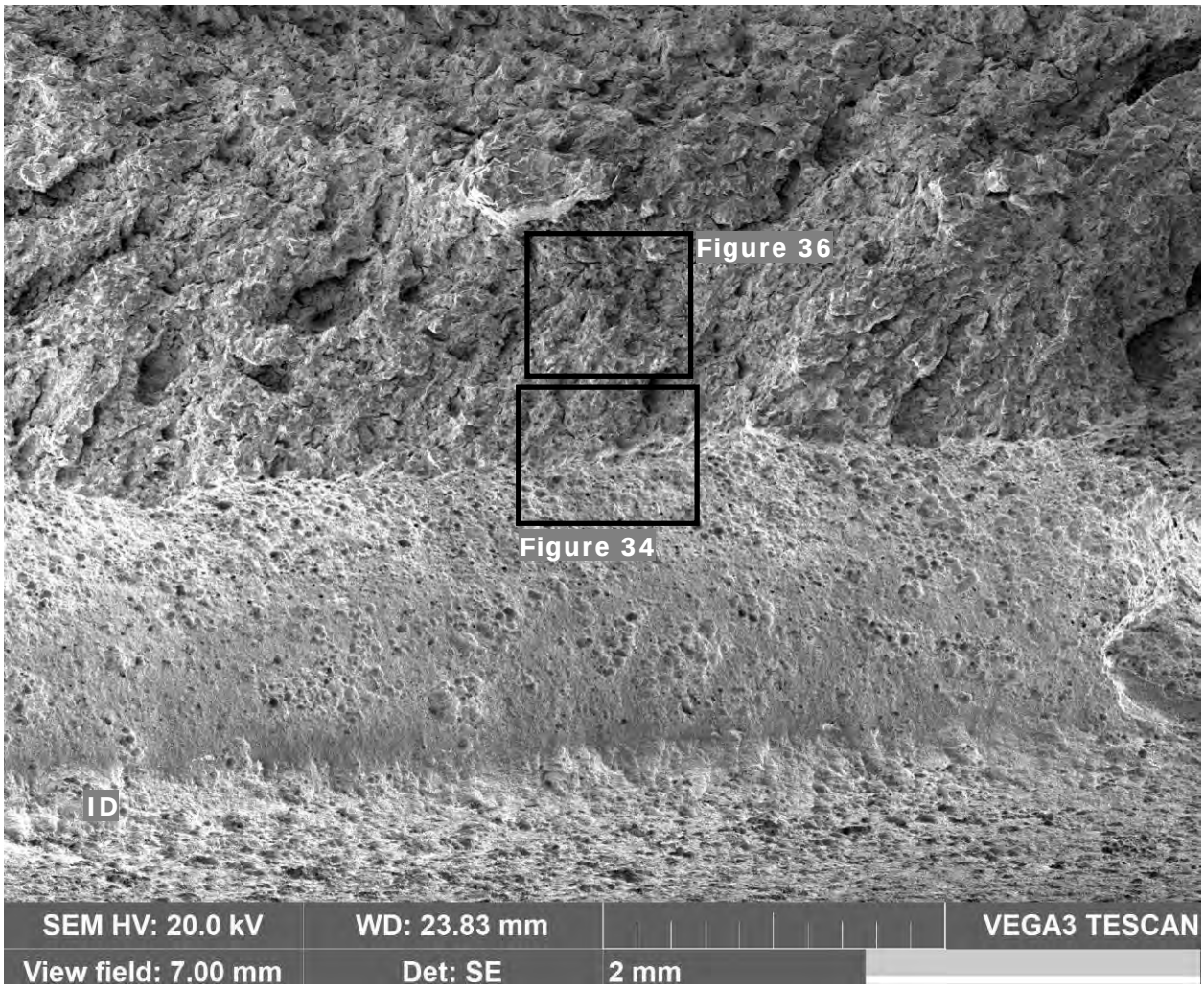


Figure 33. SEM image of Sample S2 adjacent to the ID surface; area indicated in Figure 32.

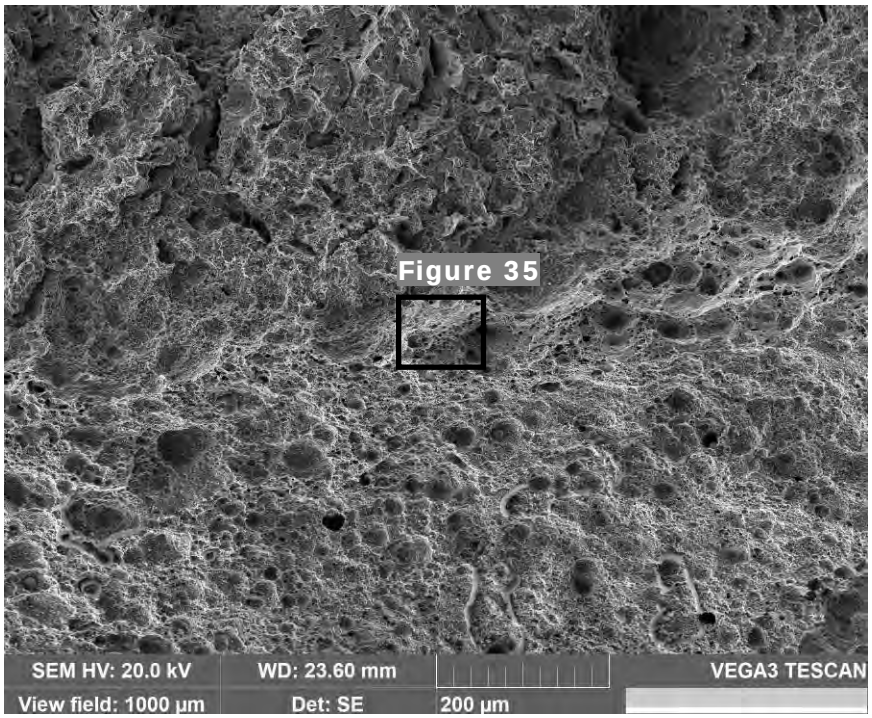


Figure 34. SEM image of Sample S2 at the interface of a macroscopically smooth and rough region; area indicated in Figure 33.

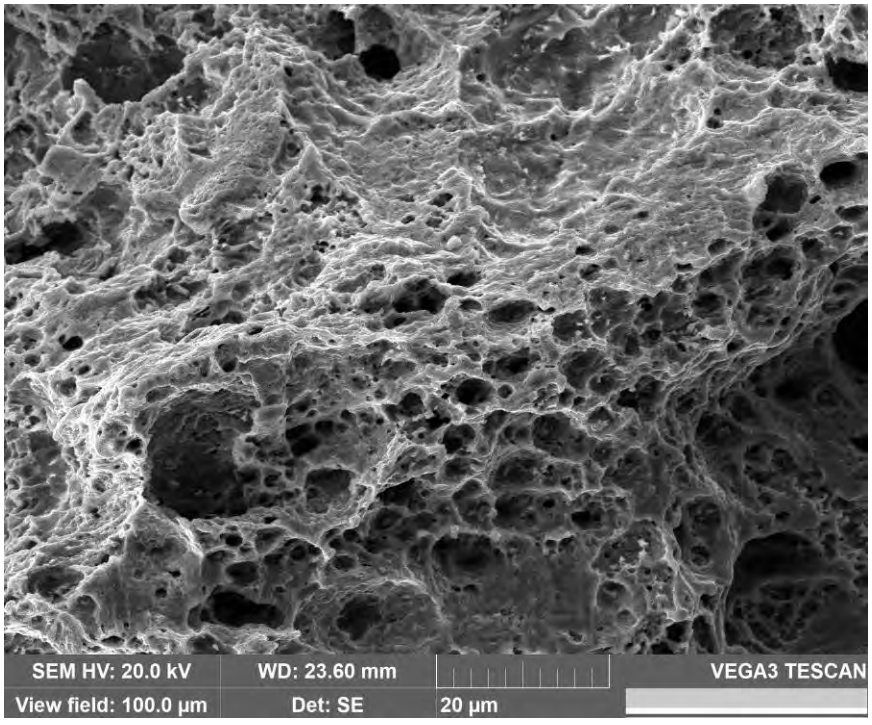


Figure 35. High magnification SEM image of Sample S2 in the macroscopically smooth region; area indicated in Figure 34.

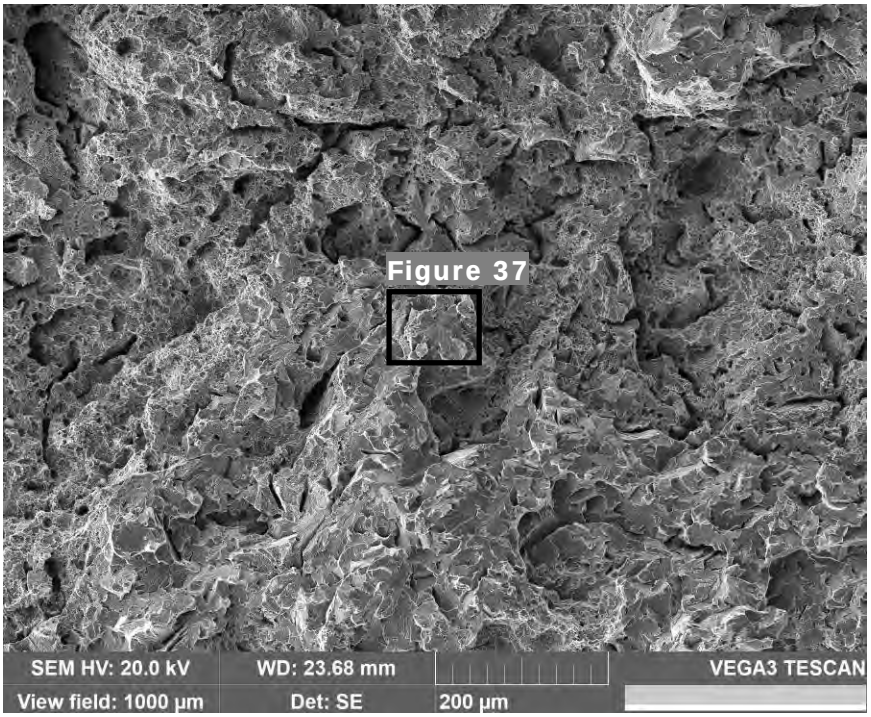


Figure 36. SEM image of Sample S2 in a macroscopically rough region; area indicated in Figure 33.

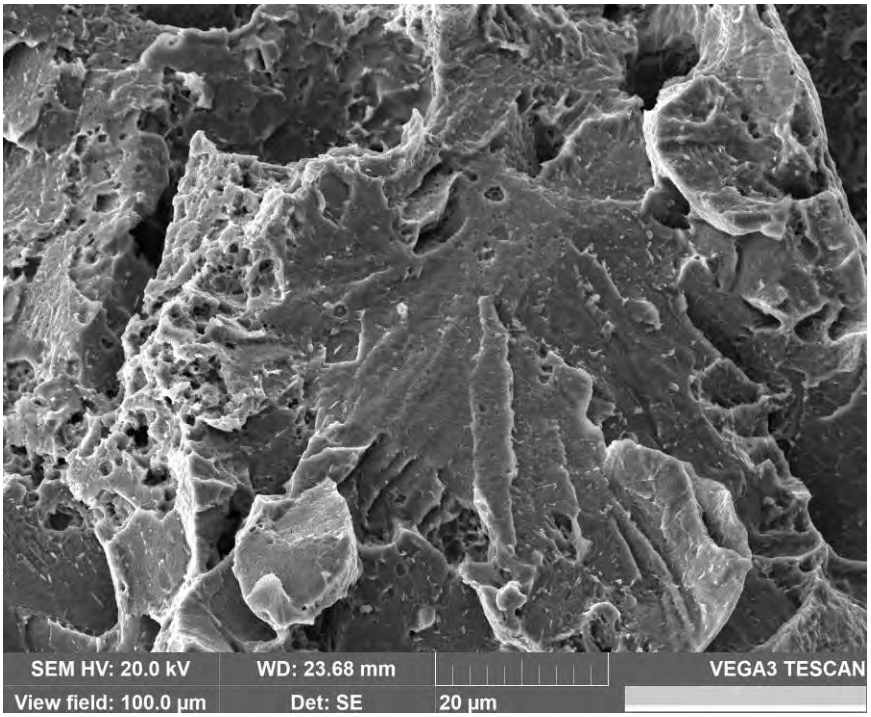


Figure 37. High magnification SEM image of Sample S2 in a macroscopically rough region; area indicated in Figure 36.

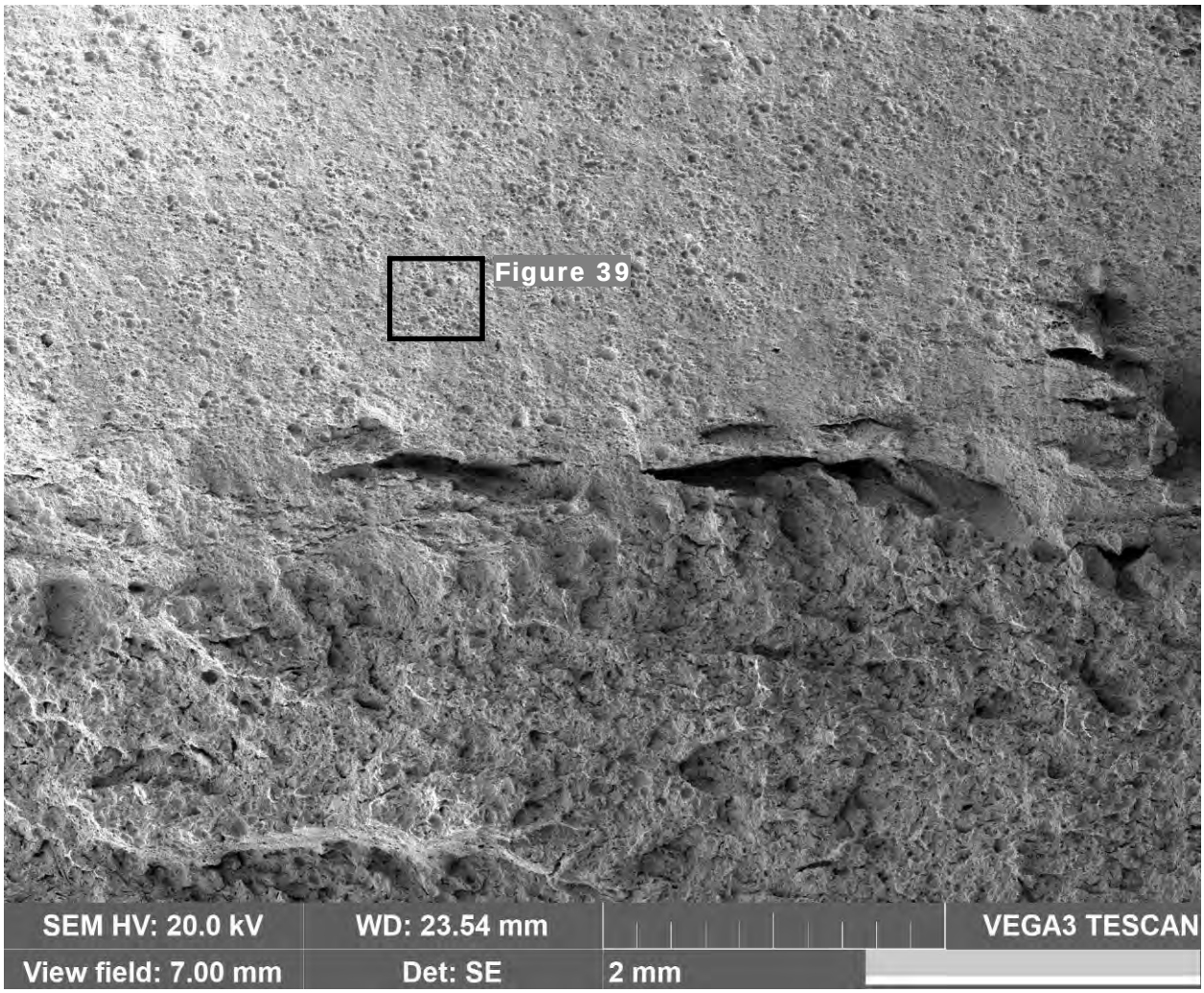


Figure 38. SEM image of Sample S2 midwall, showing macroscopically rough and smooth regions; area indicated in Figure 32.

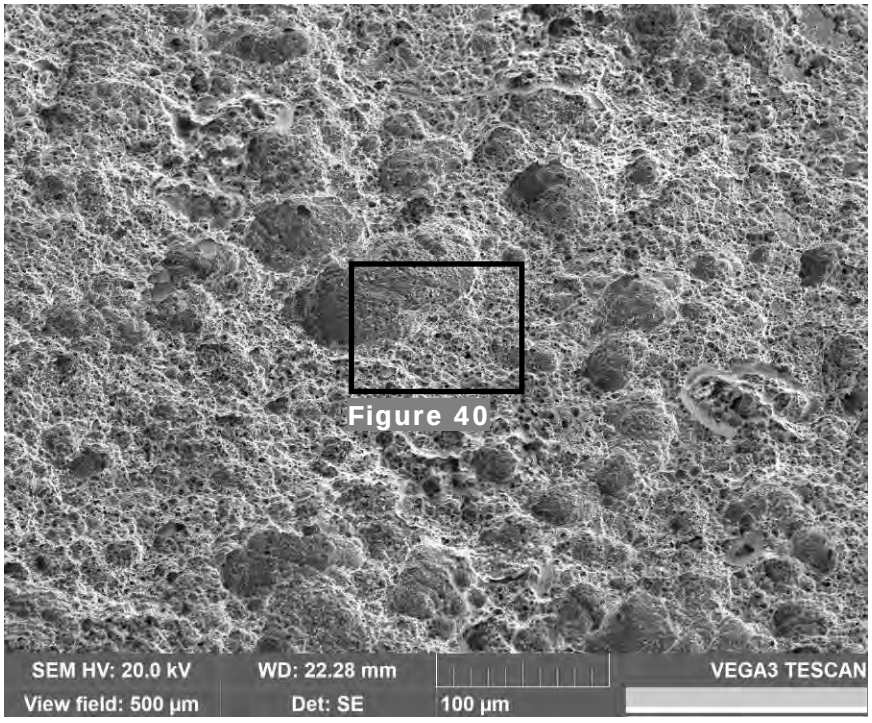


Figure 39. SEM image of Sample S2 in a macroscopically smooth region, near the OD surface; area indicated in Figure 38.

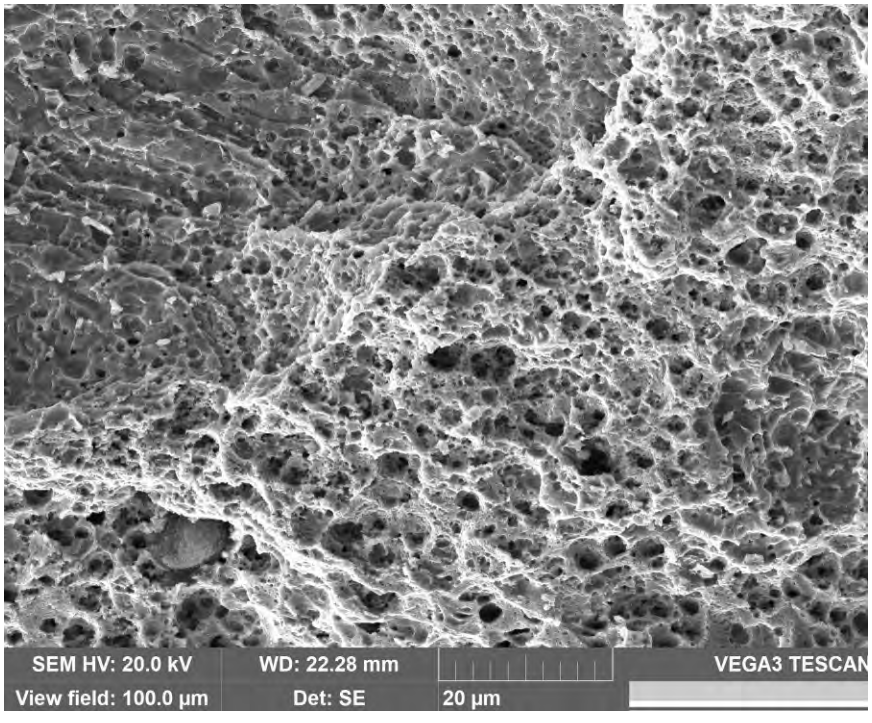


Figure 40. High magnification SEM image of Sample S2 in a macroscopically smooth region, near the OD surface; area indicated in Figure 39.

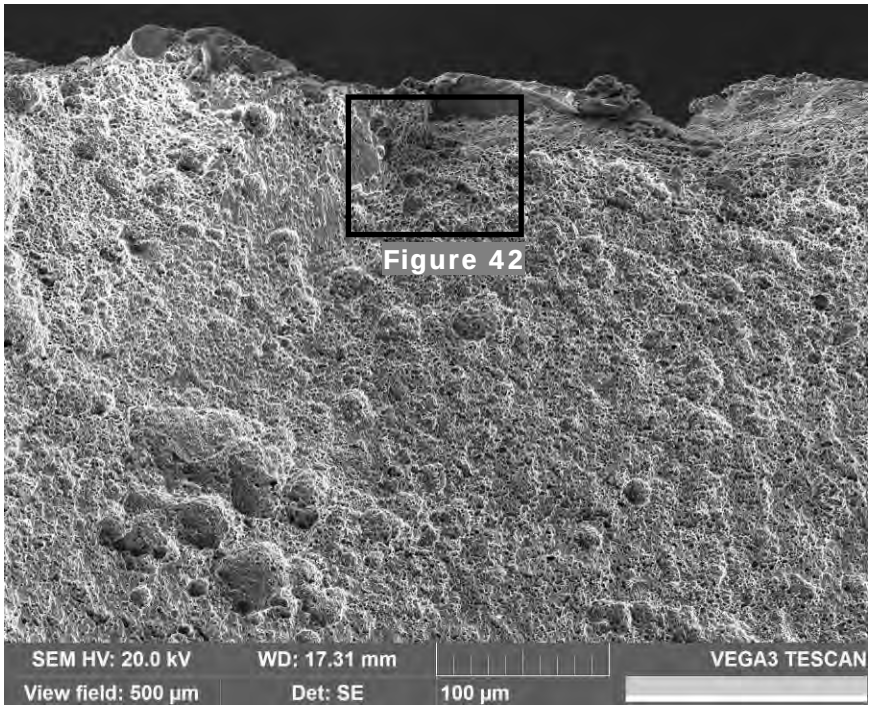


Figure 41. SEM image of Sample S2 adjacent to the OD surface; area indicated in Figure 32.

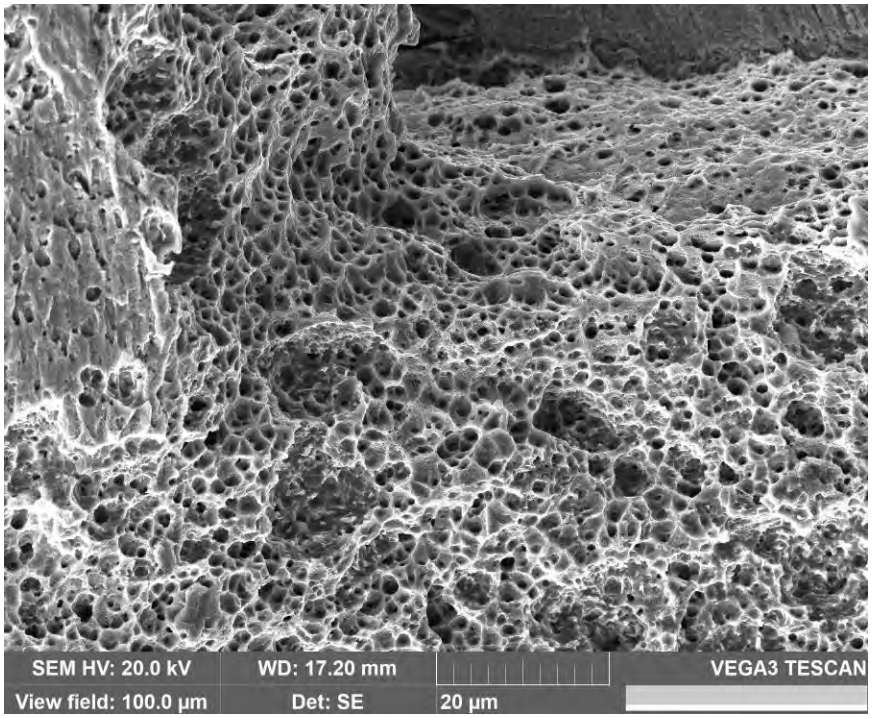


Figure 42. High magnification SEM image of Sample S2 adjacent to the OD surface; area indicated in Figure 41.

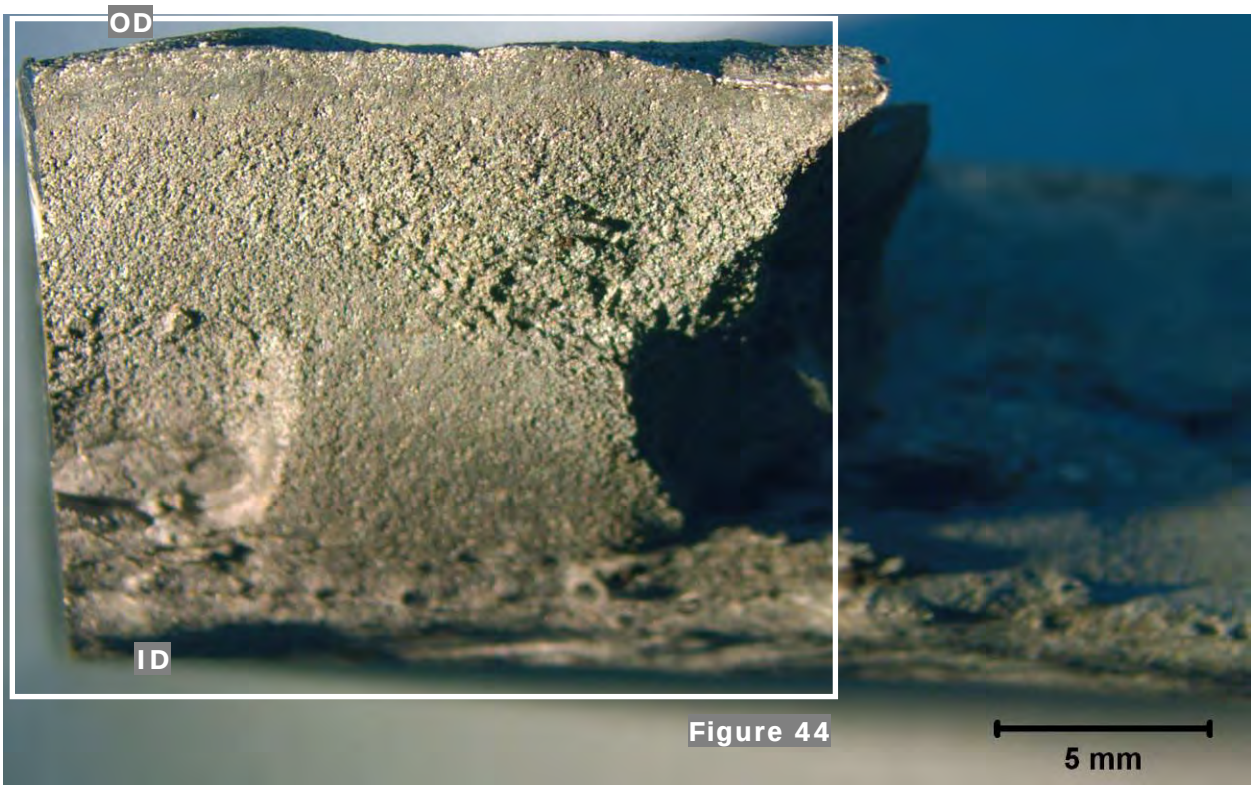


Figure 43. Light photomicrograph of the fracture surface of Sample S3, following cleaning in ENPREP® 214. The sample was removed near the 8:00 orientation; area indicated in Figure 28.

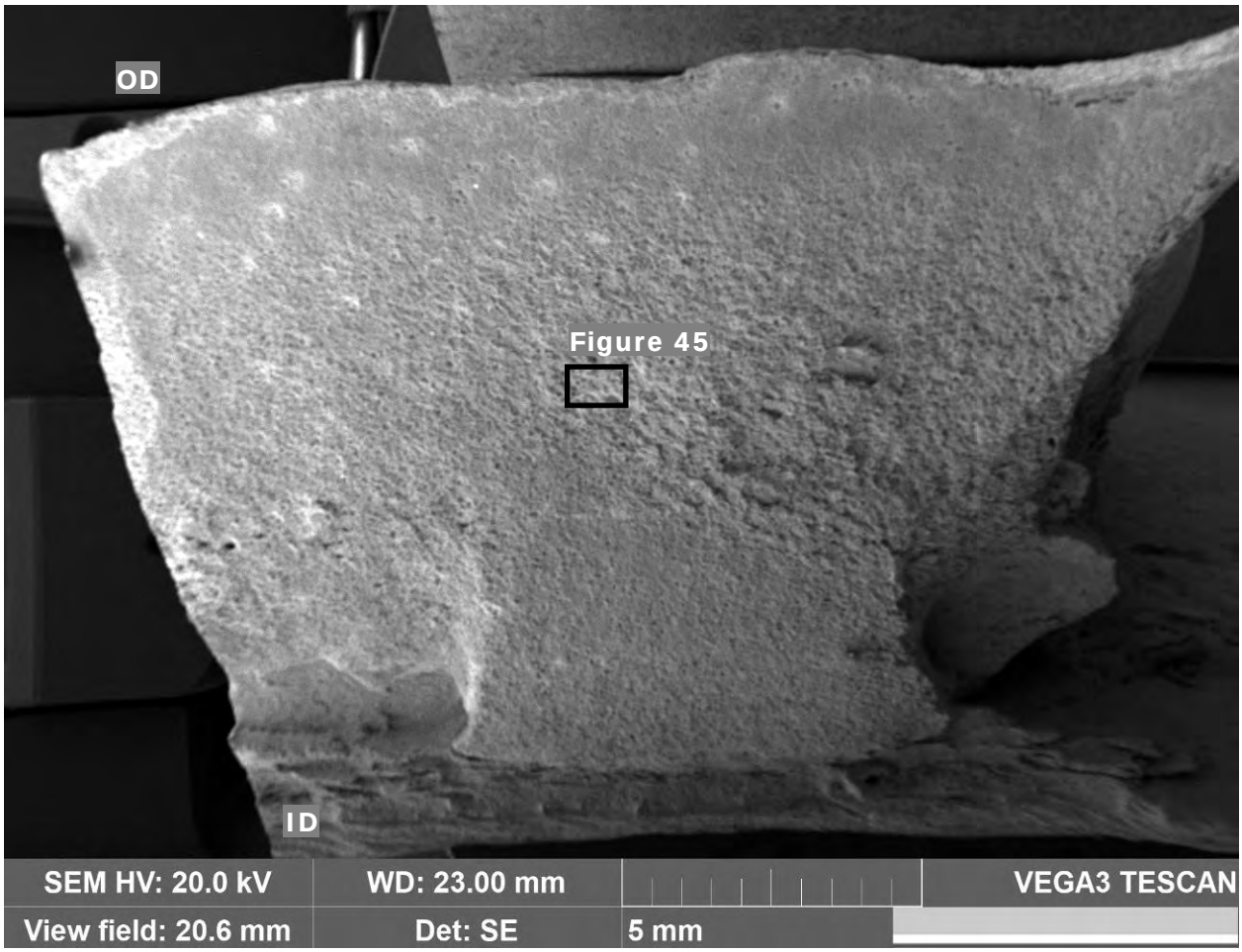


Figure 44. SEM image of Sample S3; area indicated in Figure 43.

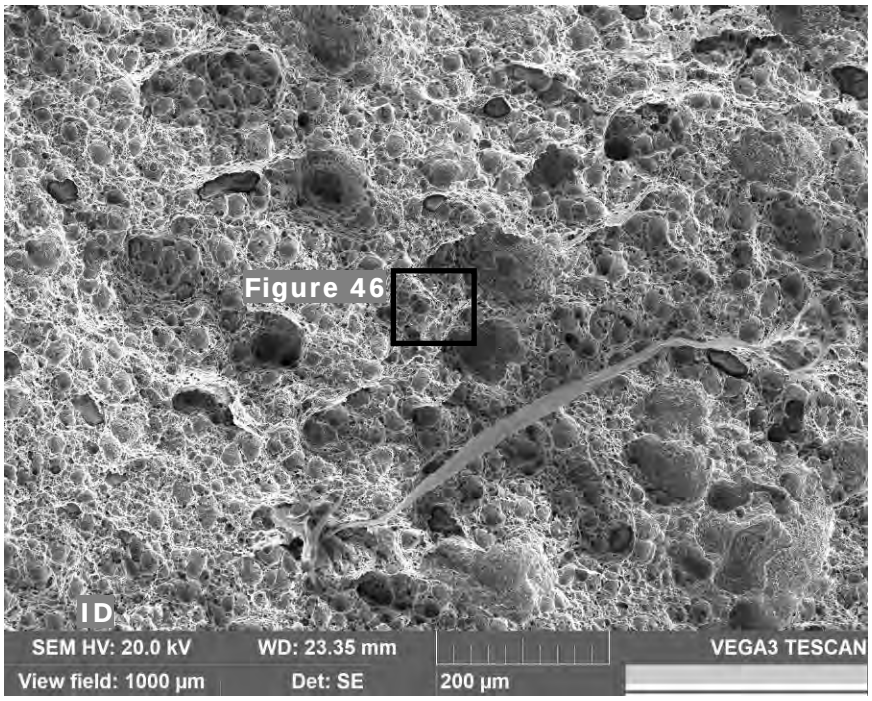


Figure 45. SEM image of Sample S3 midwall; area indicated in Figure 44.

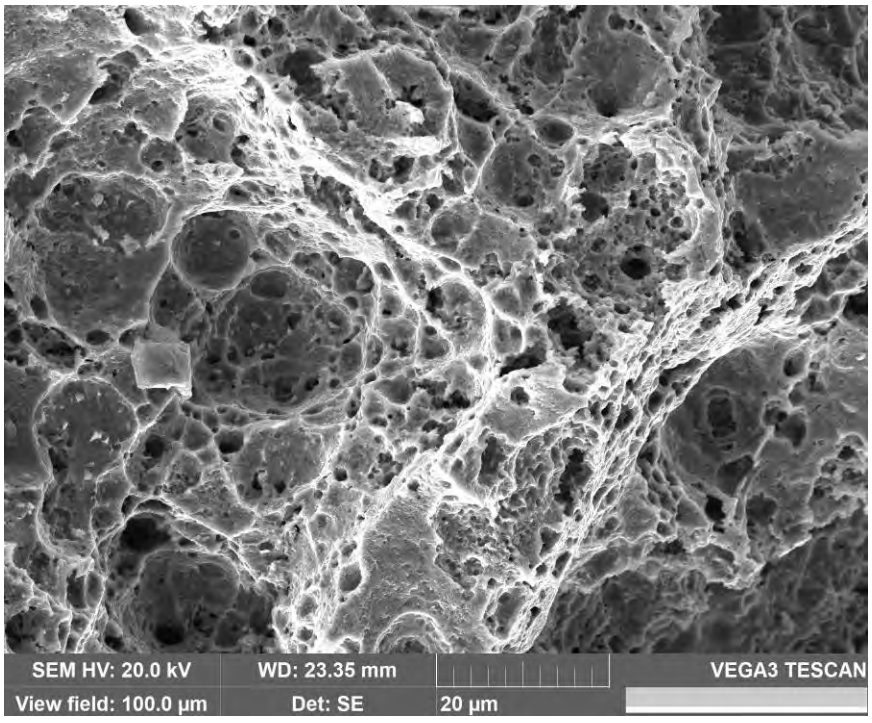


Figure 46. High magnification SEM image of Sample S3 midwall; area indicated in Figure 45.

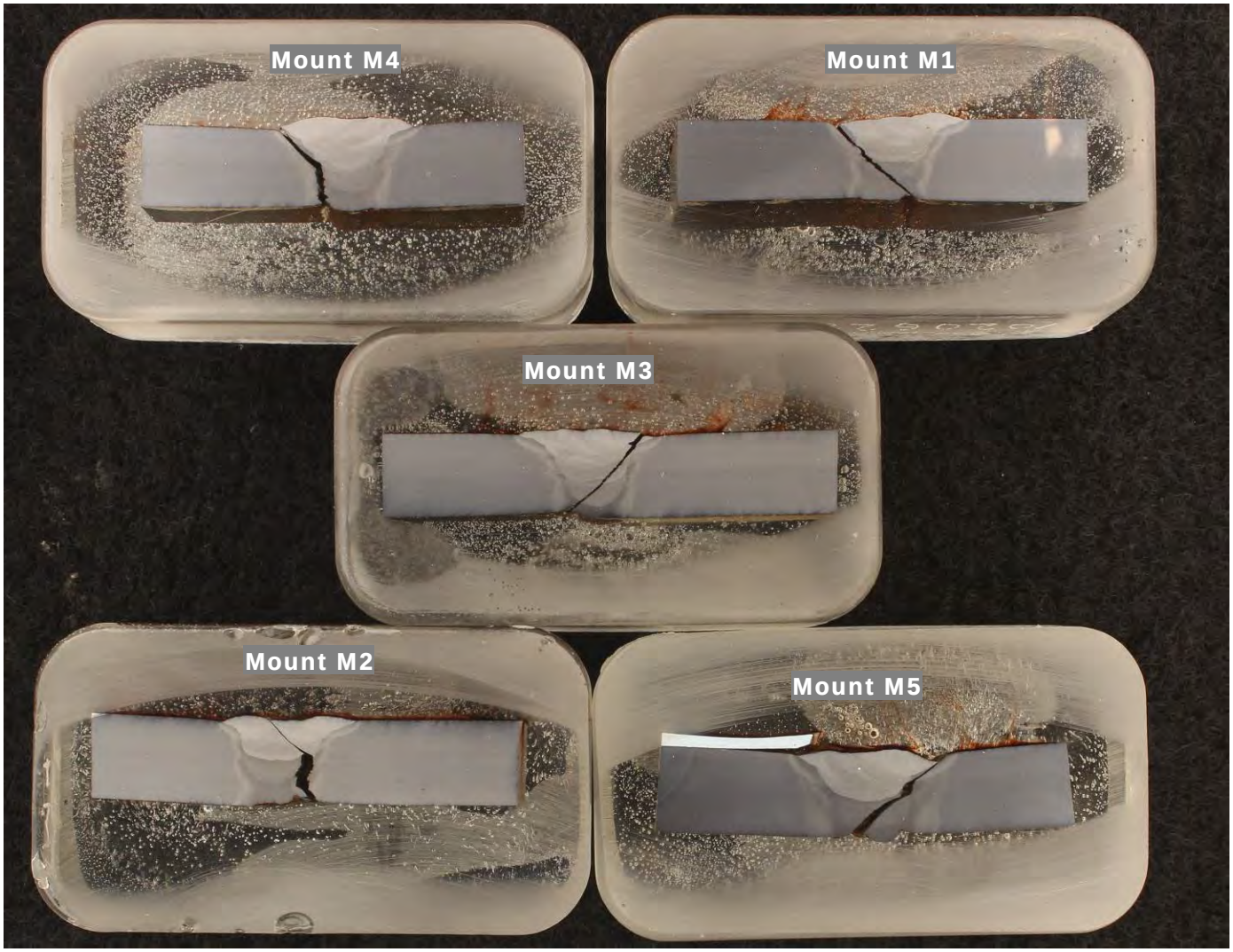


Figure 47. Photograph of the mounts (M1, M2, M3, M4, and M5) that were removed across the failure opening (2% Nital Etchant).

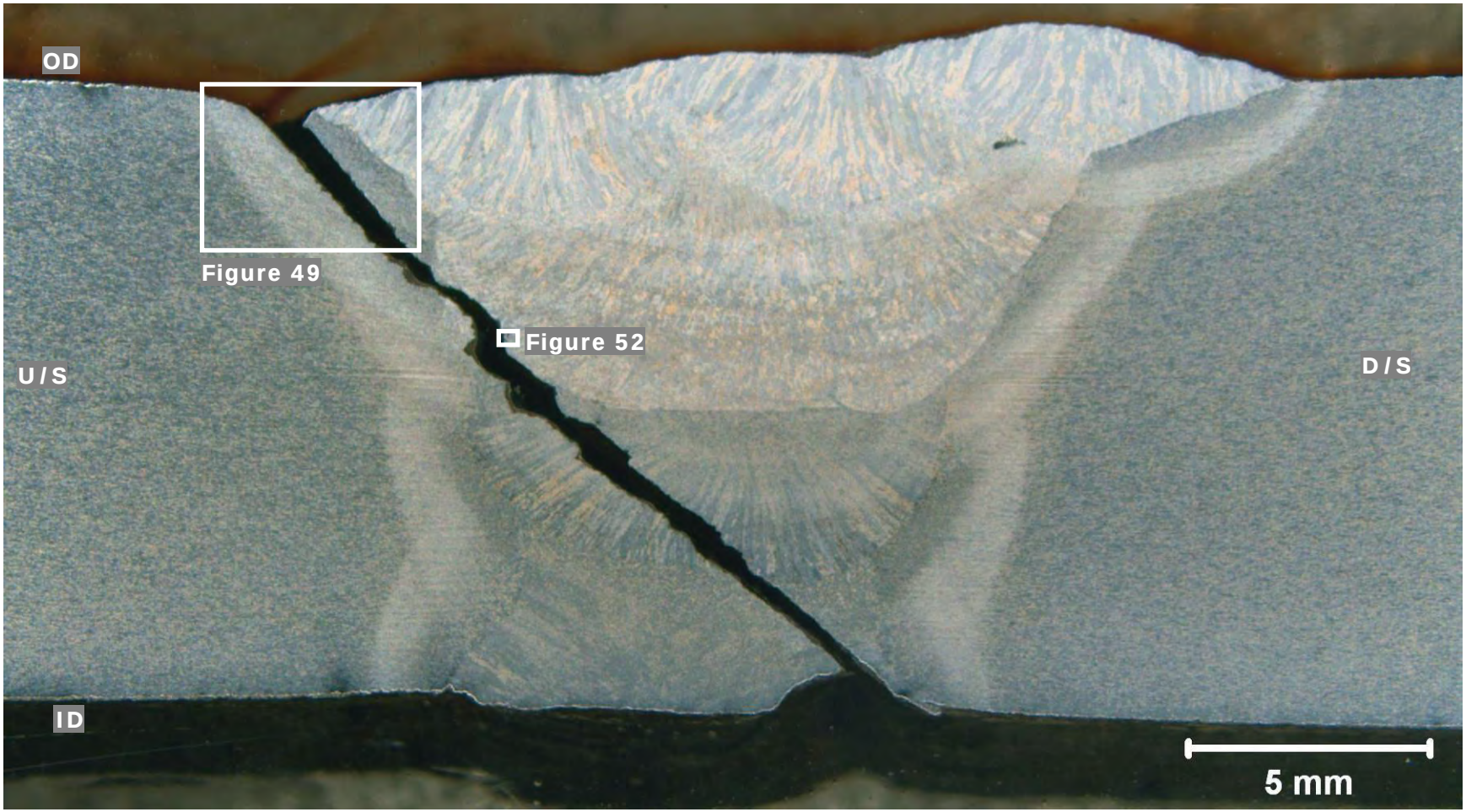


Figure 48. Light photomicrograph of Mount M1 (axial cross-section), which was removed from the failed GW at the 1:35 orientation; refer to Figure 1, Figure 11, and Figure 21 for location (2% Nital Etchant).

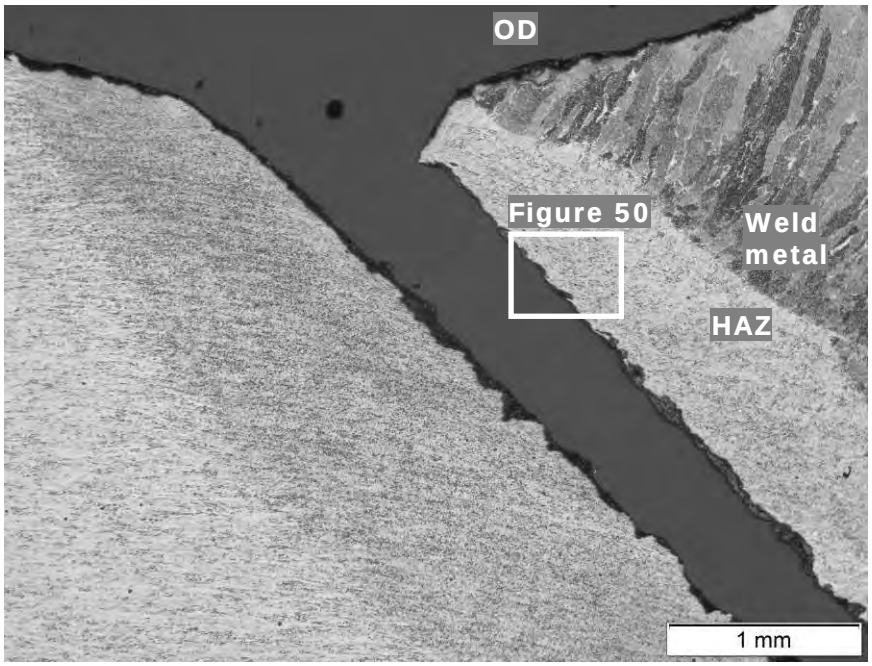


Figure 49. Light photomicrograph of Mount M1 adjacent to the OD surface (2% Nital Etchant); area indicated in Figure 48.

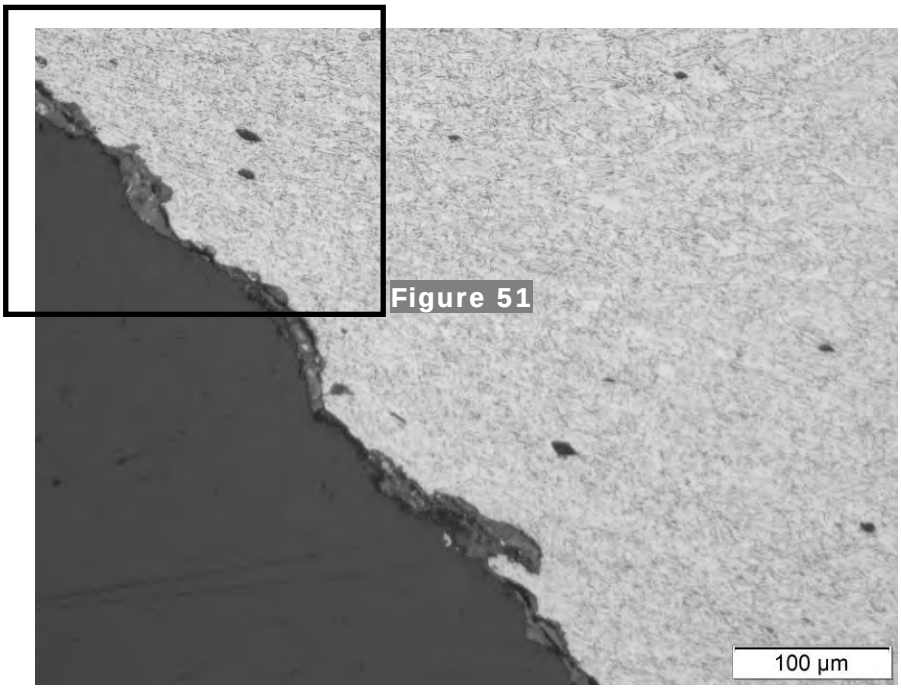


Figure 50. Light photomicrograph of Mount M1 showing inclusions in HAZ adjacent to the fracture surface; area indicated in Figure 49.

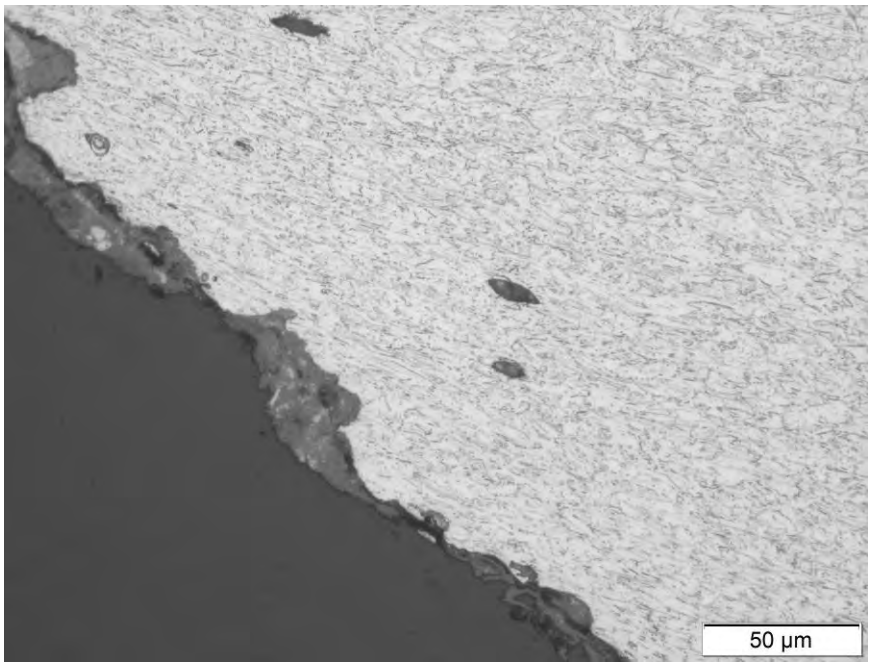


Figure 51. High magnification light photomicrograph of Mount M1 showing grain elongation adjacent to the fracture surface; area indicated in Figure 50.

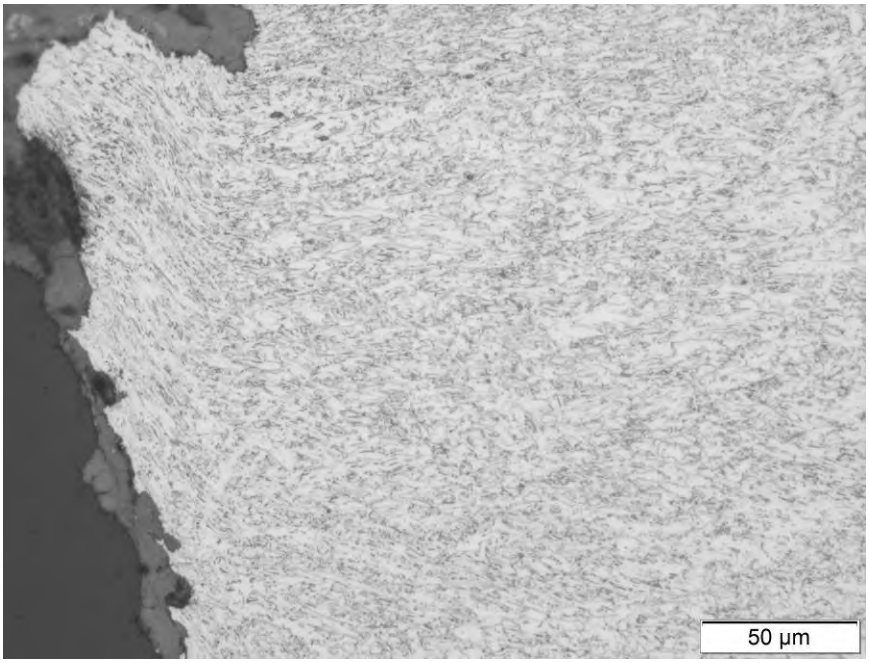


Figure 52. High magnification light photomicrograph of Mount M1 midwall adjacent to the fracture surface (2% Nital Etchant); area indicated in Figure 48.

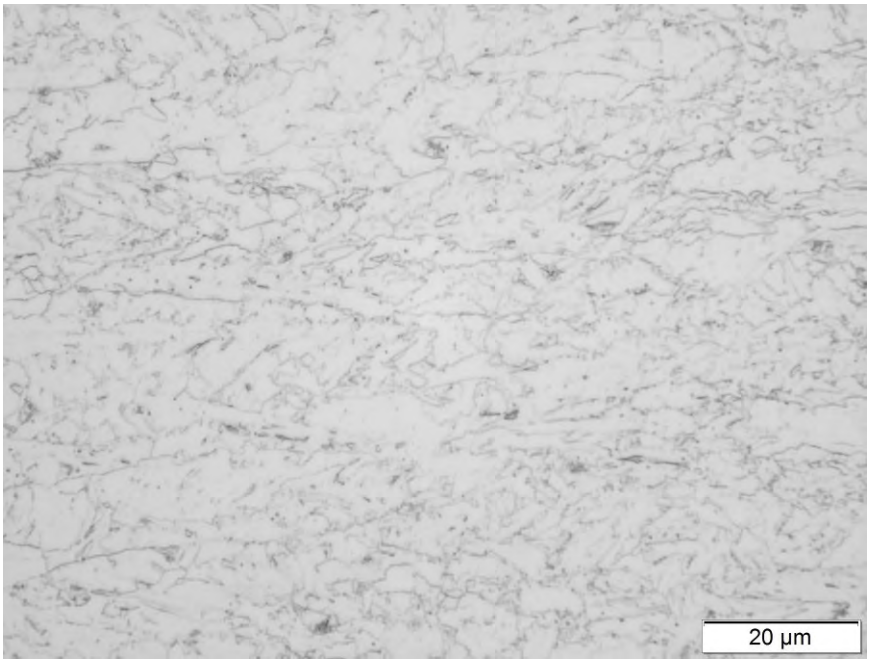


Figure 53. High magnification light photomicrograph of Mount M1 showing the typical base metal microstructure of the U/S Joint (PS B, 2% Nital Etchant).

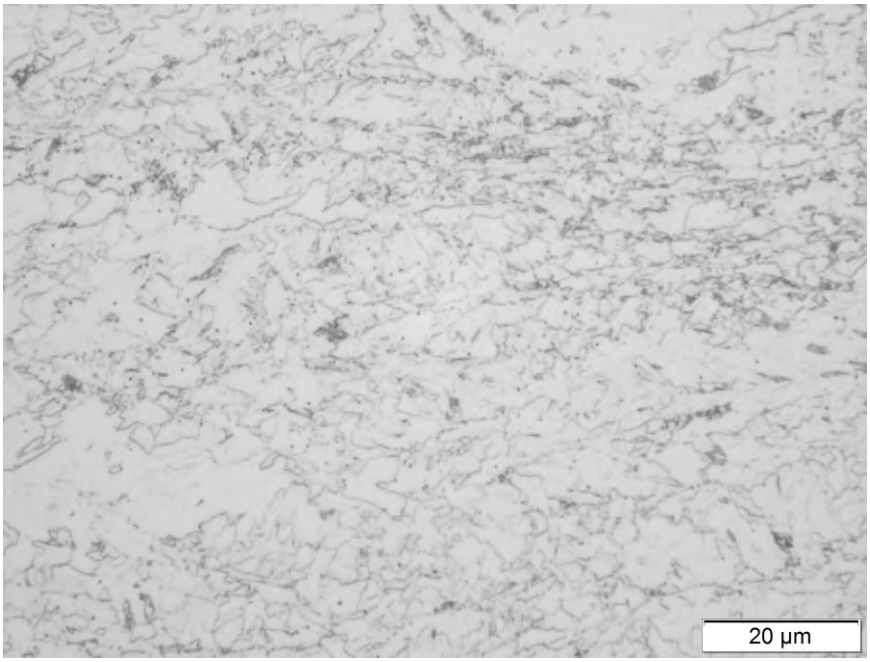


Figure 54. High magnification light photomicrograph of Mount M1 showing the typical base metal microstructure of the D/S Joint (PS A, 2% Nital Etchant).

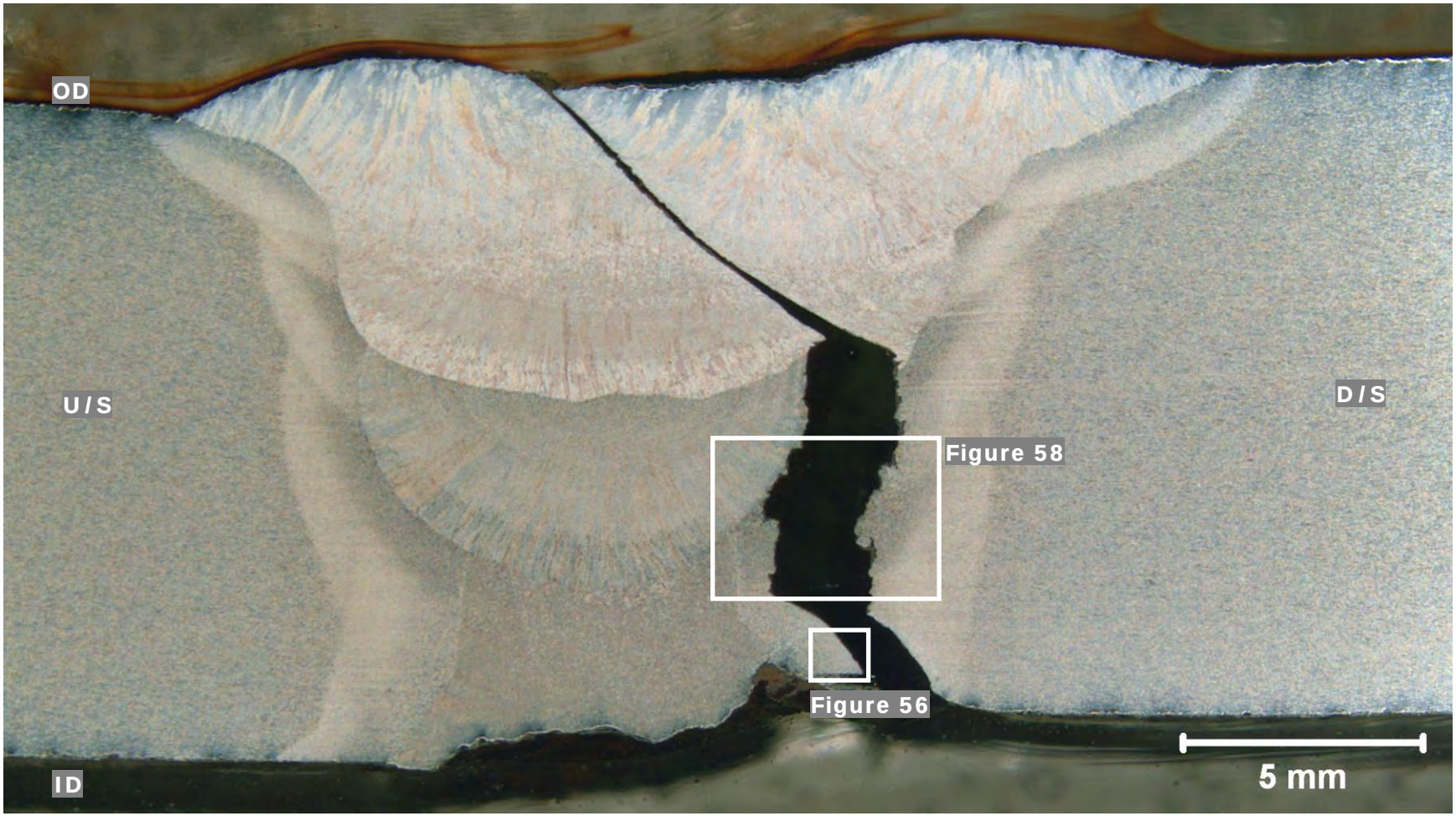


Figure 55. Light photomicrograph of Mount M2 (axial cross-section), which was removed from the GW at the 3:55 orientation; refer to Figure 1, Figure 12, and Figure 23 for location (2% Nital Etchant).

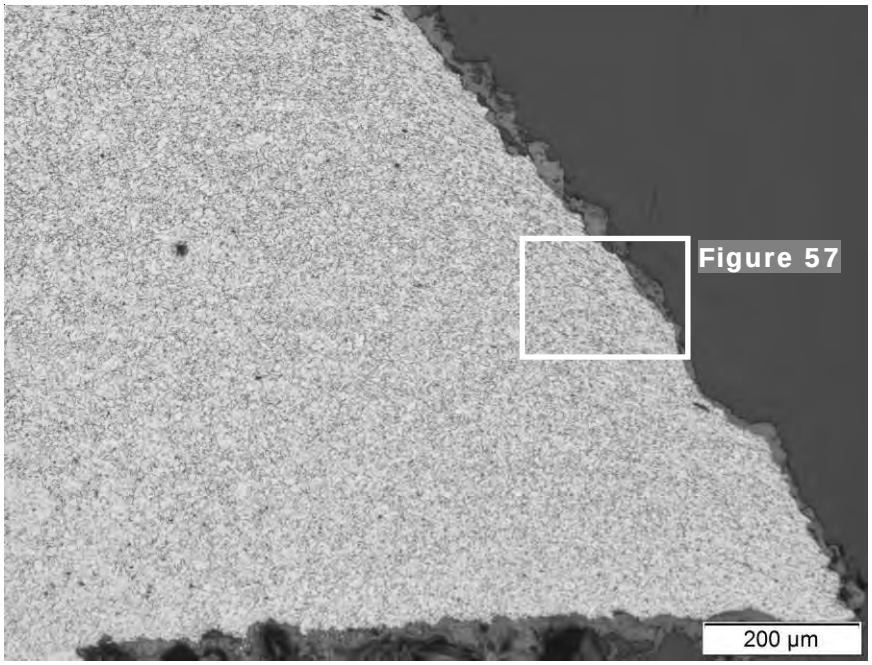


Figure 56. Light photomicrograph of Mount M2 adjacent to the ID surface (2% Nital Etchant); area indicated in Figure 55.

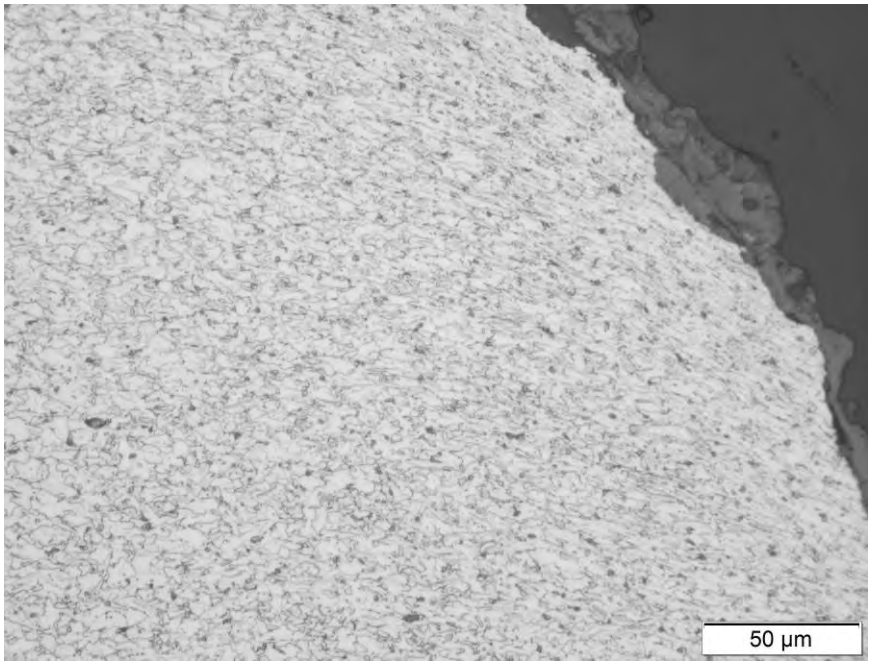


Figure 57. High magnification light photomicrograph of Mount M2 near the ID surface, adjacent to the fracture surface (2% Nital Etchant); area indicated in Figure 56.

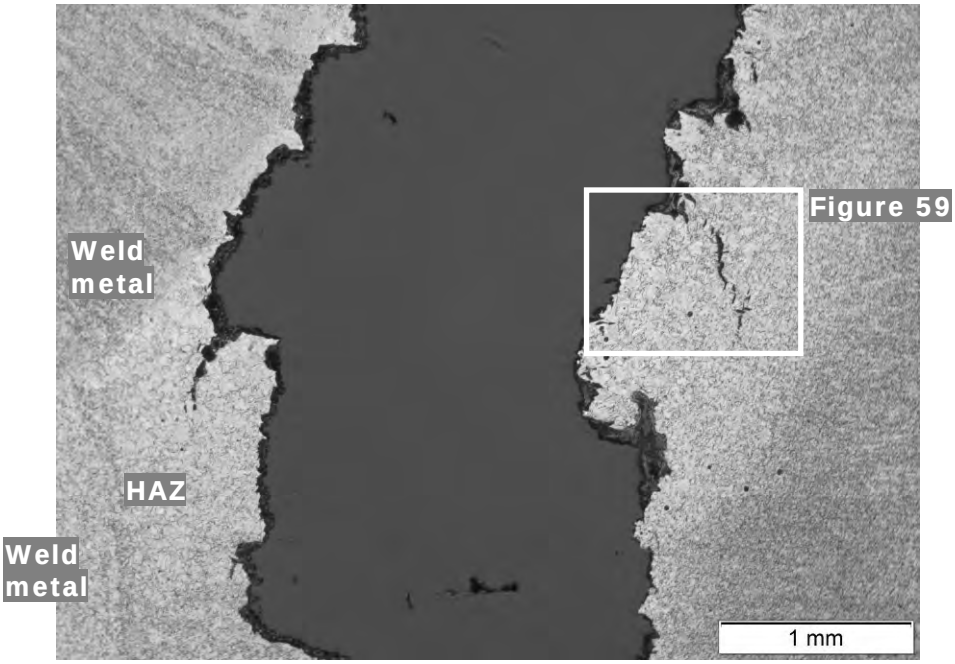


Figure 58. Light photomicrograph of Mount M2 midwall (2% Nital Etchant); area indicated in Figure 55.

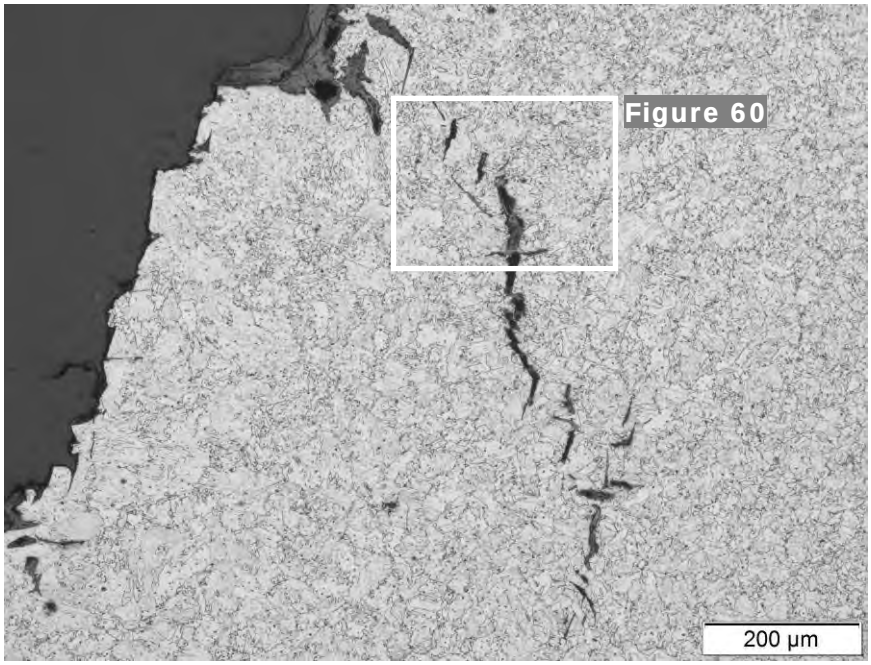


Figure 59. Light photomicrograph of Mount M2 adjacent to the fracture surface showing fissures (2% Nital Etchant); area indicated in Figure 58.

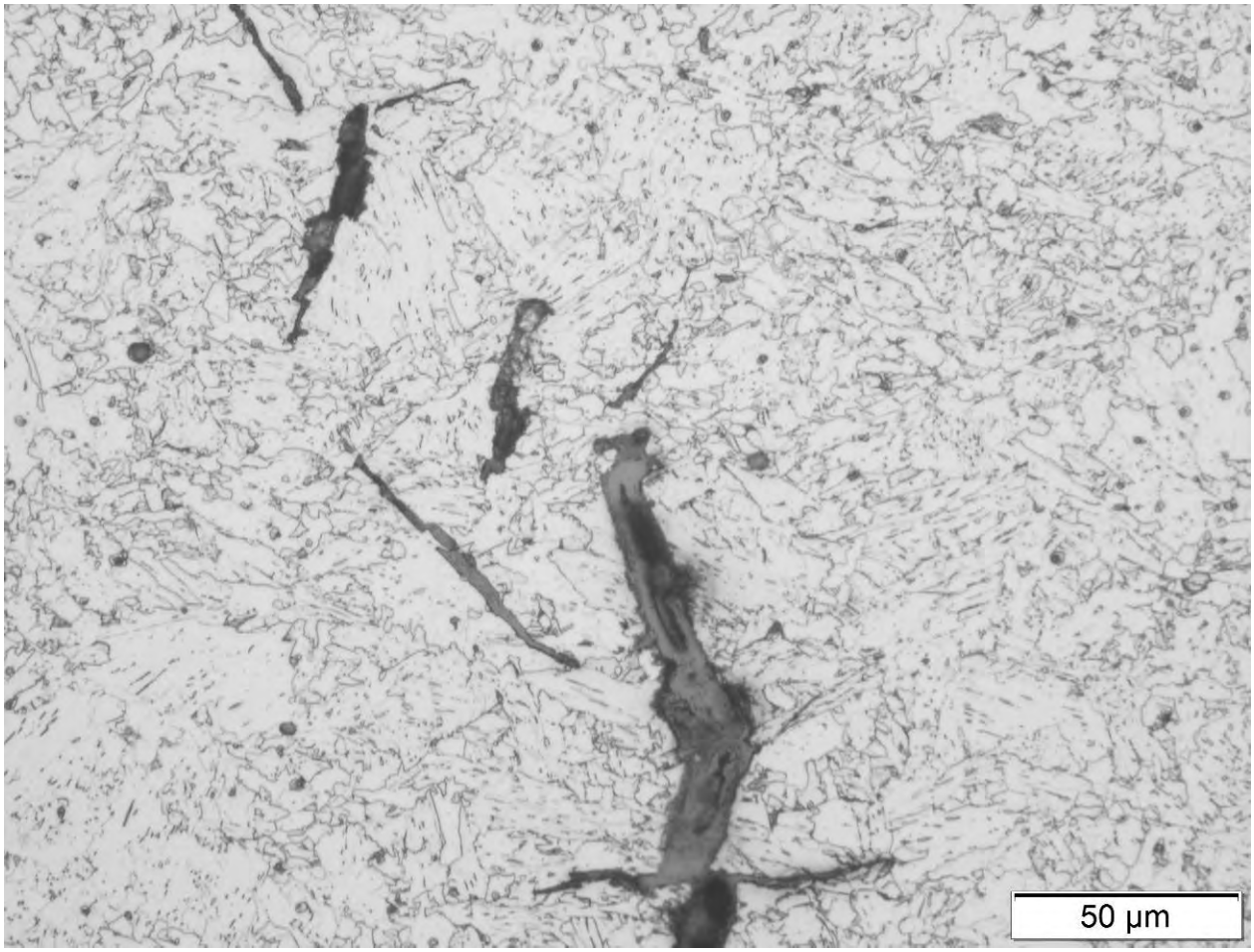


Figure 60. High magnification light photomicrograph of Mount M2 at fissures (2% Nital Etchant); area indicated in Figure 59.

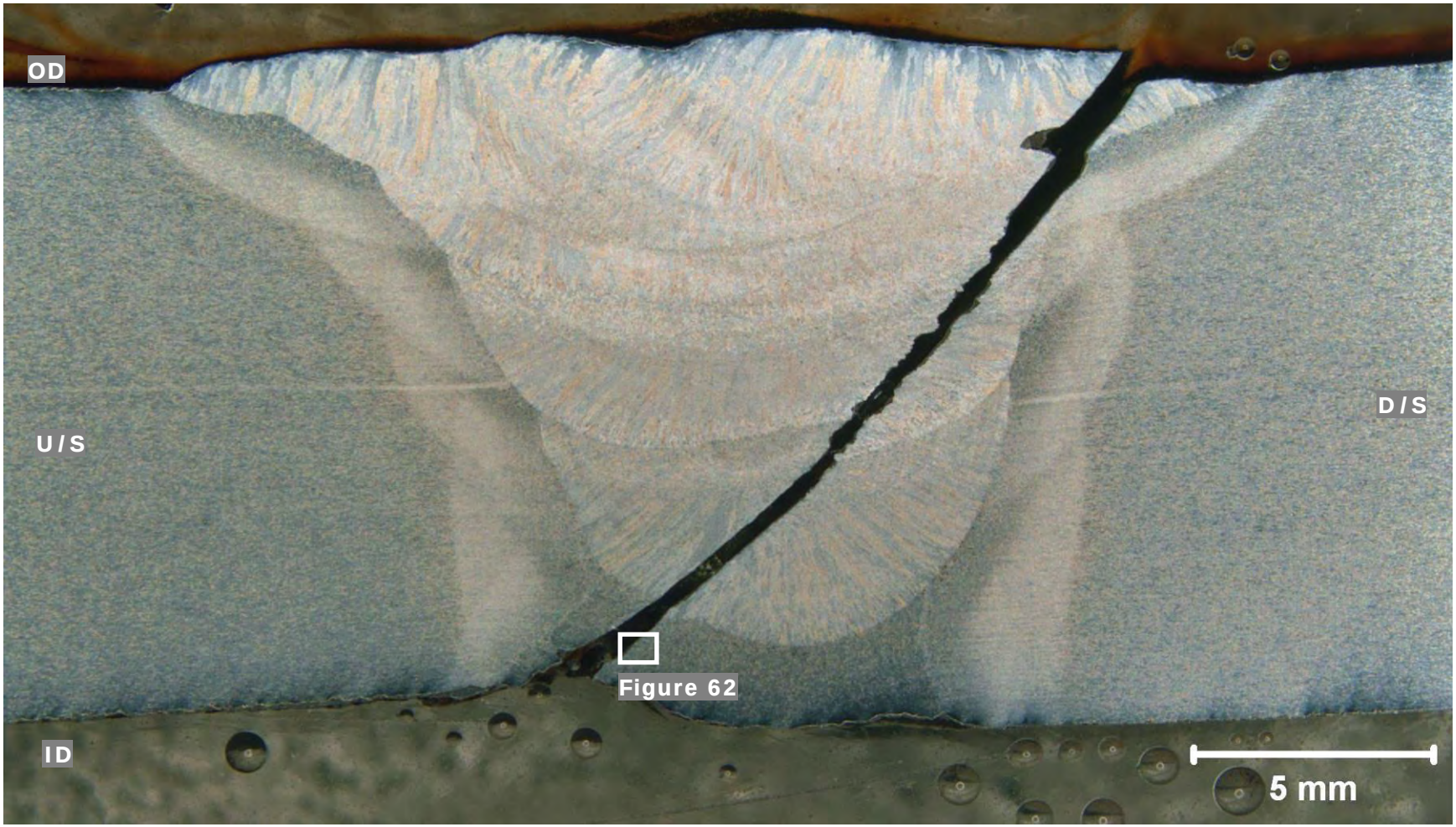


Figure 61. Light photomicrograph of Mount M3 (axial cross-section), which was removed from the GW at the 8:35 orientation; refer to Figure 1, Figure 13, and Figure 28 for location (2% Nital Etchant).

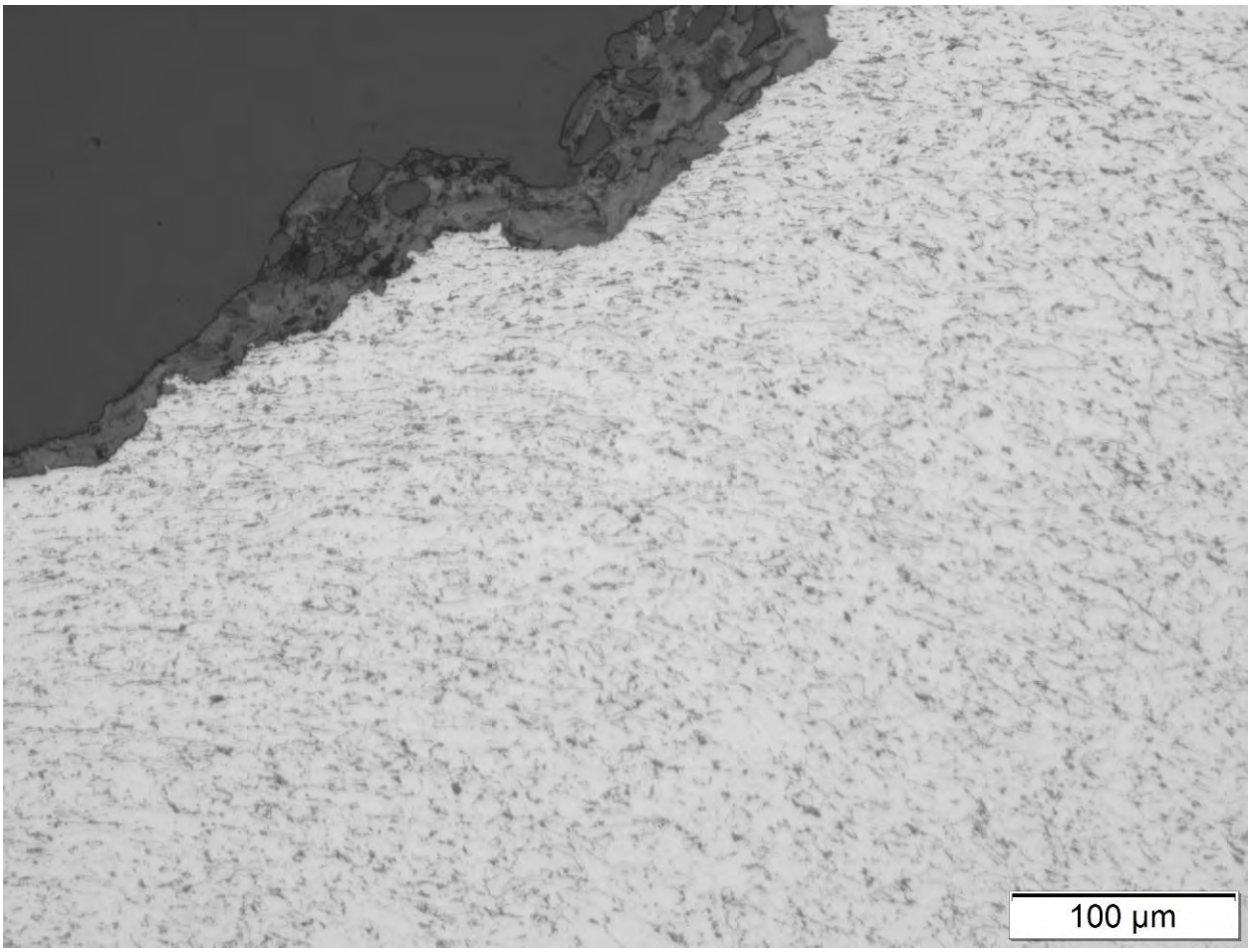


Figure 62. Light photomicrograph of Mount M3 adjacent to the fracture surface, near the ID surface (2% Nital Etchant); area indicated in Figure 61.

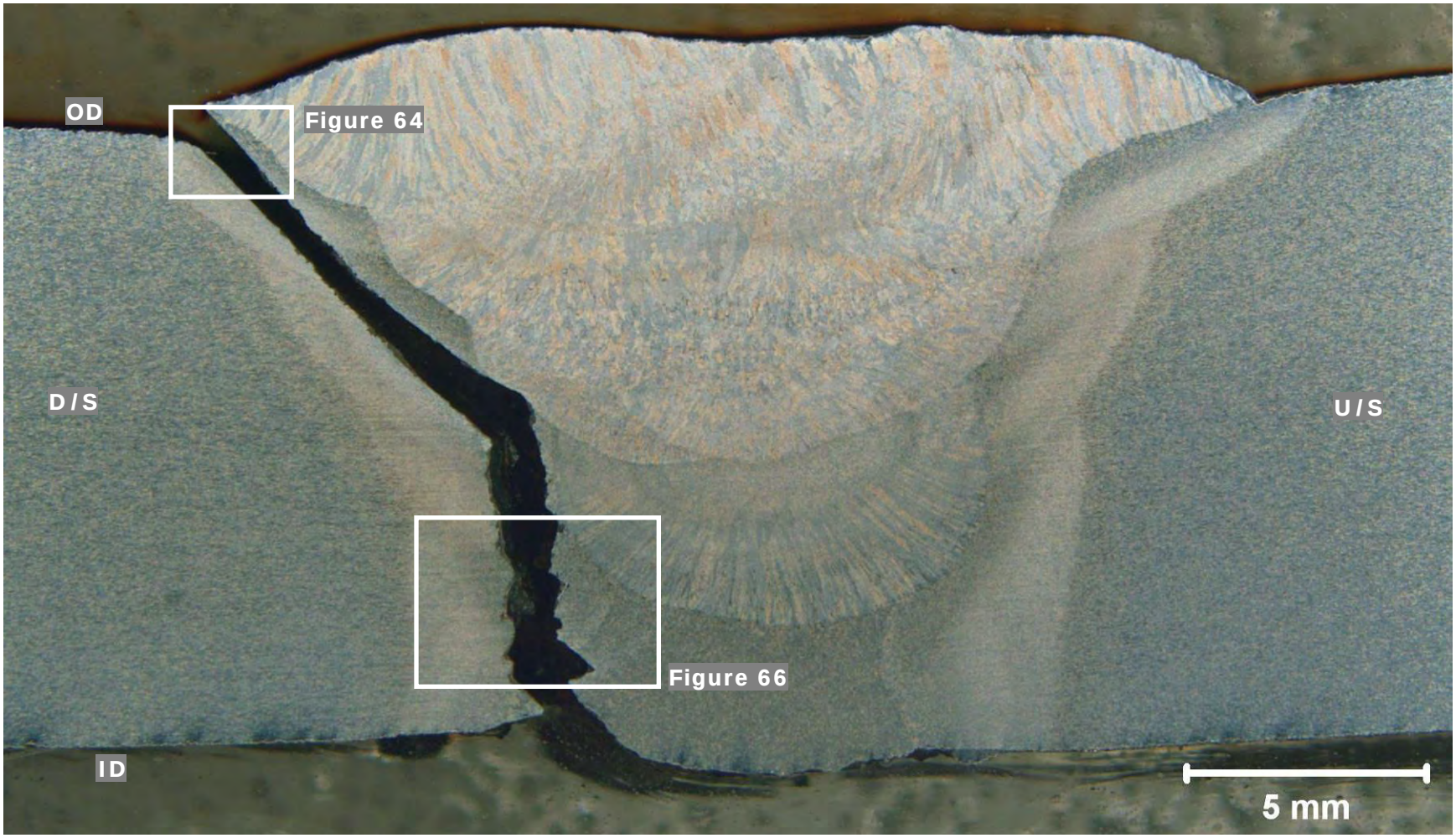


Figure 63. Light photomicrograph of Mount M4 (axial cross-section), which was removed from the GW at the 10:24 orientation; refer to Figure 1, Figure 14, and Figure 30 for location (2% Nital Etchant).

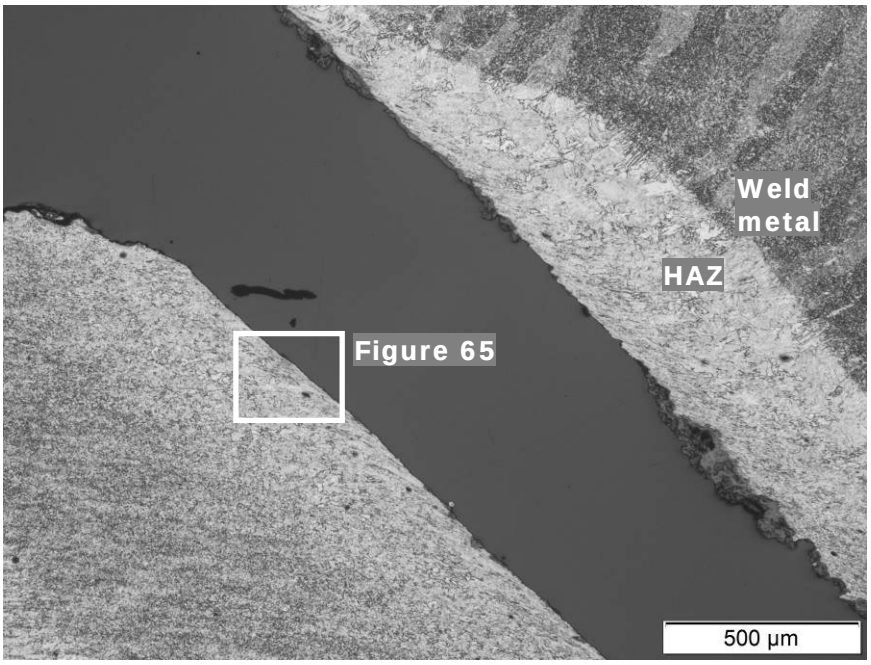


Figure 64. Light photomicrograph of Mount M4 near the OD surface (2% Nital Etchant); area indicated in Figure 63.

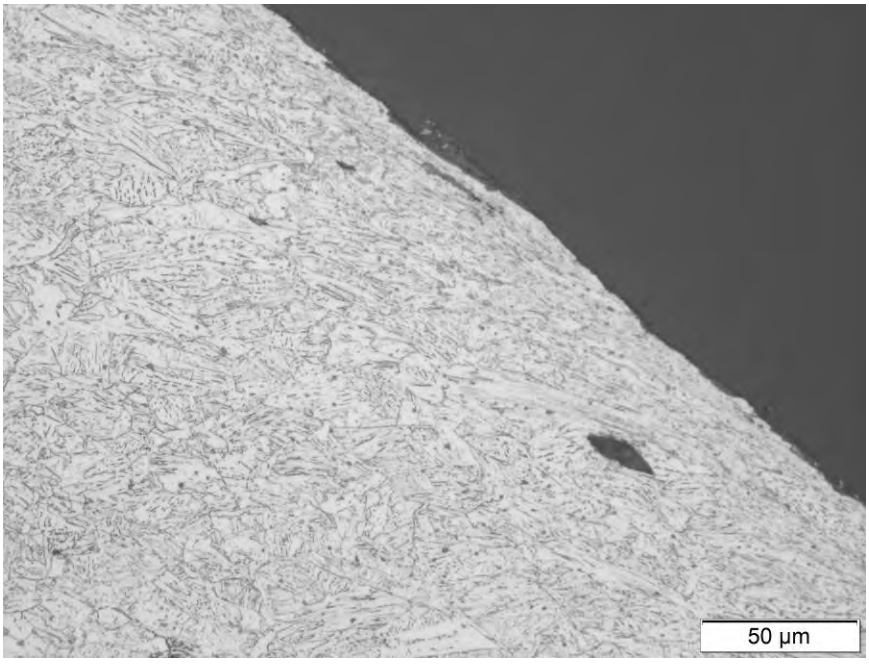


Figure 65. High magnification light photomicrograph of Mount M4 showing grain elongation adjacent to the fracture surface (2% Nital Etchant); area indicated in Figure 64.

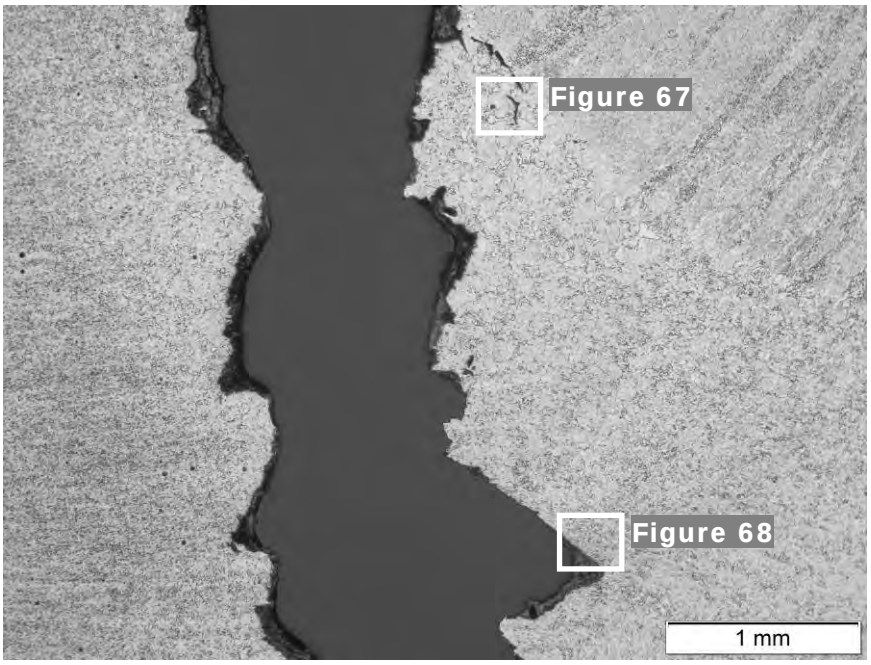


Figure 66. Light photomicrograph of Mount M4 near the ID surface (2% Nital Etchant); area indicated in Figure 63.

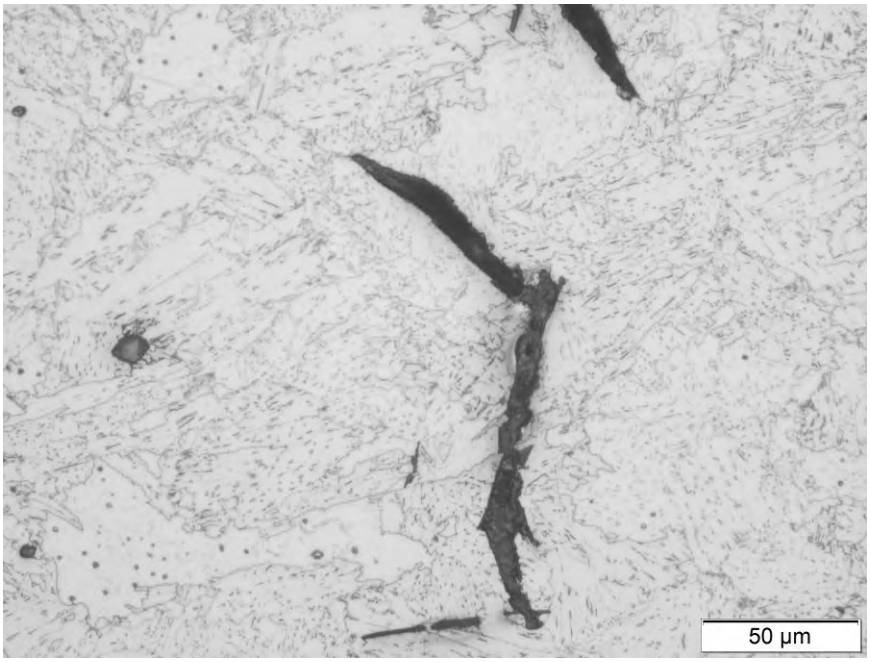


Figure 67. High magnification light photomicrograph of Mount M4 showing fissures (2% Nital Etchant); area indicated in Figure 66.

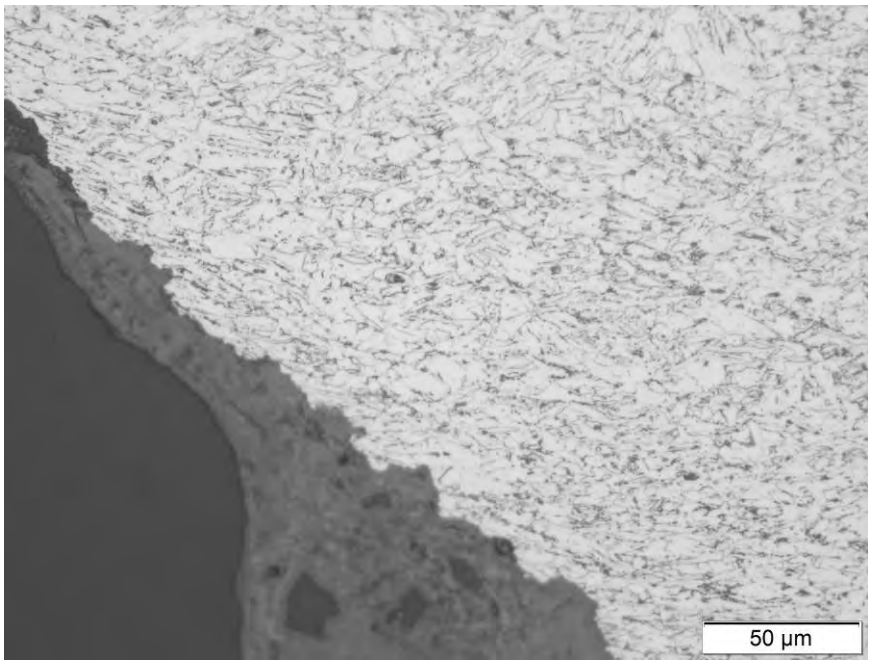


Figure 68. High magnification light photomicrograph of Mount M4 showing grain elongation adjacent to the fracture surface, near the ID surface (2% Nital Etchant); area indicated in Figure 66.



Figure 69. Light photomicrograph of Mount M5 (axial cross-section), which was removed from the GW at the 11:37 orientation; refer to Figure 1, Figure 14, and Figure 31 for location (2% Nital Etchant).

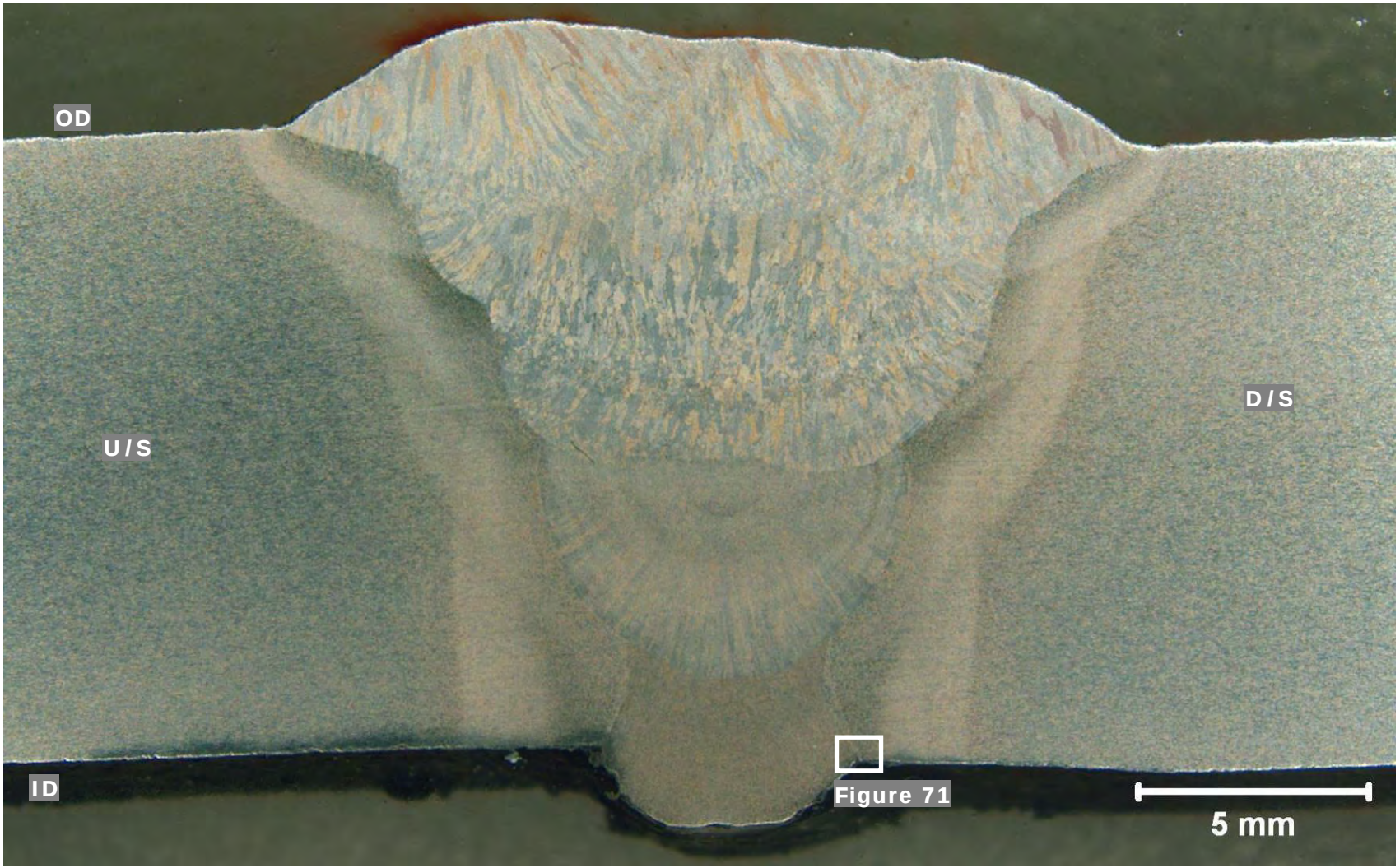


Figure 70. Light photomicrograph of Mount MU1 (axial cross-section), which was removed from the intact GW at the 12:27 orientation; refer to Figure 1 and Figure 17 for location (2% Nital Etchant).

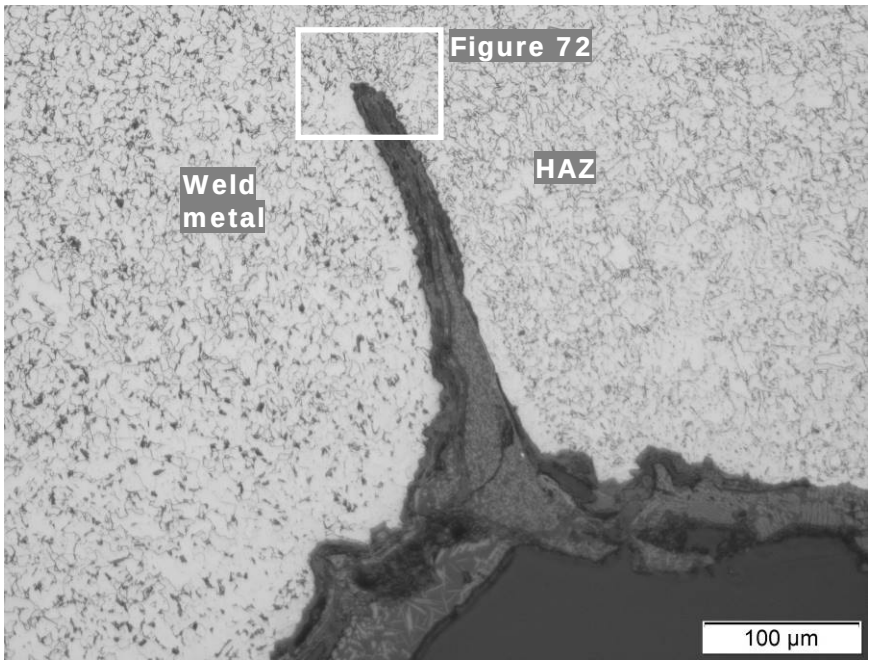


Figure 71. Light photomicrograph of Mount MU1 adjacent to the ID surface (2% Nital Etchant); area indicated in Figure 70.

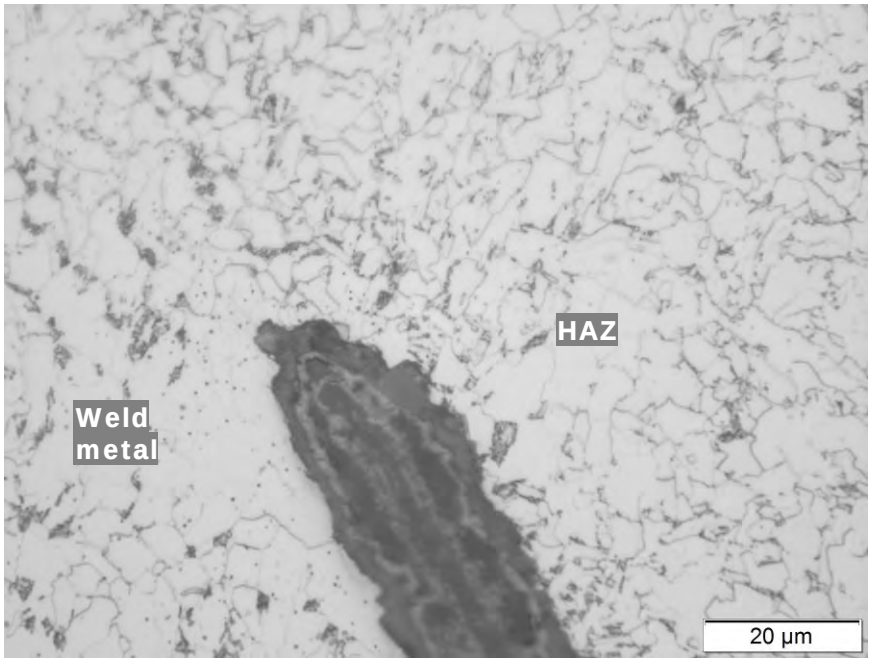


Figure 72. High magnification light photomicrograph of Mount MU1 at the tip of a shallow incomplete fusion (IF) flaw (2% Nital Etchant); area indicated in Figure 71.

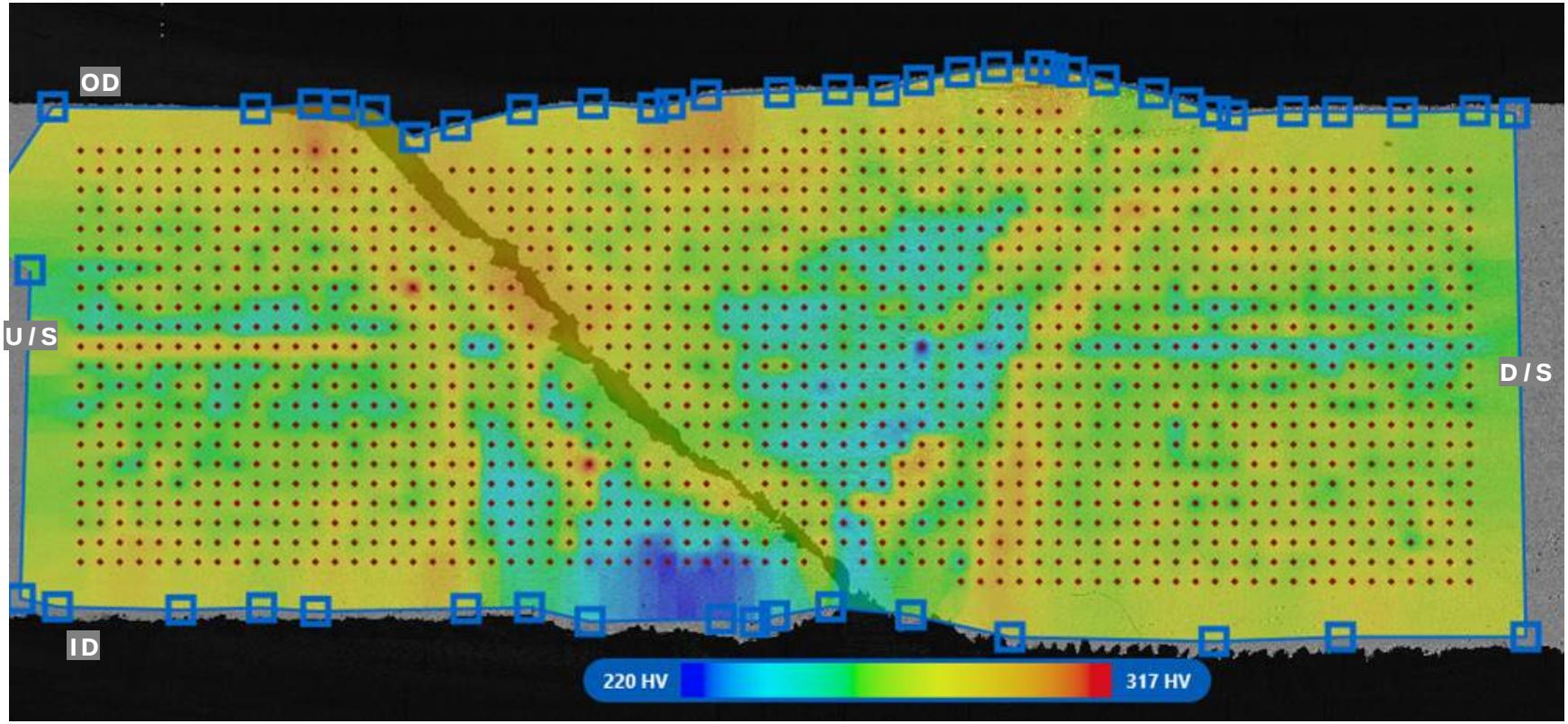


Figure 73. Hardness map overlay following hardness testing (Vickers 1 kg load) performed on Mount M1.

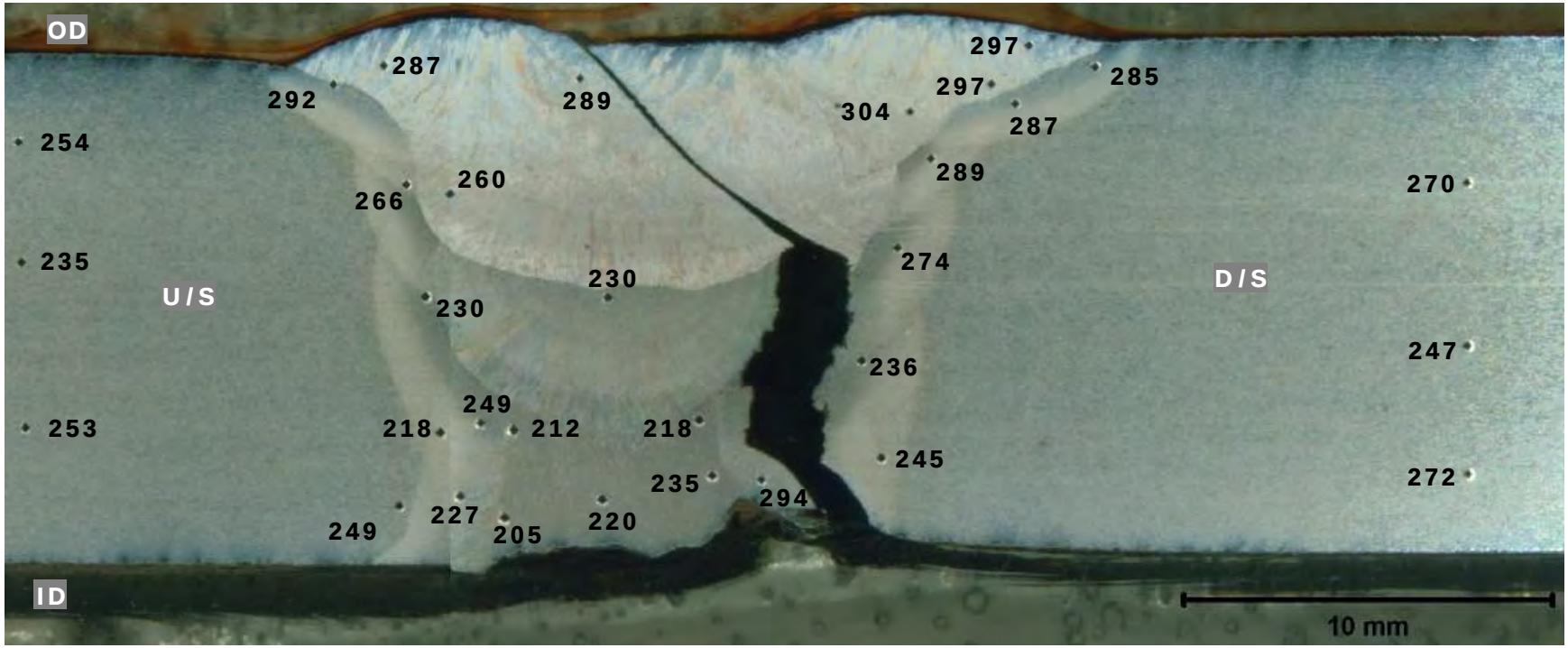


Figure 74. Light photomicrograph montage of Mount M2 (axial cross-section), showing the hardness indentations and the hardness values in HV (2% Nital Etchant).

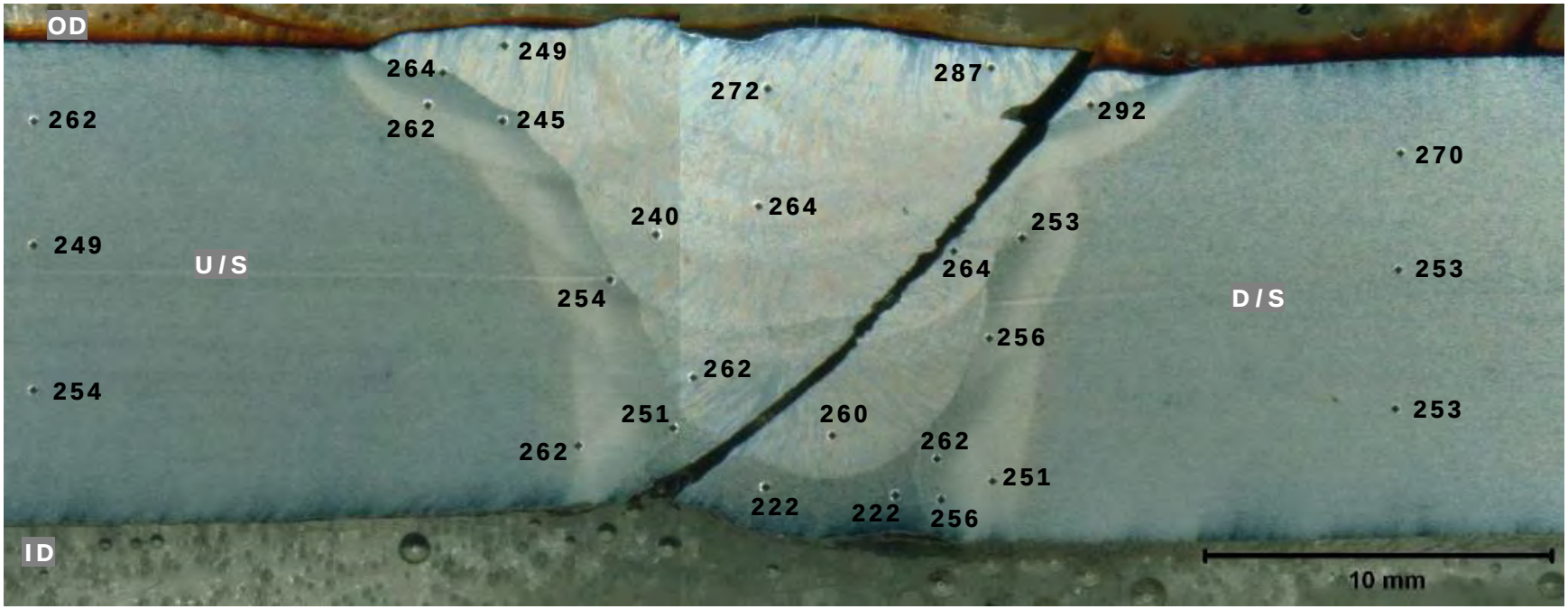


Figure 75. Light photomicrograph montage of Mount M3 (axial cross-section), showing the hardness indentations and the hardness values in HV (2% Nital Etchant).

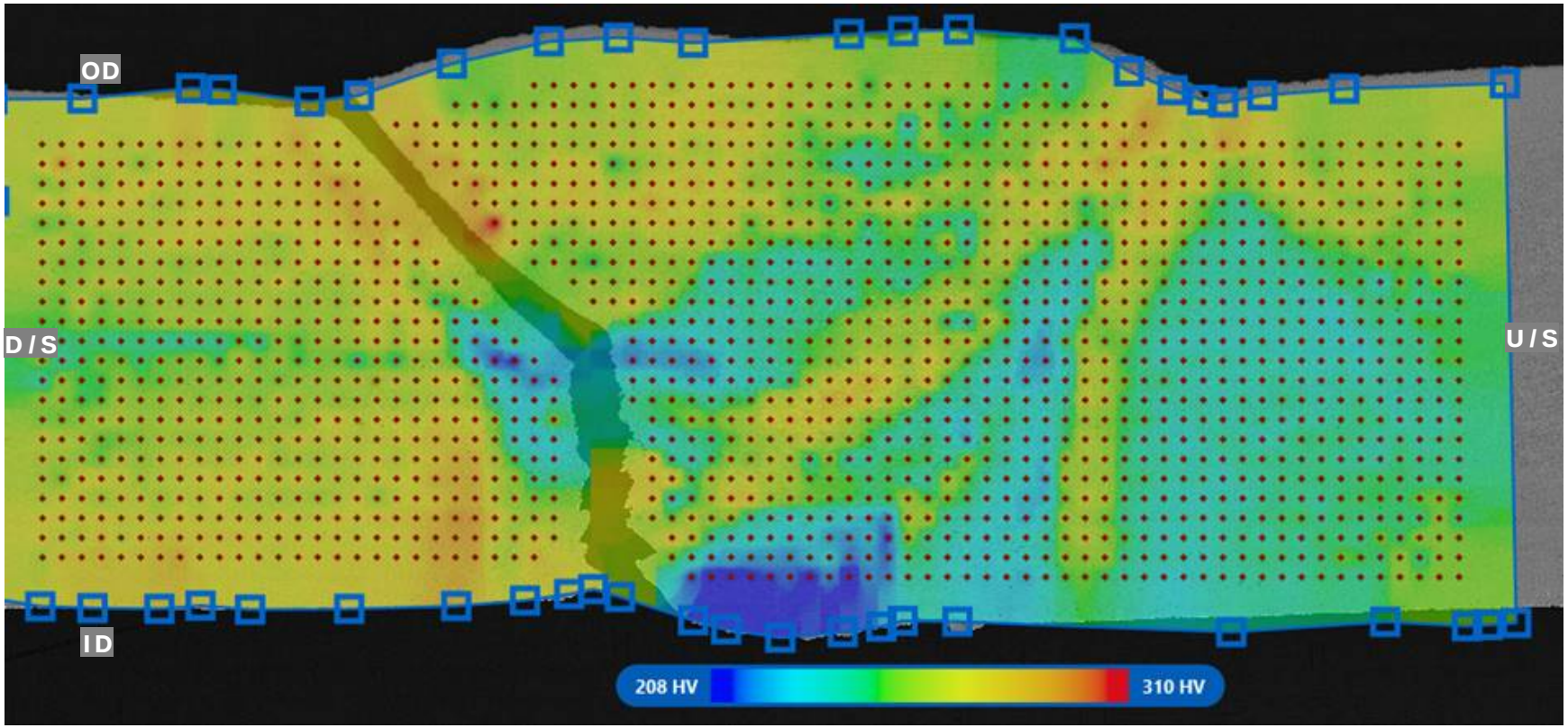


Figure 76. Hardness map overlay following hardness testing (Vickers 1 kg load) performed on Mount M4.

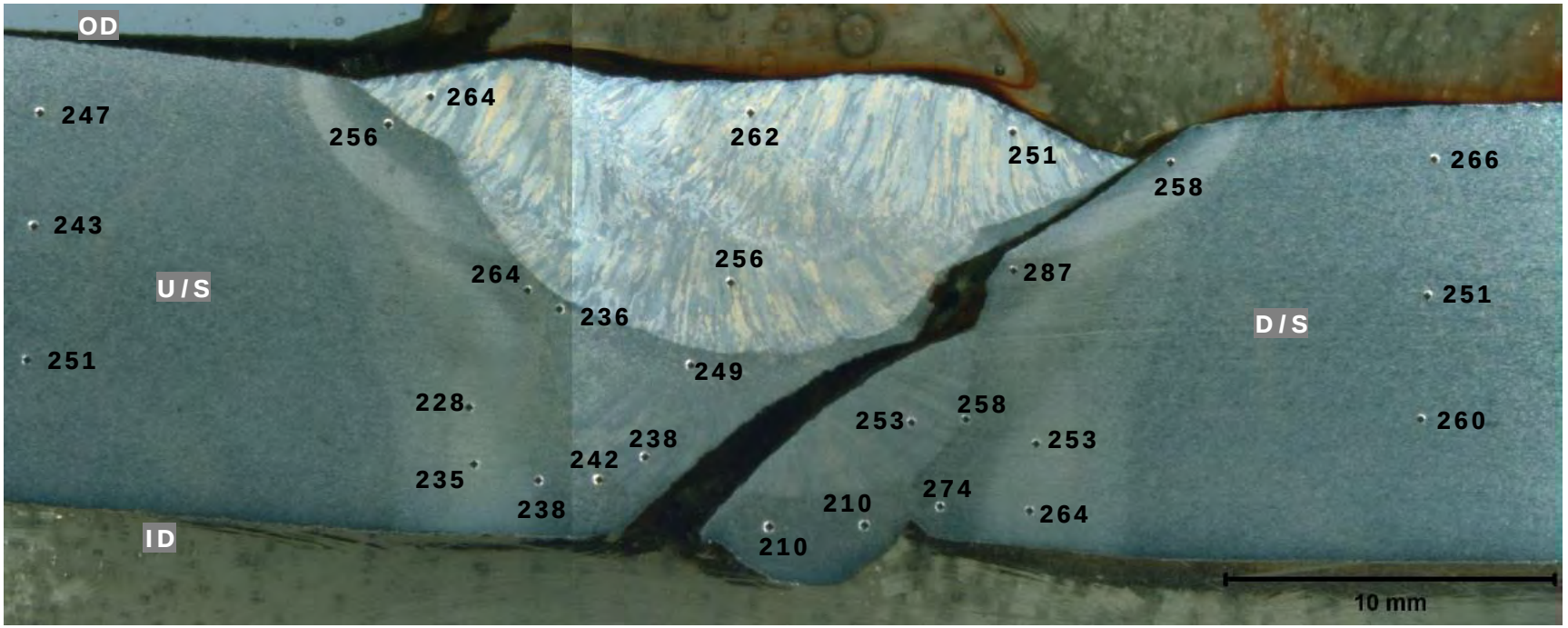


Figure 77. Light photomicrograph montage of Mount M5 (axial cross-section), showing the hardness indentations and the hardness values in HV (2% Nital Etchant).

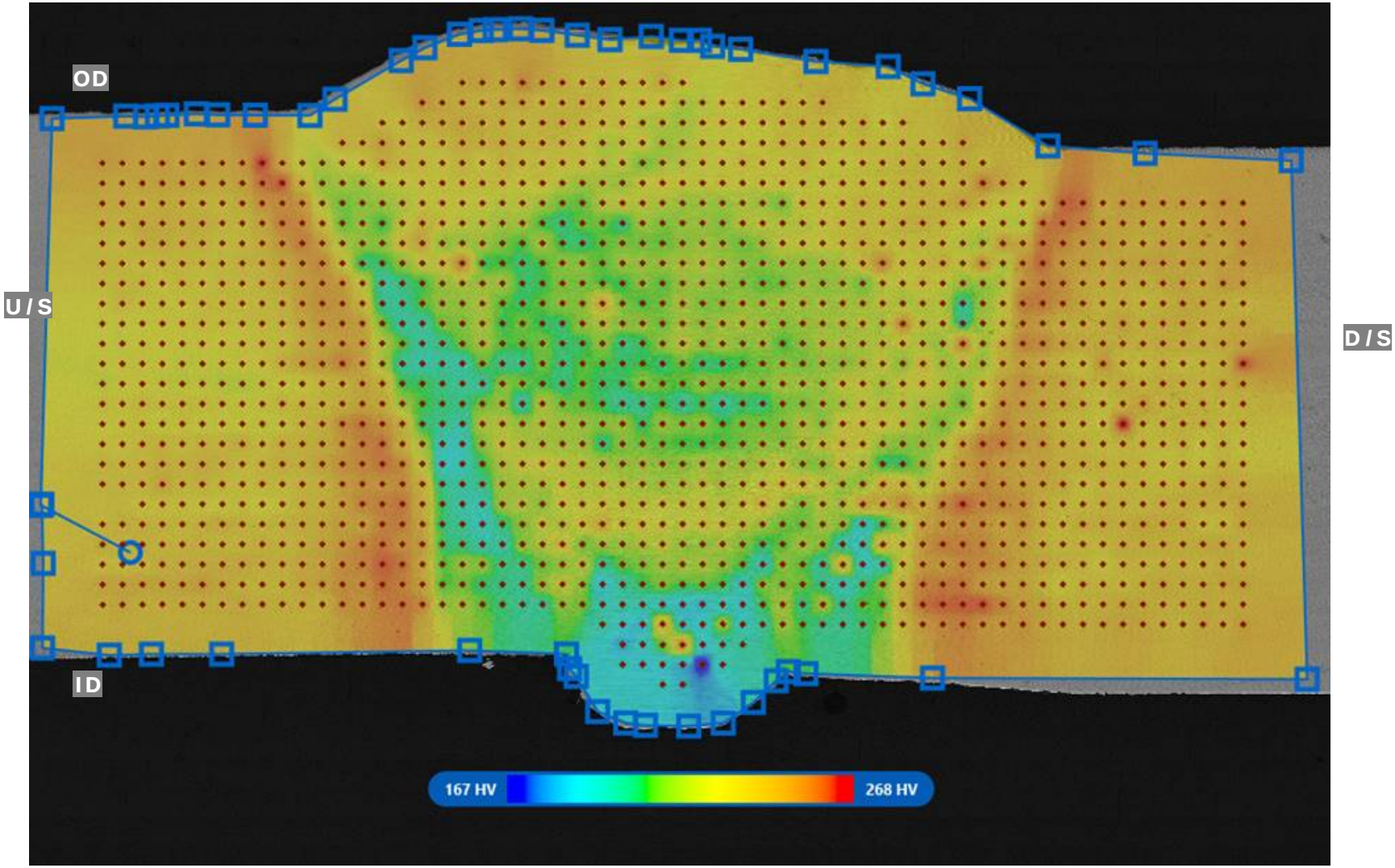


Figure 78. Hardness map overlay following hardness testing (Vickers 1 kg load) performed on Mount MU1.

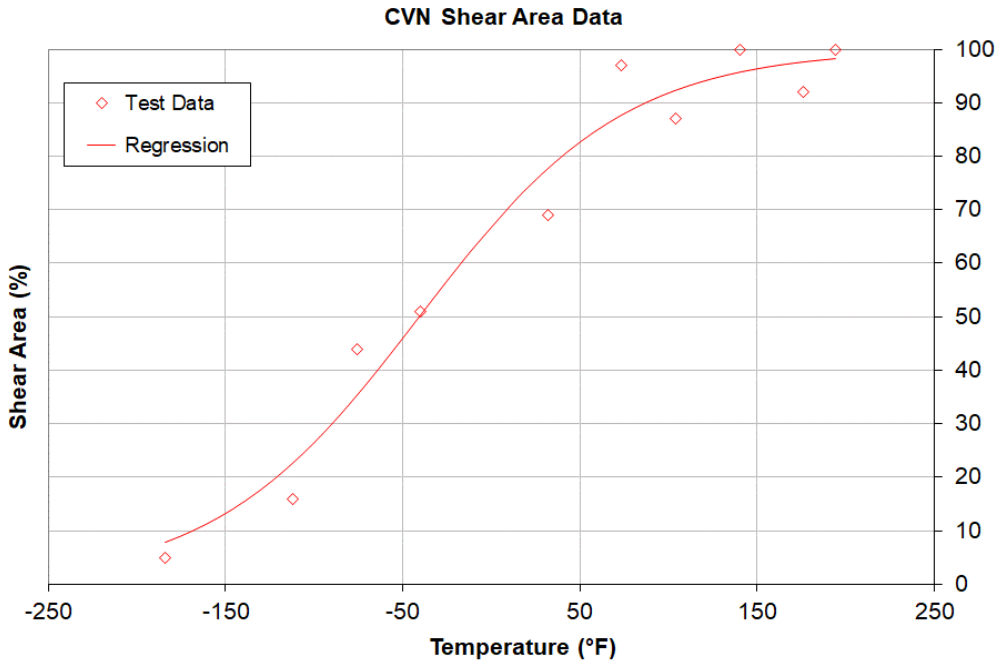


Figure 79. Percent shear from Charpy V-notch tests as a function of temperature for axial/cross-girth weld (HAZ notch) specimens removed from Pipe Section C.

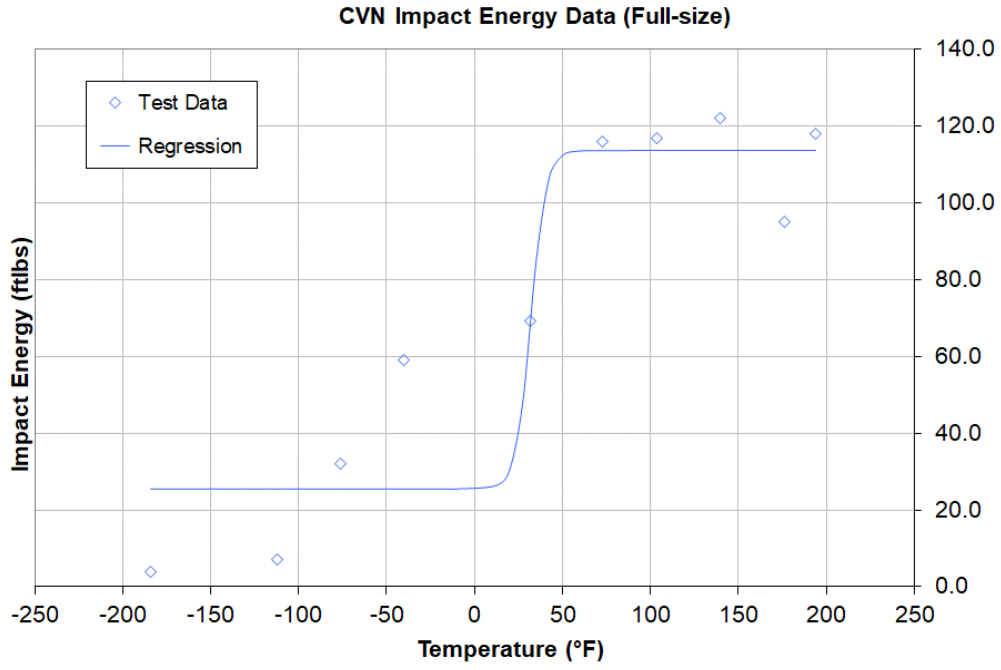


Figure 80. Charpy V-notch impact energy as a function of temperature for axial/cross-girth weld (HAZ notch) specimens removed from Pipe Section C.

ABOUT DNV GL

Driven by our purpose of safeguarding life, property, and the environment, DNV GL enables organizations to advance the safety and sustainability of their business. We provide classification and technical assurance along with software and independent expert advisory services to the maritime, oil and gas, and energy industries. We also provide certification services to customers across a wide range of industries. Operating in more than 100 countries, our professionals are dedicated to helping our customers make the world safer, smarter, and greener.

Appendix D

Responses to Questions Provided by PHMSA 4/7/2021

Questions and responses related to the Denbury Yazoo County RCA Final Report dated 8/7/2020:

1. **The metallurgy report does not reference chain-of-custody. Were chain-of-custody procedures used**

   Chain of custody procedures were used for collection and transport of the failed pipe section and samples. Copies of the chain-of-custody documentation have been provided to PHMSA and have been added to the appendices of this report.

2. **Copy and discussion of welding procedure used needed**

   A summary of the review of Denbury's welding procedure for the Delhi 24-inch Transmission Line utilized for original construction is provided below:

   Material: In this case the pipe material was high strength API 5L-X80-PSL2, 24-inch diameter, and 0.54-inch wall thickness.

   There are 3 requirements for hydrogen cracking:
   a) Hydrogen in the weld,
   b) A crack susceptible microstructure, and
   c) Tensile stresses acting on the weld

   Weld Material: The Welding Procedure Specification WPS 14 indicates the use of the following electrodes:
   a) Root Bead: E6010
   b) Hot: E9010-G
   c) 1st Fill: E10045 P2 H4R
   d) Fill (s): E10045 P2 H4R
   e) Cap (s): E10045 P2 H4R

   Post Weld Heat Treatment: Not recommended

   Comments:

   1) Cellulosic-coated electrodes (AWS EXX10-type) contain moisture and organic compounds in the electrode coatings and result in a considerable amount of hydrogen in the weld. In the Denbury procedure electrode AWS E6010 and E9010-G were used for the root and hot pass in conjunction with low-hydrogen electrodes for the fill and cap passes. The Welding Procedure indicated that this is permissible because the heat from the fill and cap passes allows the hydrogen from the first 2 passes to diffuse out of the weld.

2) Electrode E10045 P2 H4R was used as a strength level low hydrogen downhill electrode. Only consumables with a maximum diffusible hydrogen content of 4ml/100g of deposited weld metal were selected for this case. “H” stands for hydrogen, the “4” stands for a maximum of 4ml of hydrogen per 100 grams of deposited weld metal, and “R” means the consumable is resistant to absorbing moisture from atmospheric conditions. During the qualification procedure, this electrode was found to be the most suitable electrode for this project. After the destructive testing, it was determined that the 100 ksi electrodes were a better match for use on this particular X80 line material which has a yield strength approaching 100 ksi.
3) Samples obtained during the failure analysis were evaluated using standard microscopy techniques including stereographic evaluations, microscopic evaluation, and scanning electron microscopy. Five axial and cross-sections were removed from the failed girth weld and one from an intact weld for metallographic analysis.

Actual findings during the failure analysis process:

a) There was no evidence of pre-existing manufacturing or welding flaws,
b) No indications of excessive porosity and/or inclusions,
c) Slight misalignment of high-low weld in the failed girth weld between 2.6% and 6.9% of the NWT,
d) Grain elongations due to the cold work that took place during the rupture process which is consistent with ductile overloading (see fig. 21 of the Mears report),
e) The sample obtained from the intact GW presented a similar morphology to the previous mounts. The high-low weld misalignment at this location was 4.6% of the NWT. The metallography of the section does not indicate a presence of a martensitic phase.
f) Hardness measurements were conducted on all metallographic cross sections. The values ranged between 205 and 304 HV. All the values were found to be in accordance with the applicable standards. Hardness testing of the failed weld presented variability that is likely associated with cold work sustained during the failure. The intact weld was the best representation of the base hardness of the pipe metal. The results indicate lower hardness of the weld metal compared to the pipe metal, which indicates that the weld metal is softer than the parent metal, however tests results were consistent with specifications for pipe of this vintage and yield strength in both the base metal and weld metal. Typically, the parent metal is harder than the weld metal. The axial tensile tests on the intact GW show similar failure to the actual failed pipe sample, further indicating that the lower hardness typical of the weld was the preferred location for the overload failure under applied axial stress. (See fig. 39 of the Mears report).
g) The mechanical testing indicated the average yield (YS) and ultimate tensile strength (UTS) meet the requirements for API X80M PSL 2 Line pipe. The average UTS of duplicate axial specimens taken from the intact girth weld was 103.3 ksi. The same applies to the Charpy V-Notch Testing.

Based upon review of the welding procedure, we conclude that:

1) The Welding Procedure Specification WPS 14 was appropriate to be use as a welding process for the material involved in this project.

2) The testing performed on the samples obtained during the failure investigation indicate that the welds showed that the microstructure and the mechanical properties of the base material and girth weld were in accordance with industry accepted standards.

3. **Report states on page iv: "The exact location of the initiation could not be determined due to a lack of chevrons on the fracture surfaces and the fact that no significant pre-existing (prior to failure) cracks were identified." "no significant" how was this determined?**

   The failure surfaces were inspected visually and optically for indications of surface oxides associated with development and deepening of cracks over an extended period. The lack of oxides precludes the possibility of pre-existing cracks and supports the determination that the failure occurred due to a sudden axial stress. In addition, the visual and optical inspections did not identify any marks or indications on the surface of the fracture that indicated an initiation point of the failure.

4. **The section on page 7 describes figures 53 and 54 and describes the area as "mainly ferrite". Specifically characterize the complete microstructure of the pipe and the weld metal.**

   Figures 53 and 54 of the DNV Metallurgical Analysis Report (Section 3.4) characterize the microstructure of the upstream and downstream pipe. Analysis of these photomicrographs indicate a significantly larger amount of ferrite than pearlite, which is consistent with the expected microstructure for pipe with the specified minimum yield strength and vintage of the Delhi 24-inch pipeline. Compared with photomicrographs of metal samples provided through industry literature, the microstructure of the 24-inch pipeline has a low carbon content, consistent with other X-80 pipelines. The microstructure of the failed girth shows similar characteristics (see Figure 62 of the DNV Metallurgical Analysis Report.

5. **Provide the hardness montage for MU1**.

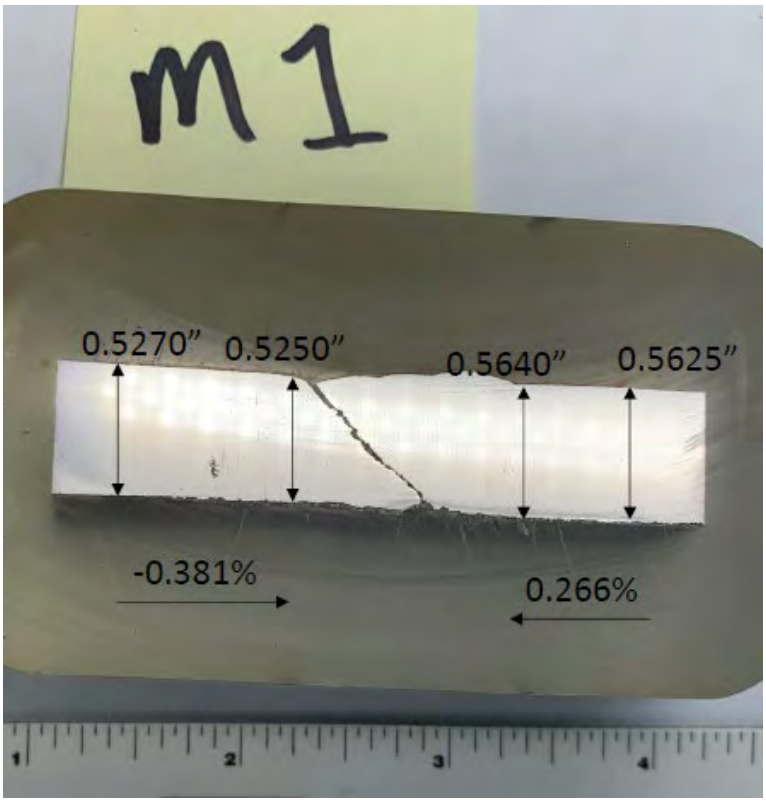
   The hardness montage for mount MU1 is provided in Figure 78 of the DNV Metallurgical Analysis Report (Appendix C).

6. **Section 3.5 on hardness testing indicates various areas related to the weld area, include a discussion of the welding procedure utilized to produce the weld.**

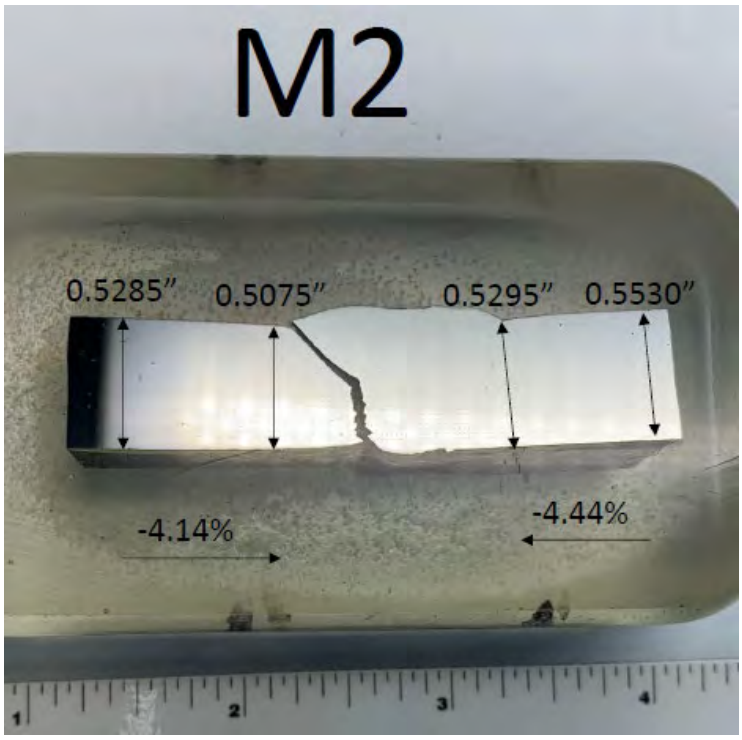
   Discussion of the welding procedure is provided in the response to question #2 above.

7. **Typically, there is narrowing of a tensile specimen due to the area reduction during tensile overload. In this case was there a measurable necking down of the wall thickness adjacent to the fracture surface**

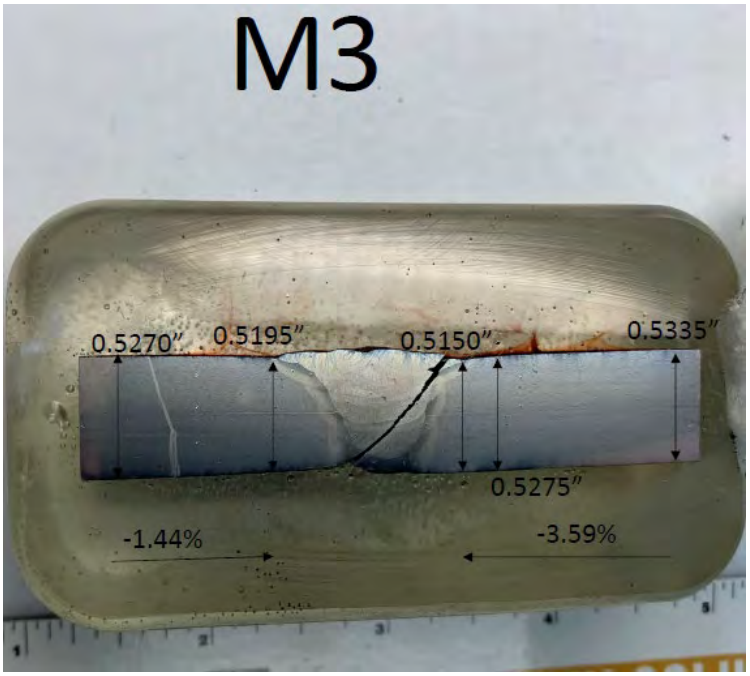
Evaluation of the metallurgical samples indicated slight reduction in wall thickness in each sample, ranging from 1.44% to 6.46%. Photos and measurements are provided in in figures 1 through 5 below:



Fi□□re□□□Cro□□□□e□tiona□Mea□□re□ent□□Mo□nt□M□



Fi□□re □□□Cro□□□□e□tiona□Mea□□re□ ent□□Mo□nt□M□□



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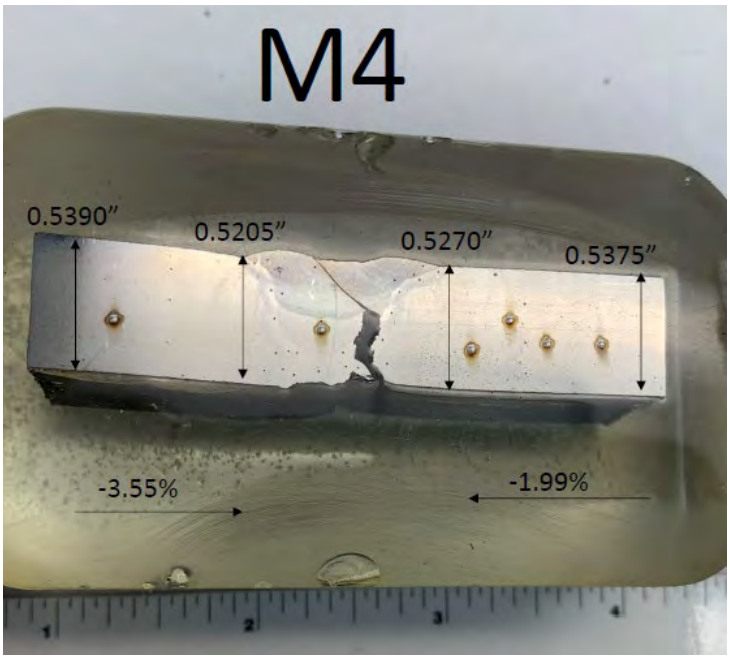


Figure Cross-sectional Measurement Point M4

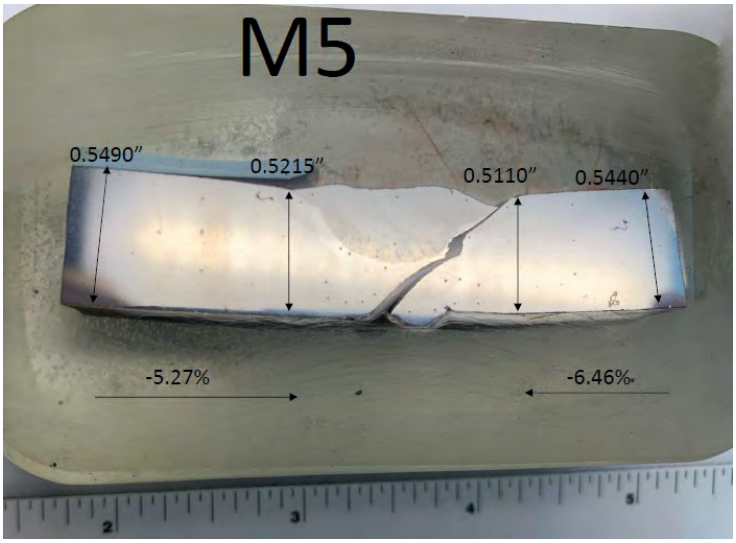


Figure Cross-sectional Measurement Point M5

These results are consistent with the characteristics of API X80M PSL 2 Line pipe.

8. Intact girth weld was tensile tested – compare and contrast fracture appearance of tested intact weld to failed girth weld

The average UTS of the axial specimens taken from the intact girth weld was 103.3 ksi, and both samples failed in the girth weld (DNV Metallurgical Analysis Report, section 3.6). While visual examination of the tensile sample fractures will confirm the location of each fracture, [illegible], as the applied stresses would not be similar. The Pipeline Stress Analysis Report

provided by Mott MacDonald provides information related to the stress analysis associated with this failure.

9. Was leak before fracture mode of failure considered

Occurrence of a leak prior to the failure was considered, however the available information supports a rupture of the pipeline, including the following:

1) There was no indication of a pre-existing defect that would have contributed to a leak and a specific failure initiation site was not apparent.
2) Based upon a witnessed examination of the pipe, there was no evidence of internal or external corrosion that may have contributed to the failure mode.
3) No indication of a leak prior to the failure was identified in operating pressure trends.

10. Failure mode and influence of CO2 on ductile/brittle transition considering leak before rupture

Based upon the metallurgical examination, there is no evidence a leak occurred prior to the failure, therefore brittle failure mode is not feasible.

11. Chemistry of weld needed as this was a girth weld failure

Chemical analysis of the GW was not performed during the investigation. The mechanical testing results were within the accepted criteria during the preparation of the Welding Procedure Specification WPS 14. No additional testing of the chemistry of the girth weld was considered necessary based upon the results of the testing conducted.

12. Report states failure caused by large axial stress but fails to quantify strain

The Pipeline Stress Analysis Report provided by Mott MacDonald identified a stress ratio approximately 43% greater than allowable stresses per ASME B31.4 (2016).

13. Strain analysis would be an input for a geohazard management plan

The Pipeline Stress Analysis Report provided by Mott MacDonald provides information related to the strain analysis associated with this failure.

14. Brittle (cleavage facets) mode of failure noted, but no chevrons – significance

V-shaped chevron markings are characteristic of brittle fracture. These markings may indicate the origin of the fracture, however in this case no chevrons were identified.

15. Explanation of ductile/brittle appearance of the failed girth weld

As described in section 5.3 of the Mears report, the samples were evaluated utilizing standard microscopy techniques including stereographic evaluations, microscopic evaluation and scanning electron microscopy. Five (5) axial and cross-sections were removed from the failed girth weld and one (1) from the intact weld for metallographic analysis. Some of the samples contain fracture paths at a shear angle (fracture path through the smooth surfaces) and other show the fracture path perpendicular to the free surface and regions of shear failure (fracture surface is rough). The appearance of these surfaces further support the mode of failure as described in the executive summary of the DNV Metallurgical Analysis Report "The results of the metallurgical analysis indicate that the failure initiated at a field girth weld, due to axial stresses sufficient to produce overload failure. No pre-existing flaws were present on the fracture surface. A contributing factor was that the pipe steel was stronger than the girth weld."

16. Correlation of hardness areas and welding procedure

Hardness measurements were conducted on all metallographic cross sections. The values ranged between 205 and 304 HV. All the values were found to be in accordance with the applicable standards. Hardness testing of the failed weld presented variability that is likely associated with cold work sustained during the failure. The intact weld was the best representation of the base hardness of the pipe metal. The results indicate lower hardness of the weld metal compared to the pipe metal. Which indicates that the weld metal is softer than the parent metal, which was in accordance with the results of the welding qualification. Typically, the parent metal is harder than the weld metal. The axial tensile tests on the intact GW show similar failure to the actual fracture to the actual fracture, further indicating that the lower hardness typical of the weld was the preferred location for the overload failure under applied axial stress. (See fig. 39 of the Mears report).

17. How does the welding procedure tensile tests compare to the intact weld tensile tests

The mechanical testing indicated the average yield (YS) and ultimate tensile strength (UTS) meet the requirements for API X80M PSL 2 Line pipe. The average UTS of duplicate axial specimens taken from the intact girth weld was 103.3 ksi. The same applies to the Charpy V-Notch Testing (see section 5.6.2 of the Mears RCA Final Report).

The results of the Procedure Qualification Record (PQR 14a) indicated cross weld UTS of 115.6 ksi to 117.3 ksi. Per the Welding Procedure Development and Qualification for X80 Line Pipe, dated 8/13/2008, section 3.1, "After destructive testing it was determined that the 100 ksi electrodes were a better match for use on this particular X80 line pipe material, which has a yield strength approaching 100 ksi." Therefore test results from the mechanical testing of the intact girth weld are consistent with the pipeline's specifications.

Appendix E

Chain of Custody Documentation

mears
A QUANTA SERVICES COMPANY

STEP 2 – CHAIN OF CUSTODY

1. ORIGINATING LOCATION – Denbury Delhi 24 inch Transmission	
Contact Person: Seth Bayham	*Phone Number: (225) 202-1402*
Title: Corrosion Foreman	*Date: 3/10/2020*
Contact Address: 31589 Netterville Rd, Denham Springs, LA 70726	
Material Location, City, State: 688 MS 433, Sartitia, MS	
Signature: Seth Bayham	*Date:* 3/10/2020

2. AUTHORIZATION FOR RELEASE	
Authorized by: Seth Bayham	*Phone Number:* (225) 202-1402
Title: Corrosion Foreman	*Date:* 3-10-20
Department:	
Authorization provided (check one): _____ *by Telephone* ✓ *in Person* _____ *in Writing*	

SHIPPING INSTRUCTIONS

Samples should be shipped to DNV GL 9037 Heritage Drive, Plain City, OH 43064. Please contact Greg Quickel. Phone: (614) 378-4083.

3. ITEMS TRANSFERED	
Reference Number: Delhi 24-3 *Sample Identifier: Sample A* *Date Collected: 3/09/2020*	*Description: 24" diameter by 6' long pipe sample (D/S failure section)*
Reference Number: Delhi 24-4 *Sample Identifier: Sample B* *Date Collected: 3/09/2020*	*Description: 24" diameter by 6 ' long pipe sample (U/S failure section)*
Reference Number: Delhi 24-5 *Sample Identifier: Sample C* *Date Collected: 3/09/2020*	*Description: 24" diameter by 8' long pipe sample (U/S pipe section containing exemplar weld)*
Reference Number: *Sample Identifier:* *Date Collected:*	*Description:*
Reference Number: *Sample Identifier:* *Date Collected:*	*Description:*

CHAIN OF CUSTODY RECORD FOR SAMPLE A, B, C

☒ Received from Denbury Resources Date: 3/10/hr 1:30P Received by P. Jo. Reid
Reason for transfer

From: Company: Denbury Resources Signature
To: Company: Reid's Dozer service Signature P-JOE REID

Until the time you transferred custody of sample
To recipient listed above, has (have) this (these) item (s) left your custody, control at any time:
YES
NO

If YES, please explain:

Signature

CHAIN OF CUSTODY RECORD FOR SAMPLE A, B, C

□ Received from Reid's Dozer Service Date: 3/12 /hr 8:10 Received by Greg Quickle

Reason for transfer Testing at DNVGL

From: Company: Reid's Dozer Sevice Signature P-JOE REID
To: Company: DNV GL Signature Greg Quickel

Until the time you transferred custody of sample A, B, C
To recipient listed above, has (have) this (these) item (s) left your custody, control at any time:
YES
✓ NO

If YES, please explain:

Signature P-JOE REID

DNV GL USA, Inc.
Materials & Corrosion Technology Center
Incident Investigation
5777 Frantz Road
Dublin, OH 43017-1886
Tel: (614) 761-1214
Fax: (614) 761-1633
www.dnvgl.com

DNV·GL

CHAIN OF CUSTODY FORM

Project No.: 10206282 Sample: 24" @ Denbury

1. ORIGINATING LOCATION	
Contact Person: Greg Quickel	Phone No.: 614 378 4083
Title: Principal Eng	Date: 9/30/2020
Contact Address: See above	
Material Location, City, State:	
Signature: Greg Quickel	Date: 9/30/2020

Description of Evidence	Date Evidence Placed into Controlled Custody:
24" @ Denbury Failure	
Four pipe sections	
One box of samples (met/FS.)	Date Evidence Released from Controlled Custody: 9/30/2020
Two bags of soil from pipe	
Five steel coupons for mech testing	
Two bags of mech specimens	
	Release of Evidence Authorized by:
Received by:	

	Date	Time
Signature: Kurt Hahn Reason: TRANSFER	9/30/20	
Signature: _____ Reason: _____		
Signature: _____ Reason: _____		

Appendix F

Welding Procedure Development and Qualification for X80 Line Pipe

8/13/2008

FINAL REPORT

PROJECT CONSULTING SERVICES, INC.

WELDING PROCEDURE DEVELOPMENT AND QUALIFICATION FOR X80 LINE PIPE

PROJECT NO. 82681591
AUGUST 13, 2008

DET NORSKE VERITAS

FINAL REPORT

Date of Issue:
August 13, 2008

Project No.:
82681591

CC TECHNOLOGIES, INC.
Integrity & Materials

5777 Frantz Road
Dublin, Ohio 43017-1386
U.S.A.
Tel: (614) 761-1214
Fax: (614) 761-1633
http://www.dnv.com
http://www.cecetinologies.com

Authored By:
Brad Etheridge
Engineer
Welding Technology

Reviewed By:
Bill Bruce
Director
Welding Technology

Approved By:
Patrick H. Vieth
Senior Vice President
Integrity & Materials

Client:
Project Consulting Services, Inc.

Summary:

CC Technologies, Inc. (CCT) was retained by Project Consulting Services, Inc. to develop and qualify welding procedures for 24 inch by 0.54 inch grade X80 line pipe. Several different production, repair, and in-service procedures were developed. These procedures were run at a Progressive Pipeline Inc. facility in Meridian, Missipppi under the supervision of a representative from CCT. The welds were sent to an independent laboratory for destructive testing. CCT then created welding procedure specifications and procedure qualification records for welds that passed all testing.

Project No:	Subject Group:	Date :	Number of Pages:
82681591	Welding Technology	August 13, 2008	6

Report Title:

Welding Procedure Development and Qualification for X80 Line Pipe

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FINAL REPORT

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Appendix A. Letter Report Pertaining to the Use of AWS E8010-G Electrodes for X80 Pipelines

Appendix B. Letter Report Pertaining to the Use of Cellulosic-Coated Electrodes for X80 Pipelines

FINAL REPORT

1. PROJECT SCOPE

CC Technologies, Inc. (CCT) was contracted by Project Consulting Services Inc. (PCS) to create and qualify welding procedure specifications (WPS) and procedure qualification records (PQR) for the construction of two 24-inch diameter x 0.54 inch wall thickness, API 5L-X80-PSL2 pipelines as per the requirements of the 19th and 20th editions of API 1104. A variety of procedure qualifications were performed so as to give PCS's client, Denbury Resources Inc. (DRI), options when selecting welding processes and consumables for construction. CCT was also asked to use their welding experience and expertise to identify the most appropriate welding procedures for the construction, maintenance, and repair of these pipelines. Procedure qualifications were performed using welding consumables and process that were suggested by PCS/DRI and using welding consumables and process that were determined by CCT to be acceptable alternatives to those suggested by PSC/DRI.

2. WORK PERFORMED

CCT attended a project kick off meeting in Birmingham, Alabama on April 2, 2008 at the PCS office. The goal of this meeting was to discuss what consumables to use for the construction of two new X80 pipelines that will operate in carbon dioxide service. When welding higher strength line pipe material such as X80, several concerns need to be addressed including weld strength level and the risk of weld metal hydrogen cracking.

In most welding applications, including pipeline girth welding, it is desirable for the weld to overmatch the strength of the base material. This ensures that the strains caused by loads imposed on the completed structure do not concentrate in the vicinity of the weld. Welds are more likely to contain discontinuities than base materials, so it is desirable to avoid the concentration of strains in the vicinity of welds. A letter report pertaining to the use of welding consumables and process that were suggested by DRI for construction of these pipelines, from the prospective of weld strength level, is shown in Appendix A.

There are three requirements for hydrogen cracking; hydrogen in the weld, a crack-susceptible weld microstructure, and tensile stresses acting on the weld. Cellulosic-coated electrodes (AWS EXX10-type) contain moisture and organic compounds in the electrode coatings and result in a considerable amount of hydrogen in the weld. Traditionally, heat-affected zone (HAZ) microstructures have been considered to be the most susceptible to hydrogen cracking. With the introduction of higher strength line pipe steels with good weldability, and the higher strength welding consumables required to weld them, weld metal microstructures are now as susceptible (if not more so) than HAZ microstructures. A letter report pertaining to the use of cellulosic-coated electrodes for construction of these pipelines, from the prospective of hydrogen cracking risk, is shown in Appendix B.

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CCT was asked to provide alternatives to traditional cellulosic-coated electrodes in the form of low-hydrogen consumables and processes. CCT provided several low-hydrogen alternatives to be qualified along with cellulosic-coated electrode procedures requested by DRI. These procedures were qualified, documented, and the completed WPS's and PQR's delivered to PCS.

The procedure qualifications were performed at a Progressive Pipeline Inc. facility in Meridian, Mississippi. A CCT employee was onsite during procedure qualification to provide support and record relevant welding parameters. The first round of welding procedure qualifications took place April 14 through 18, 2008. WPS 4 through WPS 11 (Table 1) were conducted during this first round of welding. A typical setup for these procedures is shown in Figure 1. A 2 foot long length of pipe was welded onto a longer piece of pipe using an external lineup clamp. The preheat was applied using propane with rosebud torches. These welds were inspected by radiography before being sent for destructive testing to prevent incurring the cost of performing destructive testing on welds that may contain unacceptable discontinuities. A second round of procedures was performed at the same location May 12 through 17, 2008. The procedures performed in May were WPS 14 through WPS 20 (Table 1) and included two in-service repair procedures for the installation of a tight fitting Type B repair sleeve, as shown in Figure 3.

3. RESULTS

3.1 Pipeline Girth Welding

A total of 12 procedures were qualified, a complete list of the procedures can be found in Table 1. The low-hydrogen procedures are WPS 7 through WPS 11 and WPS 17 through WPS 20. All of the other procedures involve the use of cellulosic-coated electrodes exclusively. Except for the in-service procedures (WPS 19 and 20), all of the procedures use cellulosic-coated electrodes for the root pass and the hot pass. For pipeline girth welding on thicker-wall X80 line pipe material, it is typically acceptable to use cellulosic-coated electrodes for the root and hot pass in conjunction with low-hydrogen consumables for the fill and cap passes. This is permissible because the heat from the fill and cap passes allows the hydrogen from the first two passes to diffuse out of the weld.

Three different types of low hydrogen consumables were used; low hydrogen down-hill stick electrodes (AWS EXX45-type), traditional up-hill low-hydrogen stick electrodes (AWS EXX18-type) and gas-shielded flux-cored arc welding wire (AWS E101T1-type). These consumables were used with the manual shielded metal arc welding (SMAW) process and the semi-automatic flux-core arc welding (FCAW) processes, respectively. Traditional vertical up low-hydrogen electrodes (E10018-G H4R) were used for a single repair procedure, WPS 11. Two different strength levels of the low hydrogen down-hill electrode (E9045 P2 H4R and E10045 P2 H4R) were used during the first set of welding trials. These strength levels represent the minimum ultimate tensile strength of the consumable. After destructive testing it was determined that the 100 ksi electrodes were a better match for use on this particular X80 line

pipe material, which has a yield strength approaching 100 ksi. During the second round of procedure qualifications the E10045 P2 H4R electrodes were the only low hydrogen down-hill electrodes used.

3.2 In-Service Welding

When qualifying welding procedures to be used on pipelines that are in-service, it is good practice to simulate in-service operating conditions. This is important because of the effect that the flowing contents in the pipeline has on the weld cooling rate. The flowing contents act as a heat sink when welding onto the carrier pipe, which causes the weld to solidify and cool extremely quickly. This in turn can promote the formation of crack-susceptible weld microstructures and cause large amounts of hydrogen to become trapped in the weld, if good low hydrogen welding techniques are not used. It is therefore critical to use welding processes and consumables that produce welds with a low amount of diffusible hydrogen.

For this reason, only consumables with a maximum diffusible hydrogen content of 4ml/100g of deposited weld metal were used. Notice the "H4R" designation at the end of the consumable specification in column 5 of Table 1. The "H" stands for hydrogen, the "4" stands for a maximum of 4 ml of hydrogen per 100 grams of deposited weld metal, and the "R" means the consumable is resistant to absorbing moisture from atmospheric conditions.

The setup used for the in-service welding procedure qualification can be seen in Figure 4. To create this testing rig, a section of pipe is enclosed by welding end caps to the open ends. A nozzle for an ordinary garden hose is installed on both ends of the vessel. This allows water from the faucet to flow through the pipe section while welding is performed. A valve was installed on the top of the pipe close to the end where the water exits to allow for air to be vented, ensuring the pipe is completely full of water. That end of the pipe was slightly elevated, which ensures that no air bubbles become trapped along the top of the pipe. Water flow was maintained during welding and continued until the welds cooled to room temperature.

3.3 Documentation

WPS and PQR combinations for each of the procedures that passed destructive testing were provided to PCS.

FINAL REPORT

Table 1. Qualified Welding Procedures Specifications.

Procedure	Type	Root Pass Consumable Specification	Hot Pass Consumable Specification	Fill and Cap Pass Consumable Specification
WPS 4	Production	E6010	E9010-G	E9010-G
WPS 7	Production	E6010	E9010-G	E9045 P2 H4R
WPS 8	Repair	E6010	E9010-G	E9045 P2 H4R
WPS 9	Production	E6010	E9010-G	E10045 P2 H4R
WPS 10	Repair	E6010	E9010-G	E10045 P2 H4R
WPS 11	Repair	E6010	E9010-G	E10018-G H4R
WPS 14	Production	E6010	E9010-G	E10045 P2 H4R
WPS 15	Repair	E6010	E9010-G	E10045 P2 H4R
WPS 16	Repair	E6010	E9010-G	E9010-G
WPS 17	Production	E6010	E9010-G	E101T1-GM-H8
*WPS 19	Sleeve	E10045 P2 H4R	E10045 P2 H4R	E10045 P2 H4R
*WPS 20	Sleeve	E101T1-GM-H4R	E101T1-GM-H4R	E101T1-GM-H4R

*In-service weld.

FINAL REPORT

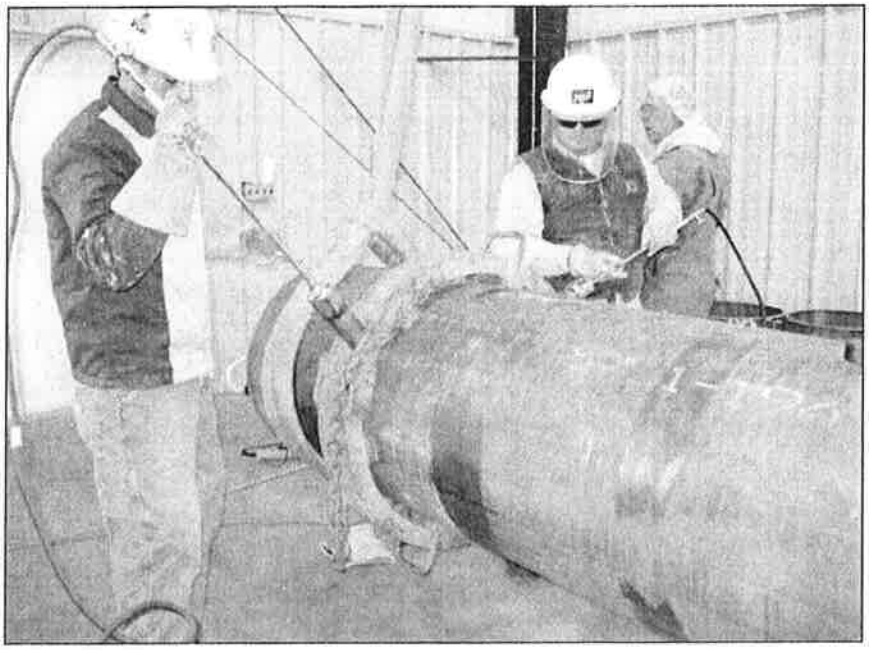


Figure 1. Typical setup for girth weld procedure qualification.



Figure 2. Typical completed girth weld coupon after cutting.

FINAL REPORT



Figure 3. In-service tight-fitting repair sleeve.

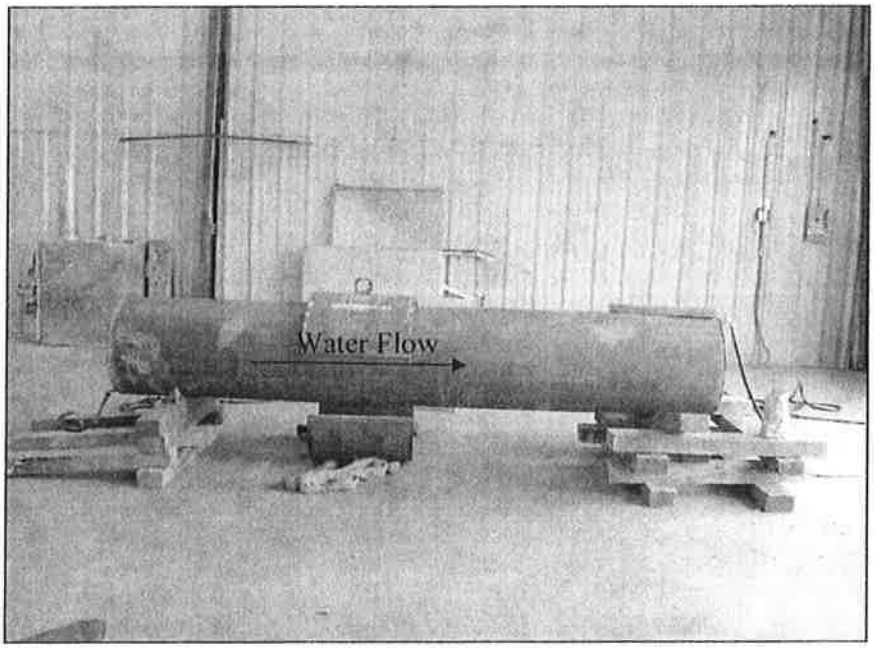
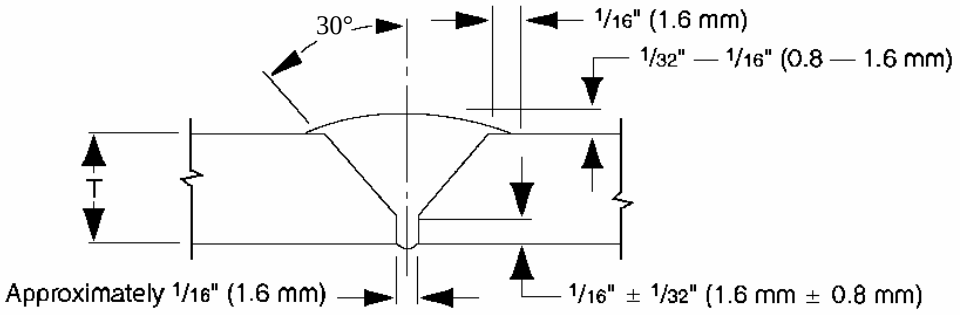
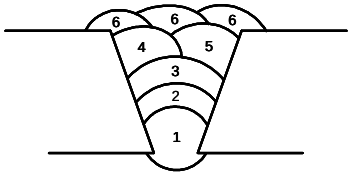


Figure 4. Setup for in-service welding procedure qualification.

Appendix G

Welding Procedure Specification WPS 14

6/18/2008

Scope of Procedure	This welding procedure specification details the procedure to be followed for the production of field butt welds in line pipe as required by the 19th and 20th editions of API 1104, Welding of Pipelines and Related Facilities			
Applicable Codes and Specifications	■ 19th & 20th Editions of API 1104 ☐ DOT 49 CFR Part 195 ☐ DOT 49 CFR Part 192	☐ ASME B 31.3 ☐ ASME B 31.4 ☐ ASME BPVC Section IX	☐ ASME B 31.8	
Supporting PQR	PQR: PQR-14a		Date Qualified: 5/14/08	
	Witnessed By: Brad Etheridge		Location: Meridian, Mississippi	
Materials	Grades Qualified	X80	PQR Material	API 5L – X80 - PSL2
	Qualified Diameter Range	All	Diameter of PQR	24 inches
	Qualified Wall Thickness Range	from 0.188" through 0.750"	Wall Thickness of PQR	0.54 inches
API 1104 Material Groupings Qualified	Diameter (inch)	☐ OD < 2.75 ☐ 2.75 < OD ≤ 12.750 ■ OD ≥ 12.750		
	Wall Thickness (inch)	☐ WT < 0.188 ■ 0.188 ≤ WT ≤ 0.750 ☐ WT > 0.750		
	SMYS (psi)	☐ ≤ 42,000 ☐ 42,000 < SMYS < 65,000 ■ ≥ 65,000		
Joint Design				
Position of Pipe Axis	■ Horizontal (1G or 5G) ☐ Vertical (2G) ☐ Inclined (6G)	■ Fixed ☐ Rolled	Generic Bead Sequence 	
Minimum Number of Welders	☐ One ■ Two ☐ Other			
Line Up Clamp	Type: External or Internal	A minimum of 50% the root bead must be completed before removal of the clamp.		
Preheating	Gas torch, electric induction coils, or any other company approved method. Verify temperature using company approved method	Preheat Temp. Min.	200℉	
		Interpass Temp. Max.	N/A	
		Interpass Temp. Min.	200℉	

Time Between Passes	Root and Hot	5 minutes	Hot and First Fill		24 hours
Cleaning	The use of both hand and power tools is acceptable. The base material should be free of scale or anything else that may impede welding before the start of any welding. Each pass should be thoroughly cleaned and free from slag and spatter before the next pass is made.				
Defect Removal	The only area that may be repaired is the weld cap. Other repairs are to be addressed by qualified repair welding procedures. Defects in the cap should be removed by grinding and welding shall follow the guidelines set forth in this procedure.				
Post Weld Heat Treatment	☐ Yes ■ No				

Welding Pass	Root Bead	Hot	1st Fill	Fill(s)	Cap(s)
Welding Process	SMAW	SMAW	SMAW	SMAW	SMAW
Manual or Automatic	Manual	Manual	Manual	Manual	Manual
Direction of Welding	Vert. Down	Vert. Down	Vert. Down	Vert. Down	Vert. Down
Shielding Gas	N/A	N/A	N/A	N/A	N/A
Flow Rate	N/A	N/A	N/A	N/A	N/A
Wire Feed Speed	N/A	N/A	N/A	N/A	N/A
Deposition Type	Stringer	Stringer/Weave	Weave	Weave	Weave
Technique	Backhand	Backhand	Backhand	Backhand	Backhand
Filler Manufacturer	Lincoln	Lincoln	Lincoln	Lincoln	Lincoln
Filler Trade Name	Fleetweld 5P+	Shield-Arc 90	LH-D100	LH-D100	LH-D100
AWS Group	1	2	3	3	3
AWS Specification	A5.1	A5.5	A5.5	A5.5	A5.5
AWS Classification	E6010	E9010-G	E10045 P2 H4R	E10045 P2 H4R	E10045 P2 H4R
Polarity	DCEP	DCEP	DCEP	DCEP	DCEP
Electrode Diameter(s)	1/8"* or 5/32"	5/32"	5/32"	5/32"	5/32"
Arc Voltage (V)	20 - 32	20 - 30	18 - 26	18 - 26	18 - 26
Current Range (Amp)	100 – 150* 110 - 170	110 - 170	150 - 230	150 - 230	150 - 230
Travel Speed Range (inch/min)	5 – 15	5 – 15	5 – 20	5 – 20	5 – 20

Minimum number of Passes	Wall Thickness Range (in)	Number of passes	Minimum does not include stripper passes or split caps.
	≤ 0.188	3	
	> 0.188 to 0.25	4	
	> 0.25 to 0.50	5	
	> 0.50 to 0.750	7	

Notes	Weave the hot pass as necessary to prevent wagon tracks. Stripper passes are optional. Either a two or three bead cap is acceptable.		
Submittal	Author: Brad Etheridge	Title: Welding Engineer	
	Company: CC Technologies Inc. A DNV Company		Date: 5/30/08

Owner Approvals	Title	Name	Signature	Date

Company Name: Progressive Pipeline	Date: 5/14/08	Notes: Welding machine used was a Lincoln Red-D-ARC, D300K 3+3 Diesel	
Project Number:	Location: Meridian, MS @ Progressive Pipeline facility		
PQR #: 14a	Inside/Outside: Inside, with open bay doors		
WPS #: 14	Temperature: 78 inside shop		
Coupon #:	Recorded by: Brad Etheridge		

#	Material	OD	WT	Length	Joint ID #	Heat #	Test Position	Horizontal	Time between root and hot			2:55
1	API 5L - X80 - PSL2	24	0.54	2 feet	L	8791-1940-06	Preheat Temp	200	Time between hot and first			
2	API 5L - X80 - PSL2	24	0.54	N/A	R	8791-1943-06	Clamp Type	EXT	Start	9:41 AM	Stop	11:00 PM

Filler Metal #	Manufacturer	Trade name	Classification	Specification	Diameter	Batch/Lot #	Welder Information	
1	Lincoln	Fleetweld 5P+	E6010		5/32	11558962	Side A Welder	Randall Nunez
2	Lincoln	Shield-Arc 90	E9010	G	5/32	11558966	Welder Stamp	
3	Lincoln	LH-D100	E10045	P2 H4R	5/32	Lot Q2 863C	Side B Welder	Ken Abernathy
4							Welder Stamp	

Notes: External linup clamp used to tack 2 foot coupon onto long joint. The short side of the coupon is "R" and the long side is "L". Pass 2 and 3 were split passes; they were placed side by si

Pass Type/ Number / Welder ID	Filler #	Process	Travel Direction	Amps	Volts	Distance (in)	Arc Time (Sec)	Travel Speed (IPM)	WFS (IPM)	Heat Input (KJ/in)	Oscillation		Method	Welding Gas		Interpass Temp
											Freq cycle/sec	Width ( )	Stringer or Weave	Type	Flow ( )	( )
Root A	1	SMAW	VD	116	22	6	33	10.91		13.7			S			
Root A	1	SMAW	VD	118	23	2.25	14	9.64		16.5			S			
Root A	1	SMAW	VD	107	24	8	45	10.67		14.1			S			
Root B	1	SMAW	VD	128	23	9	54	10.00		17.3			S			
Root B	1	SMAW	VD	137	24	2.5	16	9.38		21.0			S			
Hot A	2	SMAW	VD	141	29	8	32	15.00		16.0			S/W			
Hot B	2	SMAW	VD	138	30	6	36	10.00		24.3			S/W			
Hot B	2	SMAW	VD	136	30	6	36	10.00		24.1			S/W			
Fill 1-1 A	3	SMAW	VD	194	22	7	50	8.40		30.4			S/W			
Fill 1-2 A	3	SMAW	VD	218	21	8.5	46	11.09		24.8			S/W			
Fill 1 A	3	SMAW	VD	208	24	13	51	15.29		19.2			S/W			

Pass Type/ Number / Welder ID	Filler #	Process	Travel Direction	Amps	Volts	Distance (in)	Arc Time (Sec)	Travel Speed (IPM)	WFS (IPM)	Heat Input (KJ/in)	Oscillation		Method	Welding Gas		Interpass Temp
											Freq cycle/sec	Width ( )	Stringer or Weave	Type	Flow ( )	( )
Fill 1-1 B	3	SMAW	VD	198	20	6.5	48	8.13		28.4			S/W			
Fill 1-3 B	3	SMAW	VD	216	20	8.5	48	10.63		24.4			S/W			
Fill 2-1 A	3	SMAW	VD	199	22	8.5	48	10.63		24.1			S/W			
Fill 2-3 A	3	SMAW	VD	215	20	8	43	11.16		23.1			S/W			
Fill 2-1 B	3	SMAW	VD	205	21	8.75	55	9.55		26.4			S/W			
Fill 2-2 B	3	SMAW	VD	199	20	12	55	13.09		17.8			S/W			
Fill 3-1 A	3	SMAW	VD	197	22	8.5	51	10.00		25.4			S/W			
Fill 3-3 A	3	SMAW	VD	176	21	8	35	13.71		16.1			S/W			
Fill 3-1 B	3	SMAW	VD	196	20	7.5	49	9.18		25.6			S/W			
Fill 3 B	3	SMAW	VD	201	20	8.75	49	10.71		21.9			S/W			
Fill 4-1 A	3	SMAW	VD	195	20	8	46	10.43		22.4			S/W			
Fill 4-3 A	3	SMAW	VD	215	20	9	36	15.00		17.2			S/W			
Fill 4-1 B	3	SMAW	VD	184	21	8.5	45	11.33		20.4			S/W			
Fill 5-1 A	3	SMAW	VD	195	21	8	42	11.43		21.4			S/W			
Fill 5 A	3	SMAW	VD	212	20	9	34	15.88		16.0			S/W			
Fill 5-1 B	3	SMAW	VD	205	20	13.5	53	15.28		16.1			S/W			
Fill 5 B	3	SMAW	VD	198	20	9.5	49	11.63		20.4			S/W			
Cap 1 A	3	SMAW	VD	205	20	7	42	10.00		24.6			W			

Pass Type/ Number / Welder ID	Filler #	Process	Travel Direction	Amps	Volts	Distance (in)	Arc Time (Sec)	Travel Speed (IPM)	WFS (IPM)	Heat Input (KJ/in)	Oscillation		Method	Welding Gas		Interpass Temp
											Freq cycle/sec	Width ( )	Stringer or Weave	Type	Flow ( )	( )
Cap 1 A	3	SMAW	VD	208	20	9.5	58	9.83		24.8			W			
Cap 1 B	3	SMAW	VD	198	20	9	37	14.59		16.3			W			
Cap 1 B	3	SMAW	VD	214	20	8	33	14.55		17.6			W			
Cap 2 A	3	SMAW	VD	201	20	7.5	44	10.23		23.6			W			
Cap 2 B	3	SMAW	VD	207	20	10	46	13.04		19.0			W			
Cap 2 B	3	SMAW	VD	212	20	7	27	15.56		15.9			W			

Bodycote

Bodycote Testing Group, Houston North Laboratory, 9925 Regal Row, Houston, Texas, 77040
Tel: 281-848-0270, Fax: 281-848-0275

ACCREDITED CERTIFICATE 1283.01

CC Technologies, Inc.
5777 Frantz Road
Dublin, OH
43017-1386

REF No O802887 : Issue 1
Ord No 82681591

Date Tested 06/02/08
Date Reported 06/02/08

Attn: Brad Etheridge

Item - 24" OD x 1/2" Wall girth welded pipe sample
WPS 14

Specification - API 1104 & Client Requirement

Cross Weld Tensile - API 1104

	Dimensions [in]	Area [in^2]	UTL [lbs]	UTS [psi]	Fracture Location	Fracture Type
001:Cross Weld	0.9770x 0.5440	0.5315	61872.0	116400	Base	Ductile
002:Cross Weld	0.9720x 0.5400	0.5249	61559.0	117300	Base	Ductile
003:Cross Weld	0.9810x 0.5330	0.5229	60659.0	116000	Base	Ductile
004:Cross Weld	1.0170x 0.5400	0.5492	63462.0	115600	Base	Ductile

Item 01: Quad 1
Item 02: Quad 2
Item 03: Quad 3
Item 04: Quad 4

Charpy Test - ASTM E 23

	Position	Dimensions [mm]	Denomination	Test Temp [°F]	Energy Absorbed [ft.lbf]	Average [ft.lbf]	Comments
005:Weld Centre Line	N/A	10x10x2V	N/A	32.0	79, 69, 70	72.7	See Below
006:Weld Centre Line	N/A	10x10x2V	N/A	-50.0	45, 39, 29	37.7	See Below
007:Weld Centre Line	N/A	10x10x2V	N/A	-80.0	15, 31, 14	20.0	See Below

Item 05: Percent Shear: 85, 80, 75 / Mils Lat Exp: 58, 53, 46
Item 06: Percent Shear: 25, 35, 10 / Mils Lat Exp: 33, 25, 21
Item 07: Percent Shear: 10, 20, 10 / Mils Lat Exp: 12, 24, 14

Bend Test - API 1104

	Position	Dimension [in]	Bend Angle [°]	Former Dia	Result	Comments
008:Face Bend	Quad 1	.500	180	3.5"	Acceptable	Nil

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Tel: 281-848-0270, Fax: 281-848-0275

ACCREDITED CERTIFICATE 1283.01

CC Technologies, Inc.
24" OD x 1/2" Wall girth welded pipe sample
WPS 14

REF No O802887 : Issue 1

Bend Test - API 1104

	Position	Dimension [in]	Bend Angle [°]	Former Dia	Result	Comments
009:Face Bend	Quad 2	.500	180	3.5"	Acceptable	Nil
010:Face Bend	Quad 3	.500	180	3.5"	Acceptable	Nil
011:Face Bend	Quad 4	.500	180	3.5"	Acceptable	Nil
012:Root Bend	Quad 1	.500	180	3.5"	Acceptable	Nil
013:Root Bend	Quad 2	.500	180	3.5"	Acceptable	Nil
014:Root Bend	Quad 3	.500	180	3.5"	Acceptable	Nil
015:Root Bend	Quad 4	.500	180	3.5"	Acceptable	Nil

Nick Break Test - API 1104

	Result	Comments
016:Weld	Unacceptable	Quad 1
017:Weld	Acceptable	Quad 2
018:Weld	Acceptable	Quad 3
019:Weld	Unacceptable	Quad 4

Approved By **Jim Blevins**

Jim Blevins
For and on authority of
Bodycote Testing Group

The failed two nick break tests were replaced by four acceptable retests of adjacent specimens. This is common practice in welding procedure qualification testing. The retest results can be found on the next page.

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Page 2 of 2

Bodycote MATERIALS TESTING
METAL TECHNOLOGY
Bodycote Testing Group, Houston North Laboratory, 9925 Regal Row, Houston, Texas, 77040
Tel: 281-848-0270, Fax: 281-848-0275

ACCREDITED CERTIFICATE 1283.01

Test Certificate

CC Technologies, Inc.
5777 Frantz Road
Dublin, OH
43017-1386

REF No O803170 : Issue 1
Ord No 82681591

Date Tested 06/09/08
Date Reported 06/09/08

Attn: Brad Etheridge

Item - 24" OD x 1/2" Wall girth welded pipe sample
WPS 14

Specification - API 1104 & Client Requirement

Nick Break Test - API 1104		
	Result	Comments
001:Weld	Acceptable	Quad 1
002:Weld	Acceptable	Quad 1
003:Weld	Acceptable	Quad 4
004:Weld	Acceptable	Quad 4

Certificate Comments

This is an electronic copy. See original certificate for photographs and figures where referenced.

Approved By Jim Blevins

Kevin J. Elliott
For and on authority of
Bodycote Testing Group

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Appendix H

Stress Analysis Report

Denbury Delta Pipeline Repair

7/28/2020

Denbury

MOTT MACDONALD

Document No. 20200724_MM_507102444_Pipeline Stress Analysis Report_EN_0015

PIPELINE STRESS ANALYSIS REPORT
DENBURY GULF COAST PIPELINES, LLC

DELHI PIPELINE REPAIR PROJECT

SATARTIA, MISSISSIPPI

Issue and Revision Record					
Rev	**Date**	**Originator**	**Checker**	**Approver**	**Description**
A	06/12/20	D. Dowling, PE	R. Sprague	R. Spence, PE	Draft
B	07/27/20	D. Dowling, PE	R. Sprague	R. Spence, PE	For Review
C	07/28/20	D. Dowling, PE	R. Sprague	R. Spence, PE	Final

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1 EXECUTIVE SUMMARY

Mott MacDonald (MM) has performed a stress analysis on the piping associated with the Delhi Pipeline incident/release on February 22, 2020. The piping was modeled using dimensions from Denbury supplied as-built records and Mott MacDonald survey data using AutoPIPE CONNECT Advanced Edition 12.02.00.14. The model was analyzed utilizing a combination of stress engineering methodologies and computational stress analysis.

Mott MacDonald performed a site-specific soil movement analysis that was used to establish soil loading on the pipeline for the stress analysis Utilizing guidance presented in the American Lifelines Alliance (guidance for the design of buried steel pipe July 2001) the Peak lateral earth pressure was calculated by utilizing Horizontal Bearing Capacity factors.

The mitigation procedure involved the identification and evaluation of critical areas against code allowable stress combinations. The results were compared using the stress ratio experienced by the component. A stress ratio greater than 1.0 represents components exhibiting stresses greater than the allowable stresses per ASME B31.4 (2016).

The following stress conditions were evaluated in the stress analysis:

- Load Cases
- Code Combinations
- Non-Code Combinations
- Thermal Analysis
- Soil Spring Analysis
- Soil Settlement Analysis
- Thermal Displacement

The geotechnical properties simulated within the models were reflective of the soil spring results presented in Section 7.2. Based on the models developed for this analysis, it is apparent that the soil movement present at the incident location was capable of exerting forces on the pipeline that exceed allowable limits. Mott MacDonald has reviewed the stress results with Denbury and developed solutions for the repair of the pipeline.

2 PROJECT DESCRIPTION

On February 22, 2020 the 24" CO2 Delhi Pipeline ruptured near a crossing of Mississippi Highway 433 approximately 1 (one) mile southeast of Satartia, MS. To help evaluate the cause of the release, Denbury contracted Mott MacDonald to gather information to support a thorough investigation. Mott MacDonald collected drone photogrammetry, terrestrial LIDAR and contracted PSI to perform a geotechnical investigation. Using this information Mott MacDonald performed a nodal evaluation using Bentley AutoPIPE CONNECT Advanced Edition Version 12.02.00.14 to determine stresses from external loading near the release of the Delhi Pipeline.

3 SCOPE

The stress model reflects the design of the project drawings and as-built information. The models were further analyzed using the various code and non-code guidelines listed in this section. These load combination guidelines can be generally categorized as follows:

- Hoop
- Sustained
- Occasional
- Expansion
- Combined Stress
- Unrestrained
- Support Loads

3.1 LOAD COMBINATIONS

Mott MacDonald analyzed the following code combinations as required by ASME B31.4. The loads are listed in Table 1 and 2 shown below. For allowable stress limits definition, see Appendix A.

Table 1 – Code Combinations

Case No.	Load Case Combinations	Category	Load Description
1	Max P	Hoop	Hoop Stress; ASME B31.4 Para. 402.3.5
2	GR + Max P	Sustained	Stress due to Sustained Loads; ASME B31.4 Para 402.6
3	Amb to T1	Expansion	Thermal stress range from restraint temp to the maximum temperature; ASME B31.4, Para. 402.5
7	Max Range	Expansion	Thermal stress range from the minimum temp to the maximum temperature (refer to all combinations); ASME B31.4, Para. 402.5
8	SUS + U1	Sustained	Stress due to Sustained Load and Soil Settlement; Sustained ASME B31.4, Para. 402.6

4 DESIGN INPUTS AND RESOURCES

The following resources and reports were utilized to provide design information and engineering inputs to various portions of the stress calculations and analysis:

Codes, Standards and Regulations - Applicable Federal, Provincial and Territorial Regulations, Codes and Bylaws – Latest Edition

1. ASME B31.4, Pipeline Transportation Systems for Liquids and Slurries
2. Federal Energy Regulatory Commission (FERC), Onshore Pipeline Regulations

External References

1. 49 CFR Part 195, Transportation of Hazardous Liquids by Pipeline
2. American Lifelines Alliance, Guidelines for the Design of Buried Steel Pipe, 2001
3. Peng, L.-C., & Peng, T.-L. (2009). Pipe Stress Engineering. New York, NY: The American Society of Mechanical Engineers.

The Project Data Sheet (Table 3) and additional variables (Table 4) defined below contain the design information and engineering inputs that were used for the stress calculations and analysis:

Table 3 – Project Data Sheet Variables

General Project Information			
Project Name:	Delhi Pipeline Repair Project	**Project No:**	507102444
Description:	Pipeline Repair Project		
Pipeline Data			
General Location	Satartia, MS		
MOP [psig]	2160		
Maximum Operating Temperature [˚F]	Maximum: +120˚F		
Pipe Data	API 5L 24" – 0.469" W.T., X80		
	API 5L 24" – 0.540" W.T., X80		
Pipeline Data			
Minimum Operational Design Temperature [˚F]	Above grade:	32˚F	
	Below grade:	70˚F	
Design Temperature [˚F]	Minimum:	-20˚F	
	Maximum:	120˚F	
Pipe Installation Temperature [˚F]*	60˚F		

* Based on average low temperature for this region during the month of construction.

5 ANALYSIS ASSUMPTION SUMMARY

The facility stress analysis was carried out using the following assumptions.

- Minimum Installation temperature of 60˚F.
- All welds connecting assembly piping are defect free
- Pipe is homogeneous and does not contain defects.
- Strains due to welding were ignored for this analysis.
- Bolt up strains are negligible.
- Small bore attachments do not govern the design.
- Dynamic Fluid loads were ignored for this analysis.
- Pressure and viscous drag effects were ignored for this analysis.
- All dynamic loads applied internally/externally were minimal.
- All material properties were assumed to be linear and elastic.
- Soil is represented by discrete linear elastic perfectly plastic springs.
- Welded branch connections consist of an ASME B31.4 listed fitting and is constructed with adequate strength.

6 PROJECT ANALYSIS

6.1 SOILS

Soil data used for the analysis was taken from soil bore samples provided by Intertek-PSI USA. For each USCS soil type, average values were developed for the peak and remolded undrained shear strengths and typical values were used for the soil densities. This data was applied to all below grade piping by centering the soil blocks at each of the shear vane locations. American Lifelines Alliance (ALA) soil spring calculations were generated manually using the ALA formulas at a depth appropriate for the location and spacing appropriate for the pipe size. The soil spring summary is included in Table 4.

Table 4 – Soil Spring Summary			
Stiff Clay – Under Road (SCUR)			
Total Unit Weight below pipe (lb/ft³)	**100**		
Dry Unit Weight above pipe (lb/ft³)	**97**		
Effective Unit Weight above pipe (lb/ft³)	**100**		
Soil Cohesion (psf)	**1000**		
Friction Angle (deg)	**0**		
Direction Specific Soil Spring Values			
	K1 (lbf/in/ft)	P1 (lbf/ft)	Yield Disp. (in)
Trans. Horizontal	5780.82	13873.96	2.4
Longitudinal	14566.52	4369.96	0.3
Trans. Vertical Up	4166.67	20000	4.8
Trans. Vertical Dn	2643.55	12689.02	4.8
Soft Clay – Embankment (SOE)			
Total Unit Weight below pipe (lb/ft³)	**100**		
Dry Unit Weight above pipe (lb/ft³)	**97**		
Effective Unit Weight above pipe (lb/ft³)	**100**		
Soil Cohesion (psf)	**250**		
Friction Angle (deg)	**0**		
Direction Specific Soil Spring Values			
	K1 (lbf/in/ft)	P1 (lbf/ft)	Yield Disp. (in)
Trans. Horizontal	920.34	3313.22	3.60
Longitudinal	3941.42	1576.57	0.40
Trans. Vertical Up	833.33	4000	4.80
Trans. Vertical Dn	871.78	4184.57	4.80
Soft Clay – Landside Edge (LSE)			
Total Unit Weight below pipe (lb/ft³)	**100**		
Dry Unit Weight above pipe (lb/ft³)	**97**		
Effective Unit Weight above pipe (lb/ft³)	**100**		
Soil Cohesion (psf)	**200**		
Friction Angle (deg)	**0**		
Direction Specific Soil Spring Values			
	K1 (lbf/in/ft)	P1 (lbf/ft)	Yield Disp. (in)

Trans. Horizontal	657.98	2470.98	3.76
Longitudinal	3171.19	1268.48	0.40
Trans. Vertical Up	416.67	2000.00	4.8
Trans. Vertical Dn	639.78	3070.94	4.8
Stiff Clay – Outside Landslide (OLS)			
Total Unit Weight below pipe (lb/ft³)		**100**	
Dry Unit Weight above pipe (lb/ft³)		**97**	
Effective Unit Weight above pipe (lb/ft³)		**100**	
Soil Cohesion (psf)		**250**	
Friction Angle (deg)		**0**	
Direction Specific Soil Spring Values			
	K1 (lbf/in/ft)	P1 (lbf/ft)	Yield Disp. (in)
Trans. Horizontal	1072.47	3088.72	2.88
Longitudinal	3941.42	1576.57	0.40
Trans. Vertical Up	520.83	2500.00	4.80
Trans. Vertical Dn	746.79	3584.57	4.80

6.2 ENVIRONMENTAL LOADING

During the initial site visit, Mott MacDonald noticed evidence of soil movement along the ROW. The soil failure planes in the ROW extended approximately 900 ft at varying angles from 45˚ to 90˚. Figure 1 and Figure 2 below show 3D photogrammetry scans taken of the ROW and displays the long linear failures.



FIGURE 1: SOIL MOVEMENT PLAN VIEW



FIGURE 2: SOIL MOVEMENT ROW VIEW

The depth of the soil failures varied throughout the ROW, but as shown in Figure 3, the high level of detail captured with the 3D photogrammetry allowed for accurate measurements.

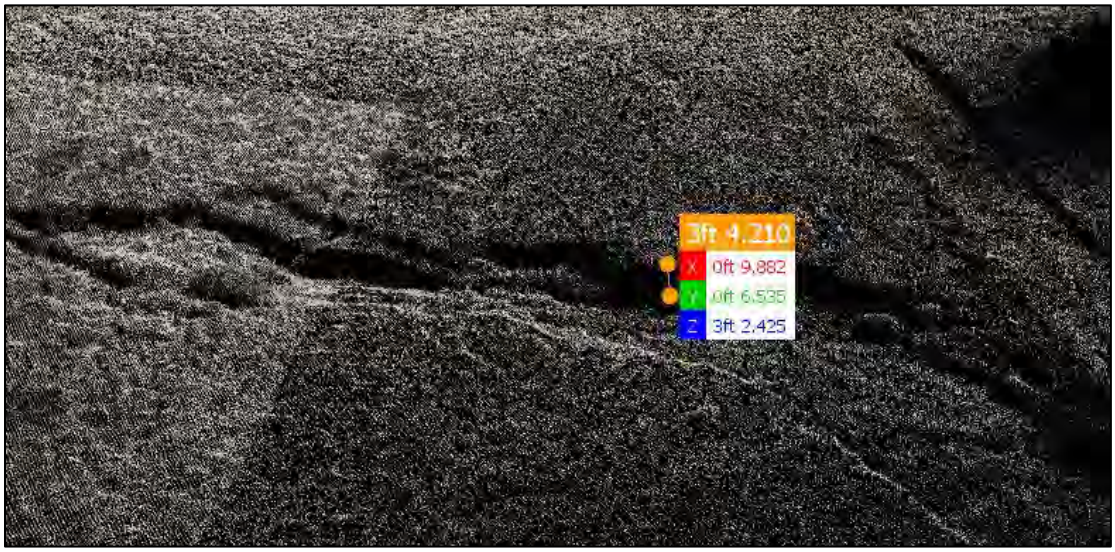


FIGURE 3: SOIL FAILURE DEPTH

To model the external force due to soil movement appropriately, Mott MacDonald's geotechnical team performed a soil movement analysis. Based upon information of the soil properties, pipeline burial depth and relative slope movement a calculation of the maximum earth pressure which could be applied to the pipe was developed. This value represents the maximum force per unit length which the soil could apply to the pipeline.

Note that this calculation method is applicable to small strain (pipe-soil localized strain) situations. Utilizing guidance presented in the American Lifelines Alliance

(guidance for the design of buried steel pipe July 2001) the Peak lateral earth pressure was calculated by utilizing Horizontal Bearing Capacity factors. This calculation resulted in a value of **2,800lb/ft** (force per foot length of pipe) being the maximum force the moving soil could apply to the pipeline at small strain. For this calculation, the following assumptions were made:

- Ground surface to spring line = 5ft
- Soil cohesion = 200 psf
- Soil angle of internal friction = zero
- Applied distributed load value = the maximum force per unit length of pipe that the soil could transmit to the pipe. This force may not have fully mobilized if pipe failed before sufficient earth strain occurred to reach this maximum force.
- Calculations follow American lifeline alliance, guideline for the design of buried steel pipe 2001 (B-2).

Utilizing the as-built data in conjunction with the photogrammetry, the Mott MacDonald team was able to provide varying environmental loading conditions for the pipeline. Table 6 below presents the soil classification (from geotechnical investigations performed by PSI), applied environmental loads and general soil description.

Table 6 – Environmental Loading

Station	Soil Classification	Applied Distributed Loads	General Description
361+00 -> 349+80	[A] Stiff Clay		Stronger soils restraining movements at boundary
349+80 -> 348+50	[B] Stiff Clay		Stronger soils with deep burial from highway embankment causing strong pipe restraint
348+50 -> 347+00	[C] Soft Clay		Softer soils down from highway embankment.
347+00 -> 346+50	[D] Soft Clay	2,800 lb/ft	Moving landslide body edge
346+50 -> 340+00	[E] Soft Clay [Horiz. Strength = 0]	2,800 lb/ft	Moving landslide body middle

340+00 -> 339+00	[D] Soft Clay	2,800 lb/ft	Moving landslide body edge
339+00 -> 338+50	[C] Soft Clay		Softer materials outside landslide body
339+00 -> 325+00	[A] Stiff Clay		Stronger soils restraining movements at boundary

The distributed loads were applied in the model based on understanding of the topography in the area as shown in the Figure 4 below.

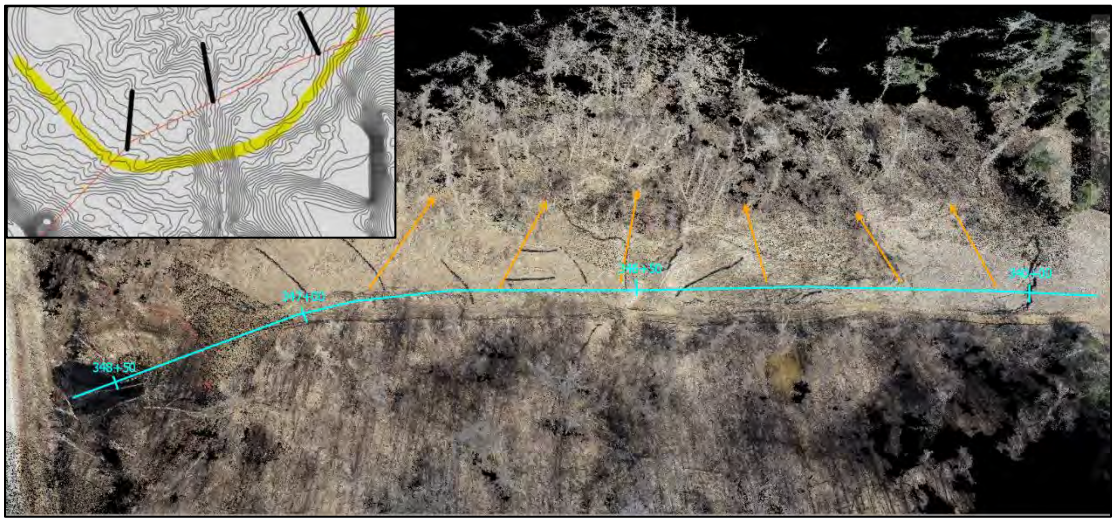


FIGURE 4: SOIL MOVEMENT DIRECTION

□□□ □□□r□□□□□d□d□□ □□ □□□□ □□□□ □□□□ r□ □□□□d □□r □□□ □□□□□□□□ □

- 347+00 -> 346+50 Azimuth 005 (5° east of north)
- 346+50 -> 340+00 Azimuth 350 (10° west of north)
- 340+00 -> 339+00 Azimuth 335 (25° west of north)

7 ANALYSIS RESULTS

7.1 PIPELINE ANALYSIS

The pipeline was modeled as per the above listed design information. Though not all of the model is shown the below Figure 5, Figure 6 and Figure 7 display the area of concern.

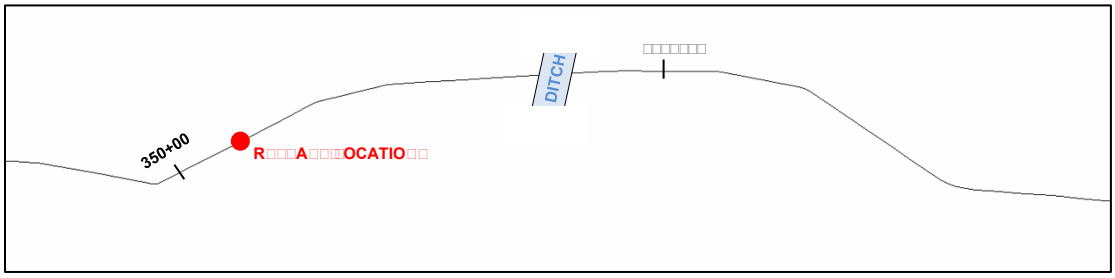


FIGURE 5: AUTOPIPE MODEL

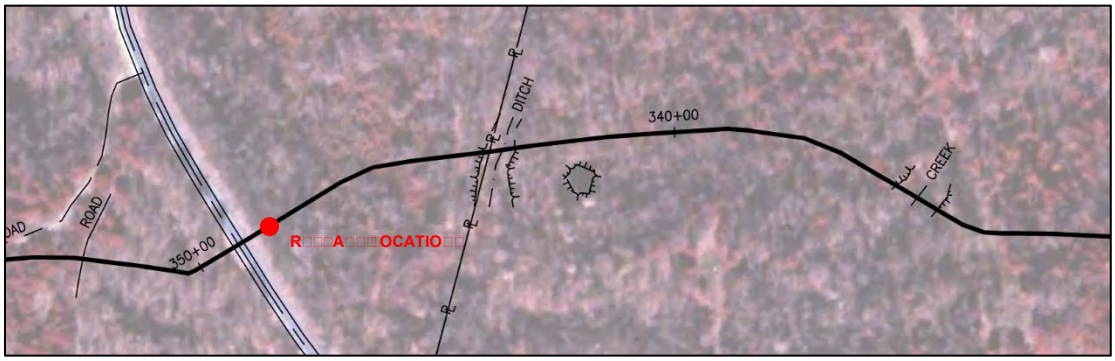


FIGURE 6: AS-BUILT ALIGNMENT SHEET

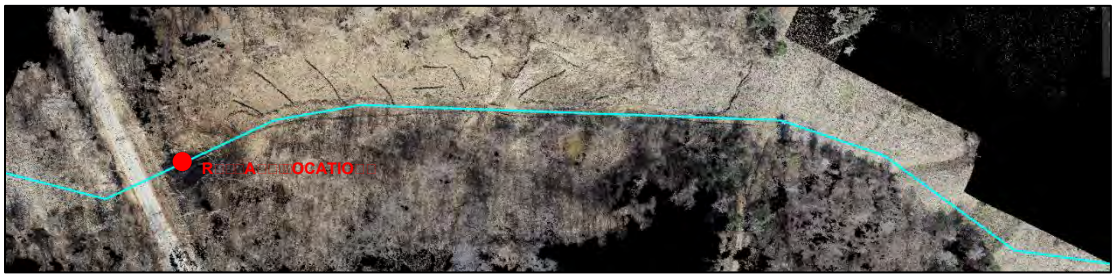


FIGURE 7: MODEL OVERVIEW

The road crossing utilized thicker pipe and was modeled as per the as-built alignment sheet, as shown in Figure 8.1.3.

- 24"-0.540 in – API 5LX-X80 – Cyan
- 24"-0.469 in – API 5LX-X80 – Red

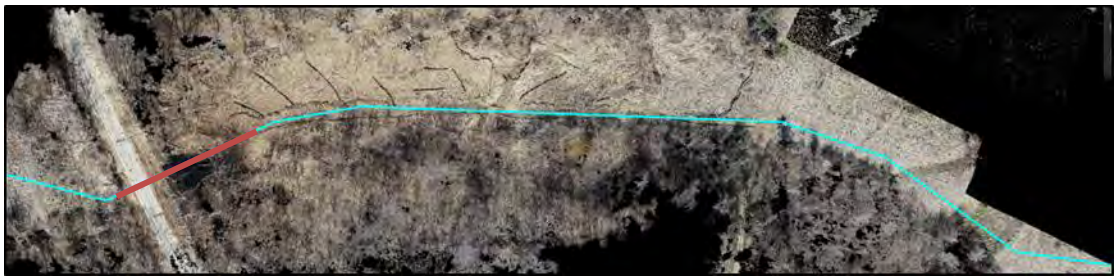


FIGURE 8: PIPE IDENTIFIER

Below shows the soil modeling based on the guidelines set forth in Section 7.1. The colors shown below denote the division in the soil as defined in Table 6.



FIGURE 9: SOIL IDENTIFIERS

The piping model was analyzed at low temperature limits defined by the project data sheet. At this location, the entire design was modelled at installation temperature, 60ºF. The effects of thermal expansion due to temperature within the pipeline as well as environmental changes are negligible.

The most significant stress values came from the external loading from soil movement. To establish a baseline, the stress team determined the maximum horizontal distributed load the pipe could withstand without rupture. Once the geotechnical team determined the estimated distributed loads, these numbers were compared. The comparison showed that the geotechnically determined loads exceeded the allowable horizontal distributed loads by more than 300 lbs/ft (2,800 lbs/ft vs. 2,475 lbs/ft).

As shown in Figure 10 below, the pipeline release location experienced excessive stress. The focal point of the stress at this location shows a maximum stress ratio of 1.43.

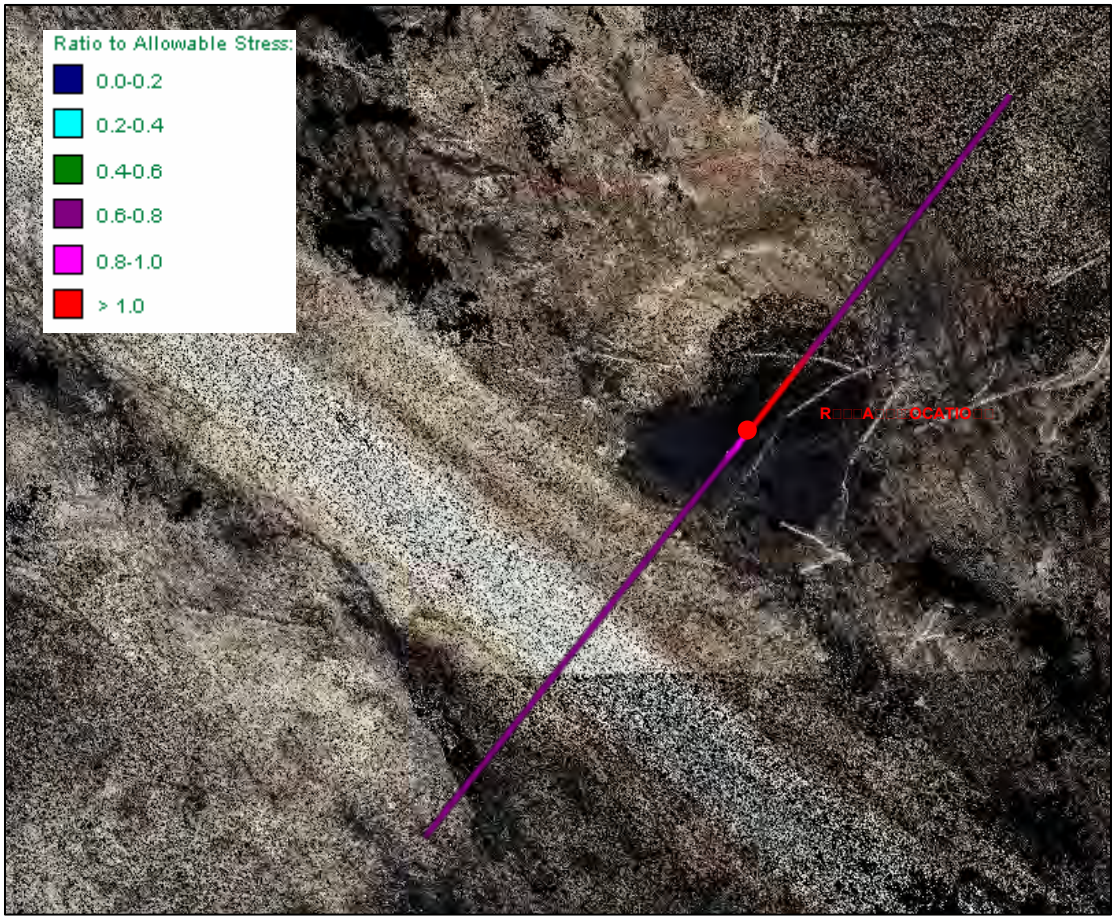


FIGURE 10: FAILURE LOCATION

[illegible] r[illegible] [illegible] [illegible] [

8 CONCLUSION

Mott MacDonald performed a nodal analysis to analyze the Denbury Delhi Pipeline for stress concerns surrounding the rupture area. Key information (i.e. soil bores, topography, LIDAR scans) was gathered, interpreted and used in the evaluation.

The initial task performed by the stress team was to determine the maximum distributed load due to soil movement the pipeline could withstand under the given environmental conditions without exceeding the allowable stress. The results of this study found that at 2475 lb/ft certain areas began to exceed the allowable stress.

Utilizing the geotechnical investigation results and drone topography, the geotechnical team performed a soil movement analysis. The analysis concluded that the soil movement could project a load of 2800 lb/ft on the pipeline.

Under the provided 2800 lb/ft condition, the stress analysis showed the area of rupture on the Delhi Pipeline could have experienced stress ratios up to 1.43 or 43% greater than the allowable stresses under ASME B31.4 code.

The results of the analysis concluded that the soil movement found on the Delhi Pipeline Right-of-Way could induce axial stresses sufficient to cause an overload condition in the pipeline near the incident location.

9 RECOMMENDATION

Based on the results of the evaluation, Mott MacDonald recommends to stress relieve the pipeline by exposing approximately 135 feet of pipe near the opposing soil failure plane(at 339+00) then cut and replace a length of pipe.

The length of stress relieving area was determined by evaluating the over stressed model from the previous analysis. Using the deflection curve and stress ratio visuals in conjunction, the stress team identified a length of pipeline that exhibited a peak in stress values near the soil failure plane or at approximately 339+00.

On the upstream side of 339+00, the stress values decrease from 1.51 to 1.2 where they remained as it progressed upstream. These values are acceptable given these forces were due to axial stress and therefore were relieved when the pipeline failed.

The stress on the downstream side of 339+00 was caused by the restrained/unrestrained boundary condition created by the soil movement. This bending stress is the target of the relief exercise. The area shown in Figure 12 below, show a sharp rise in stress from a ratio of 0.70 to 1.51 in less than 50 ft. This boundary condition at the soil failure plane did not relieve after the pipeline failure and will have to be repaired.

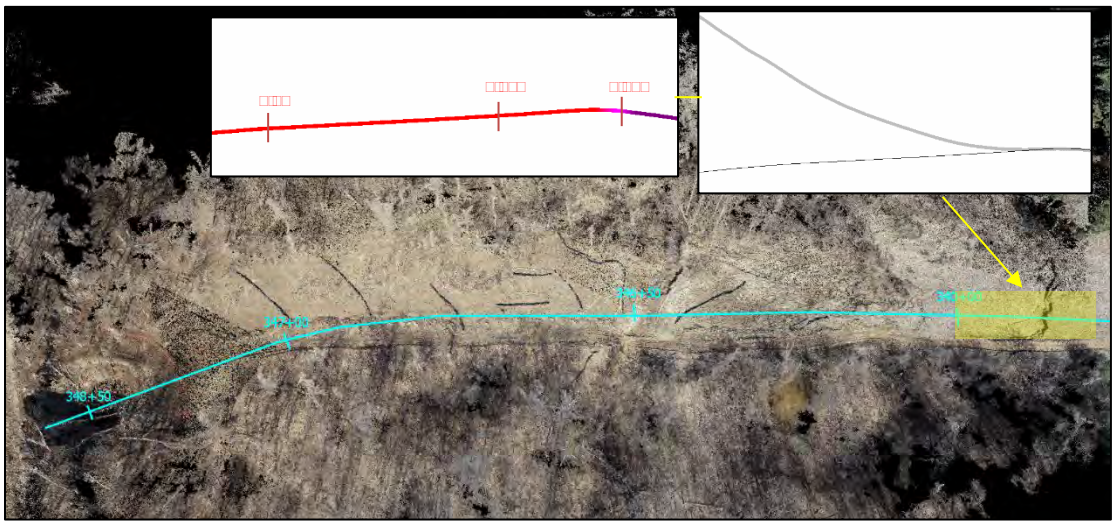


FIGURE 12: RECOMMENDED

Exposing at least 135 ft and removing and replacing as least a 10 ft section of pipe as recommended in the repair alleviates the overstressed boundary condition left by the soil movement and allows for safe transition between the two soil conditions. This recommendation is with the understanding that the remainder of the area of concern will be hydrotested as per ASME B31.4 to ensure the integrity of the pipe that experienced high tensile loads.

APPENDIX A: SUPPORTING INFORMATION

TEMPERATURE FOR SATARTIA, MS

History

September Data	Choose another month: September Submit		
Averages			
Average High Temperature	31 °C	Average Morning Relative Humidity	94%
Average Low Temperature	18 °C	Average Afternoon Relative Humidity	55%
Average Mean Temp	24 °C	Typical Sky Cover	CLR
Average Dew Point	19 °C	Average Precipitation (US Only)	91 mm
Average Windspeed	13 km/h	Average Snowfall (US Only)	0.00 cm
Average Wind Direction	SE		
Daily Counts			
Days With Precipitation	8	Days With Snow	0
Days With Thunderstorms	5	Days With Lows Below Freezing	0
Days With Fog	20	Days above 90° F (32.2° C)	12
Records			
Record High	40 °C	Record 24-hour Snowfall	0.00 cm
Record Low	2 °C	Record Monthly Rainfall	244 mm
Record Wind Speed	83 km/h	Record 24-hour Rainfall	117 mm
Record Monthly Snowfall	0.00 cm	Record Minimum Monthly Precipitation	15 mm

[illegible]

ALLOWABLE STRESS LIMITS

HOOP STRESS

Hoop Stress (ASME B31.4 - 2016)

The hoop stress (Shoop) is calculated per A402.3.5

$$S_h = (P_i - P_e) \cdot \frac{D}{2t} \leq F_1 ST \quad (1)$$

$$\left[S_h = (P_i - P_e) \cdot \frac{D}{2000t}\right] \leq F_1 ST \quad (2)$$

$$S_h = (P_i - P_e) \cdot \frac{D-t}{2t} \leq F_1 ST \quad (3)$$

$$\left[S_h = (P_i - P_e) \cdot \frac{D-t}{2000t}\right] \leq F_1 ST \quad (4)$$

Where,

D is the nominal outside diameter of pipe, in. (mm)

F1 is the hoop stress design factor from Table A402.3.5-1

Pe is the external pressure, psi (kPa)

Pi is the internal pressure, psi (kPa)

S is the yield strength, psi (MPa)

Sh is the hoop stress, psi (MPa)

T is the temperature derating factor, found in the Results Model Options dialog

t is the nominal wall thickness, in. (mm)

Notes:
1. Equation 1 should be used if D/t is greater than or equal to 30. Equation 3 should be used if D/t is less than 30.
2. Equations 2 and 4 are the SI equivalents of equations 1 and 3, respectively.
3. In AutoPIPE, pressure data is gage pressure. In other words, $P_{AutoPIPE} = P_i - P_e$

SUSTAINED LOADS

Restrained

Calculations for restrained piping take into account flexibility and stress intensification factors of piping components. Longitudinal stress in restrained piping is calculated as:

$$S_L = S_E + \nu S_H \pm \frac{M}{Z} + \frac{F_a}{A}$$

Where sE is the restrained **thermal expansion stress**, sH is the **hoop stress** and A is the cross sectional area of steel.

When the "Use rest. long. code eq" option is not taken into account, AutoPIPE considers the actual restraint condition from supports and soil stiffness for longitudinal stress calculation.

$$S_L = MAX(\sigma_a + \sigma_b;\ \sigma_a - \sigma_b)$$

Where

$$\sigma_a = \frac{P_i D}{4t} - \frac{F_a}{A}$$

$$\sigma_b = \frac{\sqrt{M_i^2 + M_o^2}}{Z}$$

AutoPIPE reports sL and the allowable stress (0.90 Sy), where Sy is the specified minimum yield strength. If more than one operating load condition exists there may be more than one P value. Results are output for the operating load condition which produces the smallest margin (i.e., smallest value of 0.90· Sy, sL) at each point.

Note: AutoPIPE does not use the exact code equation for the longitudinal pressure stress. The code requires the use of vSH, whereas AutoPIPE uses PD/4t, which is approximately equal to 0.5SH.

THERMAL EXPANSION

Thermal Expansion Stress Range (ASME B31.4 - 2016)

Unrestrained

The stress due to defined thermal expansion ranges (sE) is calculated per the equation listed in para. 419.6.4(c) of the code, and as shown in Equation I.5-5:

$$S_E = \sqrt{S_b^2 + 4 \cdot S_t^2} \quad \text{(I.5 5)}$$

where:

$$S_b = \frac{\sqrt{(i \cdot M_{it})^2 + (i_o \cdot M_{ot})^2}}{Z_{cor}} \quad \text{(I.5 6)}$$

and:

$$S_t = \frac{M_{tt}}{2 \cdot Z_{cor}} \quad \text{(I.5 7)}$$

AutoPIPE reports sE, and the allowable stress (SA).

Restrained

The thermal expansion stress in restrained pipe is calculated as shown in Equation I.5-8:

$$S_E = E\alpha(T_1 - T_2) \quad \text{(I.5 8)}$$

Where E is the cold modulus of elasticity, a is coefficient of thermal expansion, in./in./F (mm/mm/C), T1 is the temperature of the pipe at installation or completion of final tie-in, F(C), and T2 is the operating temperature, F(C).

AutoPIPE reports sE and the allowable stress (0.90 Sy), where Sy is the specified minimum yield strength of the pipe material, in psi (MPa).

Appendix E CTEH Air Monitoring Summary Report

CTEH®

THE SCIENCE OF READY℠

DENBURY RESOURCES

AIR MONITORING REPORT

Satartia, Mississippi

Carbon Dioxide Pipeline Release

February 22-23, 2020

Project #112628

Report Submitted on June 05, 2020

1.0 INTRODUCTION

On February 22, 2020, CTEH®, LLC (CTEH) responded to a request from Denbury Resources (Denbury) to provide toxicology and air monitoring support following a carbon dioxide (CO_2) pipeline release near the town of Satartia, Mississippi. The village of Satartia was evacuated at approximately 2100 Central Standard Time (CST)[1] by local emergency management personnel and first responders. At 2230 on February 22, a CTEH consultant arrived onsite with air monitoring instrumentation and began monitoring areas in and around the village of Satartia for the presence of CO_2. As the potential for residual hydrogen sulfide (H_2S) resided in the line and complaints of an odor were received, monitoring was also conducted for the presence of H_2S. Additional CTEH personnel arrived and conducted air monitoring throughout the community. Once CO_2 levels returned to near ambient within the community, CTEH personnel conducted clearance monitoring within eighteen homes and three churches and their associated buildings. Denbury demobilized CTEH once ambient CO_2 concentrations within those structures were sustained below 5,000 parts per million (ppm) and residents had returned to their homes. This report summarizes data collected from February 22 through February 23.

2.0 METHODS

2.1 Handheld Real-Time Air Monitoring

Prior to CTEH's arrival, an air Sampling and Analysis Plan (SAP, Attachment A) was developed for worker monitoring, community monitoring, and site characterization. Based on site characteristics and associated scope of work, no worker monitoring or site characterization readings were recorded. In accordance with the SAP, CO_2, H_2S, and oxygen (O_2) concentrations were monitored using handheld real-time instrumentation throughout the community as well as within homes of residents who requested monitoring prior to re-occupancy. Monitoring was performed using RAE Systems by Honeywell MultiRAE Pro instruments. All instrumentation was calibrated prior to use.

Community monitoring was delineated into two subcategories: community real-time monitoring and indoor assessment real-time monitoring. Community real-time monitoring consisted of roaming handheld monitoring performed outdoors and downhill from the incident site, including checkpoints and church parking lots. Indoor assessments consisted of real-time monitoring within residences and church buildings potentially affected by the incident at the request of community members. If the initial indoor assessment resulted in CO_2 levels above the CTEH project-specific action level, another indoor assessment was performed after allowing the building to air out. For example, if real-time monitoring during the initial indoor assessment detected CO_2 levels above the CTEH project-specific action level, the windows and doors were opened and the occupant was advised not to re-enter until CO_2 concentrations returned to ambient levels, as determined by another indoor assessment. The ambient levels CO_2 in the non-industrial

[1] All other times referenced in the report will be CST unless otherwise delineated.

indoor environments may have a variety of sources, including human metabolism, and CO_2 levels can vary based on the number of people present, how long the area has been occupied, and the amount of outdoor fresh air entering the area.

2.2 Protective Action Criteria and CTEH Project-Specific Action Levels

The U.S. Department of Energy's Subcommittee on Consequence Assessment and Protective Actions (SCAPA) has established Protective Action Criteria (PACs) for over 3,300 chemicals for planning and response to uncontrolled releases of hazardous chemicals (DOE/SCAPA 2018). These criteria, combined with estimates of actual exposure, provide information necessary to evaluate chemical release events for the purpose of taking appropriate protective actions. During an emergency response, these criteria may be used to evaluate the severity of the event and to inform decisions regarding what protective actions may be taken. The PAC values for the chemicals of concern for this response are provided in Attachment B. The PAC-1, -2, and -3 for CO_2 are 30000, 40000, and 50000 ppm, respectively. For comparison, the American Conference of Governmental Industrial Hygienists (ACGIH) threshold limit values (TLVs) are also included in Attachment B. Although the TLVs are intended for occupational daily work shift exposures over an entire working lifetime, the literature regarding reviewed human studies involving CO_2 within the TLV documentation were referred to and will be discussed in Section 4.0. The current ACGIH TLV-Time Weighted Average (TLV-TWA) for CO_2 (5,000 ppm) is based on the lack of inhalation toxicity data in humans at this level and the ACGIH TLV-Short Term Exposure Limit (STEL) for CO_2 is 30,000 ppm. The TLV documentation cites data indicating elevated concentrations (above 50,000 ppm) of CO_2 can produce '*mild narcotic effects, stimulation of the respiratory center, and asphyxiation*', depending on exposure duration and conditions (ACGIH 2001). CTEH project-specific action levels for both monitoring plans were set at 5,000 ppm (sustained for 15 minutes) for CO_2 based on the ACGIH TLV-TWA (well below PAC-1 and ACGIH TLV-STEL), and the action level for H_2S was set at 1 ppm, which was also based on the ACGIH TLV-TWA.

In accordance with the SAP, CTEH project-specific action levels were used to provide information for assessing need to take corrective action to limit the potential of exposure. These values do not replace community exposure standards or guidelines but are intended to be a concentration limit that triggers a course of action to better address public safety.

3.0 RESULTS

Handheld real-time air monitoring results are summarized by subcategory in Tables 1 and 2: community real-time air monitoring and indoor assessment real-time air monitoring. Maps of the site location, community real-time monitoring locations, and indoor assessment real-time air monitoring locations are provided in Attachment C.

Table 1 Community Real-Time Air Monitoring Results

Analyte	Instrument	Number of Readings	Number of Detections	Concentration Range[1]
CO_2	MultiRAE Pro	108	108	100 – 26,000 ppm
H_2S	MultiRAE Pro	85	0	< 0.1 ppm
O_2	MultiRAE Pro	84	84	20.9 - 21.1 %

[1]A value preceded by the "<" symbol is considered below the instruments limit of detection and the value to the right is the instrument detection limit. ppm = parts per million.

Table 2 Indoor Assessment Real-Time Air Monitoring Results

Analyte	Instrument	Number of Readings	Number of Detections	Concentration Range[1]
CO_2	MultiRAE Pro	30	30	200 – 28,000 ppm
H_2S	MultiRAE Pro	18	0	< 0.1 ppm
O_2	MultiRAE Pro	8	8	20.9 %

[1]A value preceded by the "<" symbol is considered below the instruments limit of detection and the value to the right is the instrument detection limit. ppm = parts per million.

4.0 DISCUSSION

CTEH performed real-time air monitoring using handheld real-time instrumentation. Results of handheld real-time air monitoring are discussed below.

No H_2S detections were observed during handheld real-time air monitoring in the community or indoor assessment real-time monitoring. O_2 concentrations were not observed below 20.9%. Outdoor CO_2 concentrations ranged from 100 through 26,000 ppm in the community. Five detections of CO_2 exceeded 5,000 ppm. Residents of the community were already evacuated when these detections were observed.

After outdoor community CO_2 levels were sustained continually measured below 5,000 ppm, initial indoor assessment real-time monitoring was performed inside residences and church buildings potentially impacted by the incident, at owners'/occupants' request. During initial indoor assessment real-time monitoring, CO_2 concentrations ranged from 200 through 28,000 ppm, with six detections exceeding 5,000 ppm. In these instances, occupants of these structures were advised to open doors and windows and not to occupy those structures prior to re-assessment.

Indoor assessment real-time monitoring was performed for six structures to further assess homes and church buildings in which CO_2 concentrations above 5,000 ppm were observed during initial indoor assessment real-time monitoring. No readings of CO_2 greater than 3,500 ppm were recorded following any of these re-assessments.

While CTEH personnel were onsite, values of CO_2 were recorded up to 28,000 ppm. A notice issued by the Satartia Fire Department advising residents and members of the general public to evacuate the area was active during the period in which elevated CO_2 concentrations were observed. The ACGIH TLV documentation reports several effects resulting from inhalation of elevated CO_2 concentrations, including mild narcotic effects (30,000 ppm) and unconsciousness (> 50,000 ppm). Additional reports of human exposure to CO_2 indicate 20,000 ppm for several hours may cause transient effects, such as headaches, and exposure to up to 5,500 ppm for six hours may cause *no noticeable symptoms* (ACGIH 2001). To the best of CTEH's knowledge, including several interactions with community members during this response, there were no reports of hospitalization due to loss of consciousness within the community.

In conclusion, during the time period CTEH was present, the CO_2 concentrations observed were below the ACGIH TWA-STEL and PAC values and thus were not detected at levels that would be expected to cause anything other than transient effects, if any, or pose a chronic health risk to members of the community.

5.0 REFERENCES

ACGIH (2001) Carbon dioxide: TLV® Chemical Substances 7th Edition Documentation. Cincinnati, Ohio: American Conference of Governmental Industrial Hygienists.

ACGIH (2019) Guide to Occupational Exposure Values. Cincinnati, Ohio: American Conference of Governmental Industrial Hygienists.

DOE/SCAPA (2018) Protective Action Criteria (PAC): Chemicals with AEGLs, ERPGs, & TEELS: Rev. 29A. Washington, DC: U. S. Department of Energy. Available at:https://www.energy.gov/ehss/protective-action-criteria-pac-aegls-erpgs-teels-rev-29-chemicals-concern-may-2016.

Attachment A

Sampling and Analysis Plan

CTEH®
THE SCIENCE OF READY℠

Carbon Dioxide Pipeline Release

Satartia, MS

Air Sampling and Analysis Plan (SAP)

Version 1.0

Prepared on Behalf of:

Denbury Resources

Prepared By:

CTEH, LLC

5120 Northshore Drive

Little Rock, AR 72118

501-801-8500

February 22, 2020

	Name/Organization	Signature	Date Signed
Prepared by:	Pamella Tijerina, Ph.D.	PBT	02-22-2020
Reviewed by:	Eric Allaby		02-22-2020
Approved by:			
Approved by:			

Air Monitoring Strategy

CTEH® is focusing on the chemicals below chosen below because they are among the most important and readily monitored hazards of a carbon dioxide (CO_2) release. It is notable, however, that some chemicals may also be included within the SAP on the basis that some uncertainty exists during incidents and monitoring for these chemicals is necessary to ensure that a hazard does not exist. Monitoring for some chemicals or indicators of the presence of CO_2 may be conducted less frequently or even discontinued as product-specific information becomes available or as initial air monitoring results indicate that these chemicals and indicators do not pose a health concern.

The strategy is to utilize three broadly defined monitoring plans: **1)** Work Area Monitoring; **2)** Community Monitoring; and **3)** Site Assessment. Work Area monitoring will generally take place in those areas where workers are actively performing/supporting remediation operations. The readings will generally be taken at a height consistent with that of the workers breathing zone and in close proximity to workers without interfering or obstructing their remediation tasks. Community Monitoring may take place in those residential and/or commercial locations immediately surrounding the incident site, not necessarily currently occupied by members of the community. Unlike Work Area and Community monitoring, Site Assessment does not necessarily represent ambient air monitoring near breathing zone level. Site Assessment may involve a variety of different monitoring tasks intended to provide information that may help to delineate the nature and extent of the release (e.g. fence line monitoring, worst case determination, container head space, ground level, etc.).

Free-roaming handheld real-time air monitoring may be conducted in a variety of areas based on levels of activity, proximity to the release, and site conditions. Fixed-location handheld real-time locations may be established in the Community in order to provide concentration averages that may be observed and analyzed over time in distinct geographic locations in the community. AreaRAEs may be utilized to monitor the scene from remote location, if necessary.

CTEH® has the capabilities on site to collect ambient air samples, if necessary. These sampling methodologies may be utilized if the results from real-time air monitoring efforts indicate the potential for exposure above acceptable occupational or community exposure levels. CTEH® will discuss these methodologies with Denbury staff prior to implementation.

CTEH Site-Specific Action Levels

CTEH® site-specific action levels may be employed in all air monitoring plans to provide information for corrective action to limit potential exposures. These values do not replace occupational or community exposure standards or guidelines, but are intended to represent a concentration limit that triggers a course of action to better address worker and public safety. Action level exceedances will be communicated to Site Management and the CTEH Project Technical Director by the CTEH Project Manager (PM). Work practice may be assessed and then altered if necessary. Site-Specific Action Levels are not utilized for Site Assessment monitoring.

Plan 1: Work Area Monitoring

Objective: Report air levels before they reach those requiring respiratory protection

Analyte	Action Level	Action to be Taken	Basis	Instrument	Detection Limit	Notes	Correction Factor
CO_2	5,000 ppm 15 min.	Egress & Notify PM	OSHA PEL & ACGIH TLV	MultiRAE Sensor	100 ppm	Measuring Range: 0 – 50,000 ppm	N/A
	30,000 ppm* 1 min.	Egress & Notify PM	ACGIH STEL				
O_2	< 20.3 %	Egress and Notify PM	ACGIH STEL for CO_2	MultiRAE Sensor	0.1 %	Range: 0 – 30 %	N/A
Hydrogen Sulfide	1 ppm	Egress and Notify PM	ACGIH TLV-TWA; Precautionary Monitoring to Rule Out	MultiRAE Sensor	0.1 ppm	Range: 0 – 100 ppm	N/A

* Note small margin between STEL and NIOSH IDLH (40,000 ppm)

Plan 2: Community Assessment

Objective: Report air levels before they reach those causing nuisance or health issues

Analyte	Action Level	Action to be Taken	Basis	Instrument	Detection Limit	Notes	Correction Factor
CO_2	5,000 PPM* 15 min.	Notify PM	Warning prior to reaching PAC-1	MultiRAE Sensor	100 ppm	Measuring Range: 0 – 50,000 ppm	N/A
O_2	< 20.3 %	Notify PM	Precautionary	MultiRAE Sensor	0.1 %	Range: 0 – 30 %	N/A
Hydrogen Sulfide	Detection	Notify PM	Precautionary	MultiRAE Sensor	0.1 ppm	Range: 0 – 100 ppm	N/A

* Note: PAC-1 is 30,000 ppm, PAC-2 is 40,000 ppm, PAC-3 is 50,000 ppm

Plan 3: Site Assessment							
Objective: Characterize nature and extent of release							
Analyte	Action Level	Action to be Taken	Basis	Instrument	Detection Limit	Notes	Correction Factor
CO_2	NA	Report reading to PM	NA	MultiRAE PID	0.1 ppm	Measuring range: 1 – 5,000 ppm	NA

All Plans (1-3): Flammability								
Analyte	Action Level	Corrected Value/ Instrument Reading	Action to be Taken	Basis	Instrument	Detection Limit	Notes	Correction Factor
LEL				CO_2 is non-flammable; Notify PM & PTD if LEL detected.				

General Information on Procedures (Assessment Techniques) Used

Procedure	Description
Real-Time Handheld Survey	CTEH staff members may utilize handheld instruments (e.g. MultiRAE Plus; ppbRAE, Gastec colorimetric detector tubes, etc.) to measure airborne chemical concentrations. CTEH will use these handheld instruments primarily to monitor the ambient air quality at breathing zone level. Additionally, measurements may be made at grade level, as well as in elevated workspaces, as indicated by chemical properties or site conditions. CTEH may also use these techniques to verify detections observed by the AreaRAE network.
Radio-Telemetering Network	CTEH may deploy a radio-telemetering network of AreaRAEs in locations where monitoring from a remote location would be beneficial. These instruments will relay readings back to a centralization location that is monitored by CTEH.
Fixed Real-Time Monitoring locations	Multiple Community locations may be identified and monitored at the same location approximately once per hour using handheld instruments. This allows the use of statistical analysis more effectively than with a random approach.

Quality Assurance/Quality Control Procedures

Method	Procedure
Real-Time	Real-time instruments may be calibrated in excess of the manufacturer's recommendations.

Method	Procedure
	At a minimum whenever indicated by site conditions or instrument readings. Co-located sampling for analytical analysis may be conducted, if necessary, to assess accuracy and precision in the field. Lot numbers and expiration dates may be recorded with use of Gastec colorimetric tubes.
Reporting	Daily data summaries may be provided for informational purposes using data that have not undergone complete QA/QC. Comprehensive reports of real-time and/or analytical data may be generated following QA/QC and may be delivered 60 days following receipt of validated results, if applicable.

Glossary

Term	Definition
Sustained	Instrument reading above the action level continuously for the listed time period.
Breathing zone	The area within an approximate 10-inch radius of an individual's nose and mouth.
Ambient Air	That portion of the atmosphere (indoor or outdoor) to which workers and the general public have access.

Attachment B

SCAPA PACs and ACGIH TLVs

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No.	Chemical Name	CASRN	PACs based on AEGLs, ERPGs, or TEELs			Units
			PAC-1	PAC-2	PAC-3	
570	Carbon dioxide	124-38-9	30,000	40,000	50,000	ppm
1426	Hydrogen sulfide	7783-06-4	0.51	27	50	ppm

Chemical Name	CASRN	ACGIH TLVs		Units
		TWA	STEL	
Carbon dioxide	124-38-9	5,000	30,000	ppm
Hydrogen sulfide	7783-06-4	1.0	5.0	ppm

Attachment C

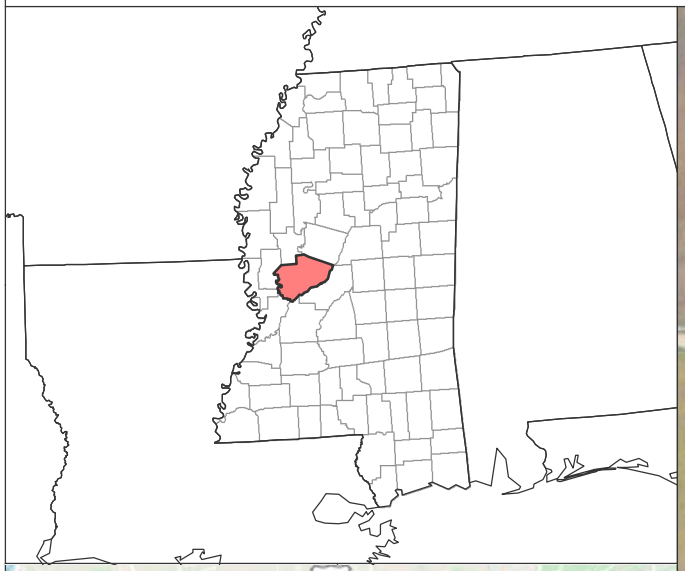
Site Maps

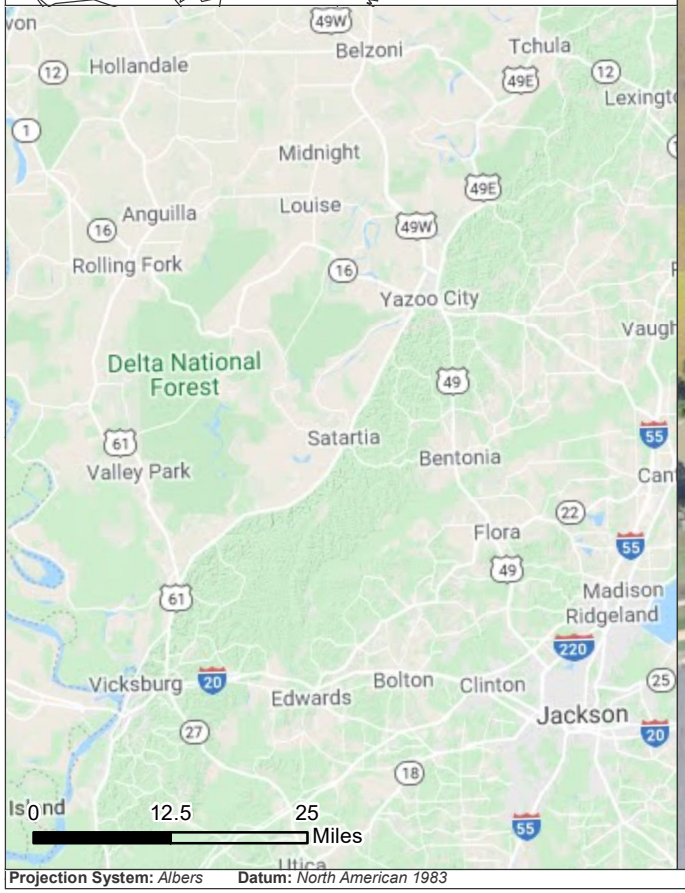
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Site Location

CO_2 Pipeline Release

Project: 112628
Client: Denbury
City: Satartia, MS
County: Yazoo







Projection System: *Albers* **Datum:** *North American 1983*

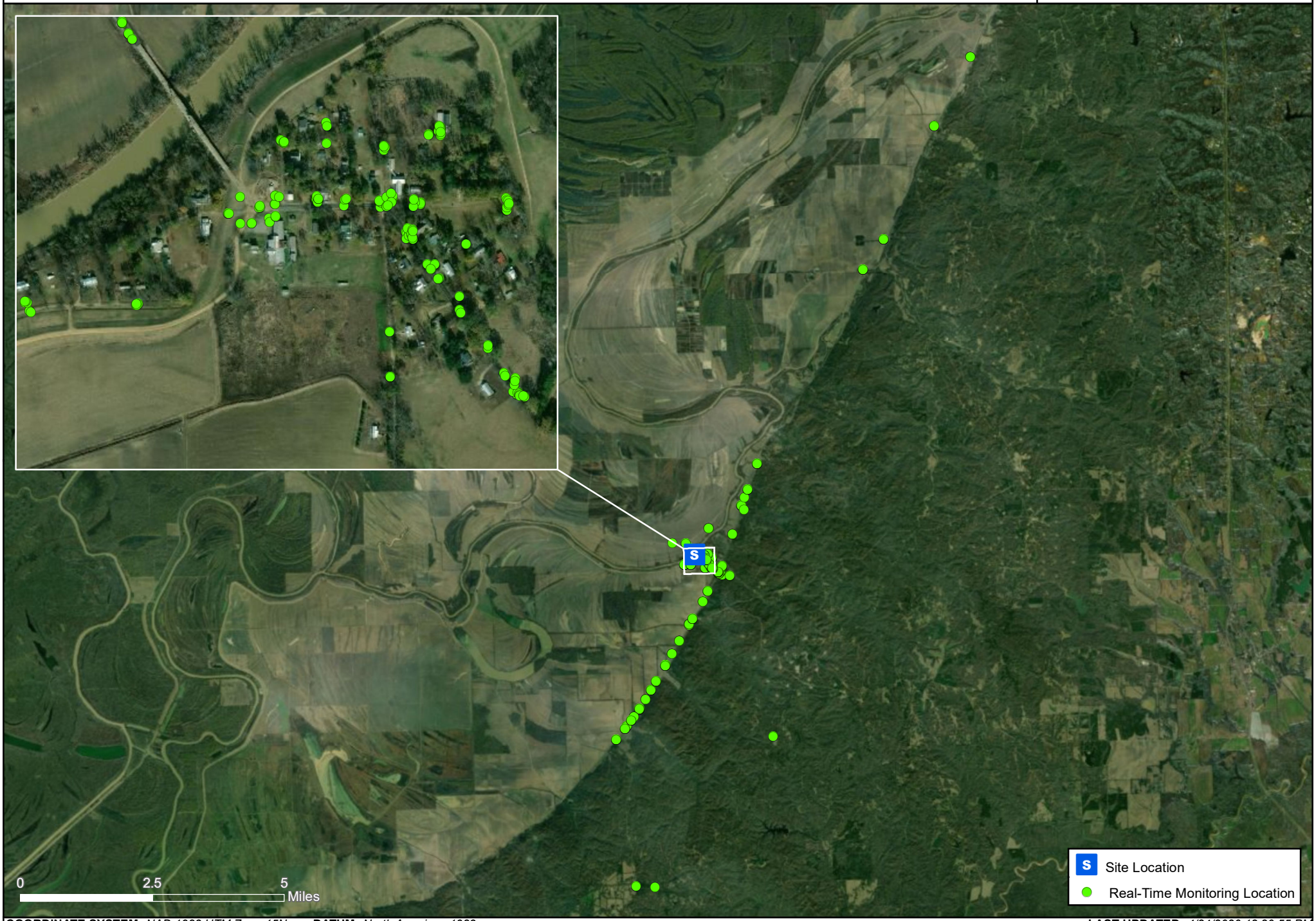
Document Name: 112628_site_location

Last Updated: *3/19/2020 1:44:18 PM*

Community Real-Time Air Monitoring Locations

CO_2 Pipeline Release | Satartia, MS | 2/22/2020 2230 - 2/23/2020 1134 CST

Project:112628
Client: Denbury
City: Satartia, MS
County: Yazoo



COORDINATE SYSTEM: *NAD 1983 UTM Zone 15N* **DATUM:** *North American 1983* **LAST UPDATED:** *4/24/2020 12:20:55 PM*

Indoor Assessment Real-Time Monitoring Locations

CO_2 Pipeline Release l Satartia, MS | 2/23/2020 0636 - 2/23/2020 1805 CST

Project:112628
Client: Denbury
City: Satartia, MS
County: Yazoo



COORDINATE SYSTEM: *NAD 1983 UTM Zone 15N* **DATUM:** *North American 1983* **LAST UPDATED:** *4/24/2020 12:10:31 PM*

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B.4 Miscellaneous Air Quality Attachments

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THE CARL MOYER PROGRAM GUIDELINES

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VOLUME I: PROGRAM OVERVIEW, PROGRAM ADMINISTRATION AND PROJECT CRITERIA









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California Environmental Protection Agency

Air Resources Board



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EXECUTIVE SUMMARY

or Board) and California's air pollution control and air quality districts) through new guidelines to serve California's air quality goals. SB 513 requires

California's strategic plans for air quality and mobility, including the Sta
move is critical to California's clean air mission, to the attainment of health

Collaboration is paramount to the Moyer Program's ongoing success. The changes

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and beyond California. Staff's proposed changes will ensure that Moyer can a□□□

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APPENDIX

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THE CARL MOYER PROGRAM GUIDELINES

PROGRAM OVERVIEW, PROGRAM ADMINISTRATION AND PROJECT CRITERIA

VOLUME I

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CHAPTER 1: PROGRAM OVERVIEW

[illegible] Program complements California's regulatory program by providing [illegible] and surplus emission reductions to be credited toward California's legally [illegible] – California's road map for attaining [illegible]

[illegible] are relying on emission reductions from incentive programs. California's strategic plans [illegible] tate's clean air mission, to the attainment of air quality standards, and to meeting [illegible]

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Project Types. The Water Quality Improvement Fund provides funding for projects that address water quality problems caused by nonpoint source pollution. Eligible projects include:

- **Replacement.** Replacement of failing or inadequate septic systems or other wastewater treatment systems that are contributing to water quality problems. Projects may include the construction of a new wastewater treatment system or connection to an existing wastewater treatment system. Projects may also include the abandonment of failing or inadequate septic systems or other wastewater treatment systems.

- **Recover.** Recovery of abandoned or underutilized properties contaminated with petroleum products or other hazardous substances.

- **Retrofit.** Retrofitting of existing storm water treatment systems to address water quality problems.

- **Decentralized Retirement.** Decentralized projects that reduce pollutant loads to surface waters or groundwater by providing treatment, infiltration, or evapotranspiration of storm water runoff or dry weather urban runoff.

- **Infrastructure.** Modification of existing infrastructure to address water quality problems caused by nonpoint source pollution. Projects may include the construction of new infrastructure to address water quality problems caused by nonpoint source pollution.

Modifications to existing infrastructure may be funded to meet water quality objectives, including treatment control measures, low impact development practices, and storm water runoff capture and reuse. Projects may also include the construction of new infrastructure to address water quality problems caused by nonpoint source pollution. Modifications to existing infrastructure may be funded to meet water quality objectives, including treatment control measures, low impact development practices, and storm water runoff capture and reuse. Modifications to existing infrastructure may be funded to meet water quality objectives, including treatment control measures, low impact development practices, and storm water runoff capture and reuse.

Funding Source. The Water Quality Improvement Fund receives funding from various sources, including state bonds, federal grants, and local contributions. The Water Quality Improvement Fund has been established to provide funding for projects that address water quality problems caused by nonpoint source pollution. The Water Quality Improvement Fund has been established to provide funding for projects that address water quality problems caused by nonpoint source pollution. The Water Quality Improvement Fund has been established to provide funding for projects that address water quality problems caused by nonpoint source pollution.

mechanisms since its inception in 1998. In the program's first four years, the *Proposition 40: The California Clean Water, Clean Air, Safe Neighborhood Parks, and Coastal Protection Act of 2002*

Funding provided by the Water Quality Improvement Fund may be used to pay for the costs of abatement, including the costs of abatement, including the costs of abatement, including

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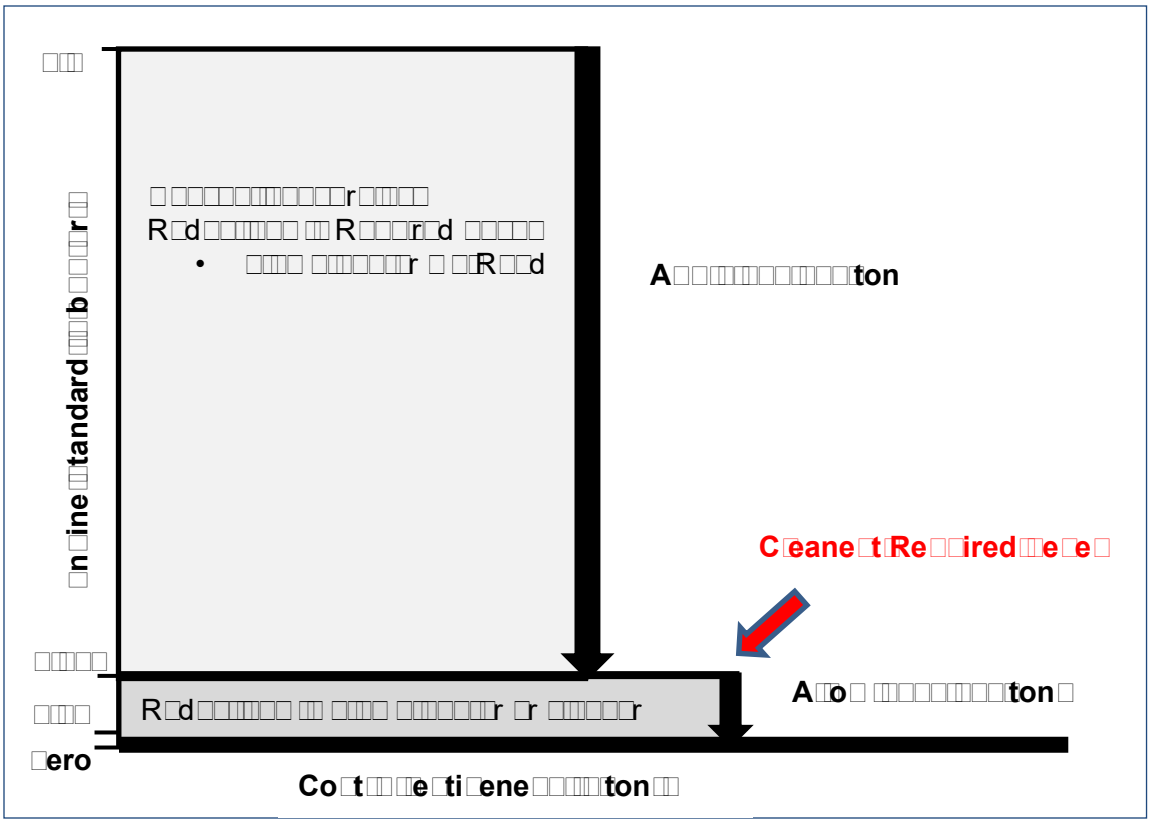
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[illegible]

[illegible]Change to the Off-Road Section [illegible]

Change to the [illegible] [illegible]

Change to the Marine Section [illegible]

[illegible] Estimate and Deterioration [illegible]

Other Changes

[illegible]

[illegible]

[illegible]

CHAPTER 2: GENERAL CRITERIA

[illegible]

A [illegible]

B [illegible] need to consider the rule in evaluating whether the project's emission reductions [illegible]

C [illegible]

D [illegible]

[illegible]

F [illegible]

□ □□Moyer Program grants can be no greater than a project'□ □□□r□□ □□□□□□□□□□□□
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CHAPTER 3: PROGRAM ADMINISTRATION

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CHAPTER 3: PROGRAM ADMINISTRATION

[illegible]

A. Background

[illegible]

[illegible] Program Year 20) and subsequent years' funds. The 2017 Guidelines may be [illegible]

[illegible]

[illegible]

B. Grant Fund Allocation and Limitation

1. **Grant Fund Notification.** [illegible] letter to each air district's Air Pollution Control Officer (APCO) with notification [illegible]

2. **Tentative and Final Fund Allocation.** [illegible]

disbursement and subsequent expenditure of a fiscal year's grant funds is

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Recordkeeping. The air district shall maintain records of all inspections conducted pursuant to this rule, and any subsequent action taken by the air district with respect to any violations identified during such inspections.

Inspection after Contractor Certification. The air district may randomly conduct inspections of any building for which contractor certification is required, at any time after the start of construction, demolition, or renovation, to verify that the contractor certification requirements of this rule have been met. The air district may conduct inspections of any building for which contractor certification is required, at any time after the start of construction, demolition, or renovation, to verify that the contractor certification requirements of this rule have been met.

(1) The air district shall conduct inspections of buildings for which contractor certification is required, as follows:

(2) The air district shall conduct inspections of buildings for which contractor certification is required, as follows: at least one inspection for each project involving the demolition of a building, or the removal of a load-supporting structural member of a building, regardless of the amount of asbestos present; and at least one inspection for each project involving the removal of more than 100 square feet, 100 linear feet, or 35 cubic feet of asbestos-containing material.

(3) The air district's Policies and Procedures Manual clearly specifies the procedures for conducting inspections of buildings for which contractor certification is required, and the qualifications for air district personnel who conduct such inspections. At a minimum, air district personnel who conduct inspections shall successfully complete training equivalent to the training required for contractor certification.

Procedures for Inspection

Requirements. The air district shall require that any person who conducts inspections of buildings for which contractor certification is required, as specified in Section 5.0, shall comply with the Model Air District Asbestos Inspection Procedures Manual, and with the requirements of this section.

(1) The air district shall require that any person who conducts inspections of buildings for which contractor certification is required, as specified in Section 5.0, shall comply with the Model Air District Asbestos Inspection Procedures Manual, and with the requirements of this section. Prior to conducting an inspection, the inspector shall review all relevant records and reports concerning the building, including any notifications submitted pursuant to Section 6.0 and any previous inspection reports. The inspector shall conduct a walk-through survey of the building, and shall speak with the owner or operator of the building, or with the owner's or operator's agent, to ascertain the procedures that have been or will be used to comply with this rule. The inspector shall inspect any friable asbestos material that will be removed, encapsulated, or disturbed, and any category I nonfriable asbestos-containing material that has become friable, that will be removed, encapsulated, or disturbed, and any category II nonfriable asbestos-containing material that will be removed, encapsulated, or disturbed and that has a high probability of becoming crumbled, pulverized, or reduced to powder by the time of demolition.

(2) If the inspector or the air district determines that a violation has occurred, or that any procedure is being improperly performed, the inspector shall immediately issue a written notice of violation to the owner or operator of the building, or to the owner's or operator's agent. Immediately after the issuance of a notice of violation, the inspector shall contact by telephone and inform the owner or operator of the building, or the owner's or operator's agent, of the violation. The inspector shall issue a notice to resume operations after the owner or operator of the building, or the owner's or operator's agent, corrects the violation and demonstrates compliance with this rule.

(3) The inspector or the air district shall post a notice of violation or a notice to resume operations, or both, at any building where an inspection is performed. The inspector shall also post a notice of violation or a notice to resume operations, or both, at the building owner's or operator's mailing address, if different from the location of the building.

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Ineligible Costs Costs incurred or paid for activities or equipment deemed ineligible for funding under the Program, including but not limited to costs incurred prior to the effective date of the Grant Agreement, costs for vehicles not scrapped as required, and costs exceeding the maximum grant amount.

Limitation on Applicant Action before Air District Approval The applicant shall not take any action, including but not limited to ordering, purchasing, or scrapping a vehicle, that would limit the Air District's discretion in approving or disapproving the application. Any such action taken by the applicant prior to the Air District's approval of the application shall be at the applicant's own risk and shall not obligate the Air District in any way.

Invoice Procedure The applicant shall submit invoices to the Air District in a form and manner specified by the Air District. Invoices shall be submitted only after the applicant has incurred the costs for which reimbursement is requested and has paid those costs. The Air District may withhold payment until it has received adequate documentation of the costs incurred and paid, including but not limited to proof of scrappage for each vehicle for which a grant is claimed.

On-Road Compliance If any vehicle owned by the applicant and operated on roads in California is found to be out of compliance with applicable emissions standards, the applicant may be required to repair or replace the vehicle, or to take other corrective action, at the applicant's own expense. Failure to comply with such requirements may result in the suspension or termination of the grant and the applicant may be required to repay all or a portion of the grant funds received.

Recordkeeping and Compliance The applicant shall maintain complete and accurate records relating to the vehicle for which a grant is claimed, including but not limited to records of ownership, operation, maintenance, and scrappage. The applicant shall make these records available to the Air District upon request and shall retain them for a period of at least three years after the date of scrappage. The applicant shall also comply with all applicable recordkeeping requirements of the Carl Moyer Program Guidelines and any other applicable laws or regulations. The Air District may conduct audits or inspections to verify compliance with these requirements.

Assignment Restriction The applicant shall not assign or transfer any of its rights or obligations under the Grant Agreement without the prior written consent of the Air District. Any attempted assignment or transfer without such consent shall be void and shall constitute a breach of the Grant Agreement.

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Findings Related to Forbearance Agreement

The Company's ability to meet its obligations under the Forbearance Agreement is dependent on its ability to generate sufficient cash flow from operations and obtain additional financing. The Company's cash flow from operations is subject to various risks and uncertainties, including the risk that the Company will not be able to generate sufficient cash flow from operations to meet its obligations under the Forbearance Agreement. The Company's ability to obtain additional financing is also subject to various risks and uncertainties, including the risk that the Company will not be able to obtain additional financing on terms acceptable to the Company or at all.

CHAPTER 4: ON-ROAD HEAVY-DUTY VEHICLES

[illegible]

Applicability and Funding

[illegible]

Table [illegible]
[illegible] Cargo On-Road Heavy-Duty [illegible]

[illegible]	[illegible]		[illegible]
	Replacement	Repower/Conversion	
[illegible]	✓	✓	[illegible]
[illegible]	✓	✓	[illegible]
[illegible]	✓	✓	[illegible]
[illegible]	✓	✓	[illegible]
[illegible]	✓	✓	[illegible]
[illegible]	✓	✓	[illegible]
[illegible]	✓		[illegible]

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Table

State Funding Category or Optional Method of Reference Rent[a]

Optional Method of Standard Number	2D	MD	2D
5			5
		5	
For			5

[a] For rent subject to a contract that requires the rent to be determined by a method other than the rent determined by the 5 for rent subject to a contract that requires the rent to be determined by a method other than the rent determined by the

Table

State Funding Category or Optional Method of Reference

Location Type	Funding Category
For	
Other For Used	

Table

State Funding Category or Conversion Rent for Conversion

Select Category of Location Type	Funding Category[a]
For	
2D For For	
MD For For	5
2D For For	

[a] For rent subject to a contract that requires the rent to be determined by a method other than the rent determined by the 5 for rent subject to a contract that requires the rent to be determined by a method other than the rent determined by the

Table [illegible]
[illegible]tate F[illegible]ndin[illegible] Ca[illegible]or[illegible] [illegible]brid Con[illegible]er[illegible]ion[illegible]

[illegible]

[illegible] ei[illegible]t C[illegible]a[illegible]	F[illegible]ndin[illegible] Ca[illegible][a][illegible]
[illegible]D	[illegible]5[illegible]
M[illegible]D	[illegible]
[illegible]D	[illegible]5[illegible]

[a] [illegible] [illegible] [illegible]r[illegible] [illegible] [illegible] [illegible]r[illegible] [illegible] [illegible] [

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(5) *Compliance Check Tool*. [illegible] ARB's [illegible] [illegible] [illegible]

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[illegible] [illegible] [illegible] [

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

(a) [illegible]

(b) Engine class: The engine's primary intended service class must match the replacement vehicle's weight class (i.e., an MHD diesel engine is used [illegible] percent of the engine's intended service c[illegible] vehicle, but only if the GVWR is within 10 percent of the engine's intended [illegible]

(c) [illegible]

(d) [illegible]

(e) [illegible]

(f) [illegible]

[illegible]

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application or part of an application on an owner's behalf only if the vehicle [illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

Table [illegible]
Required Inspection for On Road Projects

Inspection Type	Procedure	Timing
[illegible]	• [illegible] [illegible] [illegible] [illegible] [illegible] [illegible] • [illegible] [illegible] [illegible] [illegible] [illegible]	[illegible] [illegible] [illegible] [illegible] [illegible] [illegible] [illegible] [illegible] [illegible] [illegible] [illegible]
[illegible]	• [illegible] [illegible] [illegible] [illegible] [illegible] [illegible] [illegible] [illegible] • [illegible] [illegible] [illegible] [illegible]	[illegible] [illegible] [illegible] [illegible] [illegible] [illegible] [illegible] [illegible] [illegible] [illegible] [illegible] [illegible]
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CHAPTER 5: OFF-ROAD EQUIPMENT

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Table [illegible]
ARB and [illegible] A Tier [illegible] and [illegible] a [illegible] i [illegible] ion [illegible] tandard [illegible] or [illegible] e [illegible] O [illegible] Road Diesel Engines ≥ 25 [illegible] or e [illegible] o [illegible] er [illegible]
[illegible] ra [illegible] er bra [illegible] e [illegible] or [illegible] e [illegible] o [illegible] er [illegible] o [illegible] r [illegible] b [illegible] r [illegible]

Ma [illegible] i [illegible] [illegible] Rated [illegible] [illegible] o [illegible] er [illegible] [illegible] [illegible]	Tier [illegible]	Mode [illegible] ear [illegible]	[illegible] O [illegible]	[illegible] C [illegible]	[illegible] O [illegible] [illegible] M [illegible] C [illegible]	[illegible] M [illegible]
25≤hp<50 (19≤kW<37)	[illegible] r [illegible]	[illegible]	—	—	[illegible]	[illegible]
	[illegible] r [illegible]	[illegible]	—	—	5 [illegible]	[illegible] 5
50≤hp<75 (37≤kW<56)	[illegible] r [illegible]	[illegible]	[illegible]	—	—	—
	[illegible] r [illegible]	[illegible]	—	—	5 [illegible]	[illegible]
	[illegible] r [illegible]	[illegible]	—	—	[illegible] 5	[illegible]
75≤hp<100 (56≤kW<75)	[illegible] r [illegible]	[illegible]	[illegible]	—	—	—
	[illegible] r [illegible]	[illegible]	—	—	5 [illegible]	[illegible]
	[illegible] r [illegible]	[illegible]	—	—	[illegible] 5	[illegible]
100≤hp<175 (75≤kW<130)	[illegible] r [illegible]	[illegible]	[illegible]	—	—	—
	[illegible] r [illegible]	[illegible]	—	—	[illegible]	[illegible]
	[illegible] r [illegible]	[illegible]	—	—	[illegible]	[illegible]
175≤hp<300 (130≤kW<225)	[illegible] r [illegible]	[illegible]	[illegible]	[illegible]	—	[illegible]
	[illegible] r [illegible]	[illegible] 5	—	—	[illegible]	[illegible] 5
	[illegible] r [illegible]	[illegible]	—	—	[illegible]	[illegible] 5
300≤hp<600 (225≤kW<450)	[illegible] r [illegible]	[illegible]	[illegible]	[illegible]	—	[illegible]
	[illegible] r [illegible]	[illegible] 5	—	—	[illegible]	[illegible] 5
	[illegible] r [illegible]	[illegible]	—	—	[illegible]	[illegible] 5
600≤hp≤750 (450≤kW≤560)	[illegible] r [illegible]	[illegible]	[illegible]	[illegible]	—	[illegible]
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Table

Emission Standards for
New On-Road Heavy-Duty Engines
(grams per brake horsepower-hour)

Model Year	Nonmethane Hydrocarbons (NMHC)
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[illegible]	[illegible]
[illegible] and later	[illegible]

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C. Maximum In-Use Emissible Standard and Deterioration Factor

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□□□ □ New engines that are participating in the “Tier □ □□r□□ □□□r□d □□□□□□□□
Incentive for Engine Manufacturers” program, as detailed in
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[illegible] standard. For purposes of this section, the air district's commitment (as [illegible]

[illegible] At the applicant's request, confirmation of availability of an engine [illegible]

[illegible] standards are unavailable must be included in the air district's [illegible]

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required components as required in an individual air district's [illegible]

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[illegible] the salvage yard's receipt of the equipment through [illegible]

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(D) [illegible] a fleet's regulatory requirements for the duration of the contract term.

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[illegible] the fleet's total horsepower from which the BACT requirements of [illegible]

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Impact of the Proposed Regulation to Reduce Emissions of Diesel Particulate Matter, Oxides of Nitrogen and Other Criteria Pollutants from In-Use Heavy-Duty Diesel-Fueled Vehicles and Amendments to the California Exhaust Emission Standards and Test Procedures for 2001 and Subsequent Model Heavy-Duty Diesel Engines and Vehicles (CCR, title 13, section 1956.8)

This regulation would affect most diesel-fueled vehicles operated in California with a manufacturer's GVWR greater than 14,000 pounds. Such vehicles include, but are not limited to, trucks used to haul freight or goods; buses used for public transit; motor coaches used for intrastate operation; and specialty vehicles such as motor homes, emergency vehicles, and utility service vehicles. Diesel-fueled vehicles with a GVWR greater than 14,000 pounds are commonly referred to as heavy-duty diesel vehicles (HDDVs). The proposed regulation would require that all HDDVs operated in California meet a particulate matter (PM) emission standard of 0.01 grams per brake horsepower-hour (g/bhp-hr) by January 1, 2008. Additionally, the proposed regulation would require that all HDDVs operated in California meet a PM emission standard of 0.01 g/bhp-hr by January 1, 2011, or by January 1, 2013, if the vehicle is equipped with an engine that meets a PM emission standard of 0.01 g/bhp-hr and a nitrogen oxides (NOx) emission standard of 0.2 g/bhp-hr by January 1, 2010. The proposed regulation would require that all HDDVs operated in California meet a PM emission standard of 0.01 g/bhp-hr by January 1, 2014, or by January 1, 2016, if the vehicle is equipped with an engine that meets a PM emission standard of 0.01 g/bhp-hr and a NOx emission standard of 0.2 g/bhp-hr by January 1, 2013.

CHAPTER 6: LOCOMOTIVES

[illegible]

Appropriate Incentive Funding

[illegible]

Table [illegible]
[illegible] Locomotive Funding Opportunities

Railroad Class	Subject to ARB Rule or MOU	Moyer Funding Opportunities
[illegible]	*2005 Statewide Railyard Agreement* and *1998 South Coast MOU*[illegible]	Projects in California's goods [illegible]
[illegible]	[illegible]	[illegible]

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Tier **Qualitative Criteria for Tier 1 Corridors.** Tier 1 corridors are those corridors that are expected to have the highest demand and the greatest importance to the overall performance of the regional network. Tier 1 corridors are those corridors that are expected to have the highest demand and the greatest importance to the overall performance of the regional network. Tier 1 corridors are those corridors that are expected to have the highest demand and the greatest importance to the overall performance of the regional network.

Tier **Qualitative Criteria for Tier 2 Corridors.** Tier 2 corridors are those corridors that are expected to have a high demand and a significant importance to the overall performance of the regional network. Tier 2 corridors are those corridors that are expected to have a high demand and a significant importance to the overall performance of the regional network. Tier 2 corridors are those corridors that are expected to have a high demand and a significant importance to the overall performance of the regional network.

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CHAPTER 7: MARINE VESSELS

[illegible]

Applicability and Funding

[illegible]

Table [illegible]
[illegible] Marine Funding Opportunities

Project Type	Subject to ARB Review	Moderate Funding Opportunities[a]
[illegible]	[illegible]	[illegible]
[illegible] *not* [illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]

[a] A fleet's compliance status with the [illegible] may affect [illegible]

[illegible]

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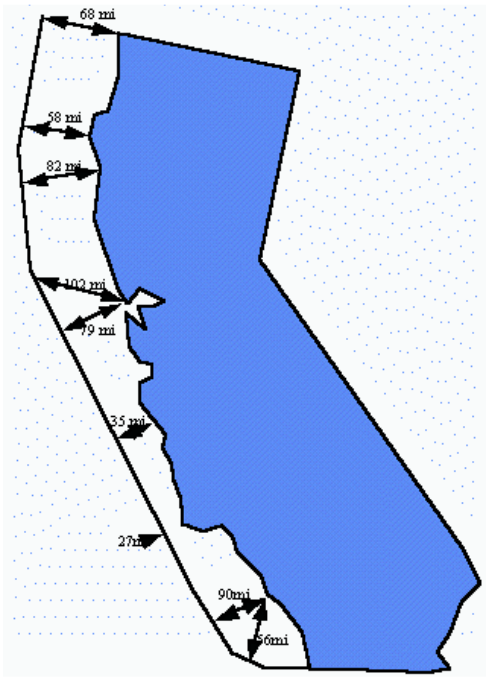
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CHAPTER 8: LIGHT-DUTY VEHICLES

Appropriate Crediting for Funding

conventional projects. To be eligible for a high emitting VAVR project, a vehicle's Smog Check results must exceed the pass/fail emission standards for the vehicle's model year and

Eligible Amount

Creditor Background

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Table 2
Retired Life Insurance Reduction Calculation

Month	ROP	OP	MP
	Total	Amount	Amount
Jan 2015	5,000	1,000	1,000
	1,000	1,000	1,000
2015	1,000	1,000	1,000
	1,000	5,000	1,000
	1,000	500	1,000
	1,000	250	250
	1,000	1,000	1,000
	1,000	1,000	1,000
	1,000	250	1,000
	1,000	1,000	1,000
	1,000	250	500
	1,000	250	1,000
2015	1,250	1,000	1,000
	1,000	1,000	1,000
	1,000	500	500
	1,000	1,000	1,000
	1,000	500	1,000
	1,000	1,000	1,000
	1,000	1,000	250
	1,000	1,000	250
	1,000	500	250
	1,000	1,000	250
2015	1,250	500	250
	1,000	1,000	1,000
	1,000	1,000	1,000
	1,000	500	1,000
	1,000	1,000	1,000
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CHAPTER 9: LAWN AND GARDEN EQUIPMENT REPLACEMENT

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Participant Requirement To participate in the Program, a Participant must meet all of the following requirements:

(1) *Application Form* The Participant must submit a complete and accurate Application Form, including all required documentation, to the Air District or Air District-specified Administrator. The Air District or Air District-specified Administrator may request additional information from the Participant to verify the Participant's eligibility. The Participant must provide the requested information within 30 days of the Air District's or Air District-specified Administrator's request. The Air District or Air District-specified Administrator may extend the deadline for the Participant's response at the Air District's or Air District-specified Administrator's discretion.

(2) *Applicant must certify in the application*:

(a) That the Participant Household has not purchased or received a new lawn mower through the Program in the previous 10 years;

(b) That the Participant has not received a Rebate for the Existing Lawn Mower through the Program or any other Air District or Air District-specified Administrator program;

(c) Acknowledgement that the Participant Household must comply with all Program requirements, including Operational Gasoline Lawn Mower Requirement, Delivery of the Existing Lawn Mower to the Air District or Air District-specified Facility, and Replacement and Operation Requirement, and that failure to comply with these requirements may result in the Participant Household being ineligible for future Air District or Air District-specified Administrator programs.

Destruction and Operation Requirement The Participant must agree to destroy the Existing Lawn Mower and operate it for the remainder of its useful life, as determined by the Air District or Air District-specified Administrator, in accordance with the following requirements:

(1) *Operational Gasoline Lawn Mowers* The Participant must operate the Existing Lawn Mower for the remainder of its useful life, as determined by the Air District or Air District-specified Administrator, and must not sell, transfer, or otherwise dispose of the Existing Lawn Mower to any other person or entity during that period.

(2) *Delivery of the Existing Lawn Mower to the Air District or Air District-specified Facility* The Participant must deliver the Existing Lawn Mower to the Air District or Air District-specified Facility for destruction. The Air District or Air District-specified Administrator will provide the Participant with a list of Air District-specified Facilities and the Participant must deliver the Existing Lawn Mower to one of those facilities.

Replacement and Operation Requirement The Participant must agree to purchase a new lawn mower and operate it for the remainder of its useful life, as determined by the Air District or Air District-specified Administrator, in accordance with the following requirements:

(1) *New, Cordless, Zero-Emission Electric Lawn Mower* The Participant must purchase a new, cordless, zero-emission electric lawn mower and must not sell, transfer, or otherwise dispose of the new lawn mower to any other person or entity during that period.

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□□ Amount air district pays from air district's local funds.

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□□□ *Operational Condition of Existing Lawn Mower*□ □r d□□r□□□r □r d□□r□□□□□□□d □□□□□□ □ □□□□□□r□ □□□□□□□ □□□□□□ □□□ □ □ □□ □r □□ □□□□r□□□□ □□□r□□□□□□□d□□□□ □□□ □r d□□r□□□□r □r d□□r□□□□□□□d □□□□□□ □ □□□r□□□□□ □□□□□□ □□□ □ □ □□ □r □□□d□□□ □d □□□□r□□□□□

□□□ *Project Payment*: Air districts must include in their P&P's a de□□□d d□□□r□□□□ □□□□ □r□□□□ □r□□□□ □ □□□ □□□ □r d□□r□□□□r□□d□□ □□□□ □□□ □□ □□rd□□□□□□r□□□ □□□□□ □□r□□□ □□□ □ □□ □r □ □□□□□□□r□r□ □ □r□□□□□□d□r □□□□□□□□

□□□ *Merchant Reimbursement Package*□ □r□r □□ r□□□□□□□ r□□ □□r□□ □□□□□□ □r d□□r□□□□□□□d □□rd □□r□□□□r□□□□□□ □ □□□□□□r□r □r □□r□□□□□□ □ □r□□□□□ □□□□□□ □□□ r□□ □□r□□ □□□□□□□□□□ □□ □□ □r d□□r□□□ □□□ d□□□ □□□□ □□□d □□ □□□d□d □□ □□□ r□□ □□r□□ □□□□□□□□□□

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□□□ *Lawn Mower Destruction Documentation*□ □ □□□□□□□□□ □□□□□□□ □□□ □ □ □□ □r□ □ □□□□□d □□□r□□□d□ □r d□□r□□□ □ □□□□□□□□□r□□ □□□r□□□□□□□ R□□□□□□□□ □ □□ □□□□□□ □□□□d r□□□□□□ □□□□□□□□ □□□ □□□ □r□□□□□□□ □ □ □□ □r□d□□r□□□d□

□□□ *Audit and Monitoring*□ □r d□□r□□□ □ □□□□□□□ □R□ □□ □ □□□□r □□□r □□□ □ replacement program which may include audits of the air district's □□ □□□ □□□□□□□ □□□□□ □r□□r□□ □

(M) *Meeting Environmental Justice (EJ) Requirements.* [illegible] determine if it helps to meet the air district's EJ requirements. [illegible]

(N) Recordkeeping. [illegible]

(1) [illegible]

(2) [illegible]

(3) [illegible]

(4) [illegible]

(5) [illegible]

(O) *Records Retention.* [illegible]

(P) Participating Manufacturer Requirements. Participating manufacturers' [illegible]

(1) *Covered Lawn Mowers.* [illegible]

(A) [illegible]

(B) [illegible]

(C) [illegible]

(D) [illegible]

(5) [illegible]

(A) [illegible]

(B) [illegible]

(C) [illegible]

[illegible]

[illegible] *Manufacturer Qualifications*. [illegible]

[illegible] [illegible]

[illegible] [illegible]

[illegible] *Aftermarket Service*. [illegible]

[illegible] *Recalls*. [illegible]

[illegible] *Air District Does Not Warrant or Endorse Lawn Mowers*. [illegible] the air district does not warrant or endorse the manufacturer's lawn [illegible]

[illegible] *Averaging, Banking, and Trading Program Exclusion*. [illegible] ARB's [illegible]

[illegible] *Return of Funds*. [illegible]

[illegible] **Participating Merchant Requirement**. Participating merchants' agreements [illegible]

□□□ *Covered Lawn Mowers*□ □□□□r□ □□□□□ □□□□□□□□□ □□rd□□□□□□□r□□□□ □□□□□□□ □□□□□r□□ □□□ □ □ □□□ □r□ □□□□□r□d □□□ □□□□ □□r□□□□ □□□□□

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□□□ *Destruction of Lawn Mowers*□ □ □□□□□□ □□□□□□□□□□□□ r□□□□□□□□□ □□□□ □□□□□ □□□□□d□□□r□□ □□□□ □□□□ □ □ □□□r □□d □□□□□□□□ □ □□□□□□ □□d □□□□ □□r□□□□□□□□□□□□ □□□□□□□□□□ □□□□ □ □ □□□r □□ □□□ □□□□□□□r □□□□r□□□□ □r r□□□□r□□□□□□□

□□□ *Receipt of Lawn Mower Destruction*□ □ □□□□□□ □□□□□□□□□□□□ r□□□□□□□□□ □□□□ □□□□□ □□□□□□□□□□□□□□□ □□□□ □□r d□□□r□□□□□□□□□ □□□□ □ □ □□□r □□d□□□r□□□d □□□ □□□□d□□□ □□□□ □□r d□□□r□□□□□ □□□□□□d r□□□□□□□□□□d□□□□□□□ □□□□ □□□□ □□r □□□□□□ □ □ □□□ □r□d□□□r□□□□d□

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CHAPTER 10: INFRASTRUCTURE

Board's (CARB or the Board) Mobile Source Control Program (Program) is designed to achieve the State's air quality goals. Specifically, Health and Safety Code (HSC) Section 43018(b)(1) requires CARB to adopt standards and regulations that will result in the attainment of the most stringent state and federal ambient air quality standards at the earliest practicable date. To comply with this mandate, CARB must adopt and implement regulations to reduce emissions from a variety of mobile sources, including on-road and off-road motor vehicles and engines.

Funding

For the Program to achieve its emission reduction goals, CARB must adopt regulations that require the purchase of cleaner vehicles and equipment. Incentive funding is then used to help offset the incremental cost of cleaner technologies. Incentive funding is also used to accelerate the penetration of cleaner technologies into the marketplace. Incentive funding is available from a variety of sources, including federal, state, and local programs.

Table 10-1
Major Incentive Programs Administered by CARB

Major Incentive Programs	Infrastructure Projects
Carl Moyer	Fueling Infrastructure
Proposition 1B	Fueling Infrastructure, Electrical Infrastructure
AB 118	Fueling Infrastructure, Electrical Infrastructure
AB 923	Fueling Infrastructure, Electrical Infrastructure
Lower-Emission School Bus	Fueling Infrastructure, Electrical Infrastructure

Infrastructure Projects

Fueling infrastructure and electrical infrastructure are necessary for the operation of many of the cleaner vehicles and equipment that are funded through incentive programs. Fueling infrastructure is also necessary for the operation of many of the cleaner vehicles and equipment that are required by regulation.

- **Battery Charging Stations** – Electrical infrastructure that is used to charge the batteries of electric vehicles and equipment. Charging stations may be dedicated to a single vehicle or piece of equipment, or may be shared by multiple vehicles or pieces of equipment.

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APPENDIX A

ACRONYMS

APPENDIX A: ACRONYMS

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APPENDIX B

DEFINITIONS

APPENDIX B: DEFINITIONS

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Table B
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APPENDIX C

COST-EFFECTIVENESS CALCULATION METHODOLOGY

APPENDIX C: COST-EFFECTIVENESS CALCULATION METHODOLOGY

A. Introduction

To determine a project's cost

Table C
Co t e ti ene i it Criteria

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Annual emissions by pollutant (tons/yr) =
*(emission factor (g/bhp-hr) + deterioration product (g/bhp-hr) (if applicable)) * horsepower (hp) * load factor * annual activity (hrs/yr) * percentage operation in California / 907,200 (g/ton)*

Hour-based deterioration product (g/bhp-hr) =
*deterioration rate (g/bhp-hr-hr) * total equipment activity (hrs)*

Total equipment activity[(c)] (hrs) =
*annual activity (hrs/yr) * deterioration life (yrs)*

Deterioration life (baseline equipment) (yrs) =
expected first year of operation – baseline engine model year + (project life / 2)

Deterioration life (reduced equipment) (yrs) =
project life / 2

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[(c)] Total equipment activity for hour-based calculations is limited to a maximum of 12,000 hours for diesel engines, 3,500 hours for large-spark ignition (LSI) engines with a model year of 2006 or older, or 5,000 hours for LSI engines with a model year of 2007 or newer.

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Annual emissions by pollutant (tons/yr) =
*emission factor (g/bhp-hr) * fuel consumption rate factor (bhp-hr/gal) * annual activity (gal/yr) * percentage operation in California / 907,200 (g/ton)*

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Annual surplus emission reductions by pollutant (tons/yr) =
annual emissions for the baseline technology (tons/yr) –
annual emissions for the reduced technology (tons/yr)

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Total annual weighted surplus emission reductions (tons/yr) =
*(fraction project life (yrs) * annual weighted surplus emissions from transaction 1 (tons/yr) /*
*total project life (yrs)) + (fraction project life (yrs) **
annual weighted surplus emissions from transaction 2 (tons/yr) / total project life (yrs))

Total annual weighted surplus emission reductions (tons/yr) =
($n_1 * a_1 / t$) + ($n_2 * a_2 / t$)
where:
n_1 = fraction project life from transaction 1 (yrs)
n_2 = fraction project life from transaction 2 (yrs)
a_1 = annual weighted surplus emissions from transaction 1 (tons/yr)
a_2 = annual weighted surplus emissions from transaction 2 (tons/yr)
t = total project life (yrs)

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Applicant cost share ($) ≥
*15 percent * Moyer eligible costs ($)*

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Total project cost ≥
applicant cost share ($) + ∑grants paid ($)

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Potential grant amount ($) =
*cost-effectiveness limit ($/ton) * estimated annual emission reductions (weighted tons/yr) /CRF*

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Capital recovery factor =
*(1 + discount rate[(d)]) ^ project life * discount rate* /((1 + discount rate*) ^ project life - 1)*

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Weighted emission reductions (weighted tons/yr) =
*NO_x reductions (tons/yr) + ROG reductions (tons/yr) + (20 * PM reductions (tons/yr))*

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Annual emission by pollutant (tons/yr) =
*(emission factor + deterioration product (if applicable)) * annual activity * adjustment factor(s) * percentage operation in California / 907,200 (g/ton)*

Deterioration product =
*deterioration rate * total equipment activity*

Total equipment activity =
*annual activity * deterioration life (yrs)*

Deterioration life (baseline) (yrs) =
expected first year of operation – baseline engine model year + (project life / 2)

Deterioration life (reduced) (yrs) =
project life / 2

[illegible]d[illegible] *Discount rate varies from year to year. See Tables D-24 and D-25 in Appendix D for CRF values at a 1 percent and 2 percent discount rate, respectively.*

For Tier 5 and Tier 4 Final engines not subject to hour-based standards:

Annual emissions by pollutant (tons/yr) =
*(emission factor (g/mi) + deterioration product (g/mi) (if applicable)) * annual activity (mi/yr) * percentage operation in California / 907,200 (g/ton)*

Mile-based deterioration product (g/mi) =
*deterioration rate (g/mi-10,000 mi) * total equipment activity (mi)*

Total equipment activity[e] (miles) =
*annual activity (mi/yr) * deterioration life (yrs)*

Deterioration life (baseline) (yrs) =
expected first year of operation – baseline engine model year + (project life / 2)

Deterioration life (reduced) (yrs) =
project life / 2

For Tier 4 Interim and Tier 4 Final engines subject to hour-based standards:

Annual emissions by pollutant (tons/yr) =
*(emission factor (g/bhp-hr) + deterioration product (g/bhp-hr) (if applicable)) * horsepower (hp) * load factor * annual activity (hrs/yr) * percentage operation in California / 907,200 (g/ton)*

Hour-based deterioration product (g/bhp-hr) =
*deterioration rate (g/bhp-hr-hr) * total equipment activity (hrs)*

Total equipment activity[f] (hrs) =
*annual activity (hrs/yr) * deterioration life (yrs)*

Deterioration life (baseline) (yrs) =
expected first year of operation – baseline engine model year + (project life / 2)

Deterioration life (reduced) (yrs) =
project life / 2

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[e] Operation of engines subject to mile-based standards in any area within California other than the California Air Basin or the Lake Tahoe Air Basin shall be considered operation outside of California. Operation of engines subject to mile-based standards in the California Air Basin or the Lake Tahoe Air Basin shall be considered operation in California.

[f] Operation of engines subject to hour-based standards in any area within California other than the California Air Basin or the Lake Tahoe Air Basin shall be considered operation outside of California. Operation of engines subject to hour-based standards in the California Air Basin or the Lake Tahoe Air Basin shall be considered operation in California.

[illegible]

Annual emissions by pollutant (tons/yr) =
*Emission factor (g/bhp-hr) * fuel consumption rate factor (bhp-hr/gal) * annual activity (gal/yr) * percentage operation in California / 907,200 (g/ton)*

[illegible]

Annual emissions by pollutant (tons/yr) =
*Ship emission factor (g/kW-hr) * power requirements (kW) * berthing time (hrs/visit) * annual number of visits (visits/yr) * 0.9 / 907,200 (g/ton)*

[illegible]

Annual surplus emission reductions by pollutant (tons/yr) =
annual emissions for the baseline technology (tons/yr) –
annual emissions for the reduced technology (tons/yr)

[illegible]

Annual surplus emission reductions by pollutant (tons/yr) =
*0.80 * (annual emissions for the baseline technology (tons/yr) –*
annual emissions for the reduced technology (tons/yr))

[illegible]

Annual surplus emission reductions by pollutant (tons/yr) =
*annual emissions for the baseline technology (tons/yr) **
reduced technology verification percentage

[illegible]

Annual surplus emission reductions by pollutant (tons/yr) =
total annual emissions (all engines on vessel) for the baseline technology (tons/yr) –
*(total annual emissions (all engines on vessel) for the baseline technology (tons/yr) **
reduced technology verification percentage)

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*Total annual surplus emission reductions for marine vessels by pollutant (tons/yr) = (propulsion engine annual surplus emission reductions (tons/yr) * number of propulsion engines) + (auxiliary engine annual surplus emission reductions (tons/yr) * number of auxiliary engines)*

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*Incremental cost ($) = cost of reduced technology ($) * maximum percentage of eligible cost*

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*Total annual weighted surplus emission reductions (tons/yr) = (fraction project life (yrs) * annual weighted surplus emissions from transaction 1 (tons/yr) / total project life (yrs)) + (fraction project life (yrs) * annual weighted surplus emissions from transaction 2 (tons/yr) / total project life (yrs))*

Total annual weighted surplus emission reductions (tons/yr) =
$(n_1 * a_1 / t) + (n_2 * a_2 / t)$
where:
n_1 *= fraction project life from transaction 1 (yrs)*
n_2 *= fraction project life from transaction 2 (yrs)*
a_1 *= annual weighted surplus emissions from transaction 1 (tons/yr)*
a_2 *= annual weighted surplus emissions from transaction 2 (tons/yr)*
t = total project life (yrs)

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Applicant cost share ($) ≥ 15 percent * moyer eligible costs ($)

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Total project cost ≥ applicant cost share ($) + ∑grants paid ($)

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*Cost-effectiveness ($/ton) = grant amount ($) * CRF / annual weighted surplus emission reductions (weighted tons/yr)*

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APPENDIX D

TABLES FOR EMISSION REDUCTION AND COST-EFFECTIVENESS CALCULATIONS

APPENDIX D:

TABLES FOR EMISSION REDUCTION AND COST-EFFECTIVENESS CALCULATIONS

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Table D-
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Adjustment Factor Life [a] and Fixed and Deterioration Rate Life Time DR

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Table D-1
Alternative Fuel Reduction Transportation Conversion Factors (pounds per gallon)[a]

Onroad Mode and Year	CO2	RO[b]	CH4[c]
Current	5.0	1.0	1.0
Future	4.0	1.0	1.0
Light Duty Vehicles Less than 8,500 lbs GVWR	1.0	1.0	1.0
Light Duty Trucks[1] Greater than 8,500 lbs GVWR	1.0	1.0	1.0
Light Duty Trucks[2] Greater than 5 Less than 8,500 lbs GVWR	1.0	1.0	1.0
Heavy Duty Vehicles[3] Greater than 8,500 lbs GVWR	1.0	1.0	1.0

Conversion factors are based on the percentage reduction in emissions from a conventional vehicle operating on gasoline or diesel fuel. Conversion factors for Light Duty Vehicles and Light Duty Trucks are based on the Tier 1 Federal Motor Vehicle Control Program (FMVCP) standards. Conversion factors for Heavy Duty Vehicles are based on the 1998 FMVCP standards. Conversion factors for Future vehicles are based on the Tier 2 FMVCP standards. Conversion factors for Current vehicles are based on the FMVCP standards for the model year of the vehicle.

[a] Mobile source emissions are calculated using the Mobile6 model.
[b] Mobile source emissions are calculated using the Mobile6 model and reported as Reactive Organic Gases (ROG).
    ROG = Reactive Organic Gases
    ROG = Reactive Organic Compounds
[c] Conversion factors for methane are based on the percentage reduction in emissions from a conventional vehicle operating on gasoline or diesel fuel. Conversion factors for Light Duty Vehicles and Light Duty Trucks are based on the Tier 1 FMVCP standards. Conversion factors for Heavy Duty Vehicles are based on the 1998 FMVCP standards. Conversion factors for Future vehicles are based on the Tier 2 FMVCP standards. Conversion factors for Current vehicles are based on the FMVCP standards for the model year of the vehicle.
[d] Conversion factors for Light Duty Trucks are based on the Tier 1 FMVCP standards for vehicles less than 6,000 lbs GVWR and on the 1998 FMVCP standards for vehicles greater than 6,000 lbs GVWR.

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Table D-1
Off-Road Diesel Engine Department Load Factors
(Continued)

Category	Equipment Type	Load Factor
Generator Sets	Generator Set 50 hp and under	0.74
	Generator Set 51 hp and over	0.74
	Grader	0.61
	Hoist	0.35
	Hydraulic Crane	0.43
	Rollers	0.56
	Rough Terrain Forklift	0.60
	Rubber Tired Dozer	0.59
	Rubber Tired Loader	0.36
	Scraper	0.72
	Signal Boat	0.27
	Skid Steer Loader	0.37
	Surfacing Equipment	0.30
	Sweeper/Scrubber	0.46
	Tractor/Loader/Backhoe	0.37
	Trenchers	0.50
	Welder	0.45
Aerial Lifts	Aerial Lifts	0.31
	Forklift	0.20
	Sweeper/Scrubber	0.46
	Welder	0.45
Cranes	Crane	0.29
	Hydraulic Crane	0.43
Other Construction Equipment	Concrete/Industrial Saws	0.56
	Cement and Mortar Mixer	0.56
	Paving Equipment	0.53
	Plate Compactor	0.43
	Pressure Washer	0.30
	Shredder	0.50
Pumps	Pump	0.74

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Table D-
Controlled Old Road Depletion Equation
Emission Factor Exponent and Deterioration Rate Parameter DR[a]

Pollutant Group	Tier	HC		RHC		PM	
		EF	DR	EF	DR	EF	DR
1985	1	5					
	2				5		
	3 (Reserved)	55	5				
	4 (Reserved)	5	5				
5	1	5	5			55	
	2	5			5		
	3[b]						
	4 (Reserved)						
	5 (Reserved)						
5	1	5	5			55	
	2	5			5		
	3						
	4 (Reserved)						
	5 (Reserved) for Engine Displacement < 1.0 L	5					
	6 (Reserved)		5	5	5		
Motorcycles	1	5	5				
	2	5		5			
	3						
	4 (Reserved)						
	5 (Reserved) for Engine Displacement < 1.0 L	5					
	6 (Reserved)			5			

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Table D
Off-Road Equipment Default Load Factors
(Continued)

Category	Equipment Type	Load Factor
[illegible]	[illegible]	[illegible]
	[illegible]	0.5
	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	[illegible]
	[illegible]	0.5

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Table D-1b
Controlled Carbon Concentration Online
Oxidation Factor Subparagraph

Corrective Order	Tier	CO2	ROG	CH4
5-5	1	0.995	0.995	0.95
	2	0.5	0.995	0.995
	3	0.5	0.995	0.995
5-10	1	0.995	0.995	0.95
	2	0.5	0.995	0.995
	3	0.5	0.995	0.995
10-15	1	0.995	0.995	0.995
	2	0.995	0.995	0.995
	3	0.995	0.995	0.995
15-5	1	0.995	0.995	0.995
	2	0.995	0.995	0.995
	3	0.995	0.995	0.995
5-10	1	0.995	0.995	0.995
	2	0.5	0.995	0.995
	3	0.995	0.995	0.995
10-5	1	0.995	0.995	0.995
	2	0.995	0.995	0.995
	3	0.995	0.995	0.995

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Table D-1
Score Power
Default Power Requirement

Risk Category	Service Temperature (Ambient Unit Temperature)	Power Requirement (kW)
Category I	[illegible]	[illegible]
	[illegible] – [illegible]	[illegible]
	[illegible] – [illegible]	[illegible]
	[illegible] – [illegible]	[illegible]
	[illegible] – [illegible]	[illegible]
	5[illegible] – 5[illegible]	[illegible]
	[illegible] – [illegible]	[illegible]5[illegible]
	[illegible] – [illegible]	[illegible]
	[illegible] – [illegible]	[illegible]
	[illegible] – [illegible]	[illegible]
Category [illegible]	[illegible] D[illegible] – [illegible] [illegible]	
Reserved	[illegible]	[illegible]
	[illegible] [illegible]	[illegible]

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Table D
Fuel Correction Factors
On-Road Diesel Engines

Model Year	On	Mid	Cold
Pre- – Pre-			
Pre-			

Table D
Capital Recovery Factor (CRF) for Various Project Lifetimes
at a Given Discount Rate

Project Lifetime	CRF
5	
5	
	55

Table D-15
Capital Recovery Factor (CRF) for Various Project Lifetimes
at a Discount Rate[a,b]

Project Lifetime	CRF
1	1.0700
2	0.5531
3	0.3811
4	0.2952
5	0.2439
6	0.2098
7	0.1856
8	0.1675
9	0.1535
10	0.1424
11	0.1334
12	0.1259
13	0.1197
14	0.1143
15	0.1098
16	0.1059
17	0.1024
18	0.0994
19	0.0968
20	0.0944

[a] The Office of Management and Budget (OMB) requires that federal agencies use a discount rate of 7 percent when evaluating the costs and benefits of proposed regulations affecting investments in private capital. OMB requires that a discount rate of 7 percent be used unless specific statutory requirements dictate the use of a different discount rate. OMB's discount rate of 7 percent is based on the estimated average before-tax rate of return to private capital in the U.S. economy. OMB's discount rate of 7 percent is also used by the Federal Energy Regulatory Commission (FERC) in evaluating the costs and benefits of proposed regulations affecting investments in private capital.

[b] The Department of Energy (DOE) requires that a discount rate of 3 percent be used when evaluating the costs and benefits of proposed regulations affecting investments in private capital. DOE's discount rate of 3 percent is based on the estimated average before-tax rate of return to private capital in the U.S. economy. DOE's discount rate of 3 percent is also used by the Federal Energy Regulatory Commission (FERC) in evaluating the costs and benefits of proposed regulations affecting investments in private capital.

APPENDIX E

CHAPTER REFERENCES

APPENDIX E: CHAPTER REFERENCES

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Indirect Source Review Program

2023 ANNUAL REPORT

July 1, 2022 - June 30, 2023

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

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Appendix A: Administrative Rule Text A-1

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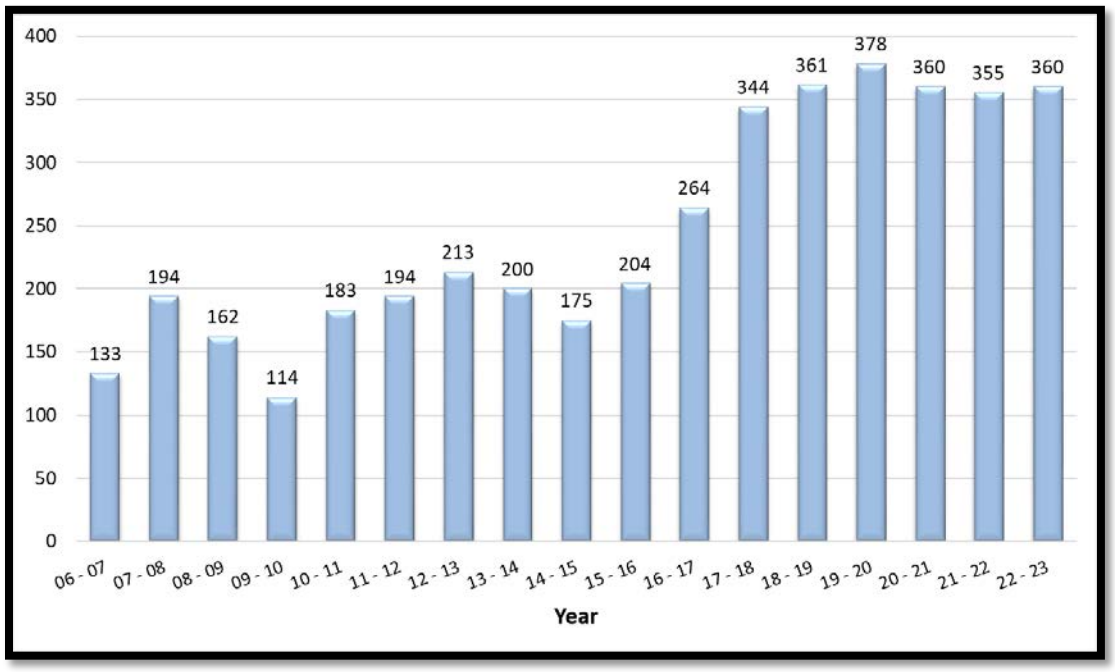
III. IMPLEMENTATION

[illegible]

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Fi[illegible]re [illegible] ber o l R A [illegible] i ation Re ei ed



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[illegible] [illegible]r [illegible] [illegible] R d [illegible] [illegible]r [illegible] [illegible] [illegible]

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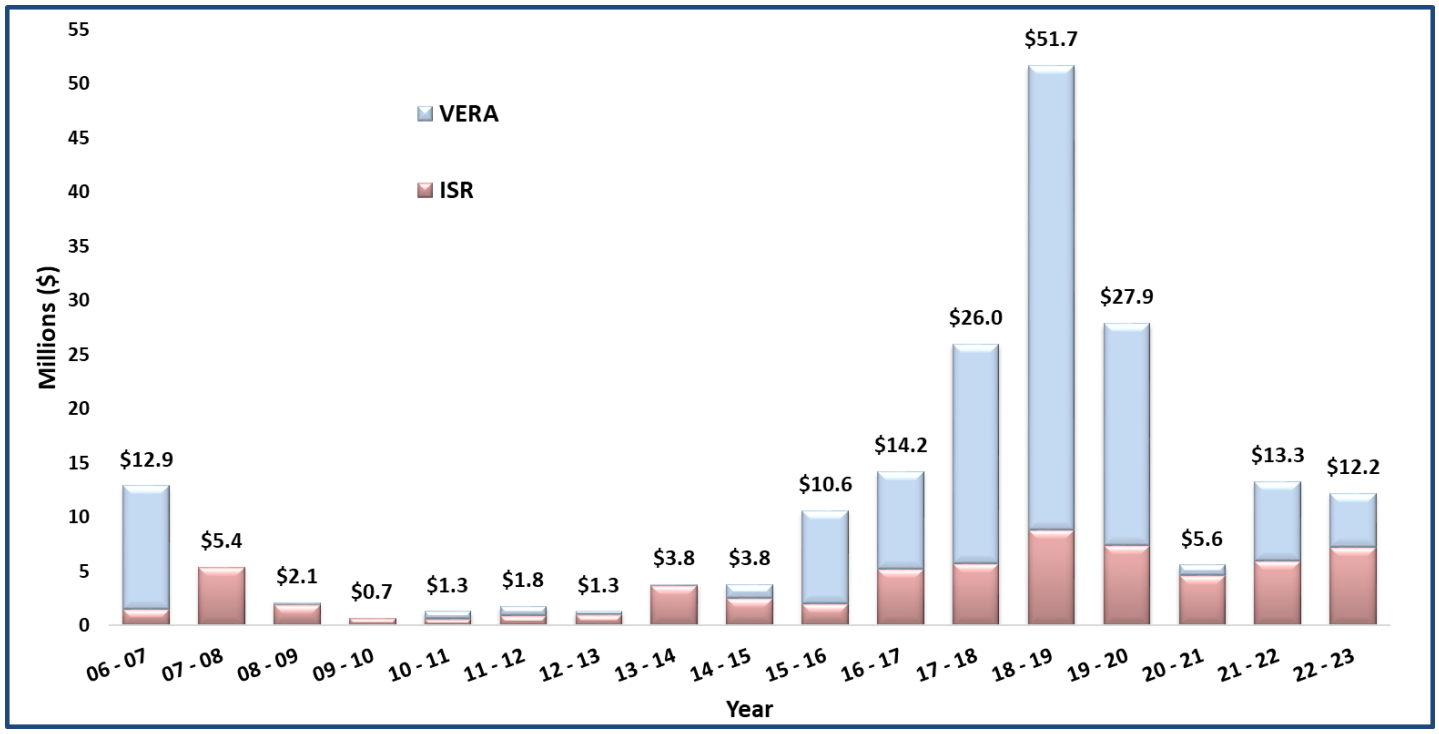
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[illegible]

Figure [illegible] [illegible] and [illegible] Funds Received



[illegible]

[illegible]

Table [illegible] IRA Fi[illegible]a[illegible] [illegible] ar[illegible]ne[illegible]

	IRA	RA	Tota[illegible]
Be innin F nd Ba an e	[illegible]	[illegible]5[illegible]	[illegible]
[illegible] R[illegible]d	[illegible]5[illegible]	5[illegible]	[illegible]5[illegible]
[illegible] R[illegible]d d	[illegible]	[illegible]	[illegible]
[illegible] [illegible] d [illegible]	[illegible]	[illegible]5	[illegible]
d[illegible] [illegible] d [illegible]	5[illegible]55[illegible]	[illegible]	[illegible]
[illegible] r d [illegible]	[illegible]5[illegible]	[illegible]5 5[illegible]	[illegible]5 5[illegible]
ndin [illegible]nen [illegible] bered A o nt	[illegible]	[illegible]	[illegible]

[illegible]MI[illegible]IO[illegible]R[illegible]D[illegible]CTIO[illegible][illegible]MMAR[illegible]

[illegible]r[illegible] [illegible] D[illegible]r[illegible] [illegible]r[illegible] [illegible]d [illegible] [illegible]r[illegible] [illegible] [illegible]r[illegible] [illegible] [illegible]r[illegible]d[illegible] [illegible]r[illegible] [illegible]d[illegible] [illegible] [illegible]r[illegible] [illegible] [illegible]r[illegible] [illegible] [illegible] D[illegible]r[illegible]d [illegible] [illegible]r[illegible] [illegible] [illegible] [illegible]d [illegible] [illegible]r[illegible] [illegible] [illegible] [illegible] [illegible]r[illegible] [illegible] [illegible] [illegible] [

[illegible]

Table [illegible] Opioid Prescription Reduction Awarded [illegible]

Program	Opioid Prescription	Medication Assisted Treatment	Total Prescription	Amount Awarded Out	Cost per Prescription Reduced
[illegible]R	[illegible]5	[illegible]	[illegible]55	[illegible]5	[illegible]
[illegible]R	[illegible]5[illegible]	[illegible]	[illegible]5[illegible]	[illegible]5	[illegible]5[illegible]
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

[illegible]R [illegible]d [illegible]R [illegible]

[illegible]d [illegible] [illegible]R [illegible]d [illegible]r [illegible]R [illegible]d [illegible]r [illegible]R [illegible]d [illegible]r

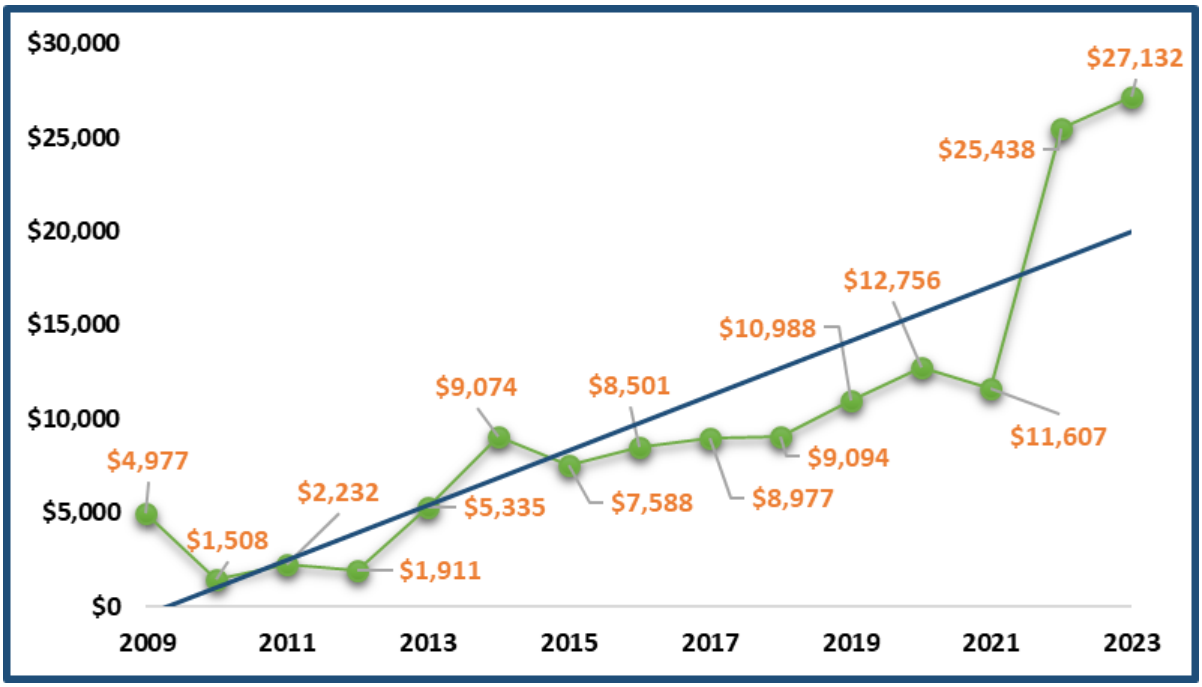
Table [illegible] Estimated [illegible] Emission Reductions from Approved Project Activities During the Crediting Period [illegible]

[illegible]	[illegible] tons [illegible]	[illegible] tons [illegible]	Total [illegible] tons [illegible]
[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]
Total	[illegible]	[illegible]	[illegible]

[illegible] CONTRIBUTION [illegible]

[illegible] [illegible] [illegible] [

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Grant Project Number	Program	Component	Option	NOx Reduced (tons/project life)	PM10 Reduced (tons/project life)
G-107675	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-100120	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-103917	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-104040	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-104804	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-104934	Burn Cleaner	Wood Stove Change Out	New Device		0.6926
G-105619	Burn Cleaner	Wood Stove Change Out	New Device		0.3199
G-105962	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-106315	Burn Cleaner	Wood Stove Change Out	New Device		0.4618
G-106544	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-106604	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-106890	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-107411	Burn Cleaner	Wood Stove Change Out	New Device		0.3182
G-107556	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-107704	Burn Cleaner	Wood Stove Change Out	New Device		0.4618
G-107705	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-107823	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-107839	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-107950	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-108075	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-108246	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-108397	Burn Cleaner	Wood Stove Change Out	New Device		0.6926
G-108719	Burn Cleaner	Wood Stove Change Out	New Device		0.08
G-109017	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-109023	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-109932	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-110787	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-111705	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-112434	Burn Cleaner	Wood Stove Change Out	New Device		0.0618
G-112948	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-113229	Burn Cleaner	Wood Stove Change Out	New Device		0.4618
G-113387	Burn Cleaner	Wood Stove Change Out	New Device		0.4618
G-114307	Burn Cleaner	Wood Stove Change Out	New Device		0.4618
G-114563	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-114633	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-114862	Burn Cleaner	Wood Stove Change Out	New Device		0.0796

G-114898	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-115675	Burn Cleaner	Wood Stove Change Out	New Device		0.4618
G-115690	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-115763	Burn Cleaner	Wood Stove Change Out	New Device		0.6926
G-115879	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-116237	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-116631	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-116641	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-117215	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-117544	Burn Cleaner	Wood Stove Change Out	New Device		0.4618
G-117560	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-117577	Burn Cleaner	Wood Stove Change Out	New Device		0.0177
G-117783	Burn Cleaner	Wood Stove Change Out	New Device		0.4798
G-117921	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-118045	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-118302	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-118621	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-118669	Burn Cleaner	Wood Stove Change Out	New Device		0.6926
G-119188	Burn Cleaner	Wood Stove Change Out	New Device		1.1544
G-119284	Burn Cleaner	Wood Stove Change Out	New Device		0.4618
G-119294	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-119375	Burn Cleaner	Wood Stove Change Out	New Device		0.9235
G-119598	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-119673	Burn Cleaner	Wood Stove Change Out	New Device		0.4946
G-119678	Burn Cleaner	Wood Stove Change Out	New Device		0.1237
G-121158	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-121965	Burn Cleaner	Wood Stove Change Out	New Device		0.1197
G-121973	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-122783	Burn Cleaner	Wood Stove Change Out	New Device		0.3199
G-123106	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-124185	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-124508	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-125410	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-126765	Burn Cleaner	Wood Stove Change Out	New Device		0.1419
G-126984	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-127445	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-127738	Burn Cleaner	Wood Stove Change Out	New Device		0.6926
G-128895	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-129431	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-130509	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-131251	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-131876	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-132276	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-132885	Burn Cleaner	Wood Stove Change Out	New Device		0.0177

G-132925	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-133166	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-133173	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-133715	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-133716	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-134058	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-135611	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-136082	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-136212	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-136364	Burn Cleaner	Wood Stove Change Out	New Device		0.1154
G-137895	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-138343	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-138833	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
G-139882	Burn Cleaner	Wood Stove Change Out	New Device		0.0577
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G-143232	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-144997	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
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G-145141	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
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G-146561	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
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G-146696	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-146719	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-146723	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-146737	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-146845	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-146879	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-146906	Burn Cleaner	Wood Stove Change Out	New Device		0.3182
G-146935	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-147005	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-147017	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-147138	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-147147	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-147189	Burn Cleaner	Wood Stove Change Out	New Device		0.3182
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G-147247	Burn Cleaner	Wood Stove Change Out	New Device		0.2309

G-147264	Burn Cleaner	Wood Stove Change Out	New Device		0.3182
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G-147313	Burn Cleaner	Wood Stove Change Out	New Device		0.1599
G-147316	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-147336	Burn Cleaner	Wood Stove Change Out	New Device		0.1599
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G-147400	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-147401	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
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G-147407	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
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G-147445	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-147446	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-147457	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
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G-147549	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-147558	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-147560	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-147561	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
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G-147567	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-147592	Burn Cleaner	Wood Stove Change Out	New Device		0.1599
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G-147634	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-147644	Burn Cleaner	Wood Stove Change Out	New Device		0.0709
G-147648	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
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G-150633	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-150635	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-150648	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-150700	Burn Cleaner	Wood Stove Change Out	New Device		0.1599
G-150725	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-150729	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-150735	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-150788	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-150800	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-150955	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-150959	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-150975	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-150982	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151052	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151070	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151172	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151173	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151206	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151212	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151218	Burn Cleaner	Wood Stove Change Out	New Device		0.2473
G-151230	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151232	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151234	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151236	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151239	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151265	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151266	Burn Cleaner	Wood Stove Change Out	New Device		0.3182
G-151294	Burn Cleaner	Wood Stove Change Out	New Device		0.3182
G-151328	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151370	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151374	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151377	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151381	Burn Cleaner	Wood Stove Change Out	New Device		0.2309

G-151387	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151390	Burn Cleaner	Wood Stove Change Out	New Device		0.0709
G-151440	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151484	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151509	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151511	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151513	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151517	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151562	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151630	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151651	Burn Cleaner	Wood Stove Change Out	New Device		0.3182
G-151653	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151665	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151669	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151670	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151673	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151690	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151725	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151730	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151759	Burn Cleaner	Wood Stove Change Out	New Device		0.3182
G-151764	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151783	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151792	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151825	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151833	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151834	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151952	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151958	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151959	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-151965	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152042	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152055	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152083	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152085	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152089	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152095	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152167	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152173	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152186	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152192	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152197	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152219	Burn Cleaner	Wood Stove Change Out	New Device		0.0709
G-152229	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152233	Burn Cleaner	Wood Stove Change Out	New Device		0.2309

G-152255	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152261	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152268	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152280	Burn Cleaner	Wood Stove Change Out	New Device		0.1599
G-152315	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152368	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152370	Burn Cleaner	Wood Stove Change Out	New Device		0.3182
G-152387	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152430	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152448	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152487	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152488	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152489	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152490	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152497	Burn Cleaner	Wood Stove Change Out	New Device		0.0709
G-152589	Burn Cleaner	Wood Stove Change Out	New Device		0.3182
G-152598	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152629	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152745	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152748	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152791	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152796	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152802	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-152830	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-153078	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-153091	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-153095	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-153245	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-153251	Burn Cleaner	Wood Stove Change Out	New Device		0.2473
G-153282	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-153455	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-153458	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-153571	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-153579	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-153611	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-153630	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-153670	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-153671	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-153677	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-153754	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-153767	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-153786	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-153833	Burn Cleaner	Wood Stove Change Out	New Device		0.0709
G-153837	Burn Cleaner	Wood Stove Change Out	New Device		0.3182

G-153914	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-154027	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-154097	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-154114	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-154132	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-154324	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-155428	Burn Cleaner	Wood Stove Change Out	New Device		0.2309
G-86836	Burn Cleaner	Wood Stove Change Out	New Device		0.1596
G-89710	Burn Cleaner	Wood Stove Change Out	New Device		0.23088
G-90802	Burn Cleaner	Wood Stove Change Out	New Device		0.23088
G-91215	Burn Cleaner	Wood Stove Change Out	New Device		0.23088
G-83839	Heavy-Duty	Off-Road	Ag Tractor Replacement	9.9	0.49
C-46128-1	Heavy-Duty	Off-Road	Ag Tractor Replacement	7.99	0.6
C-57171-1	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.04	0.11
C-59505-1	Heavy-Duty	Off-Road	Ag Tractor Replacement	6.7	0.46
C-59507-1	Heavy-Duty	Off-Road	Ag Tractor Replacement	3.99	0.26
C-62529-1	Heavy-Duty	Dairy Feed Mixer	Electrification	59.63	4.63
G-101534	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.09	0.02
G-103338	Heavy-Duty	Off-Road	Ag Tractor Replacement	38.09	1.99
G-103392	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.74	0.15
G-103397	Heavy-Duty	Off-Road	Ag Tractor Replacement	9.35	0.79
G-107026	Heavy-Duty	Off-Road	Ag Tractor Replacement	4.5	0.41
G-107105	Heavy-Duty	Off-Road	Ag Tractor Replacement	2.89	0.19
G-107121	Heavy-Duty	Off-Road	Ag Tractor Replacement	7.49	0.68
G-107141	Heavy-Duty	Off-Road	Ag Tractor Replacement	12.75	0.94
G-107431	Heavy-Duty	Off-Road	Ag Tractor Replacement	6.8	0.62
G-107830	Heavy-Duty	Off-Road	Ag Tractor Replacement	5.5	0.47
G-107832	Heavy-Duty	Off-Road	Ag Tractor Replacement	3.25	0.21
G-107838	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.44	0.36
G-108011	Heavy-Duty	Off-Road	Ag Tractor Replacement	8.94	0.62
G-108013	Heavy-Duty	Off-Road	Ag Tractor Replacement	12.95	0.69
G-108706	Heavy-Duty	Off-Road	Ag Tractor Replacement	7.28	0.93
G-108943	Heavy-Duty	Off-Road	Ag Tractor Replacement	2.57	0.23
G-109115	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.67	0.2
G-109128	Heavy-Duty	Off-Road	Ag Tractor Replacement	6.45	0.59
G-109418	Heavy-Duty	Off-Road	Ag Tractor Replacement	15.47	0.39
G-110225	Heavy-Duty	Off-Road	Ag Tractor Replacement	13.17	0.7
G-110530	Heavy-Duty	Off-Road	Ag Tractor Replacement	21.08	0.6
G-110587	Heavy-Duty	Off-Road	Ag Tractor Replacement	20.67	1.1
G-110695	Heavy-Duty	Off-Road	Ag Tractor Replacement	7.49	0.75
G-110713	Heavy-Duty	Off-Road	Ag Tractor Replacement	22.55	1.67
G-110715	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.91	0.29
G-110716	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.91	0.29
G-110717	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.91	0.29

G-110718	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.91	0.29
G-110719	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.91	0.29
G-110721	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.91	0.29
G-110864	Heavy-Duty	Off-Road	Ag Tractor Replacement	4.29	0.41
G-110910	Heavy-Duty	Off-Road	Ag Tractor Replacement	2.08	0.27
G-110959	Heavy-Duty	Off-Road	Ag Tractor Replacement	7.37	0.51
G-111049	Heavy-Duty	Off-Road	Ag Tractor Replacement	23.31	1.34
G-111249	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.73	0.23
G-111288	Heavy-Duty	Off-Road	Ag Tractor Replacement	5.72	0.42
G-111289	Heavy-Duty	Off-Road	Ag Tractor Replacement	5.72	0.42
G-111449	Heavy-Duty	Off-Road	Ag Tractor Replacement	4.17	0.35
G-111623	Heavy-Duty	Off-Road	Ag Tractor Replacement	4.71	0.35
G-111722	Heavy-Duty	Off-Road	Ag Tractor Replacement	7.08	0.65
G-112038	Heavy-Duty	Off-Road	Ag Tractor Replacement	6.68	0.5
G-112039	Heavy-Duty	Off-Road	Ag Tractor Replacement	6.68	0.5
G-113687	Heavy-Duty	Off-Road	Ag Tractor Replacement	4	0.2
G-113692	Heavy-Duty	Off-Road	Ag Tractor Replacement	19.17	1.09
G-113696	Heavy-Duty	Off-Road	Ag Tractor Replacement	5.46	0.7
G-113698	Heavy-Duty	Off-Road	Ag Tractor Replacement	9.73	0.72
G-115004	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.98	0.35
G-116114	Heavy-Duty	Off-Road	Ag Tractor Replacement	3.84	0.36
G-116974	Heavy-Duty	Off-Road	Ag Tractor Replacement	8.07	0.6
G-117435	Heavy-Duty	Off-Road	Ag Tractor Replacement	16.48	0.47
G-119291	Heavy-Duty	Off-Road	Ag Tractor Replacement	9.31	0.61
G-124495	Heavy-Duty	Off-Road	Ag Tractor Replacement	16.79	0.48
G-124546	Heavy-Duty	Off-Road	Ag Tractor Replacement	12.27	0.65
G-125113	Heavy-Duty	Off-Road	Ag Tractor Replacement	28.24	1.96
G-125670	Heavy-Duty	Off-Road	Ag Tractor Replacement	4.12	0.37
G-126551	Heavy-Duty	Off-Road	Ag Tractor Replacement	8.32	0.62
G-140677	Heavy-Duty	Ag Engine	Diesel to Diesel	2.86	0.16
G-66106	Heavy-Duty	Off-Road	Ag Tractor Replacement	14.31	0.76
G-66108	Heavy-Duty	Off-Road	Ag Tractor Replacement	17.27	1.19
G-66109	Heavy-Duty	Off-Road	Ag Tractor Replacement	13.83	1.26
G-66110	Heavy-Duty	Off-Road	Ag Tractor Replacement	25.6	0.8
G-66560	Heavy-Duty	Off-Road	Ag Tractor Replacement	9.67	0.88
G-66565	Heavy-Duty	Off-Road	Ag Tractor Replacement	10.16	0.92
G-66568	Heavy-Duty	Off-Road	Ag Tractor Replacement	9.67	0.88
G-66946	Heavy-Duty	Off-Road	Ag Tractor Replacement	14.67	0.78
G-69348	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.03	0.11
G-69618	Heavy-Duty	Off-Road	Ag Tractor Replacement	8.58	0.49
G-73414	Heavy-Duty	Locomotive	Replacement	64.69	1.5
G-73416	Heavy-Duty	Locomotive	Replacement	64.69	1.5
G-75359	Heavy-Duty	Off-Road	Ag Tractor Replacement	3.97	0.36
G-76150	Heavy-Duty	Off-Road	Ag Tractor Replacement	6.3	0.57

G-76304	Heavy-Duty	Off-Road	Ag Tractor Replacement	4.39	0.33
G-78575	Heavy-Duty	Off-Road	Ag Tractor Replacement	27.13	0.69
G-80530	Heavy-Duty	Ag Engine	Alt Fuel to Electric	4.23	0.1
G-80920	Heavy-Duty	Off-Road	Ag Tractor Replacement	3.64	0.24
G-80971	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.01	0.08
G-81259	Heavy-Duty	Off-Road	Ag Tractor Replacement	11.98	0.63
G-81732	Heavy-Duty	Off-Road	Ag Tractor Replacement	39.25	2.08
G-81861	Heavy-Duty	Off-Road	Ag Tractor Replacement	9.39	0.49
G-89922	Heavy-Duty	Off-Road	Ag Tractor Replacement	13.11	0.7
G-89925	Heavy-Duty	Off-Road	Ag Tractor Replacement	2.27	0.16
G-92722	Heavy-Duty	Off-Road	Ag Tractor Replacement	5.72	0.42
G-92840	Heavy-Duty	Off-Road	Ag Tractor Replacement	14.91	0.85
G-92845	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.16	0.04
G-92846	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.16	0.04
G-92854	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.16	0.04
G-92856	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.34	0.1
G-93091	Heavy-Duty	Off-Road	Ag Tractor Replacement	2.18	0.14
G-94125	Heavy-Duty	Off-Road	Ag Tractor Replacement	25.32	1.34
G-94432	Heavy-Duty	Off-Road	Ag Tractor Replacement	8.15	0.41
G-95177	Heavy-Duty	Off-Road	Ag Tractor Replacement	23.6	1.25
G-95421	Heavy-Duty	Off-Road	Ag Tractor Replacement	2.67	0.26
G-95474	Heavy-Duty	Off-Road	Ag Tractor Replacement	6.29	0.47
G-95716	Heavy-Duty	Off-Road	Ag Tractor Replacement	0.88	0.1
G-95717	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.49	0.18
G-95719	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.89	0.23
G-95721	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.88	0.23
G-95738	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.77	0.22
G-95744	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.34	0.16
G-95745	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.37	0.17
G-95746	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.48	0.18
G-95747	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.36	0.16
G-95748	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.01	0.12
G-96110	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.51	0.18
G-96111	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.51	0.18
G-96112	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.42	0.17
G-96113	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.51	0.18
G-96114	Heavy-Duty	Off-Road	Ag Tractor Replacement	1.47	0.18
G-97962	Heavy-Duty	Off-Road	Ag Tractor Replacement	7.56	0.56
G-98464	Heavy-Duty	Ag Engine	Alt Fuel to Electric	1.19	0.14
G-99415	Heavy-Duty	Off-Road	Ag Tractor Replacement	4.66	0.13
G-88837	Heavy-Duty	Off-Road	Ag Tractor Replacement	35.43	1.87
C-63331-1	Heavy-Duty	Off-Road	Ag Tractor Replacement	30.11	1.72
G-107900	Heavy-Duty	Off-Road	Ag Tractor Replacement	20.54	1.17
G-115048	Heavy-Duty	Off-Road	Ag Tractor Replacement	16.2	2.11

C-54743-1	Heavy-Duty	Off-Road	Ag Tractor Replacement	14.33	0.39
G-141940	Heavy-Duty	Off-Road	Ag Tractor Replacement	11.48	1.05
G-135044	Heavy-Duty	Off-Road	Ag Tractor Replacement	12.11	0.38
G-114796	Heavy-Duty	Off-Road	Ag Tractor Replacement	11.37	0.65
G-112907	Heavy-Duty	Off-Road	Ag Tractor Replacement	11.34	0.57
C-53942-1	Heavy-Duty	Off-Road	Ag Tractor Replacement	11.24	0.56
G-113329	Heavy-Duty	Off-Road	Ag Tractor Replacement	11.36	0.33
C-51760-1	Heavy-Duty	Off-Road	Ag Tractor Replacement	10.03	1.29
G-133703	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0001	0.0001
G-116489	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-125668	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-130761	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-131764	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-132155	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-132170	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-132878	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-132884	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-132979	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-133159	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0095	0.0016
G-133189	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-133341	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-133384	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-133542	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-133551	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-133627	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-133634	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0083	0.0014
G-133635	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-133638	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-133642	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-133733	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-133740	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-133834	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-133835	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-133873	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-133879	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0086	0.0014
G-133903	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0086	0.0014
G-133906	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-133913	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-133919	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-133929	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-133982	Light-Duty	Drive Clean	EV Vehicle Rebate	0.033	0.0055
G-133986	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-133993	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134003	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001

G-134014	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134020	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-134028	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-134056	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134057	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134059	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0123	0.002
G-134229	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134232	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-134236	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134254	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0067	0.0011
G-134257	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-134258	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0057	0.0009
G-134290	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-134327	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134341	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-134359	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134361	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-134367	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-134387	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-134389	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-134390	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0081	0.0013
G-134392	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-134396	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-134397	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-134401	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134402	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0148	0.0025
G-134403	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0165	0.0028
G-134413	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134414	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134417	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134425	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0011
G-134426	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0139	0.0023
G-134428	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-134430	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0186	0.0031
G-134432	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-134434	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134437	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-134439	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-134440	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0072	0.0012
G-134442	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134447	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-134452	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0264	0.0044
G-134458	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0198	0.0033
G-134474	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018

G-134478	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-134518	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-134525	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-134526	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-134529	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-134530	Light-Duty	Drive Clean	EV Vehicle Rebate	0.063	0.0105
G-134531	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-134541	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-134556	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134567	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0064	0.0011
G-134573	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134574	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-134580	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0185	0.0031
G-134586	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134587	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134589	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-134606	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-134607	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-134610	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-134671	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134682	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0159	0.0026
G-134683	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134688	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-134702	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134705	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-134719	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134720	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-134724	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-134725	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0081	0.0013
G-134726	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-134732	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-134737	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-134746	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134747	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134748	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-134757	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-134764	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134766	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134769	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-134775	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134777	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134778	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0091	0.0015
G-134779	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-134780	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012

G-134781	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134783	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-134799	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134802	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-134812	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-134815	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134816	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-134817	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-134819	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-134821	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-134822	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134826	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-134827	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-134841	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-134846	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-134853	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-134855	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-134876	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-134880	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-134885	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-134890	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-134892	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0112	0.0019
G-134893	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-134894	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0058	0.001
G-134896	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0016
G-134927	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-134928	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-134932	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-134975	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-134977	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-134979	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-134991	Light-Duty	Drive Clean	EV Vehicle Rebate	0.006	0.001
G-134993	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0093	0.0015
G-135000	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-135003	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-135018	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-135027	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0139	0.0023
G-135029	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-135035	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-135041	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0124	0.0021
G-135053	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-135059	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-135070	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-135093	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013

G-135103	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-135108	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0159	0.0026
G-135111	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-135112	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-135114	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-135123	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0165	0.0028
G-135130	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-135131	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-135132	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-135140	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0198	0.0033
G-135143	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-135144	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-135150	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-135151	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-135152	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-135163	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-135168	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0067	0.0011
G-135188	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-135190	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-135210	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-135211	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-135217	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-135239	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-135241	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-135246	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-135253	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0064	0.0011
G-135276	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-135284	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-135285	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-135288	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0198	0.0033
G-135291	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-135303	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-135304	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-135306	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0198	0.0033
G-135369	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-135384	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-135388	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-135456	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-135476	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-135480	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0057	0.0009
G-135490	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-135528	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0049	0.0008
G-135529	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-135541	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013

G-135575	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0082	0.0014
G-135675	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0112	0.0019
G-135681	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-135682	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-135697	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0198	0.0033
G-135709	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0238	0.004
G-135809	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-135822	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0165	0.0028
G-135824	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-135827	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0185	0.0031
G-135836	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-135837	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-135844	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-135876	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-135882	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-135884	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-135885	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-135935	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-135945	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0162	0.0027
G-135947	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-135967	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-135971	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-135972	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-135973	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-135974	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-135979	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-136056	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-136058	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-136059	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0198	0.0033
G-136071	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-136095	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-136131	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0231	0.0039
G-136133	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-136142	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-136146	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-136152	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0178	0.003
G-136186	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-136193	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-136195	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0264	0.0044
G-136199	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-136204	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-136213	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-136217	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-136224	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0107	0.0018

G-136233	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-136248	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0139	0.0023
G-136256	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-136259	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-136286	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0052	0.0009
G-136288	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-136346	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-136370	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0258	0.0043
G-136384	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-136433	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-136439	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-136447	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-136469	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-136473	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-136478	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0073	0.0012
G-136510	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-136556	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-136575	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-136614	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-136615	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-136637	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0047	0.0008
G-136652	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-136662	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-136947	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-136992	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-137066	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-137069	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-137265	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0198	0.0033
G-137267	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0162	0.0027
G-137460	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0082	0.0014
G-137495	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-137513	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-137519	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-137529	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-137535	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-137538	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0145	0.0024
G-137565	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0165	0.0028
G-137588	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-137602	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-137608	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-137613	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-137614	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-137678	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-137704	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0126	0.0021

G-137723	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-137831	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-137834	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-137844	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-137914	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-137974	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-138072	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0052	0.0009
G-138083	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-138092	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0073	0.0012
G-138124	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-138127	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-138137	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-138140	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-138200	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-138227	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-138233	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-138254	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-138256	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-138286	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-138299	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-138324	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0111	0.0019
G-138328	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0116	0.0019
G-138331	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-138336	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-138337	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-138387	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-138396	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-138408	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-138425	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-138449	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-138452	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-138494	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-138495	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-138496	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-138567	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-138568	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-138626	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0198	0.0033
G-138640	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-138646	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-138695	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-138696	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-138770	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0052	0.0009
G-138773	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-138786	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001

G-138794	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-138822	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-138823	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0047	0.0008
G-138841	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-138842	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-138844	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0143	0.0024
G-138852	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-138853	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-138897	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-138905	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-138950	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-138959	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-138968	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0185	0.0031
G-138978	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-139144	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-139150	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-139191	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-139201	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-139210	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-139213	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-139217	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-139302	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-139309	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-139314	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-139317	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-139333	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-139379	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-139432	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0083	0.0014
G-139436	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-139461	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-139469	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-139470	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-139471	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-139472	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-139474	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0095	0.0016
G-139476	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0159	0.0026
G-139483	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-139494	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-139506	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0083	0.0014
G-139529	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-139547	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0145	0.0024
G-139551	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-139567	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-139600	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0077	0.0013

G-139613	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-139643	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-139665	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-139678	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-139679	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-139697	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-139700	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-139722	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-139726	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-139783	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-139797	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-139805	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-139869	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-139890	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-139899	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-139924	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-139928	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-139937	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-139940	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-139953	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-139965	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-139970	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-139977	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-139979	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-139981	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-139993	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0093	0.0015
G-140024	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-140025	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-140026	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-140029	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-140031	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-140042	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0058	0.001
G-140053	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-140063	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0073	0.0012
G-140069	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-140141	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-140142	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-140152	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0141	0.0024
G-140167	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-140245	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0251	0.0042
G-140246	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-140253	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-140267	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0064	0.0011
G-140270	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001

G-140273	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-140288	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-140292	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0145	0.0024
G-140294	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0159	0.0026
G-140295	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-140296	Light-Duty	Drive Clean	EV Vehicle Rebate	0.013	0.0022
G-140305	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-140327	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-140375	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-140388	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-140393	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-140395	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-140397	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-140409	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-140411	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-140412	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-140413	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-140415	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-140427	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-140478	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-140481	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-140483	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-140527	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0157	0.0026
G-140577	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-140589	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-140641	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-140672	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-140690	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-140691	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-140692	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0058	0.001
G-140694	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-140696	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-140731	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-140749	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-140768	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-140773	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-140774	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-140789	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0149	0.0025
G-140818	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-140826	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-140828	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-140838	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-140844	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-140855	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022

G-140868	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-140882	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-140921	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0125	0.0021
G-140927	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0164	0.0027
G-140951	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-140967	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-140977	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-140983	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-141040	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0116	0.0019
G-141077	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0083	0.0014
G-141084	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-141088	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-141095	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-141101	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-141118	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-141119	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0011
G-141120	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0082	0.0014
G-141126	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-141133	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-141140	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0054	0.0009
G-141147	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-141162	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0198	0.0033
G-141171	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-141175	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-141182	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-141193	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-141207	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-141208	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-141209	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-141252	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-141299	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-141313	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-141318	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-141378	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-141430	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-141451	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-141505	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-141522	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-141584	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-141596	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0054	0.0009
G-141605	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-141611	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0238	0.004
G-141616	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0084	0.0014
G-141622	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013

G-141633	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-141644	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-141645	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-141646	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0112	0.0019
G-141648	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-141652	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-141665	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0198	0.0033
G-141681	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-141685	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-141694	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0078	0.0013
G-141708	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-141729	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-141732	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-141763	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-141764	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-141840	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-141853	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0113	0.0019
G-141877	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0051	0.0008
G-141878	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-141902	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-141933	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-141936	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-141937	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-141960	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-141966	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-141967	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-141968	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-141983	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-141993	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-142000	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-142004	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-142012	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-142016	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0185	0.0031
G-142020	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0054	0.0009
G-142063	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-142115	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-142117	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-142127	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-142157	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-142253	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0159	0.0026
G-142259	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-142265	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-142268	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-142291	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011

G-142292	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-142294	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-142302	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-142333	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-142338	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-142347	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-142350	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-142365	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0057	0.0009
G-142368	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-142375	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-142389	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-142396	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-142398	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-142403	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-142404	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-142410	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-142430	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-142466	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0096	0.0016
G-142467	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-142470	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-142488	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0086	0.0014
G-142494	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-142496	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0067	0.0011
G-142497	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-142504	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-142505	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-142513	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-142517	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-142547	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-142554	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-142560	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-142572	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-142621	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0057	0.0009
G-142628	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0188	0.0031
G-142633	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-142649	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-142650	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-142651	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-142653	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-142671	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0098	0.0016
G-142677	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0231	0.0039
G-142679	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-142698	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-142699	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002

G-142701	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-142702	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-142710	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-142721	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-142722	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-142731	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-142741	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0101	0.0017
G-142746	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-142759	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-142767	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-142770	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0051	0.0008
G-142775	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-142777	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-142782	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-142826	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-142838	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-142872	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-142923	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-142927	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-142963	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0109	0.0018
G-143036	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-143049	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-143072	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-143076	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-143078	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-143112	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-143225	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-143265	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-143266	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-143269	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-143274	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-143290	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-143294	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-143298	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0083	0.0014
G-143317	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-143318	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-143320	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-143339	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0083	0.0014
G-143340	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-143371	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-143376	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-143377	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-143381	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-143383	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009

G-143385	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0113	0.0019
G-143386	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-143396	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-143399	Light-Duty	Drive Clean	EV Vehicle Rebate	0.014	0.0023
G-143410	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0073	0.0012
G-143411	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-143414	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-143426	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0077	0.0013
G-143453	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-143463	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-143734	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0297	0.005
G-143853	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0178	0.003
G-143861	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-143899	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-143946	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-143975	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-143976	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0211	0.0035
G-143991	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-143992	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-144097	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0095	0.0016
G-144103	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-144104	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-144117	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-144126	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-144136	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-144173	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-144198	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-144212	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-144243	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-144244	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-144245	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-144246	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-144253	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0086	0.0014
G-144262	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-144272	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-144275	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-144277	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0129	0.0021
G-144286	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0054	0.0009
G-144291	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-144323	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-144325	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0157	0.0026
G-144326	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-144373	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-144428	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013

G-144457	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-144476	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-144491	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-144512	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-144519	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0093	0.0015
G-144571	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0126	0.0021
G-144574	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0077	0.0013
G-144583	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0231	0.0039
G-144615	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-144625	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-144653	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-144670	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-144688	Light-Duty	Drive Clean	EV Vehicle Rebate	0.013	0.0022
G-144691	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-144707	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-144713	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-144738	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-144746	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0057	0.0009
G-144749	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-144753	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-144755	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-144758	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-144764	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0051	0.0008
G-144783	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-144847	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-144882	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-144883	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-144884	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-144906	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0085	0.0014
G-144907	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-144937	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-144938	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-144988	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-145045	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-145054	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-145068	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-145087	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-145091	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-145113	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-145117	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-145140	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0116	0.0019
G-145161	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-145164	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-145165	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012

G-145166	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-145167	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-145171	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-145175	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0159	0.0026
G-145180	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0054	0.0009
G-145194	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-145206	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-145218	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0067	0.0011
G-145220	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0143	0.0024
G-145224	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-145233	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-145237	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-145293	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-145295	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-145338	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-145340	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-145342	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-145365	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-145393	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-145395	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-145405	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-145412	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-145481	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-145515	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-145524	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0093	0.0015
G-145525	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-145531	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-145532	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-145533	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-145534	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-145539	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-145545	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-145546	Light-Duty	Drive Clean	EV Vehicle Rebate	0.014	0.0023
G-145549	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-145551	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-145572	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-145574	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0077	0.0013
G-145580	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-145583	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-145584	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0058	0.001
G-145585	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-145586	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0129	0.0021
G-145587	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-145588	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012

G-145590	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-145591	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-145593	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-145594	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-145596	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-145598	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-145599	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0129	0.0021
G-145607	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-145614	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-145640	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0067	0.0011
G-145675	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0095	0.0016
G-145678	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-145682	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-145719	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0126	0.0021
G-145724	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-145726	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-145731	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-145746	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-145747	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-145765	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-145776	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-145783	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0083	0.0014
G-145784	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-145793	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-145794	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-145845	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-145846	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0165	0.0028
G-145864	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-145906	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-145927	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-145951	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-145955	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0188	0.0031
G-145975	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-145976	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0109	0.0018
G-145983	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-145984	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-145991	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-146015	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-146016	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0064	0.0011
G-146025	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-146029	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-146034	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-146038	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-146044	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009

G-146062	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-146081	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-146097	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-146133	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-146141	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-146146	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-146149	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-146159	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0083	0.0014
G-146160	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-146229	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0188	0.0031
G-146239	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-146242	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0162	0.0027
G-146245	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0248	0.0041
G-146281	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0198	0.0033
G-146298	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-146318	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-146328	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-146344	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-146346	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-146373	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-146376	Light-Duty	Drive Clean	EV Vehicle Rebate	0.006	0.001
G-146378	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0134	0.0022
G-146385	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-146405	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-146406	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-146408	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-146426	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0068	0.0011
G-146436	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0093	0.0015
G-146440	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-146443	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-146453	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-146456	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-146465	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-146468	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-146469	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-146475	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-146481	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-146500	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-146505	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-146507	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-146512	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0067	0.0011
G-146516	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0083	0.0014
G-146523	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-146552	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011

G-146560	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-146566	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-146567	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-146573	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0169	0.0028
G-146626	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0084	0.0014
G-146635	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-146706	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0231	0.0039
G-146718	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-146735	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-146743	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-146744	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0095	0.0016
G-146774	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-146777	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-146813	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0149	0.0025
G-146832	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0165	0.0028
G-146833	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-146840	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-146842	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-146844	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-146850	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-146853	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0165	0.0028
G-146865	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-146866	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-146887	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-146892	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-146896	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-146913	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-146917	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0011
G-146936	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-146938	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-146993	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147050	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147053	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-147055	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147065	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-147070	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-147074	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-147160	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147170	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147179	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-147196	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-147197	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-147201	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147203	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001

G-147215	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-147218	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-147222	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-147225	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-147245	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0072	0.0012
G-147257	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147266	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-147269	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147275	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147282	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147285	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-147286	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147295	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-147298	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147302	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-147307	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-147312	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0113	0.0019
G-147338	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147342	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147343	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-147348	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-147349	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147361	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147366	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-147374	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0178	0.003
G-147385	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-147394	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147395	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-147396	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-147410	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147413	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147423	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-147426	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147437	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147465	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147466	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-147482	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-147489	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-147494	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-147495	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147553	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-147559	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-147572	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-147574	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001

G-147581	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-147585	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147586	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-147587	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-147597	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-147612	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-147616	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147630	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0112	0.0019
G-147633	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-147640	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-147659	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-147663	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-147683	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-147690	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-147692	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-147696	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-147704	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-147707	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-147712	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-147714	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147726	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-147734	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-147735	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-147736	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147738	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0159	0.0026
G-147739	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0064	0.0011
G-147742	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147749	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-147750	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147751	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-147752	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-147753	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-147754	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147755	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-147763	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-147770	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147771	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-147777	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-147779	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-147781	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-147786	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147788	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-147789	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-147791	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011

G-147816	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-147818	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-147819	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-147837	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-147838	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0088	0.0015
G-147843	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147848	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-147849	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147853	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-147854	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-147859	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-147862	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147863	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-147869	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-147872	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147874	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-147876	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-147878	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147880	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0058	0.001
G-147883	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-147884	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-147909	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0058	0.001
G-147912	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-147917	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-147918	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147934	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147948	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-147950	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-147954	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-147960	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-147969	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-147977	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-147979	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-148015	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-148016	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-148025	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148026	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148029	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-148031	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0051	0.0009
G-148034	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148041	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-148042	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-148044	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-148060	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011

G-148061	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-148062	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-148064	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-148067	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-148073	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-148079	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-148081	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0127	0.0021
G-148084	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-148093	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-148096	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-148101	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148104	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-148108	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-148109	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148111	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148117	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-148144	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-148145	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-148173	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-148176	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0088	0.0015
G-148195	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-148198	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-148200	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-148201	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-148205	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-148207	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148212	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148218	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-148237	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-148263	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-148267	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-148268	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-148281	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-148286	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-148296	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-148300	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-148304	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0151	0.0025
G-148308	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0083	0.0014
G-148320	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-148321	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0082	0.0014
G-148335	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-148339	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148340	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-148341	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011

G-148348	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-148370	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-148379	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148390	Light-Duty	Drive Clean	EV Vehicle Rebate	0.014	0.0023
G-148392	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0159	0.0026
G-148395	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-148418	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0095	0.0016
G-148448	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-148460	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-148464	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-148465	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-148514	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-148547	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-148550	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-148562	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0095	0.0016
G-148591	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-148604	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-148616	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148618	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-148619	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-148624	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148631	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-148632	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-148633	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-148634	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-148636	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-148646	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148649	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-148650	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-148652	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-148655	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148657	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-148660	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-148662	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-148665	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-148672	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-148673	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-148675	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-148682	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0107	0.0018
G-148685	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0005
G-148694	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-148699	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-148702	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-148714	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011

G-148716	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-148718	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-148723	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0149	0.0025
G-148744	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0206	0.0034
G-148758	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-148764	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-148765	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0073	0.0012
G-148772	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-148781	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-148788	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-148808	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-148818	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-148831	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-148834	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0213	0.0035
G-148839	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-148840	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-148893	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0145	0.0024
G-148913	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-148919	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-148926	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-148935	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-148937	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-148938	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-148974	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0051	0.0008
G-148979	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-148996	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-149002	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0077	0.0013
G-149004	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-149005	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-149008	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-149010	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-149012	Light-Duty	Drive Clean	EV Vehicle Rebate	0.014	0.0023
G-149054	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-149063	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-149065	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-149076	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149091	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-149093	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-149094	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0054	0.0009
G-149112	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-149115	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-149125	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149127	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149135	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001

G-149138	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-149148	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-149162	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-149188	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-149191	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-149216	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149218	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149221	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149236	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0067	0.0011
G-149252	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-149273	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-149275	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-149276	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-149279	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149280	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0095	0.0016
G-149281	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149287	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-149332	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0088	0.0015
G-149352	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-149378	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0086	0.0014
G-149389	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0198	0.0033
G-149393	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-149395	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0067	0.0011
G-149407	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-149424	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0149	0.0025
G-149433	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-149438	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-149443	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149444	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-149448	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-149449	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0152	0.0025
G-149454	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149461	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-149468	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-149470	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-149473	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149475	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-149479	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-149495	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149497	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-149499	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149504	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149508	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-149513	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013

G-149515	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-149516	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149517	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149518	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0077	0.0013
G-149521	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-149524	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-149525	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0086	0.0014
G-149527	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-149536	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-149554	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149557	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-149567	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-149569	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-149580	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0165	0.0028
G-149608	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-149614	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149617	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-149625	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0238	0.004
G-149627	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-149628	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149632	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-149633	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0009	0.0006
G-149642	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0103	0.0017
G-149655	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-149657	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-149658	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149659	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149667	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0083	0.0014
G-149683	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-149691	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-149694	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-149698	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149700	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149702	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-149704	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-149705	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-149707	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-149718	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-149772	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149782	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-149787	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0149	0.0025
G-149789	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-149791	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-149805	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009

G-149807	Light-Duty	Drive Clean	EV Vehicle Rebate	0.013	0.0022
G-149810	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-149813	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-149819	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-149821	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-149831	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149832	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0112	0.0019
G-149833	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-149840	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-149867	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-149871	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149882	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-149886	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149897	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-149898	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149900	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-149904	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-149905	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-149907	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-149908	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-149910	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149913	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149915	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-149920	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-149927	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149943	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149945	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149954	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-149967	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-149977	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149981	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149983	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-149987	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-149990	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-149994	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-150005	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-150014	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-150015	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0088	0.0015
G-150045	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-150048	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-150056	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-150060	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150069	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-150095	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0057	0.001

G-150096	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0088	0.0015
G-150123	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-150142	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-150143	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0008	0.0005
G-150161	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-150163	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-150176	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0143	0.0024
G-150180	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-150181	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-150196	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0083	0.0014
G-150197	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-150206	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-150222	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0064	0.0011
G-150228	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-150241	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-150248	Light-Duty	Drive Clean	EV Vehicle Rebate	0.012	0.002
G-150249	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0057	0.0009
G-150290	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0097	0.0016
G-150295	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-150296	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-150297	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-150324	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-150329	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-150331	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-150333	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0047	0.0008
G-150345	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-150347	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-150349	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-150358	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150364	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-150376	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150381	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-150382	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0157	0.0026
G-150388	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-150402	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-150405	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-150407	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0011
G-150409	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-150416	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-150418	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-150423	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-150428	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-150430	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0101	0.0017
G-150431	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0093	0.0015

G-150433	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-150435	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-150471	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-150485	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-150486	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-150512	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-150517	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-150518	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-150525	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-150529	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-150549	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-150561	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-150576	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0057	0.0009
G-150578	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-150592	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-150598	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-150606	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-150607	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-150608	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150609	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-150610	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-150613	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-150615	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-150617	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-150618	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-150619	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150630	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-150639	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0149	0.0025
G-150642	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-150646	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-150650	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0139	0.0023
G-150694	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-150704	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-150705	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-150709	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-150712	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150736	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-150738	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150741	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150756	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-150769	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-150775	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-150776	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-150781	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0067	0.0011

G-150824	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-150826	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0052	0.0009
G-150827	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-150829	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-150832	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150839	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-150845	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-150847	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150849	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0126	0.0021
G-150853	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-150856	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150861	Light-Duty	Drive Clean	EV Vehicle Rebate	0.033	0.0055
G-150864	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150872	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-150882	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-150886	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-150889	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-150896	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-150898	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150907	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0095	0.0016
G-150913	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150914	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0093	0.0015
G-150915	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0084	0.0014
G-150927	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-150929	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-150930	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-150937	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-150948	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-150953	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-150977	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-150989	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-150994	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-151027	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-151028	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0077	0.0013
G-151032	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151049	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-151058	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-151060	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-151061	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151066	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-151118	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-151124	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-151129	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0061	0.001
G-151132	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001

G-151154	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-151155	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0084	0.0014
G-151157	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-151159	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151163	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-151174	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151191	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-151193	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-151197	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151200	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0085	0.0014
G-151203	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-151208	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0069	0.0012
G-151241	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-151243	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0078	0.0013
G-151249	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-151258	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-151260	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-151268	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-151270	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-151275	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-151280	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0058	0.001
G-151282	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-151285	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-151286	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-151303	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-151305	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-151306	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-151307	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0198	0.0033
G-151309	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0077	0.0013
G-151315	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-151317	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151318	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0118	0.002
G-151320	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-151321	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-151322	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-151323	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0058	0.001
G-151325	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151335	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-151336	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-151337	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151339	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-151349	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0238	0.004
G-151352	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0006	0.0004
G-151362	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012

G-151364	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-151366	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-151404	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0067	0.0011
G-151406	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-151409	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-151423	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-151430	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151438	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-151462	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-151465	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0064	0.0011
G-151470	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-151478	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-151479	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0054	0.0009
G-151480	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-151482	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-151542	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0047	0.0008
G-151546	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-151556	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-151560	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151564	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-151572	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-151573	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-151577	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-151578	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0067	0.0011
G-151579	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-151581	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-151636	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-151638	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-151640	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0112	0.0019
G-151647	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151657	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.0079
G-151666	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-151703	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-151709	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0067	0.0011
G-151714	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-151717	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-151718	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-151740	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-151742	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-151754	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0047	0.0008
G-151760	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-151762	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-151766	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-151779	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001

G-151782	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0077	0.0013
G-151789	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-151803	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0084	0.0014
G-151818	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-151832	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151844	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-151851	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-151855	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-151864	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0086	0.0014
G-151868	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-151873	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-151877	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151881	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-151884	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-151888	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-151889	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-151892	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-151894	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0006	0.0004
G-151900	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-151903	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-151914	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151919	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-151922	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-151927	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-151928	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0169	0.0028
G-151931	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-151932	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-151933	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151949	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-151950	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-151955	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0159	0.0026
G-151974	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-151976	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-151980	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0165	0.0028
G-151989	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-152000	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-152008	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-152014	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-152015	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152018	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-152019	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-152022	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-152025	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-152027	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012

G-152028	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-152029	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-152033	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-152036	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-152037	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-152044	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152060	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-152091	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-152105	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152108	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152117	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-152119	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0119	0.002
G-152122	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-152171	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-152175	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-152180	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-152190	Light-Duty	Drive Clean	EV Vehicle Rebate	0.01	0.0017
G-152194	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-152200	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-152222	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-152226	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152228	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-152232	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152236	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-152248	Light-Duty	Drive Clean	EV Vehicle Rebate	0.003	0.0005
G-152251	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-152260	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0033	0.0006
G-152290	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0112	0.0019
G-152292	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152297	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-152308	Light-Duty	Drive Clean	EV Vehicle Rebate	0.002	0.0003
G-152314	Light-Duty	Drive Clean	EV Vehicle Rebate	0.004	0.0007
G-152322	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-152323	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0077	0.0013
G-152325	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0067	0.0011
G-152331	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-152334	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0084	0.0014
G-152335	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152336	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152337	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0026	0.0004
G-152341	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-152343	Light-Duty	Drive Clean	EV Vehicle Rebate	0.019	0.0022
G-152344	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-152346	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0033	0.0006

G-152347	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-152349	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-152350	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-152352	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152356	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0106	0.0018
G-152359	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-152362	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-152364	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-152369	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0097	0.0016
G-152375	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-152379	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-152382	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152383	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152390	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0231	0.0039
G-152392	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0021	0.0004
G-152393	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0026	0.0004
G-152395	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-152396	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152397	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-152406	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0169	0.0028
G-152407	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-152413	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0192	0.0032
G-152417	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0057	0.0009
G-152420	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0092	0.0015
G-152424	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152431	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-152432	Light-Duty	Drive Clean	EV Vehicle Rebate	0.004	0.0007
G-152450	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-152455	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0096	0.0016
G-152460	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0094	0.0016
G-152461	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0297	0.005
G-152462	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0017	0.0003
G-152465	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0045	0.0007
G-152472	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152491	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0033	0.0006
G-152512	Light-Duty	Drive Clean	EV Vehicle Rebate	0.003	0.0005
G-152516	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-152518	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152520	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-152521	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0021	0.0004
G-152534	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-152537	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0033	0.0006
G-152543	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0036	0.0006
G-152563	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0036	0.0006

G-152565	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-152572	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0036	0.0006
G-152618	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152623	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152627	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0101	0.0017
G-152647	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-152657	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-152665	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-152670	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-152673	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0095	0.0016
G-152674	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0033	0.0006
G-152675	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0178	0.003
G-152678	Light-Duty	Drive Clean	EV Vehicle Rebate	0.004	0.0007
G-152679	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0446	0.0074
G-152680	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0165	0.0028
G-152681	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-152685	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-152686	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0126	0.0021
G-152738	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152751	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-152752	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-152785	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-152789	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-152795	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-152798	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-152801	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-152805	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0057	0.0009
G-152808	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0008	0.0005
G-152815	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-152820	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-152822	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152825	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-152826	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-152831	Light-Duty	Drive Clean	EV Vehicle Rebate	0.004	0.0007
G-152836	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152837	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-152844	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-152845	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-152846	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-152848	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-152851	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152852	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0003	0.0002
G-152854	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152855	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003

G-152858	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0006	0.0004
G-152860	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152861	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152862	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0009	0.0006
G-152864	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0002
G-152866	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152872	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152874	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-152875	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-152881	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0013	0.0009
G-152890	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0002
G-152892	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152894	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0009	0.0006
G-152898	Light-Duty	Drive Clean	EV Vehicle Rebate	0.001	0.0006
G-152904	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-152905	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-152921	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0009	0.0006
G-152924	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-152926	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0009	0.0006
G-152933	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-152936	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-152949	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0002
G-152960	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0002
G-152965	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0006	0.0004
G-152966	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-152967	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0001	0.0001
G-152970	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-152971	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-152972	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0003	0.0002
G-152976	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0002	0.0001
G-152979	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-152980	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0009	0.0006
G-153024	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-153026	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-153040	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-153053	Light-Duty	Drive Clean	EV Vehicle Rebate	0.003	0.0005
G-153054	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-153055	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-153059	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-153061	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-153066	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-153073	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-153076	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-153084	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008

G-153101	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-153105	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-153111	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-153140	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-153151	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-153152	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-153153	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-153154	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012
G-153166	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-153168	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0037	0.0006
G-153170	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0067	0.0011
G-153174	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0026	0.0004
G-153216	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-153217	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-153223	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0023	0.0004
G-153227	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-153229	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0017	0.0003
G-153231	Light-Duty	Drive Clean	EV Vehicle Rebate	0.004	0.0007
G-153232	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0019	0.0003
G-153235	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0057	0.001
G-153240	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0033	0.0006
G-153244	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0065	0.0011
G-153260	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0032	0.0005
G-153262	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0026	0.0004
G-153273	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0062	0.001
G-153274	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-153278	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-153292	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-153298	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0099	0.0017
G-153306	Light-Duty	Drive Clean	EV Vehicle Rebate	0.004	0.0007
G-153307	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-153314	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-153319	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.0011
G-153321	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0009	0.0006
G-153322	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-153325	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-153340	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-153341	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0063	0.001
G-153359	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-153360	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-153364	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-153367	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-153369	Light-Duty	Drive Clean	EV Vehicle Rebate	0.004	0.0007
G-153372	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0074	0.0012

G-153373	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0132	0.0022
G-153375	Light-Duty	Drive Clean	EV Vehicle Rebate	0.004	0.0007
G-153376	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-153377	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-153383	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-153390	Light-Duty	Drive Clean	EV Vehicle Rebate	0.002	0.0003
G-153391	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0003	0.0002
G-153393	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-153395	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0026	0.0004
G-153396	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-153397	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-153401	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0025	0.0004
G-153402	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-153404	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-153405	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0075	0.0013
G-153406	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-153409	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-153410	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-153437	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-153450	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-153460	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-153462	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0048	0.0008
G-153467	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0006	0.0004
G-153468	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0042	0.0007
G-153470	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-153471	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-153483	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0037	0.0006
G-153485	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0056	0.0009
G-153491	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-153494	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-153498	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-153500	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0149	0.0025
G-153507	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0053	0.0009
G-153509	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-153512	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0039	0.0006
G-153513	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0071	0.0012
G-153515	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-153517	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0013	0.0009
G-153519	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0042	0.0007
G-153520	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011
G-153523	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-153524	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0258	0.0043
G-153525	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-153529	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0066	0.0011

G-153530	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0028	
G-153531	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-153532	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-153534	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-153536	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0079	0.0013
G-153538	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0059	0.001
G-153541	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0046	0.0008
G-153547	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0089	0.0015
G-153562	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-153570	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-153591	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-153604	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-153608	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-153619	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0002
G-153624	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-153632	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-153641	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-153652	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0006	0.0004
G-153655	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0001	0.0001
G-153660	Light-Duty	Drive Clean	EV Vehicle Rebate	0.005	0.0008
G-153665	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-153669	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0002	0.0001
G-153674	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0002
G-153684	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-153685	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-153686	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-153688	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-153695	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0002	0.0002
G-153698	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-153699	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-153701	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0003	0.0002
G-153709	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0084	0.0014
G-153758	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0006	0.0004
G-153761	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-153762	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0002	0.0001
G-153784	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-153791	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-153793	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0003	0.0002
G-153806	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-153808	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0002	0.0001
G-153812	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0107	0.0018
G-153819	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-153820	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-153822	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0002

G-153830	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-153866	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-153884	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0002
G-153898	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0003	0.0002
G-153901	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0003	0.0002
G-153904	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0009	0.0006
G-153905	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-153906	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0002	0.0001
G-153915	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0006	0.0003
G-153916	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0016	0.001
G-153917	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0003	0.0002
G-153918	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0003	0.0002
G-153924	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0005
G-153930	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0002
G-153932	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0002	0.0001
G-153933	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-153934	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0003	0.0002
G-153936	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0009	0.0006
G-153938	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-153941	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-153942	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-153943	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0006	0.0004
G-153944	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0003	0.0002
G-153949	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0013	0.0009
G-153954	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-153956	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-153959	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0022	0.0014
G-153961	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0009	0.0006
G-153963	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0003	0.0002
G-153964	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-153967	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0002
G-153983	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-153984	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0011	0.0007
G-153987	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-153989	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-154002	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-154005	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-154006	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0016	0.001
G-154009	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-154012	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0002	0.0001
G-154022	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-154024	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0001	0.0001
G-154028	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-154030	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003

G-154039	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-154048	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-154049	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-154051	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-154053	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-154054	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0002
G-154055	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0009	0.0006
G-154060	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-154067	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-154068	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-154073	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-154094	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-154103	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-154104	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0015	0.0009
G-154106	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0003	0.0002
G-154109	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0003	0.0002
G-154111	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-154125	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-154128	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-154129	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0001	0.0001
G-154130	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0002
G-154136	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0002
G-154138	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-154139	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-154142	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0002
G-154148	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-154150	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-154154	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-154155	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-154157	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0009	0.0006
G-154159	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0002	0.0001
G-154177	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-154227	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-154284	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-154313	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-154333	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-154360	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0003	0.0002
G-154478	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-154533	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0002	0.0001
G-154563	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-154726	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-155245	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-155271	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0009	0.0006
G-155336	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0011	0.0007

G-155468	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0008	0.0005
G-155515	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-155561	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-155700	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-155738	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0003	0.0002
G-155744	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-155830	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-155971	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-156039	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0013	0.0009
G-156307	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-156314	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-156322	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-156323	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-156324	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-156341	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0005	0.0003
G-156343	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0004	0.0003
G-156374	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0007	0.0004
G-156385	Light-Duty	Drive Clean	EV Vehicle Rebate	0.0006	0.0004

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

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San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT®



AIR TOXICS

2023 Annual Report

March 21, 2024

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SAMIR SHEIKH

Executive Summary

The San Joaquin Valley Air Pollution Control District (District) is a public health agency whose mission is to improve the health and quality of life for all Valley residents through efficient, effective and entrepreneurial air quality-management strategies. The District has spent nearly three decades implementing and integrating a wide variety of methods reducing toxic air contaminant emissions in the San Joaquin Valley. Based on the latest California Toxics Inventory (CTI) available from CARB, 14% of all air toxics in the Valley are now emitted from stationary sources of pollution under the direct control and regulation of the District, while 52% comes from mobile sources such as cars and trucks, and the remaining 34% is emitted from area-wide sources like road dust, paints, solvents, and other consumer products. Mobile and area-wide sources of emissions are generally under the regulatory authority of the State of California and the federal government.

The District's integrated approach to addressing and reducing risks from toxic air contaminants has taken three main paths: reducing air toxic emissions from existing stationary sources of emissions; preventing the creation of new or modified stationary sources of significant risk; and finding creative and cooperative methods of reducing risk from emissions sources that the District does not typically regulate. This approach has resulted in dramatic reductions in emissions of air toxics from sources in the San Joaquin Valley.

Under Assembly Bill (AB) 2588 (Air Toxics Hot Spots Information and Assessment Act), the District works with facilities to quantify emissions of air toxics, determines the health risk caused by those emissions, reports emissions and any significant risks through written public reports and neighborhood public meetings, and as required, takes steps to reduce such risks. As a result of these ongoing efforts, and the resulting emissions reductions, no Valley facility currently poses a significant risk under this program.

The State's Hot Spots Act, however, is only one part of the District's comprehensive program to regulate air toxics. To achieve maximum efficiency and effectiveness, the District operates an integrated air toxics program that harmonizes local, state, and federal mandates wherever possible.

A number of regulations have also been adopted by the District, the state, and the federal government, and implemented through the District's integrated air toxics program, to directly reduce existing emissions from specific types of facilities and sources of air toxic contaminants. For example, the toxic air contaminant emissions from emissions sources like dry cleaners, chrome platers, gas stations, and diesel internal combustion engines have drastically decreased in the San Joaquin Valley since the implementation of the District's air toxic program.

In addition to the above efforts to minimize emissions, the District also performs comprehensive and conservative toxic emission evaluations and air dispersion modeling before issuing permits to new and modified stationary sources of emissions. This assures the District minimizes the increase those sources add to the existing toxic load and any

potentially significant public health impacts associated with the release of those airborne toxic emissions.

Under its integrated air toxics program, the District has also implemented numerous methods of reducing emissions from mobile sources and other sources of emissions that the District does not have the authority to regulate. For instance, the District developed the first Indirect Source Review rule in the nation, designed to reduce emissions from construction equipment and mobile sources associated with new land use development projects. The District also provides assistance and guidance to the cities and counties in the San Joaquin Valley so that they can be assured that land-use decisions are based on a full understanding of the potential for increasing emissions of air toxics, and new air toxics risks can be avoided. One of the most effective methods of reducing emissions of air toxics from emissions sources not directly regulated by the District has been the incentive grant programs that have leveraged billions of dollars in reducing emissions from diesel internal combustion engines on trucks, tractors and agricultural irrigation operations.

This 2023 Annual Air Toxics Report describes the District's ongoing efforts to regulate and minimize air toxic emissions. An electronic version of this report may be found at: http://www.valleyair.org/busind/pto/air_toxics_annual_reports.htm.

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Summary of Toxic Air Contaminants in the San Joaquin Valley

The United States Environmental Protection Agency (EPA) and the California Air Resources Board (CARB) have identified over 1,700 substances that are emitted into the air that may affect human health. Some of these substances are considered to be carcinogens, while others are known to have short-term acute or long-term chronic health impacts. As part of ongoing efforts to identify and assess potential health risks to the public, the District has collected and compiled air toxics emissions data from industrial and commercial sources of air pollution throughout the Valley. The State has developed similar inventories for mobile sources of air pollution. These District and State inventories have been combined into the CARB's California Toxic Inventory (CTI), which provides emission estimates available for hazardous air pollutants of concern from all sources. A summary of the latest available CTI data for key pollutants is presented in Table 1 below.

Table 1. Primary San Joaquin Valley Hazardous Air Pollutant Emissions

Pollutant	Inventory (tons/yr)
Acetaldehyde	3,512
Diesel Particulate Matter	2,520
Formaldehyde	2,318
Benzene	1,020
Perchloroethylene	448
1,3-Butadiene	269
Methylene Chloride	247
p-Dichlorobenzene	130
Carbon Tetrachloride	0
Chromium, Hexavalent	0

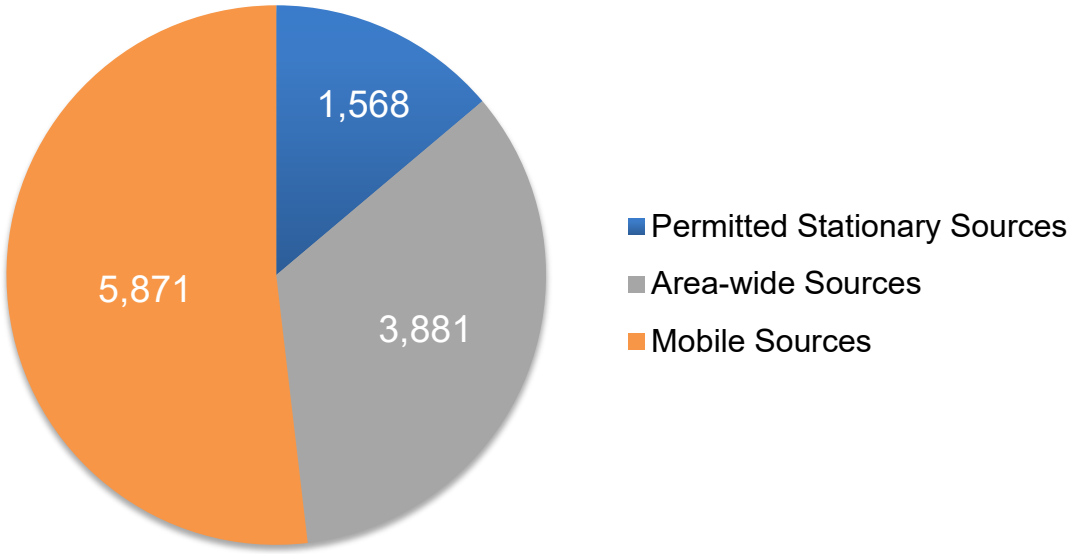
A more detailed summary of CTI emission estimates for the San Joaquin Valley is provided in Table C1 in Appendix C.

Toxic Air Contaminants (TACs), otherwise known as air toxics, are emitted from mobile sources (e.g., cars, trucks, buses, tractors, etc.), which are primarily regulated by the State and EPA; area sources (e.g., consumer products), which are regulated by the State, EPA, and the District; and from stationary sources regulated primarily by the District. Figure 1 below shows a comparison of mobile, area, and stationary source emissions of hazardous air pollutants in the San Joaquin Valley. Of these sources, approximately 86% of hazardous air pollutant emissions occurring in the Valley are from mobile sources and area sources.

Stationary sources include point source emissions provided by facility operators and/or air districts and aggregated point source emissions estimated by CARB and/or air districts.

This stationary source information is included in the CTI pursuant to the Air Toxics "Hot Spots" Act of 1987 (AB 2588). Area-wide sources are those that emit over an unspecified area. This could include paved roads, unpaved roads, or consumer product emitting sources.

Figure 1. Air Toxics Emissions (tons/year) in the San Joaquin Valley (per CARB's CTI)



California Air Toxics Assessment

The California Air Toxics Assessment (CATA)[1] is a tool that uses detailed emission inventory data from CARB, meteorological data, and an integrated modeling approach to assess health risk for air basins located throughout California. Based on risk data collected between 2012 and 2017, CATA shows an average percent reduction in cancer risk of 55% over that time period in the San Joaquin Valley Air Basin, with the majority of the cancer risk reduction from diesel particulate matter (DPM) emissions. The vast majority of the remaining cancer risk in the Valley is coming from mobile DPM emission sources under federal and state jurisdiction.

Most of the reductions seen across the air basins are attributed to reductions in on-road mobile emissions in the past years due to implementation of the state's on-road truck and bus rule and other programs. Note, the 2017 data includes wildfire emissions, which are a large contributor of certain TACs like formaldehyde and acetaldehyde but were not available for the 2012 data.

Prior to the 2017 CATA study, an initial statewide air toxics study was conducted, which covered a 2012 base year. For both years, DPM sources were the major contributor to the overall risk, and the main driver of the risk reductions from 2012 to 2017. Table 2

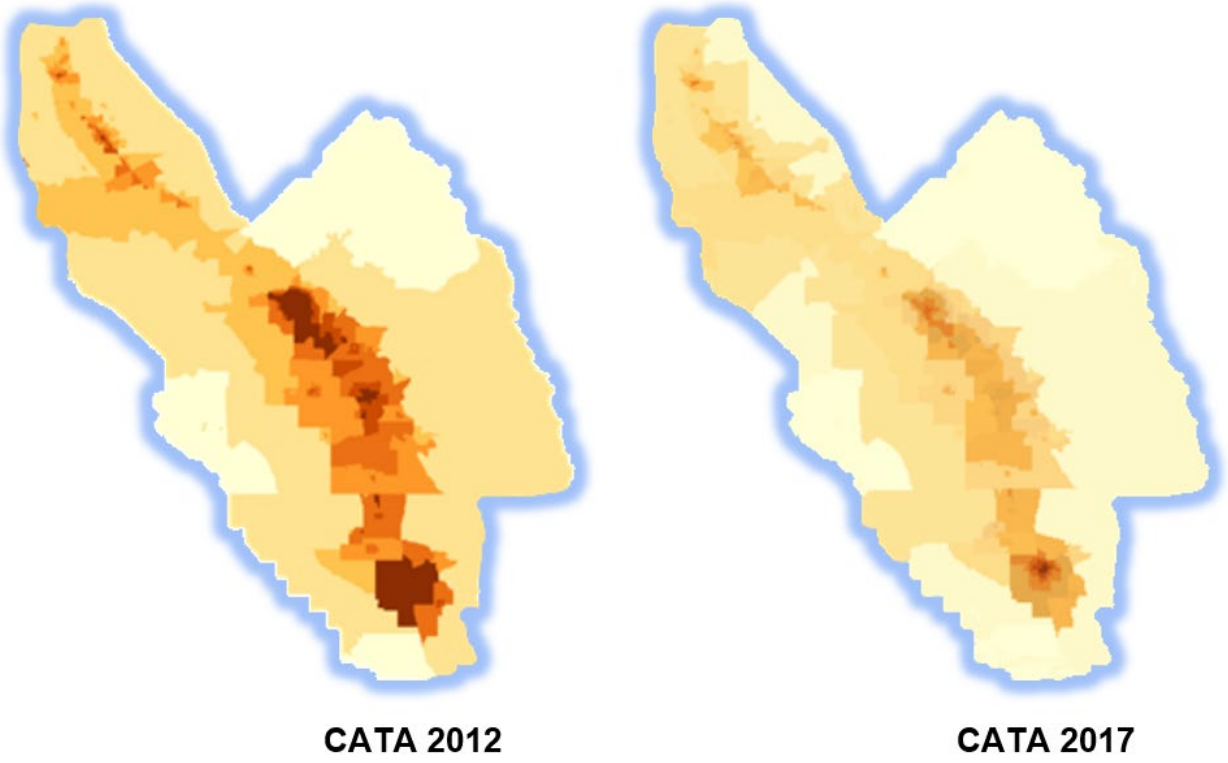
[1] https://california-air-toxics-assessment-californiaarb.hub.arcgis.com/

below presents the population-weighted averages of census tract total cancer risks in 2017 and 2012 in the six major air basins in California (from CARB's CATA Technical Report, 2023).[2] Note that the total population in the six modeling domains where exposure and cancer risk are estimated is 36,727,572, which accounted for around 99% of the total population in California.

Table 2. Population-Weighted Total Air Toxics Cancer Risk in the Six Major Air Basins (per CARB's CATA Technical Report, 2023)

Air Basin	2012 Average Risk (chances per million)	2017 Average Risk (chances per million)	Risk Change from 2012 (%)
Sacramento Valley	597	356	-40.3
San Joaquin Valley	**1,063**	**474**	**-55.4**
San Diego	803	486	-39.5
Bay Area	871	510	-41.4
Imperial	806	671	-16.7
South Coast	1,244	830	-33.3

Figure 2. Cancer Risk Trends in the San Joaquin Valley (per CARB's CATA)



[2] https://california-air-toxics-assessment-californiaarb.hub.arcgis.com/documents/9cce94a930314324a4101b5b1a549b7c/explore

As shown in Figures 3 and 4 below, for the 2017 CATA year, DPM remained the primary driver for cancer risk in the Valley, with on-road mobile being the highest contributing source.

Figure 3. Cancer Risk Contributions by Air Toxics in SJV (per CARB's CATA Technical Report, 2023)

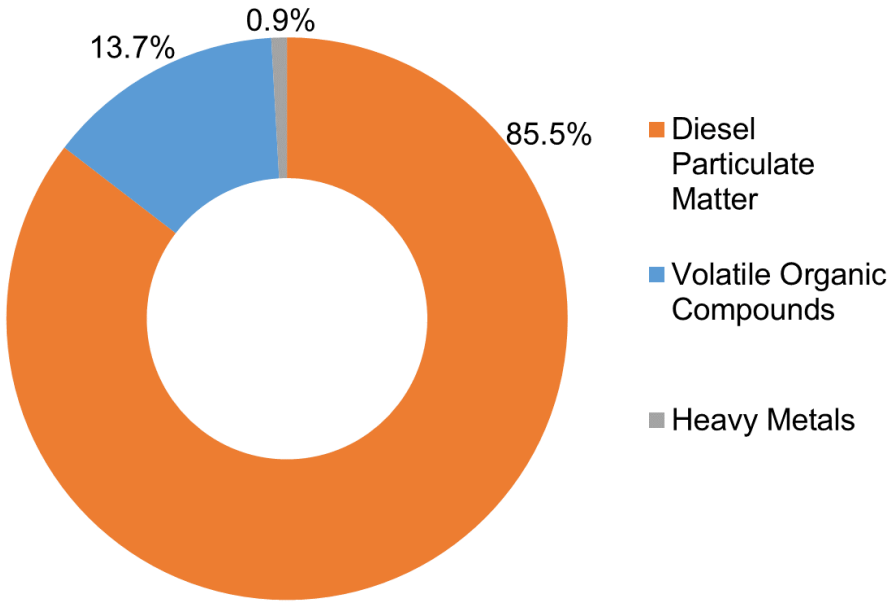
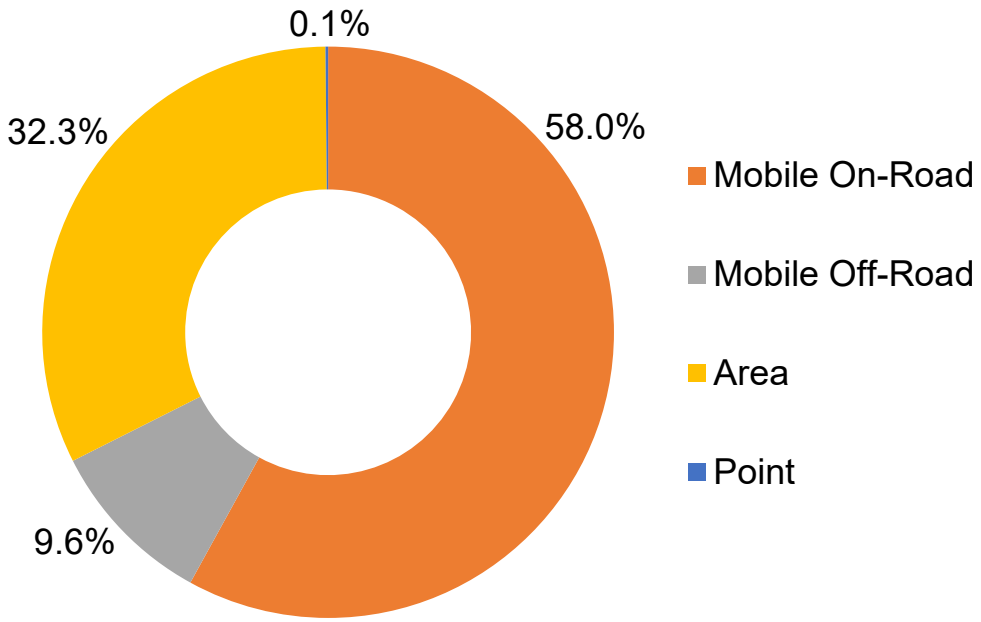


Figure 4. Diesel Particulate Matter (DPM) Population-Weighted Cancer Risk by Emission Source in SJV (per CARB's CATA Technical Report, 2023)



Note, in Figure 4 above, the emission source categories include the following specific emission activities:

- Mobile On-Road includes diesel trucks and buses,
- Mobile Off-Road includes diesel locomotives, transport refrigeration units, commercial harbor craft,
- Area Sources include mobile off-road equipment for agricultural-related activities, construction-related activities, forklifts, gen-sets, air compressors, etc.,
- Point Sources include stationary sources subject to AB 2588.

Federal EPA Air Toxics Screening Assessment

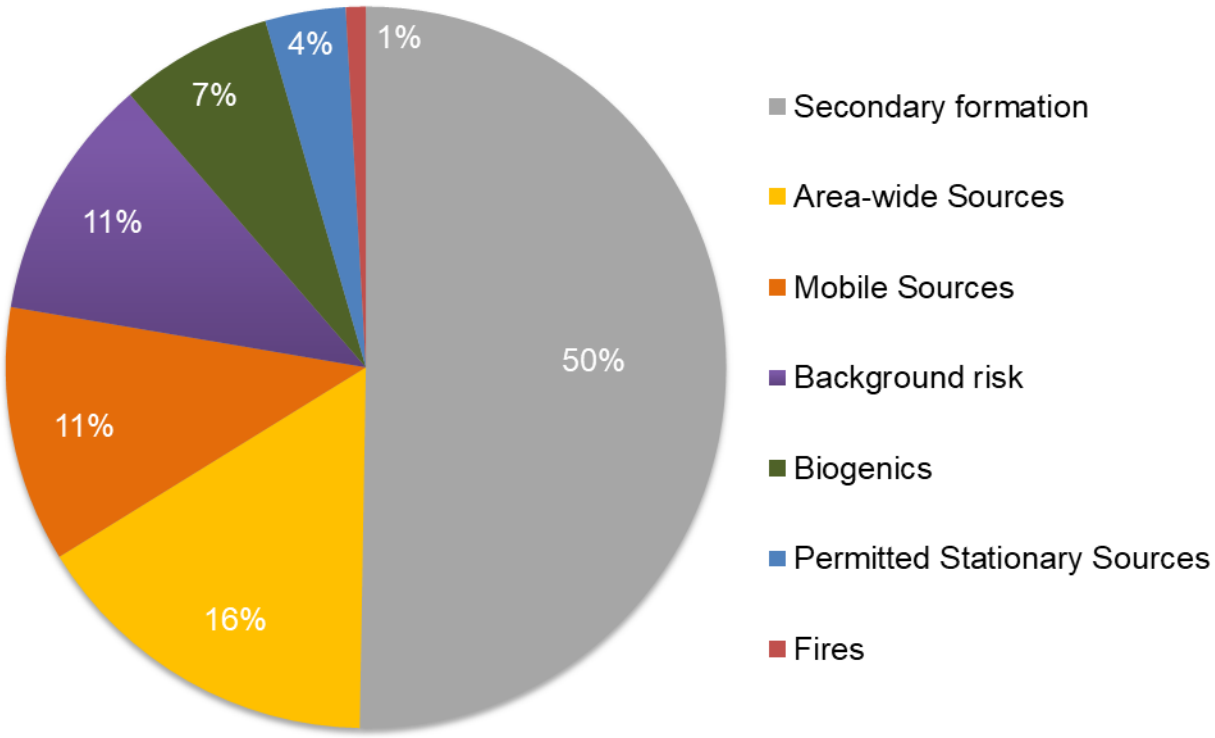
The federal Environmental Protection Agency (EPA) Air Toxics Screening Assessment (AirToxScreen), formerly known as The National Air Toxics Assessment (NATA), is a screening tool to provide communities with information about health risks from air toxics. AirToxScreen is part of EPA's approach to air toxics that provides updated data and risk analyses on an annual basis, helping state, local and tribal air agencies, EPA, and the public more easily identify existing and emerging air toxics issues. State and air district toxic emissions inventory data are compiled to create a national emissions inventory of air toxic sources, which is used by EPA to generate the AirToxScreen Mapping Tool. The AirToxScreen Mapping Tool can be found at: https://www.epa.gov/AirToxScreen/airtoxscreen-mapping-tool.

EPA's AirToxScreen calculates public health risk using a four step process. First, national emission inventories are compiled to identify all types and quantities of air toxic sources. Secondly and thirdly, those emissions are input into photochemical and steady-state air dispersion models to estimate long-term ambient air concentrations and population exposures across the United States. Finally, exposed concentrations are multiplied by corresponding air toxic's unit risk factors to estimate cancer risk and the public health impacts from breathing air toxics.

AirToxScreen estimates cancer risk from a variety of sources including secondary formation, background risk, area-wide sources, mobile sources, biogenics, fires, and permitted stationary sources. Secondary formation are the processes where emissions react in the atmosphere to form other substances. Background concentrations are emissions that exist in the air and accumulate from non-specific naturally occurring or distant sources. Biogenic emissions come from specific natural sources, like plants and trees. Fire emissions come from prescribed wildfires and agricultural burning. AirToxScreen estimated the cancer risk associated with common sources and toxic pollutants emitted during the 2019 inventory data year. Based on those emissions, the 2019 AirToxScreen identifies 25 elevated cancer risk areas in the country as having a cancer risk score of greater than 100 in a million. None of the 25 elevated cancer risk areas are located within the San Joaquin Valley. In the Valley, the average cancer risk from air toxic emissions is 28 in a million, compared to the national average of 30 in a million. As shown in Figure 5 below, about 77% of the total cancer risk in the San Joaquin

Valley came from secondary formation, area-wide, and mobile source emissions in 2019, while only 4% of the total cancer risk came from stationary source emissions.

Figure 5. Cancer Risk by Source in the San Joaquin Valley (per EPA's AirToxScreen)



Of the cancer risk data from AirToxScreen, exposure to formaldehyde is responsible for 60% of the total cancer risk in the San Joaquin Valley. Other chemicals contributing to the calculated cancer risk include carbon tetrachloride (11%), benzene (7.2%), acetaldehyde (6.9%), naphthalene (3.2%), and 1,3-butadiene (2.2%). It is important to note, diesel particulate matter (DPM) emissions are not included as an air toxic in EPA's AirToxScreen cancer risk data.

Assembly Bill (AB) 617 - Community Air Protection Program

The implementation of AB 617 (C. Garcia, 2017) has brought additional clean air resources and strategies to Valley communities. Despite the significant reductions in emissions of criteria and toxic air pollutants that have already been achieved across the Valley, there remain many Valley communities that are disproportionately burdened by the cumulative effects of various environmental and socioeconomic factors. AB 617 requires the expedited implementation of advanced control technologies for existing stationary source facilities; development and implementation of community-specific air quality monitoring networks; development and implementation of community emission reduction programs; enhanced reporting of facility emissions inventory data, and the creation of publically

accessible online clearinghouses of emission control technology determinations. Resources available through this legislation have allowed the District and Community Steering Committees, through a comprehensive public outreach and community engagement process, to develop programs for community protection and develop a robust plan for reducing local exposure to fine particulate matter and toxic air contaminants in Valley communities.

Criteria Air Pollutant and Toxics Air Contaminants Reporting Regulation

AB 617 requires CARB to develop a uniform statewide system of annual reporting of emissions of criteria air pollutants and toxic air contaminants for certain categories of stationary sources. The bill requires stationary sources to report their annual emissions of criteria air pollutants and toxic air contaminants. In order to implement these reporting requirements, CARB developed the "Regulation for the Reporting of Criteria Air Pollutants and Toxic Air Contaminants" (CTR) to implement statewide annual reporting of criteria air pollutant and toxic air contaminant emissions data from facilities, and was adopted in support of mandates under AB 617, AB 197, and AB 2588. For Valley permitted facilities, the District will implement this regulation on behalf of the state through the District's existing annual emission inventory and air toxics processes. Emissions inventory data is critical to understanding the sources of emissions that may contribute to adverse health risks or other impacts at the local, regional, and statewide level. In 2023, more than 6,700 facilities reported their emissions inventory-related data, including process rates, types of fuels used, materials received and processed. Utilizing this information, the District quantified the criteria and toxic emissions for these facilities and transmitted the inventory to CARB. Facility emissions reported under the state's CTR regulation are visualized in CARB's Pollution Mapping tool. The tool provides an interactive platform where users can select facilities by name, location, or industrial sector; view their reported emissions using maps, charts and tabular formats; and download data. It can be found at: https://ww3.arb.ca.gov/ei/tools/pollution_map/.

Summary of California's Air Toxics "Hot Spots" Information and Assessment Act

Background

The *Air Toxics "Hot Spots" Information and Assessment Act* (AB 2588, 1987, Connelly) was enacted in September 1987 and later strengthened in 1992. Under this act, stationary sources are required to report the types and quantities of certain toxic substances their facilities routinely release into the air. The goals of AB 2588 are:

- to identify Valley facilities that release toxic air contaminants as a result of their day to day operations
- to collect and quantify emission data
- to identify facilities causing localized impacts
- to determine facility-wide health risks
- to notify nearby residents and businesses of significant risk facilities in their vicinity
- to require that significant-risk facilities reduce their risks below the level of significance in accordance with the provisions of the "Emissions Inventory Criteria and Guidelines Report" adopted by the Air Resources Board

The District's implementation of AB 2588 has minimized health risks to the public associated with the release of air toxic emission from sources located within the San Joaquin Valley. Under this right-to-know law, the District has worked with facilities to quantify air toxic emissions, determine the potential health risk associated with those emissions, and report any risk determined to be significant by the District through written public reports and neighborhood public meetings. A flowchart summarizing the AB 2588 implementation process is provided in Appendix C.

Assessing the Risk to the Public

The State Air Toxics "Hot Spots" Act requires the District to compile an inventory of toxic emissions from Valley facilities, prioritize facilities for health risk, evaluate public health risks for facilities ranked as high priority, and notify individuals who may be impacted by any significant health risks. Although Hot Spots is primarily a public right-to-know and notification program, the public awareness achieved through the Hot Spots program has led many Valley businesses to voluntarily reduce their toxic emissions to ease community concerns.

Implementation

The District utilizes the applicability criteria outlined in CARB's Emission Inventory Criteria and Guidelines Regulation (EICGR) to determine which facilities are evaluated under the program. Facilities are subject to quantifying and reporting their toxic emissions if one or more of the criteria below is met:

- Emit 10 or more tons per year of criteria pollutants (particulate matter, oxides of nitrogen, oxides of sulfur, or organic gasses)
- Emit less than 10 tons per year of criteria pollutants, but meet one or more of the classes listed in Appendix E of the EICGR
- Emit toxic substances that have been added to Appendix A of the EICGR
- Emit toxic substances that have new health risk values published by the state's Office of Environmental Health Hazard Assessment (OEHHA)
- Increase of potential health risk from the previously evaluated level due to an increase in actual emissions, change to a state-established risk value, threshold, or other calculation or methodology changes.

The District's implementation of the AB 2588 Hot Spots Program incorporates the state's guidelines for evaluating health risks from stationary sources in the Valley. Facilities determined to be subject to the Air Toxics "Hot Spots" program are required to prepare a Toxic Emission Inventory Plan (Plan) and a Toxic Emission Inventory Report (Report) in order to provide site-specific inventories of air emissions of toxic substances.

In 2016, the District began the outreach and reassessment of facilities by following the phased processing schedule outlined in AB 2588, which was originally implemented in the late 80's and early 90's. AB 2588 subjected three major categories (or phases) of facilities to the regulation based upon their level of annual emissions. The AB 2588 regulation also allows for "Industry-wide" toxics emissions inventory, which consist of facilities that are small businesses where emissions can be generally characterized such as gasoline dispensing facilities, auto body coating facilities, etc. These industry-wide facilities are being addressed under the fourth assessment phase. Similar to industry-wide facilities, small single source facilities, such those with only diesel internal combustion engines (DICE), are also being assessed in the fourth phase of the implementation schedule. The fourth phase also includes auto body shops and agricultural facilities. The following summary outlines each phase within the District's implementation plan:

First phase:	Phase I Facilities (≥ 25 tons emissions per year)
Second phase:	Phase II Facilities (10 ≤ tons emissions per year < 25)
Third phase:	Phase III Facilities (< 10 tons emissions per year)
Fourth phase:	Phase IV Facilities (Industry-wide such as Gas Stations, Auto Body Shops; DICE only, Agricultural facilities)

AB 2588 Evaluation Process

Toxic Emission Inventory Plans and Reports

Under this act, facilities are required to prepare Toxic Emission Inventory Plans and Reports to develop site-specific inventories of air emissions from toxic substances. Plans provide an outline and methodology for calculating toxic emissions for all permitted and non-permitted stationary sources operated at the facility. This is reviewed and approved by the District prior to emission quantification. Reports Include calculations of facility's toxic emissions using site-specific process rates and emission factors in order to perform a "Prioritization" of the facility's air toxic emissions.

Prioritization

AB 2588 requires air districts to prioritize facilities to determine a facility's status within the program. In establishing priorities, the air districts are to consider the potency, toxicity, quantity, and volume of hazardous materials released from the facility, the proximity of the facility to potential receptors, and any other factors that the district determines may indicate that the facility may pose a significant health risk. The District uses the prioritization methodology outlined in the California Air Pollution Control Officers Association (CAPCOA) *Facility Prioritization Guidelines* to prioritize facilities under AB 2588. Utilizing the facility's approved Plan and Report, a facility's priority status is determined using the prioritization thresholds listed in District Policy APR 1906, as identified in Table 3 below.

Table 3: AB 2588 Prioritization Thresholds and Categories

Prioritization Thresholds	Priority Category	Category Requirements
≤ 1	Low Priority	Facility is conditionally exempt from further AB 2588 requirements
>1 and ≤ 10	Intermediate Priority	Facility is required to provide an update summary on a quadrennial basis
> 10	High Priority	Facility is required to perform a Health Risk Assessment

Health Risk Assessment

Facilities that classify as "High" priority are required to perform a Health Risk Assessment (HRA) to determine whether its toxic emissions are expected to pose a significant risk to nearby residents and workers. Under AB 2588, the District and the Office of Environmental Health Hazard Assessment's (OEHHA) review each HRA. HRAs performed under the program are required to use the methodologies and procedures outlined in District guidelines and OEHHA's 2015 Air Toxic Hot Spots Program "*Guidance Manual for Preparation of Health Risk Assessments*". A facility's status under the program is determined using established health risk thresholds as identified in Table 4 below:

Table 4: AB 2588 Health Risk Assessment Thresholds

Health Risk Thresholds	Risk Category	Category Requirements
Cancer risk < 1 in a million, and Total hazard index of < 0.1	Low Risk	Facility is conditionally exempt from further AB 2588 requirements
1 ≤ Cancer risk <10 in a million, or 0.1 ≤ Total hazard index ≤ 1.0	Intermediate Risk	Facility is required to provide an update summary on a quadrennial basis
Cancer risk ≥ 10 in a million, or Total hazard index of > 1.0	Public Notification Required	Facility is required to go through the public notification process
Cancer risk > 100 in a million, or Total hazard index of > 5.0	Risk Reduction	Facility is required to go through the public notification process and prepare a Risk Reduction Plan

Public Notification

Facilities that are determined to pose a potential health risk to nearby residents or workers by exceeding the District's public notification risk thresholds are required to notify those exposed persons, through the District's Public Notification process. This process allows the District to inform the public of their potential exposure to toxic substances routinely released into the air from facilities and the potential health risks associated with those exposures. Additionally, this process allows any public questions or concerns regarding exposure and health risk associated with the facility's toxic emissions to be heard and discussed.

Risk Reduction Audit and Plan

Facilities that pose health risks above District action levels are required to submit risk reduction audits and plans (RRAP) to reduce their risk. The District's review of completeness of any facility RRAP includes a substantive analysis of the emission reduction measures included in the plan, and the ability of those measures to achieve emission reduction goals as quickly as feasible. If the District determines that the RRAP does not meet those requirements, the District shall return the audit and plan to the facility to remedy the deficiencies identified by the District. No District permitted facilities have been determined to pose risks in excess of the risk reduction action levels.

Update Summary Facilities

Intermediate Priority and Intermediate Risk facilities are subject to the regulation's Update Summary reporting process. At least once every four years, these facilities must provide their annual activity and resulting emissions inventory in order to provide the District with updated facility information and to determine whether any operational changes at the facility have the potential to affect the facility's health risk status under the program. Operational changes could consist of increasing process rates, or by operating new or modified equipment at the facility.

In addition, each Update Summary provided by facilities undergoes an assessment based on their toxic weighted emissions (TWE). These TWE values are aggregated into three risk categories: cancer, chronic, and acute, and are compared over the four-year update summary inventory cycle. This comparative analysis addresses any updates from OEHHA regarding risk factors or reference exposure levels on a pollutant-by-pollutant basis during the quadrennial period. Using the TWE allows a more refined evaluation to determine whether a facility needs to submit an updated Plan, because it factors the toxicity of air toxic emissions and assesses their impacts accordingly.

It is important to note that changes to the facility that require a District permit or permit modification must be approved by the District prior to being implemented. Based on the information submittal, the District determines if an updated AB 2588 assessment is required (reinstatement).

Industry-wide and Small Single Source Facilities

Under the state's regulation, common types of smaller commercial facilities where the air toxics emissions from individual facilities can easily and generically be characterized and calculated, qualify for a more streamlined assessment process referred to as "industry-wide." These facility industry-wide classes include gasoline dispensing facilities, dry cleaning operations, and automotive coating facilities.

Similar in concept to the industry-wide facilities, smaller operations operating only a single type of emission unit, cannot qualify as industry-wide, and where the emissions can easily and generically be characterized and calculated, qualify for a more streamlined assessment process referred to as "small single source" facilities. Small single sources include facilities only operating a diesel-fired emergency IC engine.

CARB's Recent Updates to AB 2588 Guidance

Recent Amendments to the Emission Inventory Criteria and Guidelines Regulation

Amendments were made to the Emission Inventory Criteria and Guidelines Regulation (EICGR) and approved by the Office of Administrative Law on March 21, 2022. CARB amended the EICGR to collect more comprehensive emission data across the state. The primary amendments to the EICGR include:

- Updated reporting requirements for diesel engines
- Added factors in determining facility exemptions, reinstatements, and update reporting provisions
- Increased the number of reportable substances in Appendix A from approximately 700 to over 1,700 substances
- Established a phase-in schedule for evaluating newly added substances, consistent with the CTR Regulation's emissions inventory schedule
- Added new source test requirements for certain source types

Gasoline Service Station Industrywide Risk Assessment Guidance

To assist air districts in assessing Gasoline Dispensing Facilities (GDF) as required under AB 2588, CARB and California Air Pollution Control Officers Association (CAPCOA) prepared an updated standardized Gasoline Service Station Industrywide Risk Assessment Guidance in 2022. This guidance provides a framework for air districts to use when evaluating the public health risks from GDFs. This guidance replaces the 1997 Gasoline Service Station Industrywide Risk Assessment Guidelines that was previously used by air districts for their health risk evaluations. Changes in the 2022 technical guidance include new health risk methodologies, updated emission factors for gas stations, and new information on the toxic chemicals in gasoline. Due to the significant changes in the methodology and the state-wide effort to evaluate GDFs under AB 2588, the District recently evaluated the Valley's permitted GDF facilities (approximately 1,500 facilities).

Air Toxics Hot Spot Assessments Summary

The District has finalized 7,425 AB 2588 facility assessments from 2016 - 2023. Table 5 below identifies the number of facilities assessed in 2023 through a prioritization analysis (after completion of a Plan and Report), applicability exemption determination, or a health risk assessment (after completion of a prioritization).

Table 5: Summary of Facilities Assessed Under AB 2588 in 2023

AB 2588 Category	Number of Facilities Assessed in 2023
Low/Exempt Priority	213
Low/Exempt Risk	7
Intermediate Priority	238
Intermediate Risk	31
High Priority	10
Public Notification Required	0
Risk Reduction	0
Total	**499**

A detailed list of the facilities evaluated in 2023 and their current status under AB 2588 can be found in Appendix A, along with maps that visually display the location of those facilities that were evaluated as intermediate priority, high priority, and intermediate risk.

The District also re-evaluated 95 facilities subject to the update summary reporting process in 2023 to determine whether reinstatement into the program is required in order to perform an updated AB 2588 facility assessment. A detailed list of those facilities and associated reinstatement status can be found in Appendix B.

Table 6: Summary of Quadrennial Reporting (Update Summaries)

AB 2588 Category	Number of Facilities Assessed in 2023
Needs Reassessment	6
Continued Quadrennial Reporting Cycle	89
Total	**95**

Preventing Creation of Significant Health Risk

The overall goal of the District's integrated approach to air toxics emissions in the San Joaquin Valley aims to maximize public health improvements and minimize public exposure to air toxic emissions. The integrated air toxics program assists in preventing, minimizing, and reducing health risks through a variety of programs.



New or Modified Stationary Source Evaluations

One goal of District risk management review efforts is to minimize the increase that new and modified stationary sources add to the existing toxic load and any potentially significant public health impacts associated with the release of those airborne toxic emissions. In order to achieve this goal, the District evaluates the health risk of stationary sources as part of the District's permitting process and engineering evaluation.

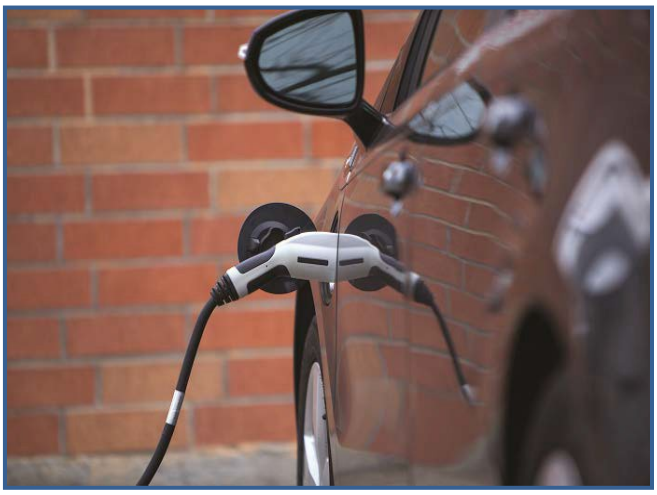
Under the District's risk management policy, Toxic Best Available Control Technology must be applied to all units that may pose greater than de minimis levels of risk (i.e., a cancer risk greater than one in one million). Projects that would pose significant impacts to nearby residences or businesses (i.e., by causing an increased cumulative facility cancer risk of 20-in-a-million or greater) are not approvable. When a project is determined not to be approvable as proposed, District staff will work with the applicant to find approvable low-risk alternatives, such as installing air toxic emissions control devices or limiting the operation of the proposed equipment. Under this program, the District has performed over 16,800 Risk Management Reviews for facilities throughout the District. As a consequence, no permit for a new or modified operation has been approved since the program was initiated in 1995 that would have created a significant health impact through increases in air toxic emissions.

Air Toxics "Hot Spots" Information and Assessment Act

As noted earlier in this report, this law is designed to provide information on the extent of emissions from existing stationary sources and the potential public health impacts of those emissions. Facilities are required to calculate and report to the District their actual emissions of air toxic emissions. Facilities with health risk assessment score above public notice thresholds must disclose their impacts to nearby residents that may be impacted. Facilities that exceed a higher risk reduction action threshold must go even further and reduce emissions of air toxics. No Valley facility currently poses a significant risk under the "Hot Spots" program utilizing state/OEHHA guidance, while at the beginning of the implementation of the program, in 1989, 16 facilities were classified "Significant Risk Facilities."

Incentive-Based Programs

To assist in reducing air toxic emissions throughout the Valley, more than $6 billion in public and private funding has been invested in clean-air projects through the District's voluntary incentive programs. In total, these programs have reduced more than 271,300 tons of harmful emissions. Carcinogenic diesel particulate matter (DPM) emissions have been significantly reduced in the Valley, where District voluntary incentives programs have provided critical funding toward replacing more than 35,000 older, high-polluting heavy-duty diesel engines with zero emission electric motors or cleaner burning engines equipped with the latest emissions control technologies. In addition, these incentive programs provide critical funding to replace older, higher-polluting school buses, light-duty passenger vehicles, residential wood burning devices, and numerous others. Through the District's first-of-its-kind Ag Burn Alternatives Grant program, the District provides funding to support the Valley's ongoing phase-out of agricultural open burning and the development of innovative alternatives to open burning.



In 2017, AB 617 initiated a statewide effort to monitor and reduce localized air pollution, and highly improve public health, in communities that experience disproportionate burdens from exposure to air pollutants through new community-focused and community-driven actions. The communities of Shafter, South Central Fresno, Stockton and Arvin/Lamont were selected to receive clean air resources available under AB 617 through the Community Air Protection Program. This program includes a substantial investment of community-level funding through a wide variety of voluntary incentive funding measures, including the Tune-In & Tune-Up program and the Fireplace & Woodstove Change-Out Program. The Tune-In & Tune-Up program provides incentives for primarily low-income

District residents to perform much-needed smog related repairs to their personal vehicles. In some cases, the District is even able to offer greater incentives for residents to replace their old, high polluting vehicle with a much cleaner and much newer vehicle. Through the Fireplace & Woodstove Change-Out Program, the District is able to provide funding for District residents to replace, older, high polluting residential wood burning devices with new, clean burning devices or natural gas inserts. Through this program, the District offers a higher incentive for the District's low-income population.

Attainment Plans and Control Strategies

Within the District's *2018 $PM_{2.5}$ Plan*, the District prioritized strategies achieving the greatest public health benefits while satisfying applicable attainment planning requirements. The District also analyzed the health benefits that would result from implementation of the plan. Several examples of prioritized control strategies included in the *2018 $PM_{2.5}$ Plan* include new measures to further reduce $PM_{2.5}$ emissions, with rules since being adopted to reduce harmful emissions from residential wood burning (Rule 4901) and industrial sources. These measures reduce some of the most harmful types of particulate matter, particularly where these reductions are most needed in urban, highly populated areas. Additionally, as part of the District's *2022 Ozone Plan,* the District adopted strategies to further reduce harmful volatile organic compound (VOC) emissions from oil and natural gas sources and petroleum refining (Rules 4401, 4409, 4455, 4623, and 4624). Through ongoing attainment planning efforts, the District continues to prioritize programs and strategies that reduce harmful emissions and result in public health benefits.

Indirect Source Review Rule

The District's Indirect Source Review (ISR) rule, in place since 2005, achieves combustion-related NOx and PM10 emission reductions from the construction and operation of new development projects through the incorporation of clean-air design features and on-site mitigation measures. The focus of these emissions reductions are from development-related mobile source heavy duty off-road diesel equipment and heavy duty on-road diesel trucks, which emit diesel particulate matter, one of the most potent carcinogens.

California Environmental Quality Act and Health Risk Assessments

The California Environmental Quality Act (CEQA) requires public agencies to evaluate environmental impacts from a development project and all feasible alternatives or mitigation measures that can substantially reduce or avoid those impacts. Generally, the main responsibility for satisfying CEQA requirements, or "lead agency" role, falls under the responsibility of city or county planning agencies.

From a health risk perspective, land use decisions are critical to improving and preventing degradation of air quality within the San Joaquin Valley, as land use patterns greatly influence potential exposure of sensitive receptors to sources of air pollution. Under

CEQA, land use agencies must evaluate the potential significance of health risks associated with development projects. The District provides support to land use agencies when making air quality impact determinations by assisting in the review of health risk assessments performed for the project.

Outreach and Education



As we move forward in achieving our mission, the District shall continue its ongoing efforts to educate the public about air quality, and the significant clean air investments and air quality progress that have been made in the Valley.

The District's information and educational programs include the Real-Time Air Quality Advisory Network (RAAN), Web-based Archived Air Quality (WAAQ) System, and Healthy Air Living Schools program.

RAAN uses real-time data from air monitoring stations throughout the Valley to provide hour-by-hour air quality updates to schools and other subscribers. WAAQS was implemented in 2015 and takes RAAN a step further by providing neighborhood-by-neighborhood historical air quality data for any address in the Valley air basin. Valley residents can use this information to make informed decisions and plan outdoor activities for times with the best air quality, reducing potential air quality health risks. As a high priority area of focus, the District has continued working to expand the Healthy Air Living Schools initiative to deliver an extensive set of tools and information, including the recent launch of school-based Real-Time Electronic Air-quality Displays (READ), to enable Valley schools to understand and respond to air quality conditions and protect the health of students.

Air Toxics Regulations

In addition, the District implements a variety of state, federal, and District rules reducing and regulating the emissions of toxic air pollutants. Such regulations have generated significant reductions in air toxics from a wide variety of sources, from requiring the gradual phase-out of perchloroethylene used at dry cleaners and mandating emissions controls at chrome platers, to a large number of rules aimed at reducing particulate emissions from diesel internal combustion engines.

Due to this diverse set of risk reduction efforts, approximately 14% of all air toxics in the San Joaquin Valley are now emitted from stationary sources of pollution under the direct

control and regulation of the District, while 52% comes from mobile sources such as cars and trucks, and the remaining 34% is emitted from area-wide sources like road dust, paints, solvents, and other consumer products (per CTI). Mobile and area-wide sources of emissions are generally under the regulatory authority of the State of California and the federal government.

Diesel Particulate Matter (DPM) Risk Reduction

CARB identified particulate matter emissions from diesel-fueled engines as a toxic air contaminant with the potential to pose a significant cancer risk to the public. Historically the cancer risk from the exhaust of diesel internal combustion engines has been determined to be far higher than the estimated cancer risk from all other sources of air pollution combined. Because of the high level of risk associated with diesel exhaust, and because of the prevalence of the engines, the State chose not to address diesel exhaust using the existing risk management guidance. Instead, the State decided to establish an advisory committee of interested parties, and developed a comprehensive risk management plan that would result in significant reductions in emissions of diesel particulate matter. CARB adopted the Risk Reduction Plan to Reduce Particulate Matter Emissions from mobile and stationary Diesel-fueled Engines.

Several of the following Air Toxic Control Measures (ATCMs) were developed as a part of ARB's diesel exhaust risk reduction efforts, which continue to be developed. Related information is available on CARB's ATCM website at: https://ww2.arb.ca.gov/resources/documents/airborne-toxic-control-measures.

ATCM Portable Diesel-Fueled Engines

The purpose of the CARB adopted Portable Diesel ATCM is to protect public health by controlling particulate matter (PM) emissions from diesel fueled portable engines rated at 50 horsepower and greater operating in California. All existing portable diesel engines were required to be certified by January 1, 2010, and all new portable engines were required to meet the latest certification standards. In addition, the ATCM contains stringent diesel PM fleet standards that apply after 2010.

The latest version of the ATCM became effective on November 30, 2018 and contains stringent emissions standards and operational requirements that impact new and existing portable diesel engines. The District has been implementing the requirements of the Portable ATCM in the review of applications for District Portable Registrations and permits for portable diesel engines. This ATCM is expected to continue to result in a substantial reduction in Valley diesel PM emissions over the next several years.

ATCM Stationary Diesel-Fueled Engines

The purpose of the CARB adopted Stationary Diesel ATCM is to protect public health by controlling particulate matter (PM) and criteria pollutant emissions from stationary diesel fueled portable engines rated at 50 horsepower and greater operating in California.

This ATCM is satisfied via Rule 4702 (Internal Combustion Engines) in combination with the District's permitting or Permit-Exempt Equipment Registration (PEER) program. These District programs have collectively been found by the CARB to be equivalent to the

Stationary ATCM for stationary agricultural engines. This ATCM and District Rule 4702 are expected to continue to result in a substantial reduction in Valley diesel PM emissions over the next several years.

CARB Control Measure for In Use Off-road Diesel Vehicle Rule

The purpose of the CARB adopted an off-road diesel vehicle rule is to reduce diesel PM and oxides of nitrogen (NO_X) emissions from in-use (existing) off-road heavy-duty diesel vehicles. The regulation applies to self-propelled diesel-fueled vehicles that cannot be registered and licensed to drive on-road. Examples include loaders, crawler tractors, skid steers, backhoes, forklifts, and airport ground support equipment. Vehicles with engines less than 25 horsepower are exempt. The regulation is expected to reduce diesel exhaust emissions by over 1,600 tons per year statewide between 2010 and 2030.

Diesel Particulate Matter Control Measure for On-road Heavy-duty Diesel-fueled Vehicles Owned or Operated by Public Agencies and Utilities

The purpose of the CARB adopted control measure will reduce emissions from on-road heavy duty vehicles over several deadlines, with the first groups of vehicles required to be in compliance by December 31, 2007. This control measure is particularly effective because it reduces diesel PM emissions in the heart of residential communities where municipal and utility vehicles frequently conduct business, and where the public is significantly impacted by diesel PM emissions.

ATCM to Limit Diesel-Fueled Commercial Motor Vehicle Idling

CARB initially adopted an ATCM to reduce emissions of toxics and criteria pollutants by limiting idling of new and in-use sleeper berth-equipped diesel trucks. The emission performance requirements require technologies used as alternatives to idling the truck's main engine. The new engine requirements required 2008 and newer model year heavy-duty diesel engines to be equipped with non-programmable engine shutdown systems that automatically shut down the engine after five minutes of idling or, alternatively, meet a more stringent NO_X idling emission standard. Beginning January 1, 2008, in-use truck requirements require operators of both in-state and out-of-state registered sleeper berth equipped trucks to manually shut down their engine when idling more than five minutes at any location within California. Each year heavy-duty diesel truck idling contributes to hundreds of pounds of PM as well as other pollutants to the Valley. The District Incentive Program has subsidized truck stop support equipment to reduce diesel truck idling along the main goods movement corridors. Tests conducted by the District and CARB have determined that an idling truck can consume up to a gallon of diesel fuel an hour. The idling of heavy-duty trucks, at the time of delivery, represents a high percentage of emissions around developed areas in the Valley.

ATCM for Transport Refrigeration Units

The purpose of the CARB adopted ATCM is to reduce emissions of diesel PM from Transport Refrigeration Units (TRUs). TRUs are refrigeration systems powered by diesel internal combustion engines designed to refrigerate or heat perishable products that are transported in various containers, including semi-trailers, truck vans, shipping containers, and rail cars. Although TRU engines are relatively small, ranging from 9 to 36 horsepower, significant numbers of these engines congregate at distribution centers, truck stops, and

other facilities, resulting in the potential for health risks to those that live and work nearby. CARB estimated that diesel PM emissions from TRUs will be reduced by 83% by 2040. CARB has recently developed amendments to this ATCM. Related information is available on their TRU ATCM website at https://ww2.arb.ca.gov/our-work/programs/transport-refrigeration-unit.

ATCM for Hexavalent Chromium for Decorative and Hard Chrome Plating and Chromic Acid Anodizing Facilities

The purpose of the CARB adopted ATCM is to established new, more stringent emission limitations that depend upon size and nearness to sensitive receptors, limited the use of chemical fume suppressants, and adopted new housekeeping, education, monitoring, recordkeeping, and reporting requirements.

CARB amended the ATCM in 2023 to establish enhanced best management practices (e.g. building enclosures, limits, source testing, etc.) for all chrome plating facilities using hexavalent chrome. The stated goal of the amended ATCM is eliminating toxic hexavalent chromium emissions from the chrome plating industry in California over time. The amendments phase out the use of hexavalent chromium from chrome plating operations for all new chrome plating facilities in California. The amendments went into effect January 1, 2024.

There are numerous expected benefits from the revised ATCM, including eliminating hexavalent chromium emissions from California's chrome plating industry, reducing the potential cancer risk to individual residents and off-site workers near chrome plating facilities, and reducing occupational exposures for on-site workers.

ATCM for Perchloroethylene Emissions from Dry Cleaning Operations

The purpose of the CARB adopted ATCM is to phase out the use of perc dry cleaning machines and related equipment by January 1, 2023. In addition, the amendments will put in place revisions to the Curriculum for the Environmental Training Program for Perc Dry Cleaning Operations (Training Curriculum). There were changes to the operational requirements for dry cleaners as well. For example, the revised ATCM requires that owners/operators maintain a spare set of gaskets on-site. Also, the trained operator must now be on-site whenever the machine is operated. These amendments became effective upon final approval by the Office of Administrative Law on December 27, 2007. The District adopted the revised ATCM in 2008 by reference.

ATCM for Composite Wood Products

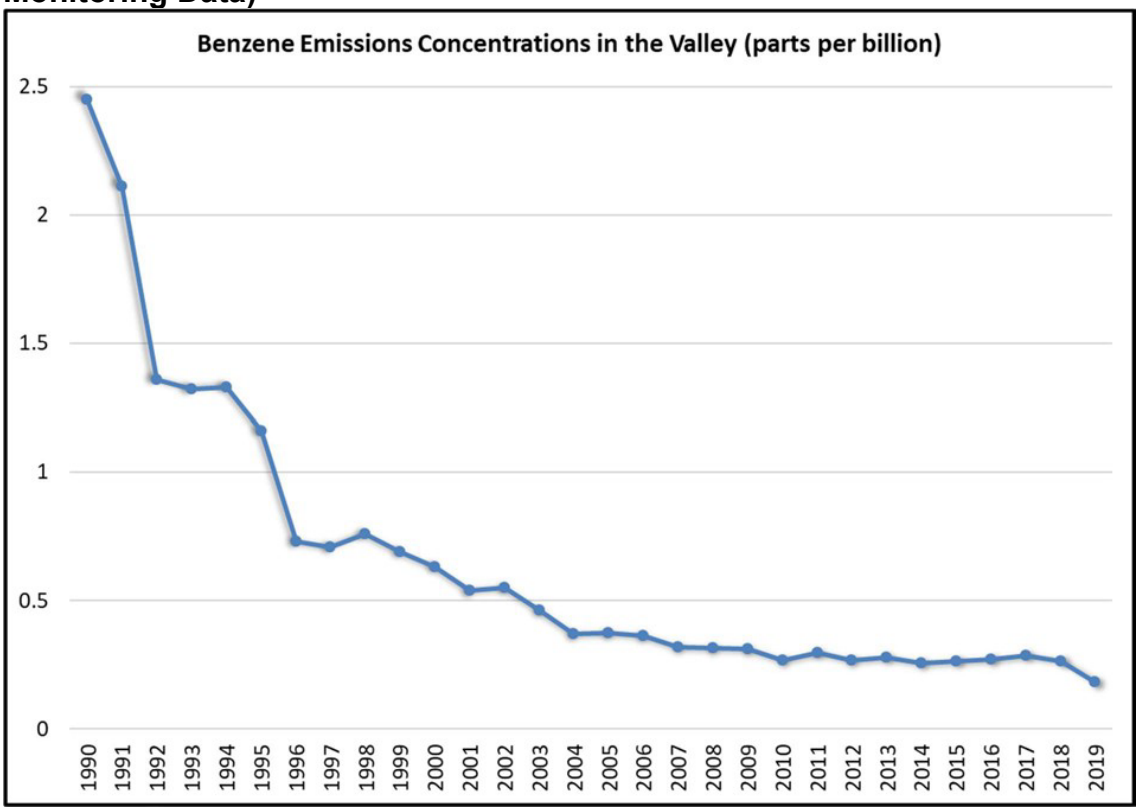
The purpose of the CARB approved ATCM is to reduce formaldehyde emissions from composite wood products including hardwood plywood, particleboard, medium density fiberboard, thin medium density fiberboard, and also furniture and other finished products made with composite wood products Formaldehyde is produced on a large scale worldwide. One major use includes the production of wood binding adhesives and resins. CARB developed a modified version of the Composite Wood Product ATCM that was released for a 15-day public comment period on January 31, 2008, and was approved April 18, 2008, by the Office of Administrative Law. Further amendments to this ATCM

were approved in May of 2012.

ATCM for Benzene from Retail Service Stations

CARB adopted the ATCM for Emissions of Benzene from Retail Service Stations. The ATCM reflects the use of best available control technology, which requires the installation of CARB-certified Phase I and II vapor recovery control equipment at all retail service stations. The ATCM is designed to reduce benzene and total hydrocarbon emissions from uncontrolled stations by 95 percent. Figure 6 shows the trend of benzene emissions in the Valley.

Figure 6. Benzene Emissions Trend, San Joaquin Valley (CARB Annual Toxics Monitoring Data)



ATCMs Adopted by the District as Regulations

- District Rule 7011: Chromium Plating And Chromic Acid Anodizing Facilities
- District Rule 7012: Hexavalent Chromium - Cooling Towers
- District Rule 7021: Ethylene Oxide - Sterilizers and Aerators
- District Rule 7031: Dioxin - Medical Waste Incinerators
- District Rule 7041: Fluorides - Phosphoric Acid Plants
- District Rule 7050: Asbestos - Containing Material for Surfacing Applications
- District Rule 7060: Toxic Metals from Non-Ferrous Metal Melting
- District Rule 7070: Perchloroethylene from Dry Cleaning Operations

Other ATCMs are implemented primarily through the permitting process. These include

the ATCM for Stationary Compression Ignition Engines and the ATCM for Diesel Particulate Matter from Portable Engines Rated at 50 Horsepower and Greater.

Reducing Health Risk through Enforcement Delegation

On July 1, 2008, the District began enforcing California Air Resources Board's ATCM to Limit School Bus Idling and Idling at Schools and ATCM to Limit Diesel-Fueled Commercial Motor Vehicle Idling, during timeframes in which state funding is available to support these efforts. The purpose of these ATCMs is to reduce toxic and criteria air pollutants by limiting idling time. By enforcing these requirements in the Valley, the District is able to directly reduce public exposure from toxic emissions, especially in sensitive areas.

The District was delegated the responsibility of enforcing the U.S. EPA's NESHAP for asbestos, a known carcinogen, and as a result performs hundreds of inspections of construction projects that have the possibility of disturbing asbestos containing materials. By ensuring that these materials are removed and handled correctly, the probability of harmful releases of asbestos is significantly reduced.

Implementation of Federal Air Toxics Mandates

EPA has issued NESHAPs through Part 61 and Part 63 of Title 40 of the Code of Federal Regulations (CFR). The Part 61 NESHAPs were issued prior to the adoption of the Federal Clean Air Act Amendments of 1990. Those NESHAPs are specific to a particular hazardous air pollutant (HAP). Due to little activity in adopting NESHAPs, the 1990 amendments to the Federal Clean Air Act established a new procedure for developing NESHAPs. A list of 189 HAPs was established. EPA identified industries that emitted those HAPs and established a prioritized list of over 70 source categories for which Maximum Achievable Control Technology (MACT) standards would be promulgated. These MACT standards apply to major sources of HAPs, defined as sources with emissions greater than 10 tons per year of a single HAP, or 25 tons per year of combined HAPs. Many of these sourcecategories are already subject to state and local regulation, which have traditionally been more stringent than the federal regulations. EPA has already adopted MACT standards to address the majority of the source categories identified.

In addition to the MACT standards for major sources, EPA is also required to adopt NESHAPs standards to reduce the health risk associated with area (non-major) sources of HAPs. As the result of a lawsuit, EPA was under court order to promulgate area source NESHAPs for 4 categories of sources by December 15, 2006; for 6 categories by June 15, 2007; and for 10 categories each 6 months thereafter until June 15, 2009. Similar to the MACT standards for major sources, many of the area sources subject to these standards are already subject to state and local regulation. Area source NESHAPs have already been promulgated for Oil and Natural Gas Production Facilities; Polyvinyl Chloride and Copolymers Production, Primary Copper Smelting, Secondary Copper Smelting, and Primary Nonferrous Metals - Zinc, Cadmium, and Beryllium; Acrylic and Modacrylic Fibers Production, Carbon Black Production, Chemical Manufacturing: Chromium Compounds, Flexible Polyurethane Foam Production and Fabrication, Lead Acid Battery

Manufacturing, and Wood Preserving; Clay Ceramics Manufacturing, Glass Manufacturing, and Secondary Nonferrous Metals Processing; Electric Arc Furnace Steelmaking Facilities; and Hospital Ethylene Oxide Sterilizers. See Appendix D for the current status of the District's implementation of NESHAPs.

An amendment to 40 CFR part 63, subpart ZZZZ (control of HAPs from reciprocating internal combustion engines) was proposed on June 6, 2012, and was finalized by EPA on January 14, 2013. This regulation requires reductions in hazardous air pollutants from stationary internal combustion engines over the next several years, and requires significant recordkeeping and monitoring of the engines affected. The District is currently developing processes and policies to assist those facilities affected to comply with the new requirements.

Many other amendments to existing NESHAPs were finalized in 2012: Chemical Manufacturing, Hard & Decorative Chrome electroplating and HCL supplements, Polyvinyl Chloride, Nitric Acid Plants, Petroleum Refineries process heaters and flares, etc. While these NESHAPs have lesser applicability in California and the San Joaquin Valley then the engine NESHAP discussed above, the District will identify, notify, and assist those facilities affected.

In December 2021, EPA issued a decision extending Toxic Release Inventory (TRI) reporting for ethylene oxide to 29 facilities across the country. These facilities were required to begin tracking their chemical activities, releases and other waste management quantities starting in January 2022 and submit TRI data to EPA in 2023. None of these facilities are located within the San Joaquin Valley.

On July 25, 2023, EPA announced proposed updates to the Air Emissions Reporting Requirements (AERR) to improve EPA's collection of certain emissions data critical for performing air quality and risk analyses, among other regulatory and non-regulatory activities. This proposed action would allow for EPA to annually collect (starting in 2027), HAP emissions data for point sources including non-major sources. The proposed amendments would ensure that EPA has sufficient information to identify and solve air quality and exposure problems and ensure that communities have the data needed to understand significant environmental risks that may be impacting them. Due to numerous requests to extend the comment period given the complexity and length of the proposed rulemaking, EPA extended the comment period for the proposed revisions to November 17, 2023. The District is following this development and will incorporate any updates into the Integrated Toxics Program as necessary.

The District currently is delegated authority by EPA to implement and enforce NESHAPs through two mechanisms. First, all major sources of HAPs are required to obtain Title V operating permits. The NESHAP requirements for these major sources are included in the Title V permits for which the District is delegated authority by EPA. Second, the District is delegated authority to implement and enforce all area source NESHAPs that are included in District Rule 4002, most recently amended on May 20, 2004. Under the District's Air Toxics Program and federal regulations, there are several options for

implementing new NESHAP requirements. These options are discussed in more detail below. The District will choose the most appropriate option for implementing each Federal standard, and will hold public workshops to obtain public input on the implementation of these additional standards.

- Straight Delegation: Accepting delegation of the federal standard as written by amending Rule 4002 or by agreeing to automatic delegation with an option of opting-out for specific NESHAPs using an approach developed by the (CAPCOA);
- Rule Adjustment: Proposing minor changes to the federal MACT rule that make the adjusted rule no less stringent than the federal standard;
- Rule Substitution: Substituting one or more existing, new, or amended District rules for the federal standard (It should be noted that California Districts have been delegated authority for the chrome plating and dry cleaning NESHAPs because EPA has agreed that the ATCMs for those source categories are equivalent to the NESHAPs.);
- Streamlining Multiple Applicable Requirements: Minimizing duplicative requirements by placing the more stringent emission limit or workplace practice standard on the permit along with the corresponding monitoring, recordkeeping, and reporting requirements;
- Program Substitution: Using existing programs to assure compliance with the requirements of federal standards;
- No Delegation: Using existing programs to reduce the emissions of hazardous air pollutants without delegation of federal standards.

The NESHAPs for which the District has received delegation through Rule 4002 are listed in Table E1 in Appendix E. All current NESHAPs for which the District has not received delegation through Rule 4002 are listed in Table E2 in Appendix E.

Regardless of the status and type of delegation, the District believes strongly in working with the affected sources to make them aware of the requirements in a timely manner, and then help them understand and comply with these public health protective regulations.

Air Dispersion Modeling



Air quality models use mathematical techniques to simulate the physical and chemical processes that affect air pollutants as they disperse and react in the atmosphere. These models form the backbone of the air toxics management process, as they are used to assess the potential exposure of the public to various toxic emissions. Using inputs of meteorological data and source parameter information such as emission rates and stack height, models predict ambient concentrations of primary pollutants that are emitted. Models are also important to the air quality management process because they determine compliance with National/State Ambient Air Quality Standards (NAAQS/SAAQS), and other regulatory requirements such as New Source Review (NSR).

EPA Regulatory Model (AERMOD)

The American Meteorological Society/Environmental Protection Agency Regulatory Model Improvement Committee (AERMIC) was formed to introduce state-of-the-art modeling concepts into the EPA's air quality models. Through AERMIC, a modeling system, AERMOD, was developed to incorporate air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including treatment of both surface and elevated sources, and both simple and complex terrain.

With the promulgation of AERMOD as the preferred air dispersion model in EPA's *Guideline on Air Quality Models* (signed by the EPA Administrator on October 21, 2005 and published November 9, 2005 in the *Federal Register*), AERMOD is used for appropriate application as a replacement for ISCST3 since November 9, 2006.

Meteorological Data

The District makes available meteorological data from both the National Climatological

Data Center (NCDC) and the Fifth-Generation Penn State/National Center for Atmospheric Research Mesoscale Model (MM5). The NCDC data were collected at major airports in the San Joaquin Valley. The MM5 data were derived from a numerical model for locations in the valley where there are no airports. These locations are primarily in the western part of the Valley. All processed data is freely available for download on the District's web page at:
https://www.valleyair.org/busind/pto/Tox_Resources/AirQualityMonitoring.htm

Appendices

Appendix A: Facilities Assessed Under AB 2588 in 2023
Appendix B: Update Summary Facilities
Appendix C: Toxic Emissions Summary
Appendix D: AB 2588 District Implementation Flow Chart
Appendix E: Current Status of NESHAP Delegation

Appendix A. Facilities Assessed under AB 2588 in 2023

Appendix A includes a detailed list of the facilities assessed under AB 2588 in 2023. Table A1 Includes facilities prioritized and Table A2 Includes the facilities with completed health risk assessments.

In addition to the tables listed below, Appendix A also includes maps that visually show the locations of all facilities that were evaluated in 2023.

Table A1. Facilities Prioritized in 2023

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
N	7856	Family Pet Mortuary	Turlock	47.8	High
N	1252	Foster Food Products	Livingston	33.8	High
N	3028	Westland Technologies, Inc.	Modesto	30.8	High
N	2369	Arrow Infrastructure Holding IA LLC	Stockton	29.9	High
C	841	Dos Palos Cooperative Gin Inc.	Chowchilla	29.1	High
C	9232	Modern Custom Fabrication, Inc.	Fresno	23.0	High
S	8848	Peters-Loyd Funeral Services	Porterville	20.7	High
S	1135	AERA Energy LLC	Kern County	19.8	High
S	1128	Chevron USA Inc.	Kern County	19.7	High
N	2174	Silgan Containers Mfr. Corp.	Riverbank	18.1	High
S	2777	California Resources Production Corp.	Bakersfield	9.89	Intermediate
N	3302	City of Modesto	Modesto	9.44	Intermediate
N	3510	City of Lodi (Water Well #16)	Lodi	9.41	Intermediate
C	2886	Pacific Gas & Electric Co.	Fresno	9.32	Intermediate
N	704	Dynatect Ro-Lab Inc.	Tracy	9.08	Intermediate
N	2868	Pacific Bell Telephone Co (dba AT&T CA)	Riverbank	9.04	Intermediate
C	3098	Comcast Cable Communications Inc.	Madera	8.94	Intermediate
S	8712	Kern Asphalt Paving & Sealing Co Inc.	Bakersfield	8.93	Intermediate
S	3344	Level 3 Communications	Dinuba	8.82	Intermediate
N	3305	City of Modesto	Modesto	8.73	Intermediate
S	91	Mt Poso Cogeneration Co LLC	Bakersfield	8.65	Intermediate
N	7365	Pelican Renewables LLC	Stockton	8.57	Intermediate
N	1662	Gallo Glass Company	Modesto	8.56	Intermediate
N	2873	Pacific Bell Telephone Co (dba AT&T CA)	Los Banos	8.56	Intermediate
N	3458	Applied Aerospace Structures Corp.	Stockton	8.55	Intermediate
C	214	California State Prison –	Corcoran	8.32	Intermediate

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
		Corcoran			
C	7501	Signature Flight Support	Fresno	8.27	Intermediate
C	3572	Level 3 Communications LLC	Fresno	8.23	Intermediate
C	1647	Pacific Bell Telephone Co (dba AT&T CA)	Selma	8.21	Intermediate
S	2486	Pacific Bell Telephone Co (dba AT&T CA	Dinuba	8.06	Intermediate
C	4071	Algonquin Power Sanger LLC	Sanger	8.03	Intermediate
N	4522	City of Merced	Merced	7.95	Intermediate
S	568	Rosewood Retirement Community	Bakersfield	7.88	Intermediate
N	8942	World Class Distribution, Inc.	Stockton	7.86	Intermediate
S	3546	California Water Service	Bakersfield	7.82	Intermediate
C	2055	The Ponderosa Telephone Co.	Friant	7.61	Intermediate
N	2564	Stockton Municipal Utility	Stockton	7.51	Intermediate
S	8690	Dirt Worx Inc.	Bakersfield	7.47	Intermediate
C	205	California Water Service Co.	Selma	7.35	Intermediate
N	4527	City of Merced	Merced	7.35	Intermediate
S	2474	California Water Service Co.	Bakersfield	7.33	Intermediate
C	9419	Crestwood Kingsburg Healing Center	Kingsburg	7.08	Intermediate
C	1627	Fresno County Build Maintenance Division	Fresno	7.08	Intermediate
N	4666	Dale Commons MSL LLC	Modesto	6.94	Intermediate
N	9211	San Joaquin County	Stockton	6.89	Intermediate
N	9754	Amazon.Com Services LLC	Stockton	6.85	Intermediate
S	1469	California Water Service Co.	Bakersfield	6.85	Intermediate
N	3038	Monschein Industries Inc.	Riverbank	6.84	Intermediate
N	4956	City of Newman	Newman	6.78	Intermediate
S	8561	J.P. Oil Company, LLC	Shafter	6.76	Intermediate
S	18	Kern County General Services	Lamont	6.70	Intermediate
N	3306	City of Modesto	Modesto	6.66	Intermediate
N	811	Stockton RWCF	Stockton	6.63	Intermediate
N	2885	City of Modesto	Modesto	6.54	Intermediate
N	558	Diamond Pet Foods-Lathrop	Lathrop	6.47	Intermediate
C	2054	The Ponderosa Telephone Co.	Shaver Lake	6.42	Intermediate
C	3321	City of Fresno Water Division	Fresno	6.29	Intermediate
N	9482	Keyes Community Services District	Keyes	6.28	Intermediate
N	10034	Amazon.Com Services LLC - SCK6	Tracy	6.21	Intermediate
S	1915	Tulare City Water Division	Tulare	6.13	Intermediate

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
S	6817	Lowe's HIW Inc.	Tulare	6.07	Intermediate
S	2609	The Cardinal Group LLC	Bakersfield	6.00	Intermediate
N	1647	Martin Marietta CA A&P, LLC - Merced HMA	Merced	5.96	Intermediate
N	3087	City of Modesto	Modesto	5.83	Intermediate
C	3318	City of Fresno Water Division	Fresno	5.80	Intermediate
S	9681	Chevron Cogeneration Company	Bakersfield	5.80	Intermediate
S	1131	Chevron USA Inc.	Kern County	5.80	Intermediate
S	88	Kern River Cogeneration Facility	Bakersfield	5.8	Intermediate
S	511	Sycamore Cogeneration Facility	Bakersfield	5.8	Intermediate
N	4724	City of Atwater	Atwater	5.76	Intermediate
N	4723	City of Atwater	Atwater	5.74	Intermediate
S	2634	Kern County Supt of Schools	Bakersfield	5.73	Intermediate
N	3086	City of Modesto	Modesto	5.61	Intermediate
S	9156	Alliance Ready Mix, Inc.	Shafter	5.49	Intermediate
N	2456	City of Stockton/CB Richard Ellis Inc.	Stockton	5.47	Intermediate
C	9905	EZ-Trip	Madera	5.43	Intermediate
C	1059	Saint Agnes Medical Center	Fresno	5.25	Intermediate
S	2568	Pacific Bell Telephone Co (dba AT&T CA)	Earlimart	5.21	Intermediate
C	3615	City of Fresno	Fresno	5.11	Intermediate
C	930	Pacific Gas & Electric Co.	Fresno	5.07	Intermediate
N	4519	City of Merced	Merced	5.02	Intermediate
N	4016	Comcast Cable Communications Inc.	Stockton	5.01	Intermediate
S	2493	California Water Service Co.	Bakersfield	5.01	Intermediate
S	4275	City of Wasco	Wasco	4.93	Intermediate
S	2300	California Water Service Co.	Bakersfield	4.89	Intermediate
S	3391	Verizon Wireless - Woodmere	Bakersfield	4.80	Intermediate
C	3368	AT&T Mobility	Madera	4.69	Intermediate
C	1764	Madera Valley Water Company	Madera	4.64	Intermediate
N	3842	City of Stockton, California	Stockton	4.61	Intermediate
N	2022	Sutter Valley Hospitals dba Memorial Medical	Modesto	4.59	Intermediate
C	3008	MCI	Fresno	4.52	Intermediate
C	3026	Frontier California Inc.	Reedley	4.48	Intermediate
N	8553	New Bethany	Los Banos	4.37	Intermediate
N	4727	City of Atwater	Atwater	4.36	Intermediate
N	4728	City of Atwater	Atwater	4.36	Intermediate

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
N	3482	City of Ripon	Ripon	4.27	Intermediate
C	216	California Air National Guard	Fresno	4.17	Intermediate
N	4824	Los Banos Police Department	Los Banos	4.08	Intermediate
N	4472	City of Modesto	Modesto	4.06	Intermediate
N	4725	City of Atwater	Atwater	4.02	Intermediate
N	1670	Georgia-Pacific Corrugated LLC	Modesto	4.00	Intermediate
N	2875	Pacific Bell Telephone Co (dba AT&T CA)	Gustine	3.92	Intermediate
S	6527	Visalia Eye Center	Visalia	3.89	Intermediate
C	8864	City of Fresno	Fresno	3.86	Intermediate
C	9728	JT Atwal Petroleum Inc.	Fresno	3.84	Intermediate
N	1758	Berry Seed & Feed Company	Keyes	3.71	Intermediate
N	4521	City of Merced	Merced	3.70	Intermediate
S	1160	Pacific Bell Telephone Co dba AT&T CA	Frazier Park	3.58	Intermediate
C	2953	City of Selma Fire Dept.	Selma	3.57	Intermediate
S	3897	Centennial Asphalt Company	Bakersfield	3.56	Intermediate
S	8857	FJM Inc.	Fellows	3.56	Intermediate
N	2859	Pacific Bell Telephone Co (dba AT&T CA)	Newman	3.51	Intermediate
N	3932	Plymouth Square	Stockton	3.43	Intermediate
S	1167	Pacific Bell Telephone Co (dba AT&T CA)	Shafter	3.42	Intermediate
C	9490	Jammu Petroleum Inc.	Fresno	3.40	Intermediate
N	9517	Lakha Corporation	Atwater	3.39	Intermediate
C	8863	City of Fresno	Fresno	3.36	Intermediate
C	1607	Bear Communications	Squaw Valley	3.28	Intermediate
N	8880	Fedex Freight Inc. – STK	Stockton	3.18	Intermediate
S	9576	California Water Service Co.	Bakersfield	3.12	Intermediate
N	2860	Pacific Bell Telephone Co. (dba AT&T CA)	Crows Landing	3.11	Intermediate
N	2866	Pacific Bell Telephone Co. (dba AT&T CA)	Waterford	3.07	Intermediate
C	933	Pacific Gas & Electric Co.	Fresno	3.03	Intermediate
S	1470	California Water Service Co.	Bakersfield	3.02	Intermediate
C	2684	City of Corcoran Public Works	Corcoran	2.98	Intermediate
N	4181	City of Modesto	Grayson	2.96	Intermediate
S	1494	California Water Service Co.	Bakersfield	2.92	Intermediate
S	9230	City of Tulare, Public Works, Water Dept.	Tulare	2.91	Intermediate
S	1164	Pacific Bell Telephone Co. dba AT&T CA	Mettler	2.89	Intermediate

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
N	4017	Comcast Cable Communications Inc.	Stockton	2.85	Intermediate
N	608	Pacific Gas & Electric Co.	Holt	2.81	Intermediate
N	7341	City of Patterson	Patterson	2.81	Intermediate
N	4653	City of Tracy	Tracy	2.81	Intermediate
S	9727	City of Delano	Delano	2.77	Intermediate
N	4525	City of Merced	Merced	2.73	Intermediate
N	7499	Travelcenters of America Operating Corp.	Livingston	2.72	Intermediate
S	6161	Level 3 Communications	Tulare	2.68	Intermediate
N	2874	Pacific Bell Telephone Co. (dba AT&T CA)	Planada	2.64	Intermediate
S	2483	Pacific Bell Telephone Co. (dba AT&T CA)	Woodlake	2.64	Intermediate
S	2847	California Water Service Co.	Bakersfield	2.62	Intermediate
S	1158	Pacific Bell Telephone Co. (dba AT&T CA)	Lebec	2.59	Intermediate
C	3296	Comcast Cable Communications Inc.	Fresno	2.59	Intermediate
N	9641	City of Modesto	Modesto	2.58	Intermediate
S	2476	Pacific Bell Telephone Co. (dba AT&T CA)	Pixley	2.58	Intermediate
N	2877	Pacific Bell Telephone Co. (dba AT&T CA)	Le Grand	2.54	Intermediate
C	2877	Del Rey Community Ser District	Del Rey	2.51	Intermediate
N	9919	Jim Todd C/O Todd Energy Corporation	Los Banos	2.47	Intermediate
S	2479	Pacific Bell Telephone Co. (dba AT&T CA)	Terra Bella	2.46	Intermediate
S	3035	California Water Service Co.	Bakersfield	2.45	Intermediate
C	3104	Housing Authority City of Madera	Madera	2.45	Intermediate
C	8773	New Cingular Wireless PCS, LLC dba AT&T	Chowchilla	2.45	Intermediate
S	2475	Pacific Bell Telephone Co. (dba AT&T CA)	Orosi	2.41	Intermediate
S	8762	Sully's Food Stores LLC	Bakersfield	2.39	Intermediate
S	2234	California Resources Elk Hills LLC	Tupman	2.38	Intermediate
S	9168	Elk Hills Power LLC	Tupman	2.38	Intermediate
N	9297	City of Oakdale	Oakdale	2.36	Intermediate
C	1649	Pacific Bell Telephone Co. (dba AT&T CA)	Avenal	2.34	Intermediate
S	2487	Pacific Bell Telephone Co. (dba AT&T CA)	Farmersville	2.33	Intermediate
C	1955	Biola Community Services Dist.	Biola	2.27	Intermediate

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
N	9555	BP Products North America Inc.	Modesto	2.26	Intermediate
S	8912	Sullivan Petroleum LLC	Bakersfield	2.25	Intermediate
C	2876	Malaga County Water District	Fresno	2.22	Intermediate
S	267	California Water Service Co	Visalia	2.18	Intermediate
S	6276	MCI	Bakersfield	2.12	Intermediate
C	1614	Fresno County Build Maintenance Div.	Fresno	2.10	Intermediate
S	4202	Housing Authority of the County of Kern	Bakersfield	2.08	Intermediate
N	4182	City of Modesto	Del Rio	2.07	Intermediate
S	3991	Foster Farms- Traver Feedmill	Traver	2.04	Intermediate
C	1648	Pacific Bell Telephone Co dba AT&T CA)	Stratford	2.03	Intermediate
C	9635	SCI California Funeral Services, Inc.	Reedley	2.02	Intermediate
S	8013	Sullivan Petroleum LLC	Bakersfield	2.01	Intermediate
C	9034	California Highway Patrol	Fresno	2.00	Intermediate
N	9529	Fam Autobody	Stockton	1.98	Intermediate
N	9686	San Joaquin County Office of Education	Stockton	1.98	Intermediate
S	1471	California Water Service Co.	Bakersfield	1.98	Intermediate
S	8351	Hope Elementary School	Porterville	1.95	Intermediate
S	1760	VSS Emultech	Bakersfield	1.95	Intermediate
N	2867	Pacific Bell Telephone Co. (dba AT&T CA)	Turlock	1.92	Intermediate
S	2489	Pacific Bell Telephone Co. (dba AT&T CA)	Ivanhoe	1.92	Intermediate
S	8918	Timothy Van Beek, SP dba Two Fiets	Tipton	1.91	Intermediate
N	9893	Westley Property LLC	Westley	1.89	Intermediate
C	3204	City of Fresno Water Division	Fresno	1.85	Intermediate
C	1664	Pacific Bell Telephone Co (dba AT&T CA)	Lemoore	1.85	Intermediate
C	3783	Cocola Broadcasting Companies	Fresno	1.84	Intermediate
N	8255	Linden County Water District	Linden	1.82	Intermediate
N	7839	Doctors Behavioral Health Center	Modesto	1.76	Intermediate
N	9927	ATC Sequoia LLC	Modesto	1.75	Intermediate
S	3675	Home Depot #6687	Bakersfield	1.73	Intermediate
C	3581	Millbrook Fresno LLC Dba Cottonwood Center	Fresno	1.73	Intermediate
N	9208	San Joaquin County	French Camp	1.68	Intermediate
S	2645	Horizon Nut LLC	Tulare	1.67	Intermediate

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
S	2478	Pacific Bell Telephone Co. (dba AT&T CA)	Springville	1.67	Intermediate
C	3163	Kfsn-Tv/ABC Inc.	Meadow Lakes	1.66	Intermediate
C	3440	Sinclair Television-Fresno LLC-Kmph-TV	Fresno	1.66	Intermediate
C	9199	California Rock Crusher	Various Unspecified	1.65	Intermediate
S	9664	City of Shafter	Shafter	1.61	Intermediate
N	9993	Denair Community Service District	Denair	1.60	Intermediate
C	3316	City of Fresno Water Division	Fresno	1.57	Intermediate
N	9792	Home Depot USA, Inc.	Tracy	1.56	Intermediate
N	4730	City of Atwater	Atwater	1.51	Intermediate
N	474	Leprino Foods	Tracy	1.51	Intermediate
S	691	Bakersfield City C/O Cal Water	Bakersfield	1.50	Intermediate
N	9645	City of Lathrop	Lathrop	1.47	Intermediate
C	1951	California Water Service Co.	Selma	1.44	Intermediate
C	1952	California Water Service Co.	Selma	1.44	Intermediate
N	9912	Cepheid	Lodi	1.44	Intermediate
C	3552	City of Madera	Madera	1.44	Intermediate
N	2929	City of Stockton	Stockton	1.41	Intermediate
N	2861	Pacific Bell Telephone Co. (dba AT&T CA)	Knights Ferry	1.40	Intermediate
N	3521	City of Modesto, Public Works	Modesto	1.37	Intermediate
C	2438	City of Sanger	Sanger	1.36	Intermediate
C	195	CA State Prison - Avenal	Avenal	1.34	Intermediate
N	4149	Keyes Community Services Dist.	Keyes	1.34	Intermediate
C	954	Prison Industry Authority - Avenal	Avenal	1.34	Intermediate
S	614	California Water Service Co.	Visalia	1.33	Intermediate
C	2042	J.W. Myers Inc.-Chevron	Madera	1.33	Intermediate
N	8803	Walmart Store #5843	Patterson	1.33	Intermediate
N	2942	City of Ripon	Ripon	1.33	Intermediate
S	2924	Wasco City Westside Pump Station	Wasco	1.31	Intermediate
C	2882	County of Kings	Kettleman City	1.31	Intermediate
C	544	Fresno County Service Area #31	Shaver Lake	1.31	Intermediate
N	9817	7-Eleven Store #41187	Stockton	1.30	Intermediate
S	3857	California Water Service Co.	Bakersfield	1.28	Intermediate
N	3995	City of Escalon	Escalon	1.28	Intermediate
N	9478	City of Modesto	Modesto	1.28	Intermediate

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
C	7868	Home Garden Community Service District	Hanford	1.28	Intermediate
N	9935	Amazon.com Services LLC-SCK9	Stockton	1.26	Intermediate
S	2485	Pacific Bell Telephone Co. (dba AT&T CA)	Camp Nelson	1.23	Intermediate
N	8102	Anthony Souza	Tracy	1.22	Intermediate
S	6860	California Water Service Co.	Bakersfield	1.22	Intermediate
C	2361	Madera Valley Water Company	Madera	1.20	Intermediate
N	7386	City of Ripon - Public Works	Ripon	1.19	Intermediate
S	799	California Water Service Co.	Visalia	1.19	Intermediate
S	9805	American Towers LLC	Bakersfield	1.19	Intermediate
N	1910	Crystal Creamery, Inc.	Modesto	1.17	Intermediate
S	6541	California Water Service Co.	Bakersfield	1.16	Intermediate
S	9141	El Centro Corner Petroleum LLC	Visalia	1.16	Intermediate
C	7569	Kuldeep Dhaliwal	Coalinga	1.11	Intermediate
S	9760	American Towers LLC	Bakersfield	1.09	Intermediate
S	258	California Water Service Co.	Visalia	1.09	Intermediate
N	9420	Department of Transportation	Los Banos	1.08	Intermediate
S	1377	California Water Service Co.	Bakersfield	1.07	Intermediate
S	3234	KGET-TV 17	Bakersfield	1.06	Intermediate
C	3705	Lowe's HIW Inc. #795	Fresno	1.06	Intermediate
C	1646	Pacific Bell dba SBC	Parlier	1.04	Intermediate
C	1814	Pacific Bell Telephone Co. (dba AT&T CA)	Chowchilla	1.04	Intermediate
N	9872	City of Newman	Newman	1.03	Intermediate
N	2010	George W. Lowry, Inc.	Modesto	1.03	Intermediate
C	1662	Pacific Bell Telephone Co. (dba AT&T CA)	Kingsburg	1.02	Intermediate
C	8740	Kings Nursing & Rehabilitation Center	Hanford	1.00	Exempt/Low
N	3973	Level 3 Communications LLC	Modesto	0.99	Exempt/Low
N	4585	The Dimare Company	Newman	0.98	Exempt/Low
N	7480	Canary Renewables Corp.	Stockton	0.97	Exempt/Low
S	1475	California Water Service Co.	Bakersfield	0.96	Exempt/Low
C	3885	City of Fresno, Police Dept.	Fresno	0.95	Exempt/Low
N	3692	Pacific Bell Telephone Co. (dba AT&T CA)	Lockeford	0.94	Exempt/Low
S	8521	Express Messenger Systems Inc.	Visalia	0.92	Exempt/Low
S	1689	Quality Refinishing	Bakersfield	0.92	Exempt/Low
S	1491	California Water Service Co.	Bakersfield	0.91	Exempt/Low

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
S	9656	Rocket #0255	Goshen	0.90	Exempt/Low
S	4124	California Water Service	Bakersfield	0.90	Exempt/Low
S	2481	Pacific Bell Telephone Co. (dba AT&T CA)	Tipton	0.88	Exempt/Low
N	1248	Foster Poultry Farms-Kopro	Livingston	0.88	Exempt/Low
S	266	California Water Service Co.	Visalia	0.87	Exempt/Low
N	3673	City of Ripon	Ripon	0.84	Exempt/Low
S	3315	Porterville Fire Dept.	Porterville	0.83	Exempt/Low
C	3030	Frontier California Inc.	Squaw Valley	0.82	Exempt/Low
C	3327	Qwest Communications Co LLC/Centurylink	Fresno	0.81	Exempt/Low
C	3250	KGPE Television	Auberry	0.81	Exempt/Low
N	3113	San Joaquin Co. Public Works	Manteca	0.79	Exempt/Low
C	1661	Pacific Bell Telephone Co. (dba AT&T CA)	Huron	0.79	Exempt/Low
C	1667	Pacific Bell Telephone Co. (dba AT&T CA)	Madera	0.77	Exempt/Low
S	268	California Water Service Co.	Visalia	0.77	Exempt/Low
S	183	Crop Production Services Inc.	Alpaugh	0.77	Exempt/Low
C	1654	Pacific Bell Telephone Co. (dba AT&T CA)	Del Rey	0.76	Exempt/Low
C	1651	Pacific Bell Telephone Co. (dba AT&T CA)	Caruthers	0.72	Exempt/Low
C	9930	Amazon.com Services LLC	Fresno	0.72	Exempt/Low
S	265	California Water Service Co.	Visalia	0.72	Exempt/Low
C	4168	City of San Joaquin	San Joaquin	0.70	Exempt/Low
N	4009	Level 3 Communications LLC	Winton	0.70	Exempt/Low
N	5404	JCPenney Company	Merced	0.69	Exempt/Low
S	2480	Pacific Bell dba SBC	Three Rivers	0.69	Exempt/Low
N	4530	City of Merced	Merced	0.67	Exempt/Low
N	5088	JCPenney Company	Modesto	0.66	Exempt/Low
N	472	Lawrence Livermore Natl Security, LLC	Tracy	0.65	Exempt/Low
N	4183	City of Waterford	Waterford	0.64	Exempt/Low
C	1645	Pacific Bell Telephone Co. (dba AT&T CA)	Riverdale	0.64	Exempt/Low
N	9730	Vanguard of California	Stockton	0.63	Exempt/Low
N	3555	Pacific Bell Telephone Co. (dba AT&T CA)	Manteca	0.62	Exempt/Low
S	2484	Pacific Bell Telephone Co. (dba AT&T CA)	Ash Mountain	0.61	Exempt/Low
C	2179	Sierra Unified School District	Prather	0.61	Exempt/Low
N	9059	New Cingular Wireless Pcs LLC	El Nido	0.607	Exempt/Low

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
		dba AT&T			
S	7131	AT&T Corp	Mckittrick	0.604	Exempt/Low
C	1663	Pacific Bell Telephone Co (dba AT&T CA)	Laton	0.569	Exempt/Low
N	4289	MCI Worldcom	Turlock	0.562	Exempt/Low
C	4261	Seaboard Energy California, LLC	Madera	0.56	Exempt/Low
C	9418	Del Rey CSD	Del Rey	0.553	Exempt/Low
C	70	Burrows & Castadio Inc.	Lemoore	0.548	Exempt/Low
N	4358	City of Livingston	Livingston	0.541	Exempt/Low
N	9679	Pacific Gas & Electric Company	Merced	0.533	Exempt/Low
S	263	California Water Service Co.	Visalia	0.532	Exempt/Low
N	3817	Covanta Stanislaus, Inc.	Crows Landing	0.526	Exempt/Low
S	2418	Jeffries Brothers Inc.	Buttonwillow	0.52	Exempt/Low
N	9850	7-Eleven, Inc.	Stockton	0.511	Exempt/Low
S	9698	7-Eleven, Inc. #41516	Bakersfield	0.511	Exempt/Low
C	9075	New Cingular Wireless Pcs, LLC dba AT&T	Firebaugh	0.506	Exempt/Low
N	4096	MCI World Com Corp	Lodi	0.503	Exempt/Low
C	3240	Hanford Mall	Hanford	0.497	Exempt/Low
S	3708	California Water Service Co.	Bakersfield	0.494	Exempt/Low
N	3691	Pacific Bell Telephone Co. (dba AT&T CA)	Thornton	0.493	Exempt/Low
S	1375	Ming Property LLC	Bakersfield	0.488	Exempt/Low
C	8894	Fedex Ground	Fresno	0.473	Exempt/Low
N	7768	Modesto Irrigation District	Modesto	0.467	Exempt/Low
N	9180	City of Lathrop - Lathrop Well #10	Lathrop	0.459	Exempt/Low
C	8188	State of California Dept. of Transportation	Miramonte	0.452	Exempt/Low
C	9091	Eriksson LLC	Riverdale	0.449	Exempt/Low
C	1650	Pacific Bell Telephone Co. (dba AT&T CA)	Burrel	0.448	Exempt/Low
S	1487	California Water Service Co.	Bakersfield	0.44	Exempt/Low
N	4306	City of Los Banos	Los Banos	0.438	Exempt/Low
C	3502	Sears Roebuck & Co. #1098	Clovis	0.423	Exempt/Low
N	3996	Level 3 Communications LLC	Tracy	0.403	Exempt/Low
S	3977	California Water Service Co	Bakersfield	0.399	Exempt/Low
N	4603	City of Manteca	Manteca	0.392	Exempt/Low
N	2909	Pacific Bell Telephone Co (Dba AT&T CA)	Modesto	0.382	Exempt/Low
C	7256	Garry Packing, Inc.	Del Rey	0.365	Exempt/Low

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
N	4742	Hilmar County Water District	Hilmar	0.365	Exempt/Low
S	4266	City of Bakersfield / CA Water Services	Bakersfield	0.358	Exempt/Low
C	1644	Pacific Bell Telephone Co. (dba AT&T CA)	Orange Cove	0.354	Exempt/Low
C	2124	Biola Community Services Dist.	Biola	0.344	Exempt/Low
C	973	Fig Garden Packing Inc.	Fresno	0.334	Exempt/Low
N	5024	City of Los Banos Fire Department	Los Banos	0.333	Exempt/Low
N	4334	City of Manteca	Manteca	0.33	Exempt/Low
S	5256	California Water Service Co	Visalia	0.327	Exempt/Low
S	4226	Golden Empire Concrete Products	Bakersfield	0.322	Exempt/Low
N	9861	Prologis	Tracy	0.318	Exempt/Low
S	2951	Taft City Wastewater Plant	Taft	0.305	Exempt/Low
S	8652	Verizon Wireless Tulare	Tulare	0.296	Exempt/Low
C	4057	Cocola Broadcasting Companies LLC	Auberry	0.274	Exempt/Low
N	9373	City of Livingston	Livingston	0.259	Exempt/Low
N	3516	City of Modesto	Modesto	0.254	Exempt/Low
C	1987	Ponderosa Paint Co., Inc.	Fresno	0.254	Exempt/Low
S	3547	California Water Service	Bakersfield	0.25	Exempt/Low
N	4097	Level 3 Communications LLC	Stockton	0.245	Exempt/Low
C	3425	Comcast Cable Communications Inc.	Clovis	0.241	Exempt/Low
N	8549	Department of Transportation	Terminous	0.24	Exempt/Low
C	1868	Manheim Central CA/TRA-Central CA	Fresno	0.24	Exempt/Low
N	3344	MCI Telecommunications Corp.	Manteca	0.24	Exempt/Low
N	9381	Oak Ridge Winery LLC	Lodi	0.24	Exempt/Low
S	8711	Verizon Wireless - "Belridge & Hwy 33"	Lost Hills	0.237	Exempt/Low
C	3038	County of Fresno	Clovis	0.236	Exempt/Low
C	9248	Faraday & Future, Inc.	Hanford	0.232	Exempt/Low
N	4515	Central Valley Broadcasting	Merced	0.225	Exempt/Low
N	3263	City of Lathrop	Lathrop	0.212	Exempt/Low
C	9397	A1 Blasting	Various Unspecified	0.211	Exempt/Low
C	3546	Madera County	Madera	0.207	Exempt/Low
N	9530	City of Manteca	Manteca	0.204	Exempt/Low
S	1495	California Water Service Co.	Bakersfield	0.199	Exempt/Low
C	2404	Lotus Communications, Corp	Fresno	0.195	Exempt/Low
C	3847	City of Clovis	Clovis	0.191	Exempt/Low

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
N	4108	City of Los Banos	Los Banos	0.191	Exempt/Low
N	9585	McFadden Construction	Stockton	0.182	Exempt/Low
C	1656	Pacific Bell Telephone Co. (dba AT&T CA)	Five Points	0.177	Exempt/Low
S	3925	City of Delano CCF	Delano	0.176	Exempt/Low
S	9165	M.O Dion & Sons, Inc.	Bakersfield	0.172	Exempt/Low
S	7254	Goertzen Quality Gypsum	Bakersfield	0.171	Exempt/Low
C	9426	Superior Soils Supplements, LLC	Mendota	0.166	Exempt/Low
S	264	California Water Service Co.	Visalia	0.158	Exempt/Low
S	4248	California Water Services Co. Station 218	Bakersfield	0.158	Exempt/Low
N	5977	City of Turlock	Turlock	0.158	Exempt/Low
C	3710	City of Huron	Huron	0.156	Exempt/Low
N	3784	Kohl's Department Stores Inc.	Merced	0.151	Exempt/Low
C	3517	Clovis Unified School District	Clovis	0.149	Exempt/Low
C	3000	Clovis Unified School District	Clovis	0.144	Exempt/Low
N	1980	Evergreen Beverage Packaging	Turlock	0.141	Exempt/Low
C	9338	Gar Bennett, LLC	Reedley	0.14	Exempt/Low
C	3081	Quail Lake LLC	Clovis	0.134	Exempt/Low
N	9075	City of Tracy Utilities Dept.	Tracy	0.129	Exempt/Low
C	4044	Fresno Unified School District	Fresno	0.125	Exempt/Low
S	3503	KTFF - Telefutura	Tulare	0.119	Exempt/Low
C	3527	Educational Employees C.U.	Fresno	0.115	Exempt/Low
C	9024	New Cingular Wireless Pcs, LLC dba AT&T	Fresno	0.112	Exempt/Low
N	3397	San Joaquin County Svc Area 31	Lodi	0.11	Exempt/Low
N	9073	New Cingular Wireless Pcs LLC dba AT&T	Gustine	0.109	Exempt/Low
S	6533	City of Dinuba	Dinuba	0.0891	Exempt/Low
C	351	City of Clovis	Clovis	0.0849	Exempt/Low
S	1196	Plains Pipeline LP	Kern	0.0817	Exempt/Low
C	3511	Educational Employee Federal Credit Union	Fresno	0.081	Exempt/Low
C	3379	Ross Aviation Investment, LLC	Fresno	0.0776	Exempt/Low
N	3948	City of Riverbank	Riverbank	0.077	Exempt/Low
N	4652	Winton Water And Sanitary District	Winton	0.072	Exempt/Low
N	9371	Mcmanis Family Vineyards	Ripon	0.0719	Exempt/Low
N	4109	City of Los Banos	Los Banos	0.0636	Exempt/Low
S	3159	Plains Pipeline LP	Bakersfield	0.0622	Exempt/Low

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
N	8949	City of Tracy Dept. of Emergency Services	Tracy	0.062	Exempt/Low
C	9097	California Resources Production Corp.	Fresno	0.0464	Exempt/Low
C	7958	City of Firebaugh	Firebaugh	0.0456	Exempt/Low
N	8643	Graham Packaging LC LP Plant 0176	Modesto	0.041	Exempt/Low
S	9447	Porterville Rock And Recycle	Porterville	0.0402	Exempt/Low
N	3944	Salida Sanitary District	Salida	0.0398	Exempt/Low
N	7676	City of Dos Palos	Dos Palos	0.0383	Exempt/Low
N	7895	City of Oakdale	Oakdale	0.0352	Exempt/Low
N	7675	City of Dos Palos	Dos Palos	0.0342	Exempt/Low
N	3735	City of Tracy	Tracy	0.034	Exempt/Low
C	3791	CVIN LLC	Kettleman City	0.03	Exempt/Low
C	2906	City of Clovis	Clovis	0.0262	Exempt/Low
N	9524	Lathrop-Manteca Fire Station 35	Lathrop	0.0203	Exempt/Low
S	3624	Frontier California Inc.	Kings Canyon National Park	0.0161	Exempt/Low
S	3283	Terra Bella Irrigation Dist.	Terra Bella	0.0159	Exempt/Low
S	3559	Delaware North Parks Services	Sequoia National Park	0.014	Exempt/Low
N	4083	City of Riverbank	Riverbank	0.013	Exempt/Low
N	1004	CSREH Charter 540 E Main, LLC	Stockton	0.0127	Exempt/Low
S	7653	Edison Beneficial Reuse	Bakersfield	0.0124	Exempt/Low
S	8216	Kern County Fire Department Station #65	Bakersfield	0.00532	Exempt/Low
C	3196	Pacific Gas & Electric Co.	Shaver Lake	0.00332	Exempt/Low
S	9018	City of Woodlake	Woodlake	0.003	Exempt/Low
N	3383	David J. M. Field	Farmington	0.003	Exempt/Low
C	2875	Malaga County Water District	Fresno	0.00289	Exempt/Low
N	3380	David J. M. Field	Patterson	0.002	Exempt/Low
C	9548	Left Mendota 1, LLC	Mendota	0.00149	Exempt/Low
N	8950	City of Tracy Dept. of Emergency Services	Tracy	0.001	Exempt/Low
N	3663	Kabariti's AM/PM	Lathrop	0	Exempt/Low
S	1480	California Water Service Co.	Bakersfield	0	Exempt/Low
S	1492	California Water Service Co.	Bakersfield	0	Exempt/Low
N	7985	Cardoza Enterprises	Manteca	0	Exempt/Low
N	9782	Carriage Services Inc.	Manteca	0	Exempt/Low
N	4729	City of Atwater	Atwater	0	Exempt/Low

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
C	2904	City of Clovis	Clovis	0	Exempt/Low
C	2905	City of Clovis	Clovis	0	Exempt/Low
C	2907	City of Clovis	Clovis	0	Exempt/Low
C	3590	City of Clovis-Public Utility	Clovis	0	Exempt/Low
C	3266	City of Fresno Water Division	Fresno	0	Exempt/Low
C	3315	City of Fresno Water Division	Fresno	0	Exempt/Low
C	3317	City of Fresno Water Division	Fresno	0	Exempt/Low
C	3319	City of Fresno Water Division	Fresno	0	Exempt/Low
C	3320	City of Fresno Water Division	Fresno	0	Exempt/Low
N	4551	City of Gustine	Gustine	0	Exempt/Low
N	4360	City of Livingston	Livingston	0	Exempt/Low
N	4465	City of Lodi Station #13	Lodi	0	Exempt/Low
N	4107	City of Los Banos	Los Banos	0	Exempt/Low
C	3751	City of Parlier	Parlier	0	Exempt/Low
C	3753	City of Parlier	Parlier	0	Exempt/Low
N	7384	City of Ripon- Public Works	Ripon	0	Exempt/Low
N	3959	City of Riverbank	Riverbank	0	Exempt/Low
N	3960	City of Riverbank	Riverbank	0	Exempt/Low
N	3961	City of Riverbank	Riverbank	0	Exempt/Low
C	9725	City of Sanger	Sanger	0	Exempt/Low
N	5976	City of Turlock	Turlock	0	Exempt/Low
N	5979	City of Turlock	Turlock	0	Exempt/Low
C	2307	CLF Fresno Business Trust	Fresno	0	Exempt/Low
C	3282	County of Kings	Hanford	0	Exempt/Low
S	2025	Earlimart Public Utility Dist.	Earlimart	0	Exempt/Low
N	3255	Lowe's Home Centers, LLC	Tracy	0	Exempt/Low
S	7506	Nelson's Ace Hardware	Visalia	0	Exempt/Low
C	916	Patton Sheet Metal	Fresno	0	Exempt/Low
S	3438	Sinclair Television-Fresno LLC-KMPH-TV	Sequoia National Forest	0	Exempt/Low
S	3456	Sinclair Television-Fresno LLC-KMPH-TV	Springville	0	Exempt/Low
N	8045	Strand Ace Hardware, Inc.	Modesto	0	Exempt/Low
N	10041	Tripoint Building 5, LLC	Lathrop	0	Exempt/Low
N	10040	Tripoint Building 7, LLC	Lathrop	0	Exempt/Low
S	7448	Tulare Co RMA Delft Colony Water	Dinuba	0	Exempt/Low
S	7447	Tulare County RMA - Solid Waste	Exeter	0	Exempt/Low

Region	Facility ID	Facility Name	City	Prioritization Score	Prioritization Category
C	3630	XPO Logistics Freight, Inc.- UKC	Kettleman City	0	Exempt/Low

Table A2. Facilities with Health Risk Assessments Performed in 2023

Region	Facility ID	Facility Name	City	Cancer Score	Acute Score	Chronic Score	Risk Category
S	3149	Frontier California Inc.	Lindsay	8.89	0.00	0.00	Intermediate Risk
N	3357	City of Lathrop	Lathrop	8.67	0.00	0.00	Intermediate Risk
N	3577	West Valley Mall	Tracy	8.16	0.00	0.01	Intermediate Risk
S	1173	Pacific Bell Telephone Co. (dba AT&T CA)	Oildale	7.86	0.00	0.00	Intermediate Risk
N	3550	City of Modesto	Modesto	7.75	0.00	0.00	Intermediate Risk
N	3649	Pacific Bell Telephone Co. (dba AT&T Ca)	Stockton	6.97	0.00	0.00	Intermediate Risk
C	1933	City of Fresno Water Division	Fresno	5.99	0.00	0.00	Intermediate Risk
S	3347	Level 3 Communications	Delano	5.86	0.00	0.00	Intermediate Risk
C	2500	Comcast Cable Communications Inc.	Hanford	5.66	0.00	0.00	Intermediate Risk
C	2948	Comcast Cable Communications Inc.	Reedley	5.62	0.00	0.00	Intermediate Risk
S	3203	Valley Strong Credit Union	Bakersfield	4.93	0.00	0.00	Intermediate Risk
S	12	Judicial Council of California JCC 15-C1	Bakersfield	4.71	0.00	0.00	Intermediate Risk
S	3984	Bowman Asphalt Inc.	Bakersfield	4.71	0.54	0.11	Intermediate Risk
C	6923	Ampersand Chowchilla Biomass LLC	Chowchilla	4.68	0.09	0.16	Intermediate Risk
S	13	Kern County General Services	Bakersfield	4.63	0.00	0.00	Intermediate Risk
S	3526	City of Porterville	Porterville	4.48	0.00	0.00	Intermediate Risk
N	7617	USA Waste of California, Inc.	Lathrop	3.84	0.89	0.05	Intermediate Risk
N	624	Park View Mausoleum & Crematory	Manteca	3.65	0.11	0.34	Intermediate Risk
S	1482	California Water Service Co.	Bakersfield	2.95	0.00	0.00	Intermediate Risk
S	6847	Kern County Water Agency	Bakersfield	2.39	0.00	0.00	Intermediate Risk
N	3165	City of Modesto	Modesto	2.29	0.00	0.00	Intermediate Risk
N	3509	City of Lodi (Water Well #9)	Lodi	2.26	0.00	0.00	Intermediate Risk
S	2198	Pacific Bell Telephone Co. dba AT&T CA	Tulare	2.18	0.00	0.00	Intermediate Risk
N	4520	City of Merced	Merced	1.96	0.00	0.00	Intermediate Risk
S	3343	Level 3 Communications	Arvin	1.96	0.00	0.00	Intermediate Risk

Region	Facility ID	Facility Name	City	Cancer Score	Acute Score	Chronic Score	Risk Category
S	3362	City of Shafter	Shafter	1.91	0.00	0.00	Intermediate Risk
N	3304	City of Modesto	Modesto	1.56	0.00	0.00	Intermediate Risk
N	3164	City of Modesto	Modesto	1.50	0.00	0.00	Intermediate Risk
N	3998	Remembrance Cremation Center	Atwater	1.40	0.14	0.11	Intermediate Risk
N	3511	City of Lodi (Water Well #7)	Lodi	1.37	0.00	0.00	Intermediate Risk
N	3541	Federal Aviation Admin	Stockton	1.31	0.00	0.00	Intermediate Risk
N	3085	City of Modesto	Modesto	0.88	0.00	0.00	Exempt/Low Risk
C	2950	Geil Enterprises Inc.	Fresno	0.77	0.00	0.00	Exempt/Low Risk
N	7771	Modesto Irrigation District	Modesto	0.70	0.00	0.00	Exempt/Low Risk
S	3530	County of Tulare Resource Mgmt.	Visalia	0.68	0.00	0.00	Exempt/Low Risk
S	3704	Level 3 Communications LLC	Bakersfield	0.29	0.00	0.00	Exempt/Low Risk
N	2907	Pacific Bell Telephone Co. (dba AT&T CA)	Modesto	0.28	0.00	0.00	Exempt/Low Risk
N	3863	City of Lodi	Lodi	0.24	0.00	0.00	Exempt/Low Risk

Figure A1. Map of Intermediate Facilities Assessed in 2023

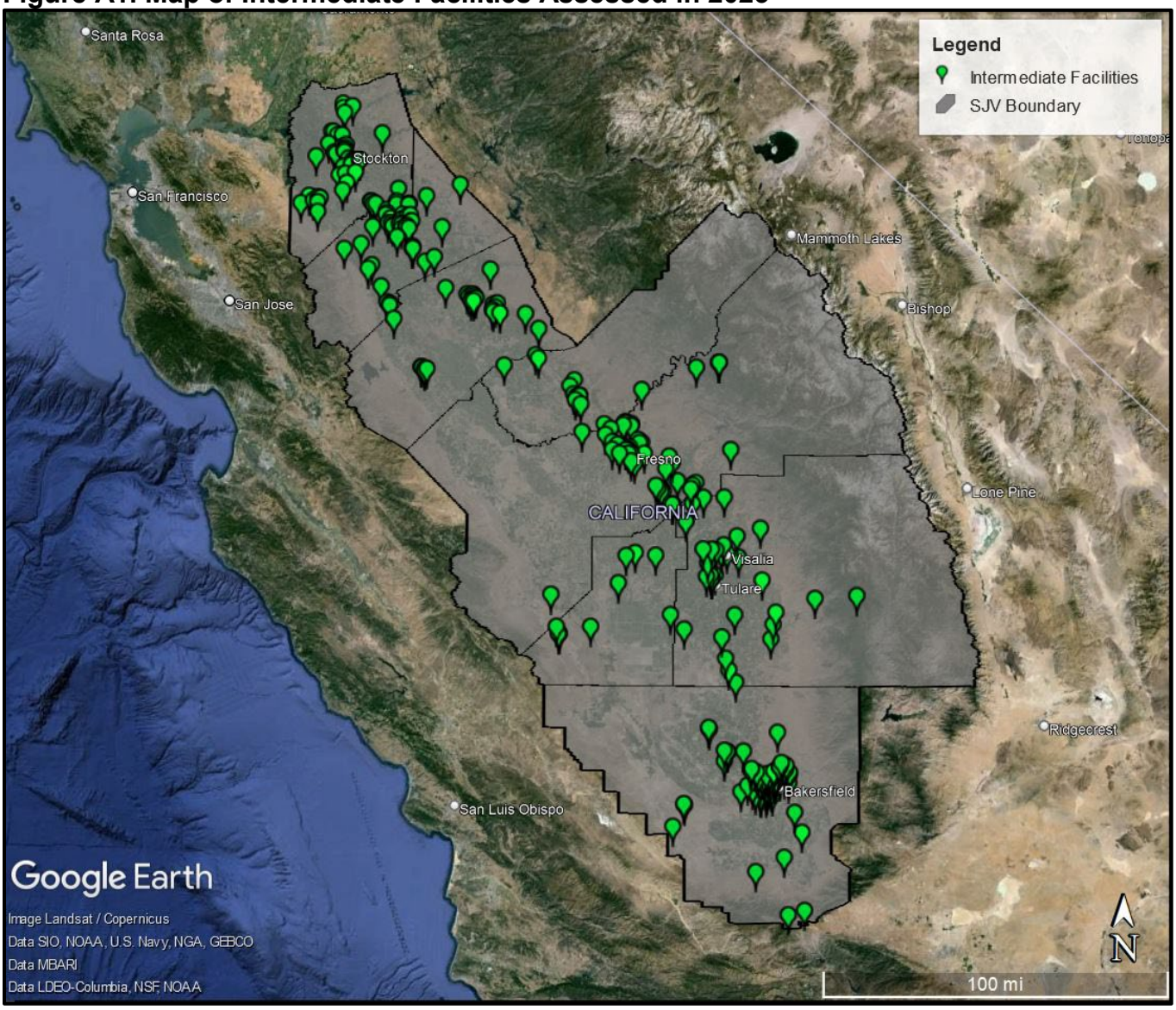
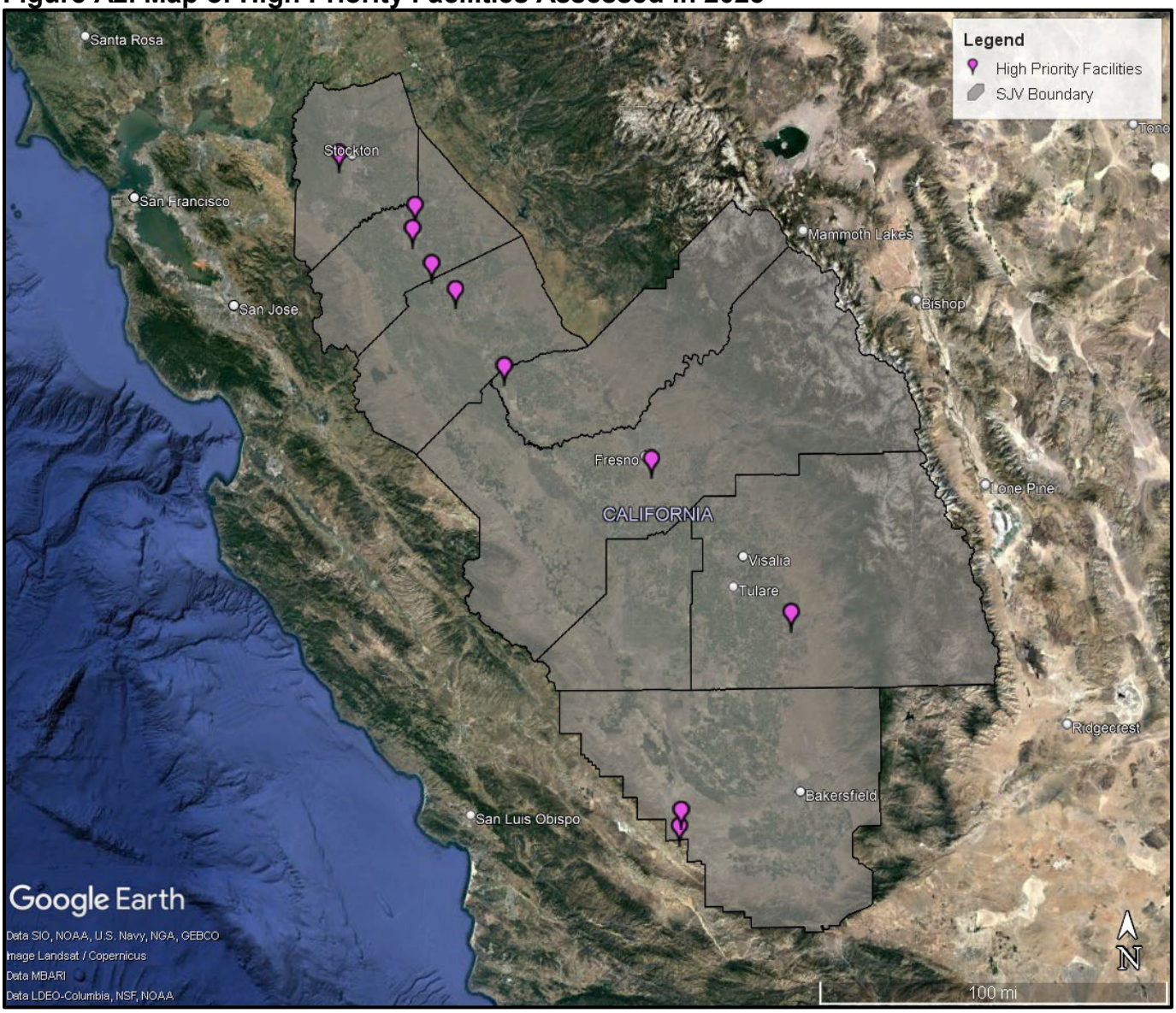


Figure A2. Map of High Priority Facilities Assessed in 2023



Appendix B. Update Summary Facilities Evaluated

Appendix B includes facilities that were re-evaluated as an update summary project.

Table B1. Update Summary Facilities Assessed in 2023

Region	Facility ID	Facility Name	City	Reinstatement Required
C	4071	Algonquin Power Sanger LLC	Sanger	Yes
N	7856	Family Pet Mortuary	Turlock	Yes
S	3991	Foster Farms- Traver Feedmill	Traver	Yes
S	3860	GMC Roofing & Paper Products	Shafter	Yes
S	8132	Golden Valley Crematory	Bakersfield	Yes
S	301	R B & J Industries Inc.	Dinuba	Yes
C	7832	Advanced Drainage System Inc.	Madera	No
N	4408	Aero Turbine Inc.	Stockton	No
N	1166	Andersen Nut Company	Gustine	No
S	3232	Bakersfield Metropolitan Landfill at Bena	Edison	No
S	3435	Best Buy	Dinuba	No
S	1876	Bluescope Buildings North America Inc.	Visalia	No
C	7542	Buttonwillow Warehouse Co	Corcoran	No
S	864	Cal Dept. of Corrections Delano	Delano	No
S	559	Cal Dept. of Corrections Wasco	Wasco	No
N	1363	California Dairies, Inc.	Los Banos	No
S	382	California Resources Elk Hills LLC	Kern	No
S	1738	California Resources Production Corp.	Kern	No
S	8282	California Resources Production Corp.	Kern	No
S	8454	California Resources Production Corp.	Kern	No
N	1788	California State University	Turlock	No
S	97	Carrage Funeral Services of California	Bakersfield	No
C	628	Cbus Ops dba Mission Bell Winery	Madera	No
N	2321	Cbus Ops Inc (dba Woodbridge Winery)	Acampo	No
C	252	Central Cal Women's Facility	Chowchilla	No
N	2518	Chemical Transfer Co., Inc.	Stockton	No
C	9095	Chevron Pipe Line Company	Kettleman Hills	No
N	3266	Chinchiolo Stemilt California LLC	Stockton	No
C	3913	City of Clovis	Clovis	No
N	7827	City of Modesto Composting Facility	Modesto	No
C	343	Clovis Unified School District	Clovis	No
C	4051	Coalinga State Hospital	Coalinga	No
N	230	Con-Fab California LLC	Lathrop	No
C	4163	Del Rey Packing	Del Rey	No
S	8504	Delano Rock And Asphalt LLC	Delano	No

Region	Facility ID	Facility Name	City	Reinstatement Required
N	283	Deuel Vocational Institute	Tracy	No
S	879	Dreyer's Grand Ice Cream	Bakersfield	No
S	2821	Drilling & Production Co.	Kern County	No
N	3386	E & J Gallo Winery	Modesto	No
N	7478	E&J Gallo – Spirits	Modesto	No
N	4939	E&J Gallo Winery - Turner Road Vinters	Lodi	No
C	3733	Evergreen Cremation Service of California	Fresno	No
N	4070	Foothill Sanitary Landfill	Linden	No
N	3838	Frazier Nut Farms, Inc.	Waterford	No
N	3309	G3 Enterprises, Label Division	Modesto	No
C	2265	Gary V. Burrows Inc.	Corcoran	No
C	7218	Golden State Crematory Inc.	Fresno	No
S	724	Grade 6 Oil, LLC - Western Power & Steam	Bakersfield	No
S	3078	Griffith Co.	Tejon Ranch	No
S	381	Heck Cellars	Digiorgio	No
N	7416	Helena Agri-Enterprises, LLC	Modesto	No
N	8533	Highway 59 Composting Facility	Merced	No
N	2140	Hunt & Sons Inc.	Newman	No
N	1380	Hunt & Sons Inc.	Atwater	No
N	2307	Hunt N Sons Inc.	Modesto	No
N	421	International Paper	Tracy	No
C	1713	J W Myers, Incorporated	Coarsegold	No
N	1161	J.R. Simplot / French Camp	French Camp	No
S	6458	Kern County Water Agency	Bakersfield	No
S	4128	Kern Valley State Prison	Delano	No
C	724	Kings County Public Works Dept.	Hanford	No
C	234	Kraft Heinz Foods Company	Fresno	No
N	2000	Lakewood Memorial Park	Hughson	No
C	848	Moore Quality Galvanizing	Madera	No
C	2341	NAS Lemoore	Lemoore	No
S	3434	Newby Rubber Inc.	Bakersfield	No
N	139	Nutrien Ag Solutions	Stockton	No
C	629	O'neill Beverages Co LLC	Parlier	No
S	3636	Pastoria Energy Facility LLC	Lebec	No
S	71	Plains LPG Services LP	Shafter	No
S	185	Porterville Developmental Center	Porterville	No
N	1646	QG Printing Ii LLC	Merced	No
S	4254	Salser & Dillard Funeral Chapel	Visalia	No
C	3029	San Joaquin Figs	Fresno	No

Region	Facility ID	Facility Name	City	Reinstatement Required
N	1655	Santa Fe Aggregates, Inc.	Winton	No
C	1080	Scelzi Enterprises Inc.	Fresno	No
N	9137	Shepard Bros, Inc.	Stockton	No
N	1717	Silgan Container Corp.	Modesto	No
C	393	Silvas Oil Company, Inc.	Fresno	No
N	2177	Sky Trek Aviation Fuels Inc.	Modesto	No
N	4986	State of California, Dept. of Trans	Stockton	No
N	913	Stockton Metropolitan Airport	Stockton	No
N	571	Stockton Port District	Stockton	No
N	4058	Stockton Rubber Mfg. Co., Inc.	Linden	No
N	810	Stockton Tri Industries, LLC	Stockton	No
N	825	Stockton Wood Shavings Company	French Camp	No
S	1602	The Boeing Co.	Taft	No
N	956	The Wine Group, Inc.	Ripon	No
N	3187	Tracy Material Recovery	Tracy	No
S	548	Tulare City Wastewater Plant	Tulare	No
N	754	US Army Garrison Presidio of Monterey	Lathrop	No
N	8114	Valley Custom Powder Coating	Lathrop	No
N	2820	Vanderlans & Sons, Inc.	Lodi	No
C	1344	Vie-Del Winery #1	Fresno	No
N	7989	Wilbur-Ellis Company - Manteca	Manteca	No

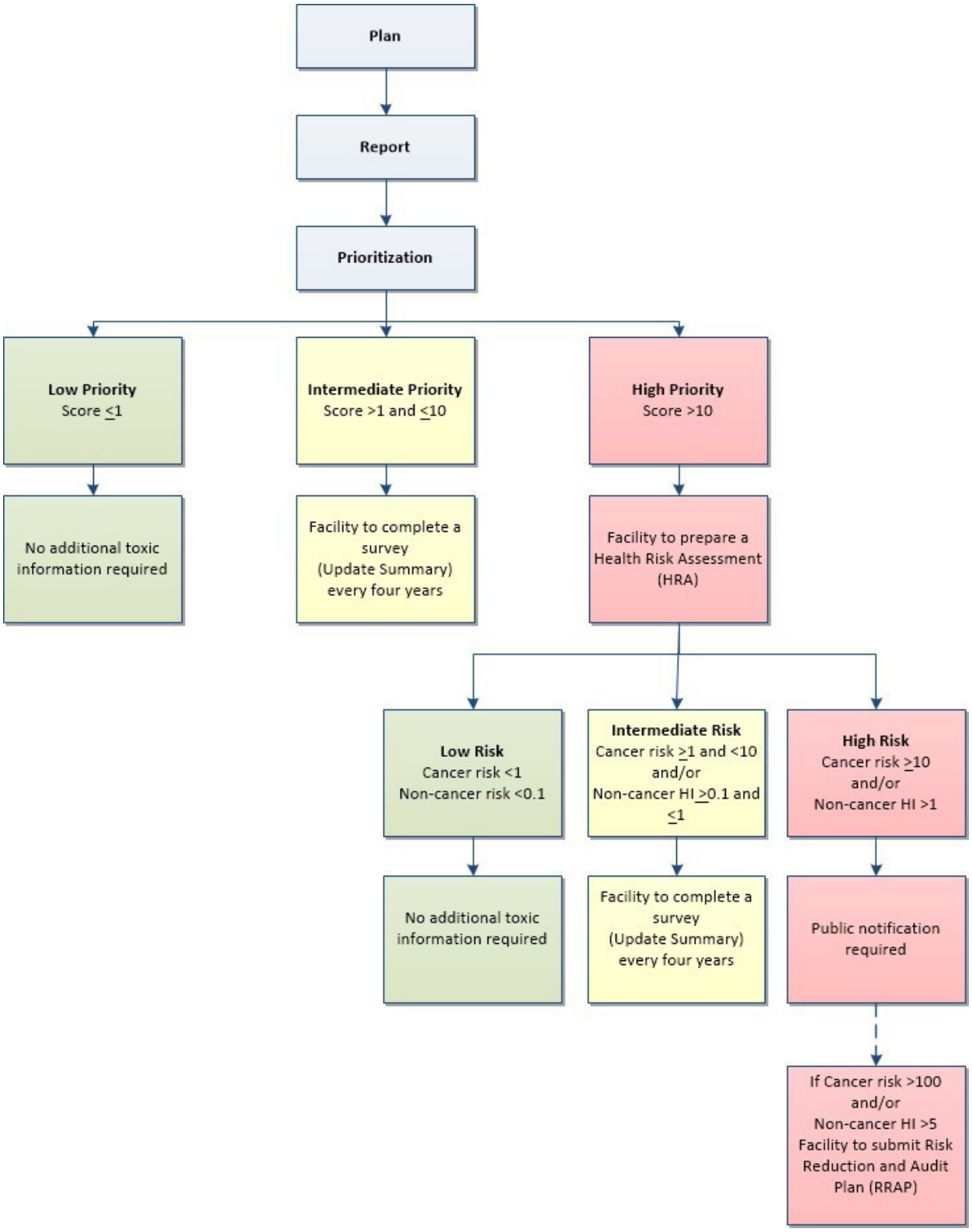
Appendix C. Toxics Emissions Summary

Emissions for eight counties of San Joaquin Valley from the latest California Air Resources Board California Toxics Inventory (CTI).

Table C1. Toxic Emissions Summary

Pollutant	CTI (tons/yr)
Acetaldehyde	3,512
Diesel Particulate Matter	2,520
Formaldehyde	2,318
Benzene	1,020
Perchloroethylene	448
1,3-Butadiene	269
Methylene Chloride	247
PAHs	238
Manganese	217
Acrolein	153
p-Dichlorobenzene	130
Styrene	96
Trichloroethylene	46
Chromium	34
Lead	28
Nickel	18
Acrylonitrile	7
Vinyl Chloride	7
Arsenic	5
Cadmium	3
Mercury	2
Chloroform	2
Ethylene Oxide	0
Ethylene Dichloride	0
Beryllium	0
Carbon Tetrachloride	0
Dioxins/Benzofurans	0
Chromium, Hexavalent	0

Appendix D. AB 2588 District Implementation Flow Chart



Appendix E. Current Status of NESHAP Delegation

National Emission Standards for Hazardous Air Pollutants (NESHAP) for which authority has been delegated to the District are included in District Rule 4002. This rule incorporates the NESHAPs from Part 61, Chapter I, Subchapter C, Title 40, Code of Federal Regulations (Table E.1), and the NESHAPs for Source Categories from Part 63, Chapter I, Subchapter C, Title 40, Code of Federal Regulations (Table E.2).

Table E1. District Delegated NESHAPs from Part 61, Chapter I, Subchapter C, Title 40, Code of Federal Regulations.

Subpart	Description
A	General Provisions
C	National Emission Standard for Beryllium
D	National Emission Standard for Beryllium Rocket Motor Firing
E	National Emission Standard for Mercury
F	National Emission Standard for Vinyl Chloride
J	National Emission Standard for Equipment Leaks (Fugitive Emission Sources) of Benzene
L	National Emission Standard for Benzene Emissions from Coke By-Product Recovery Plants
M	National Emission Standard for Asbestos
N	National Emission Standard for Inorganic Arsenic Emissions from Glass Manufacturing Plants
O	National Emission Standard for Inorganic Arsenic Emissions from Primary Copper Smelters
P	National Emission Standard for Inorganic Arsenic Emissions from Arsenic Trioxide and Metallic Arsenic Production Facilities
V	National Emission Standard for Equipment Leaks (Fugitive Emission Sources)
Y	National Emission Standard for Benzene Emissions from Benzene Storage Vessels
BB	National Emission Standard for Benzene Emissions from Benzene Transfer Operations
FF	National Emission Standard for Benzene Waste Operations

Table E2. District Delegated NESHAPs from Part 63, Chapter I, Subchapter C, Title 40, Code of Federal Regulations.

Subpart	Description
A	General Provisions
F-I	National Emission Standards for Organic Hazardous Air Pollutants From the Synthetic Organic Chemical Manufacturing Industry
J	National Emission Standards for Hazardous Air Pollutants from Polyvinyl Chloride and Copolymers Production
L	National Emission Standards for Coke Oven Batteries
R	National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations)
S	National Emission Standards for Hazardous Air Pollutants from the Pulp and Paper Industry
T	National Emission Standards for Halogenated Solvent Cleaning (except §63.462 - Batch cold cleaning machine standards)
U	National Emission Standards for Hazardous Air Pollutant Emissions: Group I Polymers and Resins
W	National Emission Standards for Hazardous Air Pollutants for Epoxy Resins Production and Non-Nylon Polyamides Production
X	National Emission Standards for Hazardous Air Pollutants from Secondary Lead Smelting
Y	National Emission Standards for Marine Tank Vessel Loading Operations AA National Emission Standards for Hazardous Air Pollutants From Phosphoric Acid Manufacturing Plants
BB	National Emission Standards for Hazardous Air Pollutants from Phosphate Fertilizers Production Plants
CC	National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries
DD	National Emission Standards for Hazardous Air Pollutants from Off-Site Waste and Recovery Operations
EE	National Emission Standards for Magnetic Tape Manufacturing Operations
GG	National Emission Standards for Aerospace Manufacturing and Rework Facilities
HH	National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities
II	National Emission Standards for Shipbuilding and Ship Repair (Surface Coating)
JJ	National Emission Standards for Wood Furniture Manufacturing Operations
KK	National Emission Standards for the Printing and Publishing Industry
LL	National Emission Standards for Hazardous Air Pollutants for Primary Aluminum Reduction Plants
MM	National Emission Standards for Hazardous Air Pollutants from Chemical Recovery Combustion Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mills
YY	National Emission Standards for Hazardous Air Pollutants: Generic Maximum Achievable Control Technology (Generic MACT)
CCC	National Emission Standards for Hazardous Air Pollutants for Steel Pickling--HCl Process Facilities and Hydrochloric Acid Regeneration Plants
DDD	National Emission Standards for Hazardous Air Pollutants for Mineral Wool Production
GGG	National Emission Standards for Hazardous Air Pollutants from Pharmaceutical Production
HHH	National Emission Standards for Hazardous Air Pollutants from Natural Gas Transmission and Storage Facilities
III	National Emission Standards for Hazardous Air Pollutants for Flexible Polyurethane Foam Production

Subpart	Description
JJJ	National Emission Standards for Hazardous Air Pollutant Emissions: Group IV Polymers and Resins
LLL	National Emission Standards for Hazardous Air Pollutants for Source Categories; Portland Cement Manufacturing Industry
MMM	National Emission Standards for Hazardous Air Pollutants: Pesticide Active Ingredient Production
NNN	National Emission Standards for Hazardous Air Pollutants for Source Categories; Wool Fiberglass Manufacturing
OOO	National Emission Standards for Hazardous Air Pollutant Emissions: Manufacture of Amino/Phenolic Resins
PPP	National Emission Standards for Hazardous Air Pollutants for Polyether Polyols Production
QQQ	National Emission Standards for Hazardous Air Pollutants from Primary Copper Smelting
RRR	National Emission Standards for Hazardous Air Pollutants for Secondary Aluminum Production
TTT	National Emission Standards for Hazardous Air Pollutants for Primary Lead Smelting
UUU	National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units
VVV	National Emission Standards for Hazardous Air Pollutants: Publicly Owned Treatment Works
XXX	National Emission Standards for Hazardous Air Pollutants for Ferroalloys Production: Ferromanganese and Silicomanganese
AAAA	National Emission Standards for Hazardous Air Pollutants from Municipal Solid Waste Landfills
CCCC	National Emission Standards for Hazardous Air Pollutants from Manufacturing of Nutritional Yeast
EEEE	National Emission Standards for Hazardous Air Pollutants from Organic Liquids Distribution (Non-Gasoline)
FFFF	National Emission Standards for Hazardous Air Pollutants from Miscellaneous Organic Chemical Manufacturing
GGGG	National Emission Standards for Hazardous Air Pollutants from Solvent Extraction for Vegetable Oil Production
HHHH	National Emission Standards for Hazardous Air Pollutants from Wet- Formed Fiberglass Mat Production
JJJJ	National Emission Standards for Hazardous Air Pollutants from Paper and Other Web Coating
KKKK	National Emission Standards for Hazardous Air Pollutants from Surface Coating of Metal Cans
MMMM	National Emission Standards for Hazardous Air Pollutants from Surface Coating of Miscellaneous Metal Parts and Products
NNNN	National Emission Standards for Hazardous Air Pollutants from Surface Coating of Large Appliances
OOOO	National Emission Standards for Hazardous Air Pollutants from Printing, Coating, and Dyeing of Fabrics and Other Textiles
PPPP	National Emission Standards for Hazardous Air Pollutants from Surface Coating of Plastic Parts and Products
QQQQ	National Emission Standards for Hazardous Air Pollutants from Surface Coating of Wood Building Products
RRRR	National Emission Standards for Hazardous Air Pollutants from Surface Coating of Metal Furniture

Subpart	Description
SSSS	National Emission Standards for Hazardous Air Pollutants from Surface Coating of Metal Coil
TTTT	National Emission Standards for Hazardous Air Pollutants from Leather Finishing Operations
UUUU	National Emission Standards for Hazardous Air Pollutants from Cellulose Product Manufacturing
VVVV	National Emission Standards for Hazardous Air Pollutants from Boat Manufacturing
WWWW	National Emission Standards for Hazardous Air Pollutants from Reinforced Plastic Composites Production
XXXX	National Emission Standards for Hazardous Air Pollutants from f Rubber Tire Manufacturing
YYYY	National Emission Standards for Hazardous Air Pollutants from Stationary Combustion Turbines
AAAAA	National Emission Standards for Hazardous Air Pollutants from Lime Manufacturing Plants
BBBBB	National Emission Standards for Hazardous Air Pollutants from Semiconductor Manufacturing
CCCCC	National Emission Standards for Hazardous Air Pollutants from Coke Ovens: Pushing, Quenching, and Battery Stacks
EEEEE	National Emission Standards for Hazardous Air Pollutants from Iron and Steel Foundries
FFFFF	National Emission Standards for Hazardous Air Pollutants from Integrated Iron and Steel Manufacturing
GGGGG	National Emission Standards for Hazardous Air Pollutants from Site Remediation
HHHHH	National Emission Standards for Hazardous Air Pollutants from Miscellaneous Coating Manufacturing
IIIII	National Emission Standards for Hazardous Air Pollutants from Mercury Emissions from Mercury Cell Chlor-Alkali Plants
JJJJJ	National Emission Standards for Hazardous Air Pollutants from Brick and Structural Clay Products Manufacturing
KKKKK	National Emission Standards for Hazardous Air Pollutants from Clay Ceramics Manufacturing
LLLLL	National Emission Standards for Hazardous Air Pollutants from Asphalt Processing and Asphalt Roofing Manufacturing
MMMMM	National Emission Standards for Hazardous Air Pollutants from Flexible Polyurethane Foam Fabrication Operations
PPPPP	National Emission Standards for Hazardous Air Pollutants from Engine Test Cells/Stands
QQQQQ	National Emission Standards for Hazardous Air Pollutants from Friction Materials Manufacturing Facilities
RRRRR	National Emission Standards for Hazardous Air Pollutants from Taconite Iron Ore Processing
SSSSS	National Emission Standards for Hazardous Air Pollutants from Refractory Products Manufacturing
TTTTT	National Emission Standards for Hazardous Air Pollutants from Primary Magnesium Refining

Appendix

San Joaquin Valley Air Pollution Control District and South Coast Air Quality Management District *Sierra Club v. County of Fresno* Amicus Curiae Briefs

SUPREME COURT COPY

CASE NO. S219783

IN THE SUPREME COURT OF CALIFORNIA

SIERRA CLUB, REVIVE THE SAN JOAQUIN, and
LEAGUE OF WOMEN VOTERS OF FRESNO,
Plaintiffs and Appellants

v.

COUNTY OF FRESNO,
Defendant and Respondent

FRIANT RANCH, L.P.,
Real Party in Interest and Respondent

SUPREME COURT
FILED
APR 13 2015
Frank A. McGuire Clerk
Deputy

After a Decision by the Court of Appeal, filed May 27, 2014
Fifth Appellate District Case No. F066798

Appeal from the Superior Court of California, County of Fresno
Case No. 11CECG00726

APPLICATION FOR LEAVE TO FILE AMICUS CURIAE BRIEF OF SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT IN SUPPORT OF DEFENDANT AND RESPONDENT, COUNTY OF FRESNO AND REAL PARTY IN INTEREST AND RESPONDENT, FRIANT RANCH, L.P.

CATHERINE T. REDMOND (State Bar No. 226957)
261 High Street
Duxbury, Massachusetts 02332
Tel. (339) 236-5720
Catherinetredmond22@gmail.com

SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT
Annette Ballatore-Williamson, District Counsel (State Bar. No. 192176)
1990 E. Gettysburg Avenue
Fresno, California 93726
Tel. (559) 230-6033
Annette.Ballatore-Williamson@valleyair.org

Counsel for San Joaquin Valley Unified Air Pollution Control District

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CATHERINE T. REDMOND (State Bar No. 226957)
261 High Street
Duxbury, Massachusetts 02332
Tel. (339) 236-5720
Catherinetredmond22@gmail.com

SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT
Annette Ballatore-Williamson, District Counsel (State Bar. No. 192176)
1990 E. Gettysburg Avenue
Fresno, California 93726
Tel. (559) 230-6033
Annette.Ballatore-Williamson@valleyair.org

Counsel for San Joaquin Valley Unified Air Pollution Control District

APPLICATION

Pursuant to California Rules of Court 8.520(f)(1), proposed Amicus Curiae San Joaquin Valley Unified Air Pollution Control District hereby requests permission from the Chief Justice to file an amicus brief in support of Defendant and Respondent, County of Fresno, and Defendant and Real Parties in Interest Friant Ranch, L.P. Pursuant to Rule 8.520(f)(5) of the California Rules of Court, the proposed amicus curiae brief is combined with this Application. The brief addresses the following issue certified by this Court for review:

> Is an EIR adequate when it identifies the health impacts of air pollution and quantifies a project's expected emissions, or does CEQA further require the EIR to *correlate* a project's air quality emissions to specific health impacts?

As of the date of this filing, the deadline for the final reply brief on the merits was March 5, 2015. Accordingly, under Rule 8.520(f)(2), this application and brief are timely.

1. Background and Interest of San Joaquin Valley Unified Air Pollution Control District

The San Joaquin Valley Unified Air Pollution Control District ("Air District") regulates air quality in the eight counties comprising the San Joaquin Valley ("Central Valley"): Kern, Tulare, Madera, Fresno, Merced, San Joaquin, Stanislaus, and Kings, and is primarily responsible for attaining air quality standards within its jurisdiction. After billions of dollars of investment by Central Valley businesses, pioneering air quality regulations, and consistent efforts by residents, the Central Valley air basin has made historic improvements in air quality.

The Central Valley's geographical, topographical and meteorological features create exceptionally challenging air quality

conditions. For example, it receives air pollution transported from the San Francisco Bay Area and northern Central Valley communities, and the southern portion of the Central Valley includes three mountain ranges (Sierra, Tehachapi, and Coastal) that, under some meteorological conditions, effectively trap air pollution. Central Valley air pollution is only a fraction of what the Bay Area and Los Angeles produce, but these natural conditions result in air quality conditions that are only marginally better than Los Angeles, even though about ten times more pollution is emitted in the Los Angeles region. Bay Area air quality is much better than the Central Valley's, even though the Bay Area produces about six times more pollution. The Central Valley also receives air pollution transported from the Bay Area and northern counties in the Central Valley, including Sacramento, and transboundary anthropogenic ozone from as far away as China.

Notwithstanding these challenges, the Central Valley has reduced emissions at the same or better rate than other areas in California and has achieved unparalleled milestones in protecting public health and the environment:

- In the last decade, the Central Valley became the first air basin classified by the federal government under the Clean Air Act as a "serious nonattainment" area to come into attainment of health-based National Ambient Air Quality Standard ("NAAQS") for coarse particulate matter (PM10), an achievement made even more notable given the Valley's extensive agricultural sector. Unhealthy levels of particulate matter can cause and exacerbate a range of chronic and acute illnesses.
- In 2013, the Central Valley became the first air basin in the country to improve from a federal designation of "extreme" nonattainment to

actually attain (and quality for an attainment designation) of the 1-hour ozone NAAQS; ozone creates "smog" and, like PM10, causes adverse health impacts.

- The Central Valley also is in full attainment of federal standards for lead, nitrogen dioxide, sulfur dioxide, and carbon monoxide.
- The Central Valley continues to make progress toward compliance with its last two attainment standards, with the number of exceedences for the 8-hour ozone NAAQS reduced by 74% (for the 1997 standard) and 38% (for the 2008 standard) since 1991, and for the small particulate matter (PM2.5) NAAQS reduced by 85% (for the 1997 standard) and 61% (for the 2006 standard).

Sustained improvement in Central Valley air quality requires a rigorous and comprehensive regulatory framework that includes prohibitions (e.g., on wood-burning fireplaces in new residences), mandates (e.g., requiring the installation of best available pollution reduction technologies on new and modified equipment and industrial operations), innovations (e.g., fees assessed against residential development to fund pollution reduction actions to "offset" vehicular emissions associated with new residences), incentive programs (e.g., funding replacements of older, more polluting heavy duty trucks and school buses)[1], ongoing planning for continued air quality improvements, and enforcement of Air District permits and regulations.

The Air District is also an expert air quality agency for the eight counties and cities in the San Joaquin Valley. In that capacity, the Air District has developed air quality emission guidelines for use by the Central

[1] San Joaquin's incentive program has been so successful that through 2012, it has awarded over $ 432 million in incentive funds and has achieved 93,349 tons of lifetime emissions reductions. *See* SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DISTRICT, 2012 PM2.5 PLAN, 6-6 (2012) *available at* http://www.valleyair.org/Workshops/postings/2012/12-20-12PM25/FinalVersion/06%20Chapter%206%20Incentives.pdf.

Valley counties and cities that implement the California Environment Quality Act (CEQA).[2] In its guidance, the Air District has distinguished between toxic air contaminants and criteria air pollutants.[3] Recognizing this distinction, the Air District's CEQA Guidance has adopted distinct thresholds of significance for *criteria* pollutants (i.e., ozone, PM2.5 and their respective precursor pollutants) based upon scientific and factual data which demonstrates the level that can be accommodated on a cumulative basis in the San Joaquin Valley without affecting the attainment of the applicable NAAQS.[4] For *toxic air* pollutants, the District has adopted different thresholds of significance which scientific and factual data demonstrates has the potential to expose sensitive receptors (i.e., children, the elderly) to levels which may result in localized health impacts.[5]

The Air District's CEQA Guidance was followed by the County of Fresno in its environment review of the Friant Ranch project, for which the Air District also served as a commenting agency. The Court of Appeal's holding, however, requiring correlation between the project's criteria

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[2] *See, e.g.*, SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DISTRICT, PLANNING DIVISION, GUIDE FOR ASSESSING AND MITIGATING AIR QUALITY IMPACTS (2015), *available at* http://www.valleyair.org/transportation/GAMAQI_3-19-15.pdf ("CEQA Guidance").

[3] Toxic air contaminants, also known as hazardous air pollutants, are those pollutants that are known or suspected to cause cancer or other serious health effects, such as birth defects. There are currently 189 toxic air contaminants regulated by the United States Environmental Protection Agency ("EPA") and the states pursuant to the Clean Air Act. 42 U.S.C. § 7412. Common TACs include benzene, perchloroethylene and asbestos. *Id.* at 7412(b).

In contrast, there are only six (6) criteria air pollutants: ozone, particulate matter, carbon monoxide, nitrogen oxides, sulfur dioxide and lead. Although criteria air pollutants can also be harmful to human health, they are distinguishable from toxic air contaminants and are regulated separately. For instance, while criteria pollutants are regulated by numerous sections throughout Title I of the Clean Air Act, the regulation of toxic air contaminants occurs solely under section 112 of the Act. Compare 42 U.S.C. §§ 7407 – 7411 & 7501 – 7515 with 42 U.S.C. § 7411.

[4] See, e.g., CEQA Guidance at http://www.valleyair.org/transportation/GAMAQI_3-19-15.pdf, pp. 64-66, 80.

[5] See, e.g., CEQA Guidance at http://www.valleyair.org/transportation/GAMAQI_3-19-15.pdf, pp. 66, 99-101.

pollutants and local health impacts, departs from the Air District's Guidance and approved methodology for assessing criteria pollutants. A close reading of the administrative record that gave rise to this issue demonstrates that the Court's holding is based on a misunderstanding of the distinction between toxic air contaminants (for which a local health risk assessment is feasible and routinely performed) and criteria air pollutants (for which a local health risk assessment is not feasible and would result in speculative results).[6] The Air District has a direct interest in ensuring the lawfulness and consistent application of its CEQA Guidance, and will explain how the Court of Appeal departed from the Air District's long-standing CEQA Guidance in addressing criteria pollutants and toxic air contaminants in this amicus brief.

2. How the Proposed Amicus Curiae Brief Will Assist the Court

As counsel for the proposed amicus curiae, we have reviewed the briefs filed in this action. In addition to serving as a "commentary agency" for CEQA purposes over the Friant Ranch project, the Air District has a strong interest in assuring that CEQA is used for its intended purpose, and believes that this Court would benefit from additional briefing explaining the distinction between criteria pollutants and toxic air contaminants and the different methodologies employed by local air pollution control agencies such as the Air District to analyze these two categories of air pollutants under CEQA. The Air District will also explain how the Court of Appeal's opinion is based upon a fundamental misunderstanding of these two different approaches by requiring the County of Fresno to correlate the project's *criteria* pollution emissions with *local* health impacts. In doing

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[6] CEQA does not require speculation. *See, e.g., Laurel Heights Improvement Ass'n v. Regents of Univ. of Cal.*, 6 Cal. 4th 1112, 1137 (1993) (upholding EIR that failed to evaluate cumulative toxic air emission increases given absence of any acceptable means for doing so).

so, the Air District will provide helpful analysis to support its position that at least insofar as criteria pollutants are concerned, CEQA does not require an EIR to correlate a project's air quality emissions to specific health impacts, because such an analysis is not reasonably feasible.

Rule 8.520 Disclosure

Pursuant to Cal. R. 8.520(f)(4), neither the Plaintiffs nor the Defendant or Real Party In Interest or their respective counsel authored this brief in whole or in part. Neither the Plaintiffs nor the Defendant or Real Party in Interest or their respective counsel made any monetary contribution towards or in support of the preparation of this brief.

CONCLUSION

On behalf of the San Joaquin Valley Unified Air Pollution Control District, we respectfully request that this Court accept the filing of the attached brief.

Dated: April 2, 2015



Annette A. Ballatore-Williamson
District Counsel
Attorney for Proposed Amicus Curiae

SAN JOAQUIN VALLEY UNIFIED
AIR POLLUTION CONTROL
DISTRICT

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CATHERINE T. REDMOND (State Bar No. 226957)
261 High Street
Duxbury, Massachusetts 02332
Tel. (339) 236-5720
Catherinetredmond22@gmail.com

SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT
Annette A. Ballatore-Williamson, District Counsel (State Bar. No. 192176)
1990 E. Gettysburg Avenue
Fresno, California 93726
Tel. (559) 230-6033
Annette.Ballatore-Williamson@valleyair.org
Counsel for San Joaquin Valley Unified Air Pollution Control District

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3.3.9; 4.14.1, available at:
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I. INTRODUCTION.

The San Joaquin Valley Unified Air Pollution Control District ("Air District") respectfully submits that the Court of Appeal erred when it held that the air quality analysis contained in the Environmental Impact Report ("EIR") for the Friant Ranch development project was inadequate under the California Environmental Quality Act ("CEQA") because it did not include an analysis of the correlation between the project's criteria air pollutants and the potential adverse human health impacts. A close reading of the portion of the administrative record that gave rise to this issue demonstrates that the Court's holding is based on a misunderstanding of the distinction between toxic air contaminants and criteria air pollutants.

Toxic air contaminants, also known as hazardous air pollutants, are those pollutants that are known or suspected to cause cancer or other serious health effects, such as birth defects. There are currently 189 toxic air contaminants (hereinafter referred to as "TACs") regulated by the United States Environmental Protection Agency ("EPA") and the states pursuant to the Clean Air Act. 42 U.S.C. § 7412. Common TACs include benzene, perchloroethylene and asbestos. *Id.* at 7412(b).

In contrast, there are only six (6) criteria air pollutants: ozone, particulate matter, carbon monoxide, nitrogen oxides, sulfur dioxide and lead. Although criteria air pollutants can also be harmful to human health,

they are distinguishable from TACs and are regulated separately. For instance, while criteria pollutants are regulated by numerous sections throughout Title I of the Clean Air Act, the regulation of TACs occurs solely under section 112 of the Act. *Compare* 42 U.S.C. §§ 7407 – 7411 & 7501 – 7515 *with* 42 U.S.C. § 7411.

The most relevant difference between criteria pollutants and TACs for purposes of this case is the manner in which human health impacts are accounted for. While it is common practice to analyze the correlation between an individual facility's TAC emissions and the expected localized human health impacts, such is not the case for criteria pollutants. Instead, the human health impacts associated with criteria air pollutants are analyzed and taken into consideration when EPA sets the national ambient air quality standard ("NAAQS") for each criteria pollutant. 42 U.S.C. § 7409(b)(1). The health impact of a particular criteria pollutant is analyzed on a regional and not a facility level based on how close the area is to complying with (attaining) the NAAQS. Accordingly, while the type of individual facility / health impact analysis that the Court of Appeal has required is a customary practice for TACs, it is not feasible to conduct a similar analysis for criteria air pollutants because currently available computer modeling tools are not equipped for this task.

It is clear from a reading of both the administrative record and the Court of Appeal's decision that the Court did not have the expertise to fully

appreciate the difference between TACs and criteria air pollutants. As a result, the Court has ordered the County of Fresno to conduct an analysis that is not practicable and not likely yield valid information. The Air District respectfully requests that this portion of the Court of Appeal's decision be reversed.

II. THE COURT OF APPEAL ERRED IN FINDING THE FRIANT RANCH EIR INADEQUATE FOR FAILING TO ANALYZE THE SPECIFIC HUMAN HEALTH IMPACTS ASSOCIATED CRITERIA AIR POLLUTANTS.

Although the Air District does not take lightly the amount of air emissions at issue in this case, it submits that the Court of Appeal got it wrong when it required Fresno County to revise the Friant Ranch EIR to include an analysis correlating the criteria air pollutant emissions associated with the project with specific, localized health-impacts. The type of analysis the Court of Appeal has required will not yield reliable information because currently available modeling tools are not well suited for this task. Further, in reviewing this issue de novo, the Court of Appeal failed to appreciate that it lacked the scientific expertise to appreciate the significant differences between a health risk assessment commonly performed for toxic air contaminants and a similar type of analysis it felt should have been conducted for criteria air pollutants.

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A. Currently Available Modeling Tools are not Equipped to Provide a Meaningful Analysis of the Correlation between an Individual Development Project's Air Emissions and Specific Human Health Impacts.

In order to appreciate the problematic nature of the Court of Appeals' decision requiring a health risk type analysis for criteria air pollutants, it is important to understand how the relevant criteria pollutants (ozone and particulate matter) are formed, dispersed and regulated.

Ground level ozone (smog) is not directly emitted into the air, but is formed when precursor pollutants such as oxides of nitrogen (NOx) and volatile organic compounds (VOCs) are emitted into the atmosphere and undergo complex chemical reactions in the process of sunlight.[1] Once formed, ozone can be transported long distances by wind.[2] Because of the complexity of ozone formation, a specific tonnage amount of NOx or VOCs emitted in a particular area does not equate to a particular concentration of ozone in that area. In fact, even rural areas that have relatively low tonnages of emissions of NOx or VOCs can have high levels of ozone concentration simply due to wind transport.[3] Conversely, the San Francisco Bay Area has six times more NOx and VOC emissions per square mile than the San Joaquin Valley, but experiences lower

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[1] *See* United States Environmental Protection Agency, *Ground-level Ozone: Basic Information*, available at: http://www.epa.gov/airquality/ozonepollution/basic.html (visited March 10, 2015).
[2] *Id.*
[3] *Id.*

concentrations of ozone (and better air quality) simply because sea breezes disperse the emissions.[4]

Particulate matter ("PM") can be divided into two categories: directly emitted PM and secondary PM.[5] While directly emitted PM can have a localized impact, the tonnage emitted does not always equate to the local PM concentration because it can be transported long distances by wind.[6] Secondary PM, like ozone, is formed via complex chemical reactions in the atmosphere between precursor chemicals such as sulfur dioxides (SOx) and NOx.[7] Because of the complexity of secondary PM formation, the tonnage of PM-forming precursor emissions in an area does not necessarily result in an equivalent concentration of secondary PM in that area.

The disconnect between the *tonnage* of precursor pollutants (NOx, SOx and VOCs) and the *concentration* of ozone or PM formed is important because it is not necessarily the tonnage of precursor pollutants that causes human health effects, but the concentration of resulting ozone or PM. Indeed, the national ambient air quality standards ("NAAQS"), which are statutorily required to be set by the United States Environmental Protection

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[4] *San Joaquin Valley Air Pollution Control District 2007 Ozone Plan*, Executive Summary p. ES-6, available at: http://www.valleyair.org/Air_Quality_Plans/docs/AQ_Ozone_2007_Adopted/03%20Executive%20Summary.pdf (visited March 10, 2015).

[5] United States Environmental Protection Agency, *Particulate Matter: Basic Information*, available at: http://www.epa.gov/airquality/particlepollution/basic.html (visited March 10, 2015).

[6] *Id.*

[7] *Id.*

Agency ("EPA") at levels that are "requisite to protect the public health," 42 U.S.C. § 7409(b)(1), are established as concentrations of ozone or particulate matter and not as tonnages of their precursor pollutants.[8]

Attainment of a particular NAAQS occurs when the concentration of the relevant pollutant remains below a set threshold on a consistent basis throughout a particular region. For example, the San Joaquin Valley attained the 1-hour ozone NAAQS when ozone concentrations remained at or below 0.124 parts per million Valley-wide on 3 or fewer days over a 3-year period.[9] Because the NAAQS are focused on achieving a particular concentration of pollution region-wide, the Air District's tools and plans for attaining the NAAQS are regional in nature.

For instance, the computer models used to simulate and predict an attainment date for the ozone or particulate matter NAAQS in the San Joaquin Valley are based on regional inputs, such as regional inventories of precursor pollutants (NOx, SOx and VOCs) and the atmospheric chemistry and meteorology of the Valley.[10] At a very basic level, the models simulate future ozone or PM levels based on predicted changes in precursor

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[8] See, e.g., United States Environmental Protection Agency, *Table of National Ambient Air Quality Standards*, available at: http://www.epa.gov/air/criteria.html#3 (visited March 10, 2015).

[9] *San Joaquin Valley Unified Air Pollution Control District 2013 Plan for the Revoked 1-Hour Ozone Standard*, Ch. 2 p. 2-16, available at: http://www.valleyair.org/Air_Quality_Plans/OzoneOneHourPlan2013/02Chapter2ScienceTrendsModeling.pdf (visited March 10, 2015).

[10] *Id.* at Ch. 2 p. 2-19 (visited March 12, 2015); *San Joaquin Valley Unified Air Pollution Control District 2008 PM2.5 Plan*, Appendix F, pp. F-2 – F-5, available at: http://www.valleyair.org/Air_Quality_Plans/docs/AQ_Final_Adopted_PM2.5/20%20Appendix%20F.pdf (visited March 19, 2015).

emissions Valley wide.[11] Because the NAAQS are set levels necessary to protect human health, the closer a region is to attaining a particular NAAQS, the lower the human health impact is from that pollutant.

The goal of these modeling exercises is not to determine whether the emissions generated by a particular factory or development project will affect the date that the Valley attains the NAAQS. Rather, the Air District's modeling and planning strategy is regional in nature and based on the extent to which *all* of the emission-generating sources in the Valley (current and future) must be controlled in order to reach attainment.[12]

Accordingly, the Air District has based its thresholds of significance for CEQA purposes on the levels that scientific and factual data demonstrate that the Valley can accommodate without affecting the attainment date for the NAAQS.[13] The Air District has tied its CEQA significance thresholds to the level at which stationary pollution sources permitted by the Air District must "offset" their emissions.[14] This "offset"

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[11] *Id.*

[12] Although the Air District does have a dispersion modeling tool used during its air permitting process that is used to predict whether a particular project's directly emitted PM will either cause an exceedance of the PM NAAQS or contribute to an existing exceedance, this model bases the prediction on a worst case scenario of emissions and meteorology and has no provision for predicting any associated human health impacts. Further, this analysis is only performed for stationary sources (factories, oil refineries, etc.) that are required to obtain a New Source Review permit from the Air District and not for development projects such as Friant Ranch over which the Air District has no preconstruction permitting authority. *See* San Joaquin Valley Unified Air Pollution Control District Rule 2201 §§ 2.0; 3.3.9; 4.14.1, available at: http://www.valleyair.org/rules/currntrules/Rule2201041l.pdf (visited March 19, 2015).

[13] *San Joaquin Valley Unified Air Pollution Control District Guide to Assessing and Mitigating Air Quality Impacts*, (March 19, 2015) p. 22, available at: http://www.valleyair.org/transportation/CEQA%20Rules/GAMAQI%20Jan%202002%20Rev.pdf (visited March 30, 2015).

[14] *Id.* at pp. 22, 25.

level allows for growth while keeping the cumulative effects of all new sources at a level that will not impede attainment of the NAAQS.[15] In the Valley, these thresholds are 15 tons per year of PM, and 10 tons of NOx or VOC per year. *Sierra Club, supra*, 172 Cal.Rptr.3d at 303; AR 4554. Thus, the CEQA air quality analysis for criteria pollutants is not really a localized, project-level impact analysis but one of regional, "cumulative impacts."

Accordingly, the significance thresholds applied in the Friant Ranch EIR (15 tons per year of PM and 10 tons of NOx or VOCs) are not intended to be indicative of any localized human health impact that the project may have. While the health effects of air pollution are of primary concern to the Air District (indeed, the NAAQS are established to protect human health), the Air District is simply not equipped to analyze whether and to what extent the criteria pollutant emissions of an individual CEQA project directly impact human health in a particular area. This is true even for projects with relatively high levels of emissions of criteria pollutant precursor emissions.

For instance, according to the EIR, the Friant Ranch project is estimated to emit 109.52 tons per year of ROG (VOC), 102.19 tons per year of NOx, and 117.38 tons per year of PM. Although these levels well

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[15] [15] *San Joaquin Valley Unified Air Pollution Control District Environmental Review Guidelines* (Aug. 2000) p. 4-11, available at: http://www.valleyair.org/transportation/CEQA%20Rules/ERG%20Adopted%20_August%202000_.pdf (visited March 12, 2015).

exceed the Air District's CEQA significance thresholds, this does not mean that one can easily determine the concentration of ozone or PM that will be created at or near the Friant Ranch site on a particular day or month of the year, or what specific health impacts will occur. Meteorology, the presence of sunlight, and other complex chemical factors all combine to determine the ultimate concentration and location of ozone or PM. This is especially true for a project like Friant Ranch where most of the criteria pollutant emissions derive not from a single "point source," but from area wide sources (consumer products, paint, etc.) or mobile sources (cars and trucks) driving to, from and around the site.

In addition, it would be extremely difficult to model the impact on NAAQS attainment that the emissions from the Friant Ranch project may have. As discussed above, the currently available modeling tools are equipped to model the impact of *all* emission sources in the Valley on attainment. According to the most recent EPA-approved emission inventory, the NOx inventory for the Valley is for the year 2014 is 458.2 tons per day, or 167,243 tons per year and the VOC (or ROG) inventory is 361.7 tons per day, or 132,020.5 tons per year.[16] Running the photochemical grid model used for predicting ozone attainment with the

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[16] *San Joaquin Valley Unified Air Pollution Control District 2007 Ozone Plan*, Appendix B pp. B-6, B-9,
available at:
http://www.valleyair.org/Air_Quality_Plans/docs/AQ_Ozone_2007_Adopted/19%20Appendix%20B%20April%202007.pdf (visited March 12, 2015).

emissions solely from the Friant Ranch project (which equate to less than one-tenth of one percent of the total NOx and VOC in the Valley) is not likely to yield valid information given the relative scale involved.

Finally, even once a model is developed to accurately ascertain local increases in concentrations of photochemical pollutants like ozone and some particulates, it remains impossible, using today's models, to correlate that increase in concentration to a specific health impact. The reason is the same: such models are designed to determine regional, population-wide health impacts, and simply are not accurate when applied at the local level.

For these reasons, it is not the norm for CEQA practitioners, including the Air District, to conduct an analysis of the localized health impacts associated with a project's criteria air pollutant emissions as part of the EIR process. When the accepted scientific method precludes a certain type of analysis, "the court cannot impose a legal standard to the contrary." *Kings County Farm Bureau v. City of Hanford* (1990) 221 Cal.App.3d 692, 717 n. 8. However, that is exactly what the Court of Appeal has done in this case. Its decision upends the way CEQA air quality analysis of criteria pollutants occurs and should be reversed.

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B. The Court of Appeal Improperly Extrapolated a Request for a Health Risk Assessment for Toxic Air Contaminants into a Requirement that the EIR contain an Analysis of Localized Health Impacts Associated with Criteria Air Pollutants.

The Court of Appeal's error in requiring the new health impact analysis for criteria air pollutants clearly stems from a misunderstanding of terms of art commonly used in the air pollution field. More specifically, the Court of Appeal (and Appellants Sierra Club et al.) appear to have confused the health risk analysis ("HRA") performed to determine the health impacts associated with a project's toxic air contaminants ("TACs"), with an analysis correlating a project's criteria air pollutants (ozone, PM and the like) with specific localized health impacts.

The first type of analysis, the HRA, is commonly performed during the Air District's stationary source permitting process for projects that emit TACs and is, thus, incorporated into the CEQA review process. An HRA is a comprehensive analysis to evaluate and predict the dispersion of TACs emitted by a project and the potential for exposure of human populations. It also assesses and quantifies both the individual and population-wide health risks associated with those levels of exposure. There is no similar analysis conducted for criteria air pollutants. Thus, the second type of analysis (required by the Court of Appeal), is not currently part of the Air District's process because, as outlined above, the health risks associated

with exposure to criteria pollutants are evaluated on a regional level based on the region's attainment of the NAAQS.

The root of this confusion between the types of analyses conducted for TACs versus criteria air pollutants appears to stem from a comment that was presented to Fresno County by the City of Fresno during the administrative process.

In its comments on the draft EIR, the City of Fresno (the only party to raise this issue) stated:

> [t]he EIR must disclose the human health related effects of the Project's air pollution impacts. (CEQA Guidelines section 15126.2(a).) The EIR fails completely in this area. The EIR should be revised to disclose and determine the significance of TAC impacts, and of human health risks due to exposure to Project-related air emissions.

(AR 4602.)

In determining that the issue regarding the correlation between the Friant Ranch project's criteria air pollutants and adverse health impacts was adequately exhausted at the administrative level, the Court of Appeal improperly read the first two sentences of the City of Fresno's comment in isolation rather than in the context of the entire comment. *See Sierra Club v. County of Fresno* (2014) 172 Cal.Rptr.3d 271, 306. Although the comment first speaks generally in terms of "human health related effects" and "air pollution," it requests only that the EIR be revised to disclose "the significance of TACs" and the "human health risks due to exposure."

The language of this request in the third sentence of the comment is significant because, to an air pollution practitioner, the language would only have indicated only that a HRA for TACs was requested, and not a separate analysis of the health impacts associated with the project's criteria air pollutants. Fresno County clearly read the comment as a request to perform an HRA for TACs and limited its response accordingly. (AR 4602.)[17] The Air District submits that it would have read the City's comment in the same manner as the County because the City's use of the terms "human health risks" and "TACs" signal that an HRA for TACs is being requested. Indeed, the Air District was also concerned that an HRA be conducted, but understood that it was not possible to conduct such an analysis until the project entered the phase where detailed site specific information, such as the types of emission sources and the proximity of the sources to sensitive receptors became available. (AR 4553.)[18] The City of Fresno was apparently satisfied with the County's discussion of human health risks, as it did not raise the issue again when it commented on the final EIR. (AR 8944 – 8960.)

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[17] Appellants do not challenge the manner in which the County addressed TACs in the EIR. (Appellants' Answer Brief p. 28 fn. 7.)

[18] Appellants rely on the testimony of Air District employee, Dan Barber, as support for their position that the County should have conducted an analysis correlating the project's criteria air pollutant emissions with localized health impacts. (Appellants Answer Brief pp. 10-11; 28.) However, Mr. Barber's testimony simply reinforces the Air District's concern that a risk assessment (HRA) be conducted once the actual details of the project become available. (AR 8863.) As to criteria air pollutants, Mr. Barber's comments are aimed at the Air District's concern about the amount of emissions and the fact that the emissions will make it "more difficult for Fresno County and the Valley to reach attainment which means that the health of Valley residents maybe [sic] adversely impacted." Mr. Barber says nothing about conducting a separate analysis of the localized health impacts the project's emissions may have.

The Court of Appeal's holding, which incorrectly extrapolates a request for an HRA for TACs into a new analysis of the localized health impacts of the project's criteria air pollutants, highlights two additional errors in the Court's decision.

First, the Court of Appeal's holding illustrates why the Court should have applied the deferential substantial evidence standard of review to the issue of whether the EIR's air quality analysis was sufficient. The regulation of air pollution is a technical and complex field and the Court of Appeal lacked the expertise to fully appreciate the difference between TACs and criteria air pollutants and tools available for analyzing each type of pollutant.

Second, it illustrates that the Court likely got it wrong when it held that the issue regarding the criteria pollutant / localized health impact analysis was properly exhausted during the administrative process. In order to preserve an issue for the court, '[t]he "exact issue" must have been presented to the administrative agency....' [Citation.] *Citizens for Responsible Equitable Environmental Development v. City of San Diego*, (2011) 196 Cal.App.4th 515, 527 129 Cal.Rptr.3d 512, 521; *Sierra Club v. City of Orange* (2008) 163 Cal.App.4th 523, 535, 78 Cal.Rptr.3d 1, 13. "'[T]he objections must be sufficiently specific so that the agency has the

opportunity to evaluate and respond to them.' [Citation.]" *Sierra Club v. City of Orange*,163 Cal.App.4th at 536.[19]

As discussed above, the City's comment, while specific enough to request a commonly performed HRA for TACs, provided the County with no notice that it should perform a new type of analysis correlating criteria pollutant tonnages to specific human health effects. Although the parties have not directly addressed the issue of failure to exhaust administrative remedies in their briefs, the Air District submits that the Court should consider how it affects the issues briefed by the parties since "[e]xhaustion of administrative remedies is a jurisdictional prerequisite to maintenance of a CEQA action." *Bakersfield Citizens for Local Control v. City of Bakersfield* (2004) 124 Cal.App.4th 1184, 1199, 22 Cal.Rptr.3d 203.

III. CONCLUSION

For all of the foregoing reasons, the Air District respectfully requests that the portion of the Court of Appeal's decision requiring an analysis correlating the localized human health impacts associated with an individual project's criteria air pollutant emissions be reversed.

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[19] *Sierra Club v. City of Orange*, is illustrative here. In that case, the plaintiffs challenged an EIR approved for a large planned community on the basis that the EIR improperly broke up the various environmental impacts by separate project components or "piecemealed" the analysis in violation of CEQA. In evaluating the defense that the plaintiffs had failed to adequately raise the issue at the administrative level, the Court held that comments such as *"the use of a single document for both a project-level and a program-level EIR [is] 'confusing',"* and *"[t]he lead agency should identify any potential adverse air quality impacts that could occur from all phases of the project and all air pollutant sources related to the project,"* were too vague to fairly raise the argument of piecemealing before the agency. *Sierra Club v. City of Orange*, 163 Cal.App.4th at 537.

correlating the localized human health impacts associated with an individual project's criteria air pollutant emissions be reversed.

Respectfully submitted,

Dated: April 2, 2015

Catherine T. Redmond
Attorney for Proposed Amicus Curiae

SAN JOAQUIN VALLEY
UNIFIED
AIR POLLUTION CONTROL
DISTRICT

CERTIFICATE OF WORD COUNT

Pursuant to Rule 8.204 of the California Rules of Court, I hereby certify that this document, based on the Word County feature of the Microsoft Word software program used to compose and print this document, contains, exclusive of caption, tables, certificate of word count, signature block and certificate of service, 3806 words.

Dated: April 2, 2015

Annette A. Ballatore-Williamson
District Counsel (SBN 192176)

Sierra Club et al, v. County of Fresno, et al
Supreme Court of California Case No.: S219783
Fifth District Court of Appeal Case No.: F066798
Fresno County Superior Court Case No.: 11CECG00726

PROOF OF SERVICE

I am over the age of 18 years and not a p[arty to the above-captioned action; that my business address is San Joaquin Valley Unified Air Pollution Control District located at 1990 E. Gettysburg Avenue, Fresno, California 93726.

On April 2, 2015, I served the document described below:

APPLICATION FOR LEAVE TO FILE AMICUS CURIAE BRIEF OF SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT IN SUPPORT OF DEFENDANT AND RESPONDENT, COUNTY OF FRESNO

On all parties to this action at the following addresses and in the following manner:

PLEASE SEE ATTACHED SERVICE LIST

(XX) **(BY MAIL)** I caused a true copy of each document(s) to be laced in a sealed envelope with first-class postage affixed and placed the envelope for collection. Mail is collected daily at my office and placed in a United State Postal Service collection box for pick-up and delivery that same day.

( ) **(BY ELECTRONIC MAIL)** I caused a true and correct scanned image (.PDF file) copy to be transmitted via electronic mail transfer system in place at the San Joaquin Valley Unified Air Pollution Control District ("District"), originating from the undersigned at 1990 E. Gettysburg Avenue, Fresno, CA, to the address(es) indicated below.

( ) **(BY OVERNIGHT MAIL)** I caused a true and correct copy to be delivered via Federal Express to the following person(s) or their representative at the address(es) listed below.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct and that I executed this document on April 2, 2015, at Fresno, California.

Esthela Soto

SERVICE LIST

Sierra Club et al, v. County of Fresno, et al
Supreme Court of California Case No.: S219783
Fifth District Court of Appeal Case No.: F066798
Fresno County Superior Court Case No.: 11CECG00726

Sara Hedgpeth-Harris, Esq. LAW OFFICE OF SARA HEDGPETH-HARRIS 2125 Kern Street, Suite 301 Fresno, California 93721 Telephone: (559) 233-0907 Facsimile: (559) 272-6046 Email: sara.hedgpethharris@shh-law.com	Attorney for Plaintiffs and Appellants, Sierra Club, et al
Daniel C. Cederborg, Esq. Bruce B. Johnson, Jr., Esq. OFFICE OF THE FRESNO COUNTY COUNSEL 2220 Tulare Street, Suite 500 Fresno, California 93721 Telephone: (559) 600-3479 Facsimile: (559) 600-3480 Email: bjohnson@co.fresno.ca.us	Attorneys for Defendant and Respondent, County of Fresno
Bryan N. Wagner, Esq. WAGNER & WAGNER 7110 N. Fresno Street, Suite 340 Fresno, California 93720 Telephone: (559) 224-0871 Facsimile: (559) 224-0885 Email: bryan@wagnerandwagner.com	Attorneys for Real Party in Interest/Respondent Friant Ranch, L.P.
Clerk of the Court Superior Court of California County of Fresno 1130 'O' Street Fresno, California 93721 Telephone: (559) 457-1900	
Clerk of the Court Fifth District Court of Appeal 2424 Ventura Street Fresno, California 93721 Telephone: (559) 445-5491	

R. Tyson Sohagim, Esq. THE SOHAGI LAW GROUP 11999 San Vicente Blvd., Suite 150 Los Angeles, California 90049 Telephone: (310) 475-5700 Facsimile: (310) 475-5707 Email: tsohagi@sohagi.com	Attorney for Amici Curiae; League of California Cities, and the California State Association of Counties
Marcia L. Scully, Esq. General Counsel METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA Post Office Box 54153 Los Angeles, California 90054 Telephone: (213) 217-6115	Attorney for Amicus Curiae, The Metropolitan Water District of Southern CA
Amy Minteer, Esq. CHATEN-BROWN & CARSTENS LLP 2200 Pacific Coast Highway, Suite 318 Hermosa Beach, California 90254 Telephone: (310) 798-2400 Facsimile: (310) 798-2402 Email: ACM@CBCEarthlaw.com	Attorney for Amici Curiae, Association of Irritated Residents, Medical Advocates for Healthy Air, and Coalition for Clean Air
Shanda M. Beltran, Esq. General Counsel BUILDING INDUSTRY LEGAL DEFENSE FOUNDATION 17744 Sky Park Cr., Suite 170 Irvine, California 92614 Telephone: (949) 553-9500 Facsimile: (949) 769-8943 Email: sbeltran@biasc.org	Attorney for Amicus Curiae, Building Industry Legal Defense Foundation
Gene Talmadge, President CALIFORNIA ASSOCIATION OF ENVIRONMENTAL PROFESSIONALS 40747 Baranda Court Palm Desert, California 92260 Telephone: (760) 340-4499 Facsimile: (760) 674-2479	Attorney for Amicus Curiae, California Association of Environmental Professionals
Jennifer L. Hernandez, Esq. HOLLAND & KNIGHT LLP 50 California Street, Suite 2800 San Francisco, California 94111	On behalf of Amicus Curiae, CEQA Research Council

Telephone: (415) 743-6927 Facsimile: (415) 743-6910 Email: Jennifer.hernandez@hklaw.com	

S219783

IN THE SUPREME COURT OF C ALIFORNIA

SIERRA CLUB, REVIVE THE SAN JOAQUIN, and
LEAGUE OF WOMEN VOTERS OF FRESNO,

Plaintiffs and Appellants,

v.

COUNTY OF FRESNO,

Defendant and Respondent,

and,

FRIANT RANCH, L.P.,

Real Party in Interest and Respondent.

SUPREME COURT
FILED
APR 13 2015
Frank A. McGuire Clerk
Deputy

After a Published Decision by the Court of Appeal, filed May 27, 2014
Fifth Appellate District Case No. F066798

Appeal from the Superior Court of California, County of Fresno
Case No. 11CECG00726
Honorable Rosendo A. Pena, Jr.

APPLICATION OF THE SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT FOR LEAVE TO FILE BRIEF OF *AMICUS CURIAE* IN SUPPORT OF NEITHER PARTY AND *[PROPOSED]* BRIEF OF *AMICUS CURIAE*

Kurt R. Wiese, General Counsel (SBN 127251)
*Barbara Baird, Chief Deputy Counsel (SBN 81507)
SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT
21865 Copley Drive, Diamond Bar, CA 91765
Telephone: 909-396-2302; Facsimile: 909-396-2961
Email: bbaird@aqmd.gov
Counsel for [Proposed] Amicus Curiae,
SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

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TO THE HONORABLE CHIEF JUSTICE AND JUSTICES OF THE SUPREME COURT:

APPLICATION FOR LEAVE TO FILE *AMICUS CURIAE* BRIEF

Pursuant to Rule 8.520(f) of the California Rules of Court, the South Coast Air Quality Management District (SCAQMD) respectfully requests leave to file the attached *amicus curiae* brief. Because SCAQMD's position differs from that of either party, we request leave to submit this amicus brief in support of neither party.

HOW THIS BRIEF WILL ASSIST THE COURT

SCAQMD's proposed amicus brief takes a position on two of the issues in this case. In both instances, its position differs from that of either party. The issues are:

1) Does the California Environmental Quality Act (CEQA) require an environmental impact report (EIR) to correlate a project's air pollution emissions with specific levels of health impacts?
2) What is the proper standard of review for determining whether an EIR provides sufficient information on the health impacts caused by a project's emission of air pollutants?

This brief will assist the Court by discussing the practical realities of correlating identified air quality impacts with specific health outcomes. In short, CEQA requires agencies to provide detailed information about a project's air quality impacts that is sufficient for the public and decisionmakers to adequately evaluate the project and meaningfully understand its impacts. However, the level of analysis is governed by a rule of reason; CEQA only requires agencies to conduct analysis if it is reasonably feasible to do so.

With regard to health-related air quality impacts, an analysis that correlates a project's air pollution emissions with specific levels of health impacts will be feasible in some cases but not others. Whether it is feasible depends on a variety of factors, including the nature of the project and the nature of the analysis under consideration. The feasibility of analysis may also change over time as air districts and others develop new tools for measuring projects' air quality related health impacts. Because SCAQMD has among the most sophisticated air quality modeling and health impact evaluation capability of any of the air districts in the State, it is uniquely situated to express an opinion on the extent to which the Court should hold that CEQA requires lead agencies to correlate air quality impacts with specific health outcomes.

SCAQMD can also offer a unique perspective on the question of the appropriate standard of review. SCAQMD submits that the proper standard of review for determining whether an EIR is sufficient as an informational document is more nuanced than argued by either party. In our view, this is a mixed question of fact and law. It includes determining whether additional analysis is feasible, which is primarily a factual question that should be reviewed under the substantial evidence standard. However, it also involves determining whether the omission of a particular analysis renders an EIR insufficient to serve CEQA's purpose as a meaningful, informational document. If a lead agency has not determined that a requested analysis is infeasible, it is the court's role to determine whether the EIR nevertheless meets CEQA's purposes, and courts should not defer to the lead agency's conclusions regarding the legal sufficiency of an EIR's analysis. The ultimate question of whether an EIR's analysis is "sufficient" to serve CEQA's informational purposes is predominately a question of law that courts should review de novo.

This brief will explain the rationale for these arguments and may assist the Court in reaching a conclusion that accords proper respect to a lead agency's factual conclusions while maintaining judicial authority over the ultimate question of what level of analysis CEQA requires.

STATEMENT OF INTEREST OF *AMICUS CURIAE*

The SCAQMD is the regional agency primarily responsible for air pollution control in the South Coast Air Basin, which consists of all of Orange County and the non-desert portions of the Los Angeles, Riverside, and San Bernardino Counties. (Health & Saf. Code § 40410; Cal. Code Regs., tit. 17, § 60104.) The SCAQMD participates in the CEQA process in several ways. Sometimes it acts as a lead agency that prepares CEQA documents for projects. Other times it acts as a responsible agency when it has permit authority over some part of a project that is undergoing CEQA review by a different lead agency. Finally, SCAQMD also acts as a commenting agency for CEQA documents that it receives because it is a public agency with jurisdiction by law over natural resources affected by the project.

In all of these capacities, SCAQMD will be affected by the decision in this case. SCAQMD sometimes submits comments requesting that a lead agency perform an additional type of air quality or health impacts analysis. On the other hand, SCAQMD sometimes determines that a particular type of health impact analysis is not feasible or would not produce reliable and informative results. Thus, SCAQMD will be affected by the Court's resolution of the extent to which CEQA requires EIRs to correlate emissions and health impacts, and its resolution of the proper standard of review.

CERTIFICATION REGARDING AUTHORSHIP AND FUNDING

No party or counsel in the pending case authored the proposed amicus curiae brief in whole or in part, or made any monetary contribution intended to fund the preparation or submission of the brief. No person or entity other than the proposed *Amicus Curiae* made any monetary contribution intended to fund the preparation or submission of the brief.

Respectfully submitted,

DATED: April 3, 2015

SOUTH COAST AIR QUALITY
MANAGEMENT DISTRICT
KURT R. WIESE, GENERAL COUNSEL
BARBARA BAIRD, CHIEF DEPUTY COUNSEL

By: Barbara Baird
Barbara Baird
Attorneys for [proposed] Amicus Curiae
SOUTH COAST AIR QUALITY
MANAGEMENT DISTICT

BRIEF OF AMICUS CURIAE

SUMMARY OF ARGUMENT

The South Coast Air Quality Management District (SCAQMD) submits that this Court should not try to establish a hard-and-fast rule concerning whether lead agencies are required to correlate emissions of air pollutants with specific health consequences in their environmental impact reports (EIR). The level of detail required in EIRs is governed by a few, core CEQA (California Environmental Quality Act) principles. As this Court has stated, "[a]n EIR must include detail sufficient to enable those who did not participate in its preparation to understand and to consider meaningfully the issues raised by the proposed project." (*Laurel Heights Improvement Assn. v. Regents of the Univ of Cal.* (1988) 47 Cal.3d 376, 405 ["*Laurel Heights I*"]) Accordingly, "an agency must use its best efforts to find out and disclose all that it reasonably can." (*Vineyard Area Citizens for Responsible Growth, Inc. v. City of Rancho Cordova* (2007) 40 Cal.4th 412, 428 (quoting CEQA Guidelines § 15144)[1].). However, "[a]nalysis of environmental effects need not be exhaustive, but will be judged in light of what is reasonably feasible." (*Association of Irritated Residents v. County of Madera* (2003) 107 Cal.App.4th 1383, 1390; CEQA Guidelines §§ 15151, 15204(a).)

With regard to analysis of air quality related health impacts, EIRs must generally quantify a project's pollutant emissions, but in some cases it is not feasible to correlate these emissions to specific, quantifiable health impacts (e.g., premature mortality; hospital admissions). In such cases, a general description of the adverse health impacts resulting from the pollutants at issue may be sufficient. In other cases, due to the magnitude

[1] The CEQA Guidelines are found at Cal. Code Regs., tit. 14 §§ 15000, *et seq.*

or nature of the pollution emissions, as well as the specificity of the project involved, it may be feasible to quantify health impacts. Or there may be a less exacting, but still meaningful analysis of health impacts that can feasibly be performed. In these instances, agencies should disclose those impacts.

SCAQMD also submits that whether or not an EIR complies with CEQA's informational mandates by providing sufficient, feasible analysis is a mixed question of fact and law. Pertinent here, the question of whether an EIR's discussion of health impacts from air pollution is sufficient to allow the public to understand and consider meaningfully the issues involves two inquiries: (1) Is it feasible to provide the information or analysis that a commenter is requesting or a petitioner is arguing should be required?; and (2) Even if it is feasible, is the agency relying on other policy or legal considerations to justify not preparing the requested analysis? The first question of whether an analysis is feasible is primarily a question of fact that should be judged by the substantial evidence standard. The second inquiry involves evaluating CEQA's information disclosure purposes against the asserted reasons to not perform the requested analysis. For example, an agency might believe that its EIR meets CEQA's informational disclosure standards even without a particular analysis, and therefore choose not to conduct that analysis. SCAQMD submits that this is more of a legal question, which should be reviewed de novo as a question of law.

ARGUMENT

I. RELEVANT FACTUAL AND LEGAL FRAMEWORK.

A. Air Quality Regulatory Background

The South Coast Air Quality Management District (SCAQMD) is one of the local and regional air pollution control districts and air quality

management districts in California. The SCAQMD is the regional air pollution agency for the South Coast Air Basin, which consists of all of Orange County and the non-desert portions of Los Angeles, Riverside, and San Bernardino Counties. (Health & Saf. Code § 40410, 17 Cal. Code Reg. § 60104.) The SCAQMD also includes the Coachella Valley in Riverside County (Palm Springs area to the Salton Sea). (SCAQMD, *Final 2012 AQMP (Feb. 2013)*, http://www.aqmd.gov/home/library/clean-air-plans/air-quality-mgt-plan/final-2012-air-quality-management-plan; then follow "chapter 7" hyperlink; pp 7-1, 7-3 (last visited Apr. 1, 2015).) The SCAQMD's jurisdiction includes over 16 million residents and has the worst or nearly the worst air pollution levels in the country for ozone and fine particulate matter. (SCAQMD, *Final 2012 AQMP (Feb. 2013)*, http://www.aqmd.gov/home/library/clean-air-plans/air-quality-mgt-plan/final-2012-air-quality-management-plan; then follow "Executive Summary" hyperlink p. ES-1 (last visited Apr. 1, 2015).)

Under California law, the local and regional districts are primarily responsible for controlling air pollution from all sources except motor vehicles. (Health & Saf. Code § 40000.) The California Air Resources Board (CARB), part of the California Environmental Protection Agency, is primarily responsible for controlling pollution from motor vehicles. (*Id.*) The air districts must adopt rules to achieve and maintain the state and federal ambient air quality standards within their jurisdictions. (Health & Saf. Code § 40001.)

The federal Clean Air Act (CAA) requires the United States Environmental Protection Agency (EPA) to identify pollutants that are widely distributed and pose a threat to human health, developing a so-called "criteria" document. (42 U.S.C. § 7408; CAA § 108.) These pollutants are frequently called "criteria pollutants." EPA must then establish "national ambient air quality standards" at levels "requisite to protect public health",

allowing "an adequate margin of safety." (42 U.S.C. § 7409; CAA § 109.) EPA has set standards for six identified pollutants: ozone, nitrogen dioxide, sulfur dioxide, carbon monoxide, particulate matter (PM), and lead. (U.S. EPA, National Ambient Air Quality Standards (NAAQS), http://www.epa.gov/air/criteria.html (last updated Oct. 21, 2014).)[2]

Under the Clean Air Act, EPA sets emission standards for motor vehicles and "nonroad engines" (mobile farm and construction equipment, marine vessels, locomotives, aircraft, etc.). (42 U.S.C. §§ 7521, 7547; CAA §§ 202, 213.) California is the only state allowed to establish emission standards for motor vehicles and most nonroad sources; however, it may only do so with EPA's approval. (42 U.S.C. §§ 7543(b), 7543(e); CAA §§ 209(b), 209(c).) Sources such as manufacturing facilities, power plants and refineries that are not mobile are often referred to as "stationary sources." The Clean Air Act charges state and local agencies with the primary responsibility to attain the national ambient air quality standards. (42 U.S.C. § 7401(a)(3); CAA § 101(a)(3).) Each state must adopt and implement a plan including enforceable measures to achieve and maintain the national ambient air quality standards. (42 U.S.C. § 7410; CAA § 110.) The SCAQMD and CARB jointly prepare portion of the plan for the South Coast Air Basin and submit it for approval by EPA. (Health & Saf. Code §§ 40460, et seq.)

The Clean Air Act also requires state and local agencies to adopt a permit program requiring, among other things, that new or modified "major" stationary sources use technology to achieve the "lowest achievable emission rate," and to control minor stationary sources as

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[2] Particulate matter (PM) is further divided into two categories: fine particulate or $PM_{2.5}$ (particles with a diameter of less than or equal to 2.5 microns) and coarse particulate (PM_{10}) (particles with a diameter of 10 microns or less). (U.S. EPA, Particulate Matter (PM), http://www.epa.gov/airquality/particlepollution/ (last visited Apr. 1, 2015).)

needed to help attain the standards. (42 U.S.C. §§ 7502(c)(5), 7503(a)(2), 7410(a)(2)(C); CAA §§ 172(c)(5), 173(a)(2), 110(a)(2)(C).) The air districts implement these permit programs in California. (Health & Saf. Code §§ 42300, et seq.)

The Clean Air Act also sets out a regulatory structure for over 100 so-called "hazardous air pollutants" calling for EPA to establish "maximum achievable control technology" (MACT) for sources of these pollutants. (42 U.S.C. § 7412(d)(2); CAA § 112(d)(2).) California refers to these pollutants as "toxic air contaminants" (TACs) which are subject to two state-required programs. The first program requires "air toxics control measures" for specific categories of sources. (Health & Saf. Code § 39666.) The other program requires larger stationary sources and sources identified by air districts to prepare "health risk assessments" for impacts of toxic air contaminants. (Health & Saf. Code §§ 44320(b), 44322, 44360.) If the health risk exceeds levels identified by the district as "significant," the facility must implement a "risk reduction plan" to bring its risk levels below "significant" levels. Air districts may adopt additional more stringent requirements than those required by state law, including requirements for toxic air contaminants. (Health & Saf. Code § 41508; *Western Oil & Gas Assn. v. Monterey Bay Unified APCD* (1989) 49 Cal.3d 408, 414.) For example, SCAQMD has adopted a rule requiring new or modified sources to keep their risks below specified levels and use best available control technology (BACT) for toxics. (SCAQMD, *Rule 1401-New Source Review of Toxic Air Contaminants*, http://www.aqmd.gov/home/regulations/rules/scaqmd-rule-book/regulation-xiv; then follow "Rule 1401" hyperlink (last visited Apr. 1, 2015).)

B. The SCAQMD's Role Under CEQA

The California Environmental Quality Act (CEQA) requires public agencies to perform an environmental review and appropriate analysis for projects that they implement or approve. (Pub. Resources Code § 21080(a).) The agency with primary approval authority for a particular project is generally the "lead agency" that prepares the appropriate CEQA document. (CEQA Guidelines §§ 15050, 15051.) Other agencies having a subsequent approval authority over all or part of a project are called "responsible" agencies that must determine whether the CEQA document is adequate for their use. (CEQA Guidelines §§ 15096(c), 15381.) Lead agencies must also consult with and circulate their environmental impact reports to "trustee agencies" and agencies "with jurisdiction by law" including "authority over resources which may be affected by the project." (Pub. Resources Code §§ 21104(a), 21153; CEQA Guidelines §§ 15086(a)(3), 15073(c).) The SCAQMD has a role in all these aspects of CEQA.

Fulfilling its responsibilities to implement its air quality plan and adopt rules to attain the national ambient air quality standards, SCAQMD adopts a dozen or more rules each year to require pollution reductions from a wide variety of sources. The SCAQMD staff evaluates each rule for any adverse environmental impact and prepares the appropriate CEQA document. Although most rules reduce air emissions, they may have secondary environmental impacts such as use of water or energy or disposal of waste—e.g., spent catalyst from control equipment.[3]

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[3] The SCAQMD's CEQA program for its rules is a "Certified Regulatory Program" under which it prepares a "functionally equivalent" document in lieu of a negative declaration or EIR. (Pub. Resources Code § 21080.5, CEQA Guidelines § 15251(l).)

The SCAQMD also approves a large number of permits every year to construct new, modified, or replacement facilities that emit regulated air pollutants. The majority of these air pollutant sources have already been included in an earlier CEQA evaluation for a larger project, are currently being evaluated by a local government as lead agency, or qualify for an exemption. However, the SCAQMD sometimes acts as lead agency for major projects where the local government does not have a discretionary approval. In such cases, SCAQMD prepares and certifies a negative declaration or environmental impact report (EIR) as appropriate.[4] SCAQMD evaluates perhaps a dozen such permit projects under CEQA each year. SCAQMD is often also a "responsible agency" for many projects since it must issue a permit for part of the projects (e.g., a boiler used to provide heat in a commercial building). For permit projects evaluated by another lead agency under CEQA, SCAQMD has the right to determine that the CEQA document is inadequate for its purposes as a responsible agency, but it may not do so because its permit program already requires all permitted sources to use the best available air pollution control technology. (SCAQMD, *Rule 1303(a)(1) – Requirements*, http://www.aqmd.gov/home/regulations/rules/scaqmd-rule-book/regulation-xiii; then follow "Rule 1303" hyperlink (last visited Apr. 1, 2015).)

Finally, SCAQMD receives as many as 60 or more CEQA documents each month (around 500 per year) in its role as commenting agency or an agency with "jurisdiction by law" over air quality—a natural resource affected by the project. (Pub. Resources Code §§ 21104(a), 21153; CEQA Guidelines § 15366(a)(3).) The SCAQMD staff provides comments on as many as 25 or 30 such documents each month.

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[4] The SCAQMD's permit projects are not included in its Certified Regulatory Program, and are evaluated under the traditional local government CEQA analysis. (Pub. Resources Code §§ 21150-21154.)

(SCAQMD Governing Board Agenda, Apr. 3, 2015, Agenda Item 16, Attachment A, http://www.aqmd.gov/home/library/meeting-agendas-minutes/agenda?title=governing-board-meeting-agenda-april-3-2015; then follow "16. Lead Agency Projects and Environmental Documents Received by SCAQMD" hyperlink (last visited Apr. 1, 2015).) Of course, SCAQMD focuses its commenting efforts on the more significant projects.

Typically, SCAQMD comments on the adequacy of air quality analysis, appropriateness of assumptions and methodology, and completeness of the recommended air quality mitigation measures. Staff may comment on the need to prepare a health risk assessment detailing the projected cancer and noncancer risks from toxic air contaminants resulting from the project, particularly the impacts of diesel particulate matter, which CARB has identified as a toxic air contaminant based on its carcinogenic effects. (California Air Resources Board, Resolution 98-35, Aug. 27, 1998, http://www.arb.ca.gov/regact/diesltac/diesltac.htm; then follow Resolution 98-35 hyperlink (last visited Apr. 1, 2015).) Because SCAQMD already requires new or modified stationary sources of toxic air contaminants to use the best available control technology for toxics and to keep their risks below specified levels, (SCAQMD Rule 1401, supra, note 15), the greatest opportunity to further mitigate toxic impacts through the CEQA process is by reducing emissions—particularly diesel emissions—from vehicles.

II. THIS COURT SHOULD NOT SET A HARD-AND-FAST RULE CONCERNING THE EXTENT TO WHICH AN EIR MUST CORRELATE A PROJECT'S EMISSION OF POLLUTANTS WITH RESULTING HEALTH IMPACTS.

Numerous cases hold that courts do not review the correctness of an EIR's conclusions but rather its sufficiency as an informative document. (*Laurel Heights 1, supra*, 47 Cal.3d at p. 392; *Citizens of Goleta Valley v.*

Bd. of Supervisors (1990) 52 Cal.3d 553, 569; *Bakersfield Citizens for Local Control v. City of Bakersfield* (2004) 124 Cal.App.4th 1184, 1197.)

As stated by the Court of Appeal in this case, where an EIR has addressed a topic, but the petitioner claims that the information provided about that topic is insufficient, courts must "draw[] a line that divides *sufficient* discussions from those that are *insufficient*." (*Sierra Club v. County of Fresno* (2014) 226 Cal.App.4th 704 (superseded by grant of review) 172 Cal.Rptr.3d 271, 290.) The Court of Appeal readily admitted that "[t]he terms themselves – sufficient and insufficient – provide little, if any, guidance as to where the line should be drawn. They are simply labels applied once the court has completed its analysis." (*Id.*)

The CEQA Guidelines, however, provide guidance regarding what constitutes a sufficient discussion of impacts. Section 15151 states that "the sufficiency of an EIR is to be reviewed in light of what is reasonably feasible." Case law reflects this: "Analysis of environmental effects need not be exhaustive, but will be judged in light of what was reasonably feasible." (*Association of Irritated Residents v. County of Madera, supra,* 107 Cal.App.4th at p. 1390; see also CEQA Guidelines § 15204(a).)

Applying this test, this Court cannot realistically establish a hard-and-fast rule that an analysis correlating air pollution impacts of a project to quantified resulting health impacts is always required, or indeed that it is never required. Simply put, in some cases such an analysis will be "feasible"; in some cases it will not.

For example, air pollution control districts often require a proposed new source of toxic air contaminants to prepare a "health risk assessment" before issuing a permit to construct. District rules often limit the allowable cancer risk the new source may cause to the "maximally exposed individual" (worker and residence exposures). (*See, e.g.*, SCAQMD Rule 1401(c)(8); 1401(d)(1), *supra* note 15.) In order to perform this analysis, it

is necessary to have data regarding the sources and types of air toxic contaminants, location of emission points, velocity of emissions, the meteorology and topography of the area, and the location of receptors (worker and residence). (SCAQMD, *Supplemental Guidelines for Preparing Risk Assessments for the Air Toxics "Hot Spots" Information and Assessment Act (AB2588), pp. 11-16*; (last visited Apr. 1, 2015) http://www.aqmd.gov/home/library/documents-support-material; "Guidelines" hyperlink; AB2588; then follow AB2588 Risk Assessment Guidelines hyperlink.)

Thus, it is feasible to determine the health risk posed by a new gas station locating at an intersection in a mixed use area, where receptor locations are known. On the other hand, it may not be feasible to perform a health risk assessment for airborne toxics that will be emitted by a generic industrial building that was built on "speculation" (i.e., without knowing the future tenant(s)). Even where a health risk assessment can be prepared, however, the resulting maximum health risk value is only a calculation of risk—it does not necessarily mean anyone will contract cancer as a result of the project.

In order to find the "cancer burden" or expected additional cases of cancer resulting from the project, it is also necessary to know the numbers and location of individuals living within the "zone of impact" of the project: i.e., those living in areas where the projected cancer risk from the project exceeds one in a million. (SCAQMD, Health Risk Assessment Summary form, http://www.aqmd.gov/home/forms ; filter by "AB2588" category; then "Health Risk Assessment" hyperlink (last visited Apr. 1, 2015).) The affected population is divided into bands of those exposed to at least 1 in a million risk, those exposed to at least 10 in a million risk, etc. up to those exposed at the highest levels. (*Id.*) This data allows agencies to calculate an approximate number of additional cancer cases expected from

the project. However, it is not possible to predict which particular individuals will be affected.

For the so-called criteria pollutants[5], such as ozone, it may be more difficult to quantify health impacts. Ozone is formed in the atmosphere from the chemical reaction of the nitrogen oxides (NO_x) and volatile organic compounds (VOC) in the presence of sunlight. (U.S. EPA, Ground Level Ozone, http://www.epa.gov/airquality/ozonepollution/ (last updated Mar. 25, 2015).) It takes time and the influence of meteorological conditions for these reactions to occur, so ozone may be formed at a distance downwind from the sources. (U.S. EPA, *Guideline on Ozone Monitoring Site Selection* (Aug. 1998) EPA-454/R-98-002 § 5.1.2, http://www.epa.gov/ttnamti1/archive/cpreldoc.html (last visited Apr. 1, 2015).) NO_x and VOC are known as "precursors" of ozone.

Scientifically, health effects from ozone are correlated with increases in the ambient level of ozone in the air a person breathes. (U.S. EPA, *Health Effects of Ozone in the General Population,* Figure 9, http://www.epa.gov/apti/ozonehealth/population.html#levels (last visited Apr. 1, 2015).) However, it takes a large amount of additional precursor emissions to cause a modeled increase in ambient ozone levels over an entire region. For example, the SCAQMD's 2012 AQMP showed that reducing NO_x by 432 tons per day (157,680 tons/year) and reducing VOC by 187 tons per day (68,255 tons/year) would reduce ozone levels at the SCAQMD's monitor site with the highest levels by only 9 parts per billion. (South Coast Air Quality Management District, *Final 2012 AQMP (February 2013)*, http://www.aqmd.gov/home/library/clean-air-plans/air-quality-mgt-plan/final-2012-air-quality-management-plan; then follow "Appendix V: Modeling & Attainment Demonstrations" hyperlink,

[5] See discussion of types of pollutants, supra, Part I.A.

pp. v-4-2, v-7-4, v-7-24.) SCAQMD staff does not currently know of a way to accurately quantify ozone-related health impacts caused by NO_x or VOC emissions from relatively small projects.

On the other hand, this type of analysis may be feasible for projects on a regional scale with very high emissions of NO_x and VOCs, where impacts are regional. For example, in 2011 the SCAQMD performed a health impact analysis in its CEQA document for proposed Rule 1315, which authorized various newly-permitted sources to use offsets from the districts "internal bank" of emission reductions. This CEQA analysis accounted for essentially *all* the increases in emissions due to new or modified sources in the District between 2010 and 2030.[6] The SCAQMD was able to correlate this very large emissions increase (e.g., 6,620 pounds per day NO_x (1,208 tons per year), 89,180 pounds per day VOC (16,275 tons per year)) to expected health outcomes from ozone and particulate matter (e.g., 20 premature deaths per year and 89,947 school absences in the year 2030 due to ozone).[7] (SCAQMD Governing Board Agenda, February 4, 2011, Agenda Item 26, *Assessment for: Re-adoption of Proposed Rule 1315 – Federal New Source Review Tracking System* (see hyperlink in fn 6*)* at p. 4.1-35, Table 4.1-29.)

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[6] (SCAQMD Governing Board Agenda, February 4, 2011, Agenda Item 26, Attachment G, *Assessment for: Re-adoption of Proposed Rule 1315 – Federal New Source Review Tracking System, Vol. 1, p.4.0-6,* http://www.aqmd.gov/home/library/meeting-agendas-minutes/agenda?title=governing-board-meeting-agenda-february-4-2011; the follow "26. Adopt Proposed Rule 1315 – Federal New Source Review Tracking System" (last visited April 1, 2015).)

[7] The SCAQMD was able to establish the location of future NO_x and VOC emissions by assuming that new projects would be built in the same locations and proportions as existing stationary sources. This CEQA document was upheld by the Los Angeles County Superior Court in *Natural Res. Def. Council v SCAQMD*, Los Angeles Superior Court No. BS110792).

However, a project emitting only 10 tons per year of NO_x or VOC is small enough that its regional impact on ambient ozone levels may not be detected in the regional air quality models that are currently used to determine ozone levels. Thus, in this case it would not be feasible to directly correlate project emissions of VOC or NO_x with specific health impacts from ozone. This is in part because ozone formation is not linearly related to emissions. Ozone impacts vary depending on the location of the emissions, the location of other precursor emissions, meteorology and seasonal impacts, and because ozone is formed some time later and downwind from the actual emission. (EPA Guideline on Ozone Monitoring Site Selection (Aug. 1998) EPA-454/R-98-002, § 5.1.2; https://www.epa.gov/ttnamti1/archive/cpreldoc.html; then search "Guideline on Ozone Monitoring Site Selection" click on pdf) (last viewed Apr. 1, 2015).)

SCAQMD has set its CEQA "significance" threshold for NO_x and VOC at 10 tons per year (expressed as 55 lb/day). (SCAQMD, *Air Quality Analysis Handbook*, http://www.aqmd.gov/home/regulations/ceqa/air-quality-analysis-handbook; then follow "SCAQMD Air Quality Significance Thresholds" hyperlink (last visited Apr. 1, 2015).) This is because the federal Clean Air Act defines a "major" stationary source for "extreme" ozone nonattainment areas such as SCAQMD as one emitting 10 tons/year. (42 U.S.C. §§ 7511a(e), 7511a(f); CAA §§ 182(e), 182(f).) Under the Clean Air Act, such sources are subject to enhanced control requirements (42 U.S.C. §§ 7502(c)(5), 7503; CAA §§ 172(c)(5), 173), so SCAQMD decided this was an appropriate threshold for making a CEQA "significance" finding and requiring feasible mitigation. Essentially, SCAQMD takes the position that a source that emits 10 tons/year of NO_x or VOC would contribute cumulatively to ozone formation. Therefore, lead agencies that use SCAQMD's thresholds of significance may determine

that many projects have "significant" air quality impacts and must apply all feasible mitigation measures, yet will not be able to precisely correlate the project to quantifiable health impacts, unless the emissions are sufficiently high to use a regional modeling program.

In the case of particulate matter ($PM_{2.5}$)[8], another "criteria" pollutant, SCAQMD staff is aware of two possible methods of analysis. SCAQMD used regional modeling to predict expected health impacts from its proposed Rule 1315, as mentioned above. Also, the California Air Resources Board (CARB) has developed a methodology that can predict expected mortality (premature deaths) from large amounts of $PM_{2.5}$. (California Air Resources Board, *Health Impacts Analysis: PM Premature Death Relationship*, http://www.arb.ca.gov/research/health/pm-mort/pm-mort_arch.htm (last reviewed Jan. 19, 2012).) SCAQMD used the CARB methodology to predict impacts from three very large power plants (e.g., 731-1837 lbs/day). (Final Environmental Assessment for Rule 1315, *supra*, pp 4.0-12, 4.1-13, 4.1-37 (e.g., 125 premature deaths in the entire SCAQMD in 2030), 4.1-39 (0.05 to 1.77 annual premature deaths from power plants.) Again, this project involved large amounts of additional $PM_{2.5}$ in the District, up to 2.82 tons/day (5,650 lbs/day of $PM_{2.5}$, or, or 1029 tons/year. (*Id.* at table 4.1-4, p. 4.1-10.)

However, the primary author of the CARB methodology has reported that this $PM_{2.5}$ health impact methodology is not suited for small projects and may yield unreliable results due to various uncertainties. [9] (SCAQMD, *Final Subsequent Mitigated Negative Declaration for: Warren*

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[8] SCAQMD has not attained the latest annual or 24-hour national ambient air quality standards for "$PM_{2.5}$" or particulate matter less than 2.5 microns in diameter.

[9] Among these uncertainties are the representativeness of the population used in the methodology, and the specific source of PM and the corresponding health impacts. (*Id.* at p. 2-24.)

E&P, Inc. WTU Central Facility, New Equipment Project (certified July 19, 2011), http://www.aqmd.gov/home/library/documents-support-material/lead-agency-permit-projects/permit-project-documents---year-2011; then follow "Final Subsequent Mitigated Negative Declaration for Warren E&P Inc. WTU Central Facility, New Equipment Project" hyperlink, pp. 2-22, 2-23 (last visited Apr. 1, 2015).) Therefore, when SCAQMD prepared a CEQA document for the expansion of an existing oil production facility, with very small $PM_{2.5}$ increases (3.8 lb/day) and a very small affected population, staff elected not to use the CARB methodology for using estimated $PM_{2.5}$ emissions to derive a projected premature mortality number and explained why it would be inappropriate to do so. (*Id.* at pp 2-22 to 2-24.) SCAQMD staff concluded that use of this methodology for such a small source could result in unreliable findings and would not provide meaningful information. (*Id.* at pp. 2-23, 2-25.) This CEQA document was not challenged in court.

In the above case, while it may have been technically possible to plug the data into the methodology, the results would not have been reliable or meaningful. SCAQMD believes that an agency should not be required to perform analyses that do not produce reliable or meaningful results. This Court has already held that an agency may decline to use even the "normal" "existing conditions" CEQA baseline where to do so would be misleading or without informational value. (*Neighbors for Smart Rail v. Exposition Metro Line* (2013) 57 Cal.4th 439, 448, 457.) The same should be true for a decision that a particular study or analysis would not provide reliable or meaningful results.[10]

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[10] Whether a particular study would result in "informational value" is a part of deciding whether it is "feasible." CEQA defines "feasible" as "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social, and

Therefore, it is not possible to set a hard-and-fast rule on whether a correlation of air quality impacts with specific quantifiable health impacts is required in all cases. Instead, the result turns on whether such an analysis is reasonably feasible in the particular case.[11] Moreover, what is reasonably feasible may change over time as scientists and regulatory agencies continually seek to improve their ability to predict health impacts. For example, CARB staff has been directed by its Governing Board to reassess and improve the methodology for estimating premature deaths. (California Air Resources Board, *Health Impacts Analysis: PM Mortality Relationship*, http://www.arb.ca.gov/research/health/pm-mort/pm-mort.htm (last reviewed Dec. 29, 2010).) This factor also counsels against setting any hard-and-fast rule in this case.

III. THE QUESTION OF WHETHER AN EIR CONTAINS SUFFICIENT ANALYSIS TO MEET CEQA'S REQUIREMENTS IS A MIXED QUESTION OF FACT AND LAW GOVERNED BY TWO DIFFERENT STANDARDS OF REVIEW.

A. Standard of Review for Feasibility Determination and Sufficiency as an Informative Document

A second issue in this case is whether courts should review an EIR's informational sufficiency under the "substantial evidence" test as argued by Friant Ranch or the "independent judgment" test as argued by Sierra Club.

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technological factors." (Pub. Resources Code § 21061.1.) A study cannot be "accomplished in a *successful* manner" if it produces unreliable or misleading results.

[11] In this case, the lead agency did not have an opportunity to determine whether the requested analysis was feasible because the comment was non-specific. Therefore, SCAQMD suggests that this Court, after resolving the legal issues in the case, direct the Court of Appeal to remand the case to the lead agency for a determination of whether the requested analysis is feasible. Because Fresno County, the lead agency, did not seek review in this Court, it seems likely that the County has concluded that at least some level of correlation of air pollution with health impacts is feasible.

As this Court has explained, "a reviewing court must adjust its scrutiny to the nature of the alleged defect, depending on whether the claim is predominantly one of improper procedure or a dispute over the facts." (*Vineyard Area Citizens v. City of Rancho Cordova, supra,* 40 Cal.4th at 435.) For questions regarding compliance with proper procedure or other legal questions, courts review an agency's action de novo under the "independent judgment" test. (*Id.*) On the other hand, courts review factual disputes only for substantial evidence, thereby "accord[ing] greater deference to the agency's substantive factual conclusions." (*Id.*)

Here, Friant Ranch and Sierra Club agree that the case involves the question of whether an EIR includes sufficient information regarding a project's impacts. However, they disagree on the proper standard of review for answering this question: Sierra Club contends that courts use the independent judgment standard to determine whether an EIR's analysis is sufficient to meet CEQA's informational purposes,[12] while Friant Ranch contends that the substantial evidence standard applies to this question.

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[12] Sierra Club acknowledges that courts use the substantial evidence standard when reviewing predicate factual issues, but argues that courts ultimately decide as a matter of law what CEQA requires. (Answering Brief, pp. 14, 23.)

SCAQMD submits that the issue is more nuanced than either party contends. We submit that, whether a CEQA document includes sufficient analysis to satisfy CEQA's informational mandates is a mixed question of fact and law,[13] containing two levels of inquiry that should be judged by different standards.[14]

The state CEQA Guidelines set forth standards for the adequacy of environmental analysis. Guidelines Section 15151 states:

> An EIR should be prepared with a sufficient degree of analysis to provide decision makers with information which enables them to make a decision which intelligently takes account of environmental consequences. An evaluation of the environmental effects of a proposed project need not be exhaustive, but the sufficiency of an EIR is to be reviewed in light of what is reasonably feasible. Disagreement among experts does not make an EIR inadequate, but the EIR should summarize the main points of disagreement among the experts. The courts have looked not for perfection, but for adequacy, completeness, and a good-faith effort at full disclosure.

In this case, the basic question is whether the underlying analysis of air quality impacts made the EIR "sufficient" as an informative document. However, whether the EIR's analysis was sufficient is judged in light of what was reasonably feasible. This represents a mixed question of fact and law that is governed by two different standards of review.

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[13] Friant Ranch actually states that the claim that an EIR lacks sufficient relevant information is, "most properly thought of as raising mixed questions of fact and law." (Opening Brief, p. 27.) However, the remainder of its argument claims that the court should apply the substantial evidence standard of review to all aspects of the issue.

[14] Mixed questions of fact and law issues may implicate predominantly factual subordinate questions that are reviewed under the substantial evidence test even though the ultimate question may be reviewed by the independent judgment test. *Crocker National Bank v. City and County of San Francisco* (1989) 49 Cal.3d 881, 888-889.

SCAQMD submits that an EIR's sufficiency as an informational document is ultimately a legal question that courts should determine using their independent judgment. This Court's language in *Laurel Heights I* supports this position. As this Court explained: "The court does not pass upon the correctness of the EIR's environmental conclusions, but only upon its *sufficiency as an informative document.*" (*Laurel Heights I, supra,* 47 Cal.3d at 392-393) (emphasis added.) As described above, the Court in *Vineyard Area Citizens v. City of Rancho Cordova, supra,* 40 Cal.4th at 431, also used its independent judgment to determine what level of analysis CEQA requires for water supply impacts. The Court did not defer to the lead agency's opinion regarding the law's requirements; rather, it determined for itself what level of analysis was necessary to meet "[t]he law's informational demands." (*Id.* at p. 432.) Further, existing case law also holds that where an agency fails to comply with CEQA's information disclosure requirements, the agency has "failed to proceed in the manner required by law." (*Save Our Peninsula Comm. v. Monterey County Bd. of Supervisors* (2001) 87 Cal.App.4th 99, 118.)

However, whether an EIR satisfies CEQA's requirements depends in part on whether it was reasonably feasible for an agency to conduct additional or more thorough analysis. EIRs must contain "a detailed statement" of a project's impacts (Pub. Res. Code § 21061), and an agency must "use its best efforts to find out and disclose all that it reasonably can." (CEQA Guidelines § 15144.) Nevertheless, "the sufficiency of an EIR is to be reviewed in light of what is reasonably feasible." (CEQA Guidelines § 15151.)

SCAQMD submits that the question of whether additional analysis or a particular study suggested by a commenter is "feasible" is generally a question of fact. Courts have already held that whether a particular alternative is "feasible" is reviewed by the substantial evidence test.

(*Uphold Our Heritage v. Town of Woodside* (2007) 147 Cal.App.4th 587, 598-99; *Center for Biological Diversity v. County of San Bernardino* (2010) 185 Cal.App.4th 866, 883.) Thus, if a lead agency determines that a particular study or analysis is infeasible, that decision should generally be judged by the substantial evidence standard. However, SCAQMD urges this Court to hold that lead agencies must explain the basis of any determination that a particular analysis is infeasible in the EIR itself. An EIR must discuss information, including issues related to the feasibility of particular analyses "in sufficient detail to enable meaningful participation and criticism by the public. '[W]hatever is required to be considered in an EIR must be in that formal report; what any official might have known from other writings or oral presentations cannot supply what is lacking in the report.'" (*Laurel Heights I, supra*, 47 Cal.3d at p. 405 (quoting *Santiago County Water District v. County of Orange* (1981) 118 Cal.App.3d 818, 831) (discussing analysis of alternatives).) The evidence on which the determination is based should also be summarized in the EIR itself, with appropriate citations to reference materials if necessary. Otherwise commenting agencies such as SCAQMD would be forced to guess where the lead agency's evidence might be located, thus thwarting effective public participation.

Moreover, if a lead agency determines that a particular study or analysis would not result in reliable or useful information and for that reason is not feasible, that determination should be judged by the substantial evidence test. (See *Neighbors for Smart Rail v. Exposition Metro Line Construction Authority, supra*, 57 Cal.4th 439, 448, 457:

whether "existing conditions" baseline would be misleading or uninformative judged by substantial evidence standard.[15])

If the lead agency's determination that a particular analysis or study is not feasible is supported by substantial evidence, then the agency has not violated CEQA's information disclosure provisions, since it would be infeasible to provide additional information. This Court's decisions provide precedent for such a result. For example, this Court determined that the issue of whether the EIR should have included a more detailed discussion of future herbicide use was resolved because substantial evidence supported the agency's finding that "the precise parameters of future herbicide use could not be predicted." *Ebbetts Pass Forest Watch v. California Dept. of Forestry & Fire Protection* (2008) 43 Cal.4th 936, 955.

Of course, SCAQMD expects that courts will continue to hold lead agencies to their obligations to consult with, and not to ignore or misrepresent, the views of sister agencies having special expertise in the area of air quality. (*Berkeley Keep Jets Over the Bay v. Board of Port Commissioners* (2007) 91 Cal.App.4th 1344, 1364 n.11.) In some cases, information provided by such expert agencies may establish that the purported evidence relied on by the lead agency is not in fact "substantial". (*Id.* at pp. 1369-1371.)

In sum, courts retain ultimate responsibility to determine what CEQA requires. However, the law does not require exhaustive analysis, but only what is reasonably feasible. Agencies deserve deference for their factual determinations regarding what type of analysis is reasonably feasible. On the other hand, if a commenter requests more information, and the lead agency declines to provide it but does *not* determine that the

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[15] The substantial evidence standard recognizes that the courts "have neither the resources nor the scientific expertise" to weigh conflicting evidence on technical issues. (*Laurel Heights I, supra,* 47 Cal.3d 376, 393.)

requested study or analysis would be infeasible, misleading or uninformative, the question becomes whether the omission of that analysis renders the EIR inadequate to satisfy CEQA's informational purposes. (*Id.* at pp. 1370-71.) Again, this is predominantly a question of law and should be judged by the de novo or independent judgment standard of review. Of course, this Court has recognized that a "project opponent or reviewing court can always imagine some additional study or analysis that might provide helpful information. It is not for them to design the EIR. That further study...might be helpful does not make it necessary." (*Laurel Heights I, supra,* 47 Cal.3d 376, 415 – see also CEQA Guidelines § 15204(a) [CEQA "does not require a lead agency to conduct every test. . . recommended or demanded by commenters."].) Courts, then, must adjudicate whether an omission of particular information renders an EIR inadequate to serve CEQA's informational purposes.[16]

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[16] We recognize that there is case law stating that the substantial evidence standard applies to "challenges to the scope of an EIR's analysis of a topic" as well as the methodology used and the accuracy of the data relied on in the document "because these types of challenges involve factual questions." (*Bakersfield Citizens for Local Control v. City of Bakersfield, supra,* 124 Cal.App.4th 1184, 1198, and cases relied on therein.) However, we interpret this language to refer to situations where the question of the scope of the analysis really is factual—that is, where it involves whether further analysis is feasible, as discussed above. This interpretation is supported by the fact that the *Bakersfield* court expressly rejected an argument that a claimed "omission of information from the EIR should be treated as inquiries whether there is substantial evidence supporting the decision approving the project. " *Bakersfield, supra,* 124 Cal.App.4th at p. 1208. And the *Bakersfield* court ultimately decided that the lead agency must analyze the connection between the identified air pollution impacts and resulting health impacts, even though the EIR already included some discussion of air-pollution-related respiratory illnesses. *Bakersfield, supra,* 124 Cal.App.4th at p. 1220. Therefore, the court must not have interpreted this question as one of the "scope of the analysis" to be judged by the substantial evidence standard.

B. Friant Ranch's Rationale for Rejecting the Independent Judgment Standard of Review is Unsupported by Case Law.

In its brief, Friant Ranch makes a distinction between cases where a required CEQA topic is not discussed at all (to be reviewed by independent judgment as a failure to proceed in the manner required by law) and cases where a topic is discussed, but the commenter claims the information provided is insufficient (to be judged by the substantial evidence test). (Opening Brief, pp. 13-17.) The Court of Appeal recognized these two types of cases, but concluded that both raised questions of law. (*Sierra Club v. County of Fresno* (2014) 226 Cal.App.4th 704 (superseded by grant of review) 172 Cal.Rptr.3d 271, 290.) We believe the distinction drawn by Friant Ranch is unduly narrow, and inconsistent with cases which have concluded that CEQA documents are insufficient. In many instances, CEQA's requirements are stated broadly, and the courts must interpret the law to determine what level of analysis satisfies CEQA's mandate for providing meaningful information, even though the EIR discusses the issue to some extent.

For example, the CEQA Guidelines require discussion of the existing environmental baseline. In *County of Amador v. El Dorado County Water Agency* (1999) 76 Cal.App.4th 931, 954-955, the lead agency had discussed the environmental baseline by describing historic month-end water levels in the affected lakes. However, the court held that this was not an adequate baseline discussion because it failed to discuss the timing and amounts of past actual water releases, to allow comparison with the proposed project. The court evidently applied the independent judgment test to its decision, even though the agency discussed the issue to some extent.

Likewise, in *Vineyard Area Citizens* (2007) 40 Cal.4th 412, this Court addressed the question of whether an EIR's analysis of water supply impacts complied with CEQA. The parties agreed that the EIR was required to analyze the effects of providing water to the development project, "and that in order to do so the EIR had, in some manner, to identify the planned sources of that water." (*Vineyard Area Citizens, supra,* at p. 428.) However, the parties disagreed as to the level of detail required for this analysis and "what level of uncertainty regarding the availability of water supplies can be tolerated in an EIR . . . ." (*Id.*) In other words, the EIR had analyzed water supply impacts for the project, but the petitioner claimed that the analysis was insufficient.

This Court noted that neither CEQA's statutory language or the CEQA Guidelines specifically addressed the question of how precisely an EIR must discuss water supply impacts. (*Id.*) However, it explained that CEQA "states that '[w]hile foreseeing the unforeseeable is not possible, an agency must use its best efforts to find out and disclose all that it reasonably can.'" (*Id.*, [Guidelines § 15144].) The Court used this general principle, along with prior precedent, to elucidate four "principles for analytical adequacy" that are necessary in order to satisfy "CEQA's informational purposes." (*Vineyard Area Citizens, supra,* at p. 430.) The Court did not defer to the agency's determination that the EIR's analysis of water supply impacts was sufficient. Rather, this Court used its independent judgment to determine for itself the level of analysis required to satisfy CEQA's fundamental purposes. (*Vineyard Area Citizens, supra,* at p. 441: an EIR does not serve its purposes where it neglects to explain likely sources of water and "... leaves long term water supply considerations to later stages of the project.")

Similarly, the CEQA Guidelines require an analysis of noise impacts of the project. (Appendix G, "Environmental Checklist Form."[17]) In *Gray v. County of Madera* (2008) 167 Cal.App.4th 1099, 1123, the court held that the lead agency's noise impact analysis was inadequate even though it had addressed the issue and concluded that the increase would not be noticeable. If the court had been using the substantial evidence standard, it likely would have upheld this discussion.

Therefore, we do not agree that the issue can be resolved on the basis suggested by Friant Ranch, which would apply the substantial evidence standard to *every* challenge to an analysis that addresses a required CEQA topic. This interpretation would subvert the courts' proper role in interpreting CEQA and determining what the law requires.

Nor do we agree that the Court of Appeal in this case violated CEQA's prohibition on courts interpreting its provisions "in a manner which imposes procedural or substantive requirements beyond those explicitly stated in this division or in the state guidelines." (Pub. Resources Code § 21083.1.) CEQA requires an EIR to describe *all* significant impacts of the project on the environment. (Pub. Resources Code § 21100(b)(2); *Vineyard Area Citizens, supra,* at p. 428.) Human beings are part of the environment, so CEQA requires EIRs to discuss a project's significant impacts on human health. However, except in certain particular circumstances,[18] neither the CEQA statute nor Guidelines specify the precise level of analysis that agencies must undertake to satisfy the law's requirements. (see, e.g., CEQA Guidelines § 15126.2(a) [EIRs must describe "health and safety problems caused by {a project's} physical changes"].) Accordingly, courts must interpret CEQA as a whole to

[17] Association of Environmental Professionals, 2015 CEQA Statute and Guidelines (2015) p.287.

[18] E.g., Pub. Resources Code § 21151.8(C)(3)(B)(iii) (requiring specific type of health risk analysis for siting schools).

determine whether a particular EIR is sufficient as an informational document. A court determining whether an EIR's discussion of human health impacts is legally sufficient does not constitute imposing a new substantive requirement.[19] Under Friant Ranch's theory, the above-referenced cases holding a CEQA analysis inadequate would have violated the law. This is not a reasonable interpretation.

IV. COURTS MUST SCRUPULOUSLY ENFORCE THE REQUIREMENTS THAT LEAD AGENCIES CONSULT WITH AND OBTAIN COMMENTS FROM AIR DISTRICTS

Courts must "scrupulously enforce" CEQA's legislatively mandated requirements. (*Vineyard Area Citizens, supra*, 40 Cal.4th 412, 435.) Case law has firmly established that lead agencies must consult with the relevant air pollution control district before conducting an initial study, and must provide the districts with notice of the intention to adopt a negative declaration (or EIR). (*Schenck v. County of Sonoma* (2011) 198 Cal.App.4th 949, 958.) As *Schenck* held, neither publishing the notice nor providing it to the State Clearinghouse was a sufficient substitute for sending notice directly to the air district. (*Id.*) Rather, courts "must be satisfied that [administrative] agencies have fully complied with the procedural requirements of CEQA, since only in this way can the important public purposes of CEQA be protected from subversion." *Schenck,* 198 Cal.App.4th at p. 959 (citations omitted).[20]

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[19] We submit that Public Resources Code Section 21083.1 was intended to prevent courts from, for example, holding that an agency must analyze economic impacts of a project where there are no resulting environmental impacts (see CEQA Guidelines § 15131) , or imposing new procedural requirements, such as imposing additional public notice requirements not set forth in CEQA or the Guidelines.

[20] Lead agencies must consult air districts, as public agencies with jurisdiction by law over resources affected by the project, *before* releasing an EIR. (Pub. Resources Code §§ 21104(a); 21153.) Moreover, air

Lead agencies should be aware, therefore, that failure to properly seek and consider input from the relevant air district constitutes legal error which may jeopardize their project approvals. For example, the court in *Fall River Wild Trout Foundation v. County of Shasta,* (1999) 70 Cal.App.4th 482, 492 held that the failure to give notice to a trustee agency (Department of Fish and Game) was prejudicial error requiring reversal. The court explained that the lack of notice prevented the Department from providing any response to the CEQA document. (*Id.* at p. 492.) It therefore prevented relevant information from being presented to the lead agency, which was prejudicial error because it precluded informed decision-making. (*Id.*)[21]

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districts should be considered "state agencies" for purposes of the requirement to consult with "trustee agencies" as set forth in Public Resources Code § 20180.3(a). This Court has long ago held that the districts are not mere "local agencies" whose regulations are superseded by those of a state agency regarding matters of statewide concern, but rather have concurrent jurisdiction over such issues. (*Orange County Air Pollution Control District v. Public Util. Com.* (1971) 4 Cal.3d 945, 951, 954.) Since air pollution is a matter of statewide concern, *Id* at 952, air districts should be entitled to trustee agency status in order to ensure that this vital concern is adequately protected during the CEQA process.

[21] In *Schenck,* the court concluded that failure to give notice to the air district was not prejudicial, but this was partly because the trial court had already corrected the error before the case arrived at the Court of Appeal. The trial court issued a writ of mandate requiring the lead agency to give notice to the air district. The air district responded by concurring with the lead agency that air impacts were not significant. (*Schenck,* 198 Cal.App.4th 949, 960.) We disagree with the *Schenck* court that the failure to give notice to the air district would not have been prejudicial (even in the absence of the trial court writ) merely because the lead agency purported to follow the air district's published CEQA guidelines for significance. (*Id.*, 198 Cal.App.4th at p. 960.) In the first place, absent notice to the air district, it is uncertain whether the lead agency properly followed those guidelines. Moreover, it is not realistic to expect that an air district's published guidelines would necessarily fully address all possible air-quality related issues that can arise with a CEQA project, or that those

Similarly, lead agencies must obtain additional information requested by expert agencies, including those with jurisdiction by law, if that information is necessary to determine a project's impacts. (*Sierra Club v. State Bd. Of Forestry* (1994) 7 Cal.4th 1215, 1236-37.) Approving a project without obtaining that information constitutes a failure to proceed in the manner prescribed by CEQA. (*Id.* at p. 1236.)

Moreover, a lead agency can save significant time and money by consulting with the air district early in the process. For example, the lead agency can learn what the air district recommends as an appropriate analysis on the facts of its case, including what kinds of health impacts analysis may be available, and what models are appropriate for use. This saves the lead agency from the need to do its analysis all over again and possibly needing to recirculate the document after errors are corrected, if new significant impacts are identified. (CEQA Guidelines § 15088.5(a).) At the same time, the air district's expert input can help the lead agency properly determine whether another commenter's request for additional analysis or studies is reasonable or feasible. Finally, the air district can provide input on what mitigation measures would be feasible and effective.

Therefore, we suggest that this Court provide guidance to lead agencies reminding them of the importance of consulting with the relevant air districts regarding these issues. Otherwise, their feasibility decisions may be vulnerable to air district evidence that establishes that there is no substantial evidence to support the lead agency decision not to provide specific analysis. (*See Berkeley Keep Jets Over the Bay, supra,* 91 Cal.App.4th 1344, 1369-1371.)

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guidelines would necessarily be continually modified to reflect new developments. Therefore we believe that, had the trial court not already ordered the lead agency to obtain the air district's views, the failure to give notice would have been prejudicial, as in *Fall River, supra,* 70 Cal.App.4th 482, 492.

CONCLUSION

The SCAQMD respectfully requests this Court *not* to establish a hard-and-fast rule concerning whether CEQA requires a lead agency to correlate identified air quality impacts of a project with resulting health outcomes. Moreover, the question of whether an EIR is "sufficient as an informational document" is a mixed question of fact and law containing two levels of inquiry. Whether a particular proposed analysis is feasible is predominantly a question of fact to be judged by the substantial evidence standard of review. Where the requested analysis is feasible, but the lead agency relies on legal or policy reasons not to provide it, the question of whether the EIR is nevertheless sufficient as an informational document is predominantly a question of law to be judged by the independent judgment standard of review.

Respectfully submitted,

DATED: April 3, 2015

SOUTH COAST AIR QUALITY
MANAGEMENT DISTRICT
KURT R. WIESE, GENERAL COUNSEL
BARBARA BAIRD, CHIEF DEPUTY COUNSEL

By: Barbara Baird
Barbara Baird
Attorneys for Amicus Curiae
SOUTH COAST AIR QUALITY MANAGEMENT DISTICT

CERTIFICATE OF WORD COUNT

Pursuant to Rule 8.520(c)(1) of the California Rules of Court, I hereby certify that this brief contains 8,476 words, including footnotes, but excluding the Application, Table of Contents, Table of Authorities, Certificate of Service, this Certificate of Word Count, and signature blocks. I have relied on the word count of the Microsoft Word Vista program used to prepare this Certificate.

DATED: April 3, 2015 Respectfully submitted,

Barbara Baird

PROOF OF SERVICE

I am employed in the County of Los Angeles, California. I am over the age of 18 years and not a party to the within action. My business address is 21865 Copley Drive, Diamond Bar, California 91765.

On April 3, 2015 I served true copies of the following document(s) described as **APPLICATION OF THE SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT FOR LEAVE TO FILE BRIEF OF *AMICUS CURIAE* IN SUPPORT OF NEITHER PARTY AND *[PROPOSED]* BRIEF OF *AMICUS CURIAE*** by placing a true copy of the foregoing document(s) in a sealed envelope addressed as set forth on the attached service list as follows:

BY MAIL: I enclosed the document(s) in a sealed envelope or package addressed to the persons at the addresses listed in the Service List and placed the envelope for collection and mailing following our ordinary business practices. I am readily familiar with this District's practice for collection and processing of correspondence for mailing. Under that practice, the correspondence would be deposited with the United States Postal Service, with postage thereon fully prepaid at Diamond Bar, California, in the ordinary course of business. I am aware that on motion of the party served, service is presumed invalid if postal cancellation date or postage meter date is more than one day after date of deposit for mailing in affidavit.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed on April 3, 2015 at Diamond Bar, California.

Patricia Anderson

SERVICE LIST

James G. Moose, Tiffany K. Wright, Laura M. Harris
REMY MOOSE MANLEY, LLP
555 Capitol Mall, Suite 800
Sacramento, CA 95814

Attorneys for Real Party in Interest and Respondent *Friant Ranch, L.P.*

Bryan N. Wagner
WAGNER & WAGNER
7110 N. Fresno St, Suite 340
Fresno, CA 93720

Attorney for Real Party in Interest and Respondent *Friant Ranch, L.P.*

Sara Hedgpeth-Harris
LAW OFFICE OF SARA HEDGPETH-HARRIS
5445 E. Lane Avenue
Fresno, CA 93727

Attorney for Plaintiffs and Appellants *Sierra Club, et al*

Daniel C. Cederborg
Bruce B. Johnson, Jr.
Zachary Stephen Redmond
OFFICE OF THE FRESNO COUNTY COUNSEL
2220 Tulare Street, Suite 500
Fresno, CA 93721

Attorneys for Respondents *County of Fresno*

Clerk of the Court
California Court of Appeal
Fifth Appellate District
2424 Ventura Street
Fresno, CA 93721
(via U.S. Mail & Electronic Transmission)

Clerk of the Court
Superior Court of California
County of Fresno
1130 O Street
Fresno, CA 93721

AIR QUALITY EMISSION REDUCTION AGREEMENT

This Air Quality Emission Reduction Agreement ("Agreement") is entered into as of _____, 2007 by and between Developer Name ("Developer") and the SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT, an air pollution control district formed pursuant to California Health and Safety Code section 40150, et seq. ("District").

RECITALS

WHEREAS, Developer is presently seeking governmental approval of land use entitlements ("Entitlements") which will permit the development of a Project located in the City/County, California, as more particularly described on Exhibit A attached hereto (the "Project"); and

WHEREAS, the Project incorporates the design features specified on Exhibit B attached hereto ("Emission Reduction Design Features"), in order to significantly reduce the air quality impacts associated with the Project; and

WHEREAS, despite incorporation of the Emission Reduction Design Features, without additional emission reductions, the Project would cause impacts on air quality within the geographical boundaries of the San Joaquin Valley Unified Air Pollution Control District, as depicted on Exhibit C attached hereto (the "District Boundaries"); and

WHEREAS, Developer anticipates that mitigation of impacts on air quality resulting from the Project will be either required as a condition to the approval of Developer's Entitlements, or voluntarily imposed by Developer as a means of reducing such impacts; and

WHEREAS, Developer desires to fully comply with all requirements of the California Environmental Quality Act codified at California Public Resources Code section 21000, et seq. ("CEQA"), including all requirements relating to the mitigation of air quality impacts arising from or in connection with the Project; and

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WHEREAS, District is an air pollution control district formed by the counties of Fresno, Kern, Kings, Madera, Merced, San Joaquin, Stanislaus and Tulare, pursuant to California Health and Safety Code section 40150, et seq.; and

WHEREAS, District is responsible for developing and implementing air quality control measures within the District Boundaries, including air quality control measures for stationary sources, transportation sources, and indirect sources; and

WHEREAS, District has determined that with appropriate funding, District can bring about a reduction of emissions from certain projects in types and in sufficient quantities to fully mitigate the net air quality criteria pollutant impacts of the Project as quantified in the Verified Air Quality Assessment (as defined in Section 2.2 below) ("Project's Air Impact"); and

WHEREAS, Developer and District desire to enter into this Agreement in order to develop and implement air quality control measures which will fully mitigate the Project's Air Impact to the extent that the development of such Project will result in no net increase in criteria pollutant emissions over the criteria pollutant emissions which would otherwise exist without the development thereof.

AGREEMENT

NOW THEREFORE, in exchange of the mutual covenants herein contained, Developer and District hereby agree as follows:

1. **Emission Reduction by Developer and District.**

1.1. **Emission Reduction Proposals.** Developer shall identify and propose to District opportunities to reduce emissions to fully mitigate Project's Air Impact, including but not limited to opportunities for removal or retrofitting of stationary, transportation, indirect, and/or mobile pollution source equipment, and/or other opportunities therefore (each, an "**Emission Reduction Proposal**"). Each Emission Reduction Proposal shall be submitted in writing to District, using District approved forms, and shall contain a representation by Developer that the owner/operator of the identified Pollution Source Equipment has expressed interest in entering into a written funding agreement with

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District in District's then standard form ("**Funding Agreement**") requiring removal or replacement of the identified equipment with new equipment under District's "Heavy Duty Engine Emission Reduction Incentive Program", or another emission reduction program adopted by District ("**District Emission Reduction Program**"). Developer shall submit Emission Reduction Proposals to District in sufficient amounts to fully mitigate emissions from each distinct phase of the project. For each phase of the project, Developer shall submit Emission Reduction Proposals to District no later than application for grading permits for, and before generating emissions from, that phase. Any Emission Reduction Shortfall for a given phase shall be addressed according to Section 1.7.2 of this Agreement.

1.2. **District's Verification of Emission Reduction.** As quickly as practicable upon Developer's submission to District of an Emission Reduction Proposal, District shall determine the types and quantities of permanent reduction in emissions which would be realized by the proposed removal or retrofit and shall advise Developer of such determination in writing ("**Emission Reduction Verification**") thereby verifying that in District's considered opinion the removal or retrofit proposed in the Emission Reduction Proposal would result in permanent emission reduction in the locality of the Project in the types and quantities so determined by District.

1.3. **Emission Reduction Proposal Advance.** Developer shall advance to District, on the date of submittal of each Developer's Emission Reduction Proposal, a monetary sum equal to the total estimated cost (as specified in each Developer's Emission Reduction Proposal), until sufficient advance is received by District to fully mitigate the Project's Air Impact ("**Emission Reduction Proposal Advance**").

1.4. **Funding Agreements.** As soon as practicable after District's receipt of Developer's Emission Reduction Proposal Advance, District shall use diligent efforts to enter into Funding Agreements with the owners and/or operators of the pollution source equipment identified in Developer's Emission Reduction Proposal, thereby providing for the removal and/or retrofit of all of such Pollution Source Equipment, and

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providing for District's payment (from the Emission Reduction Proposal Advance) t such owner or operator, of an amount equal to the estimated cost of such opportunity, as specified in Developer's Emission Reduction Proposals. District shall use diligent efforts to enter into Funding Agreements with all of the owners or operators identified in Developer's Emission Reduction Proposals within one hundred eighty (180) days following District's receipt of a complete Emission Reduction Proposal and the Emission Reduction Proposal Advance from Developer.

1.5. **Use of Emission Reduction Proposal Advance.** District shall use the Emission Reduction Proposal Advance to meet its monetary obligations under the Funding Agreements that District shall enter into with the owners of the Pollution Source Equipment identified in Developer's Emission Reduction Proposals.

1.6. **Use of Unused Portions of Emission Reduction Proposal Advance.** In the event Developer is unable to submit to District Emission Reduction Proposals providing for emission reduction in the types and quantities necessary to fully mitigate the Project's Air Impact, or in the event District is unable to enter into Funding Agreements with any of the owners or operators identified in Developer's Emission Reduction Proposals, District shall notify Developer in writing of the additional emission reductions needed to fully mitigate the Project's Air Impact, and Developer shall have a reasonable time, not to exceed one hundred eighty (180) days within which to submit to District additional or supplemental Emission Reduction Proposals in order to provide the necessary additional emission reduction.

1.7. **Unused Advance / Emission Reduction Shortfall / Additional Payment.**

1.7.1. **Unused Advance.** If, despite District's diligent efforts to enter into Funding Agreements with all of the owners or operators identified in Developer's Emission Reduction Proposals (and, if applicable, supplemental Emission Reduction Proposals submitted by Developer), District is unable to enter into Funding Agreements sufficient to fully mitigate the Project's Air Impact, then District shall use any unused portion of Developer's Emission Reduction Proposal Advance to fund emission

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reduction opportunities to mitigate the balance of the Project's Air Impact at District's actual cost of doing so, provided that such actual costs shall not exceed the costs set forth in the following Emission Reduction Cost Schedule:

Emission Reduction Cost Schedule		
Year Paid	NOx or ROG ($/ton)	PM10 ($/ton)
2007	$49,700	$55,940
2008	$65,450	$90,110
Beyond	Prevailing Costs	Prevailing Costs

District is of the considered opinion that the emission reductions listed in the above schedule can be achieved at the corresponding times and costs shown in said schedule. If, at the time of invoicing, the District has not identified Prevailing Costs for post-2008 payments, 2008 costs shall apply.

1.7.2. **Emission Reduction Shortfall/Additional Payment.** In the event the emission reduction brought about by the Funding Agreements entered into between District and the owners or operators identified in Developer's Emission Reduction Proposals (and, if applicable supplemental Emission Reduction Proposals), and that brought about pursuant to Section 1.7.1 above, are not sufficient to fully mitigate the Project's Air Impact ("**Emission Reduction Shortfall**"), then Developer shall be credited for the emission reduction brought about as a result of Funding Agreements entered into between District and the owners or operators identified in Developer's Emission Reduction Proposals and for the emission reduction brought about pursuant to Section 1.7.1 above, and Developer thereafter shall deposit with District, within 30 days of receiving notice of the Emission Reduction Shortfall from District, an additional amount equal to the product of (i) District's cost per ton of emission reduction as shown in the Emission Reduction Cost Schedule set forth in Section 1.7.1 above, multiplied by (ii) the total number of tons of emission reduction necessary to fully mitigate the Project's Air Impact less the total number of tons of emission reduction so credited to Developer. However, in no case shall the amount paid to District and the

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amount of emission reductions achieved per this agreement be less than the amount that would be paid to District or the amount of emission reductions that would be required for this Project according to District Rule 9510 (Indirect Source Review). To allow verification of equivalency of emission reductions and off-site mitigation fee amounts, according to District Rule 9510, Developer shall submit to District an ISR Air Impact Assessment Application, using District forms, no later than concurrent with the Developer's submission of the air quality assessment, as set forth in Section 2.2.

1.8. **Surplus Mitigation.** In addition to the amounts payable under paragraph 1.3, Developer shall deliver to District an additional sum equal to five percent (5%) of the Emission Reduction Proposal Advance. Said additional sum shall be paid under the same schedule as set forth in paragraph 1.3. District shall utilize such additional sum to fund further localized emission reduction opportunities in quantities consistent with the schedule set forth in paragraph 1.7.1.

1.9 **Time of Use.** Any emission reductions brought about by this Agreement prior to the date Developer receives final approval of the Project from all applicable Governmental Authorities shall be credited to the total amount of emission reductions achieved per this agreement.

1.10. **District's Obligation.** The monies paid by Developer under this Agreement shall be used by District to obtain localized emission reductions in the types and quantities necessary to fully mitigate the Project's Air Impact as quantified in the Verified Air Quality Assessment. If necessary, District shall assist Developer in securing emission reductions, consistent with the provisions established in Section 1.7.2.

1.11. **Developer's Obligation.** District acknowledges that, if the Project is not finally approved so that such development is allowed to proceed, Developer has no obligations under this Agreement relative to the respective Project. Developer acknowledges that it must satisfy the terms of this Agreement in order to develop the Project.

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2. **CEQA Compliance/Full Mitigation.** For and in exchange of Developer's payment of funds pursuant to Section 1 above, District shall ensure, by way of entering into, funding and enforcing the Funding Agreements in accordance with the provisions of Section 1.4 above, that the Project's Air Impact is fully mitigated, such that the Project, combined with the emission reductions brought about in accordance with Section 1 above, shall result in no net increase in air quality impacts over those air quality impacts which would otherwise exist without the development of such Project. For the purpose of this agreement, full mitigation means the sum of all NOx, ROG, and PM10 emission reductions achieved by the Emission Reductions Proposals equals, or is greater than, the sum of all NOx, ROG, and PM10 emissions increases calculated as the average annual construction and the peak annual area source and mobile source emissions of NOx, ROG, and PM10 less the average annual emissions that have occurred at the project site during the three years prior to release of the Notice of Preparation. In addition to entering into, funding and enforcing the Funding Agreements in accordance with the provisions of Section 1.4 above, District shall do all of the following:

2.1. **District's Verification of Air Assessment Protocol.** Within ten (10) business days following the date of this Agreement, Developer shall submit to District an air assessment protocol prepared by Developer's air quality consultant reflecting the methodology, including air quality impact modeling, to be utilized in the preparation of the air quality assessment for the Project. Within twenty-one (21) business days following District's receipt of Developer's air assessment protocol, District shall review and comment upon such air assessment protocol, and, after Developer's incorporation of any revisions suggested by District, District shall verify in writing to Developer the correctness of the air assessment protocol which will be utilized in the preparation of the air quality assessment for the Project.

2.2 **District's Verification of Air Quality Assessment.** Following District's Verification of Air Assessment Protocol, Developer shall submit to District an air quality

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assessment prepared by Developer's air quality consultant assessing the air quality impacts of the Project. District shall use its best efforts to review and comment upon Developer's air quality assessment within thirty (30) days following District's receipt of Developer's complete air quality assessment, and, after Developer's incorporation of any and all revisions suggested by District, District shall verify in writing to Developer the correctness of the air quality assessment to be utilized in connection with the CEQA documents for the Project, including (i) the methodology utilized in the preparation of the CEQA document, (ii) the types and quantities of any net air quality impacts associated with the Project, (iii) the appropriateness of the mitigation measures proposed in the CEQA document, and (iv) any other matters which may pertain to such CEQA document and/or any air quality impacts or air quality mitigation measures referenced therein (the "**Verified Air Quality Assessment**").

2.3. **District's Verification of Administrative Draft Environmental Impact Report**. Upon request by Developer, and submission by Developer to District of any administrative Draft Environmental Impact Report, or other applicable CEQA documents for the Project, District shall review, comment upon and, after incorporation of any and all revisions made by District, verify in writing to Developer the correctness of all portions thereof which pertain to air quality impacts, including, (i) the methodology utilized in the preparation of the CEQA document, (ii) the types and quantities of any net air quality impacts associated with the Project, (iii) the appropriateness of the mitigation measures proposed in the CEQA document, and (iv) any other matters which may pertain to such CEQA document and/or any air quality impacts or air quality mitigation measures referenced therein.

2.4 **District's Acknowledgment Regarding Full Mitigation.** At such time as District is provided an opportunity as a commenting agency to comment upon the Draft Environmental Impact Report and Final Environmental Impact Report for the Project, District shall comment in writing as to the correctness of all portions thereof which pertain to air quality impacts, including (i) the methodology utilized in the

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preparation of the CEQA document, (ii) the types and quantities of any net air quality impacts associated with the Project, (iii) the appropriateness of the mitigation measures proposed in the CEQA document, and (iv) any other matters which may pertain to such CEQA document and/or any air quality impacts or air quality mitigation measures referenced therein. District shall at all times fully perform its duties and obligations as a commenting agency, and the provisions of this Section 2.4 shall not be interpreted to the contrary. At such time as District has entered into Funding Agreements pursuant to Section 1.4 above and the owners/operators of equipment to be removed and/or replaced under such agreements have removed and replaced such equipment in accordance with the provisions thereof, District shall verify in writing to Developer and to the lead agency that full mitigation of the Project's Air Impact has been achieved, upon successful fulfillment of all Funding Agreements. District shall ensure that the owners/operators of equipment to be removed and/or replaced pursuant to such Funding Agreements perform all obligations to be performed on the part of such parties under said Funding Agreements. District acknowledges that the Verified Air Quality Assessment and its quantification of the Project's Air Impact will be based on the pending applications for development of the Project and that actual approvals may be for a lesser amount of development. District agrees that Developer's obligations under this Agreement shall be based on the amount of development actually approved, and the final quantification of the Project's Air Impact will be revised accordingly.

2.5. **District's Oversight of Air Quality Mitigation Monitoring Plan.** Upon request of the lead agency having jurisdiction over the Project, District shall oversee that portion of the mitigation monitoring plan adopted by the lead agency for the Project which relates to the mitigation brought about by Section 1 of this Agreement. Alternatively, upon request of that lead agency, District shall cooperate with the lead agency in the oversight of that portion of the mitigation monitoring plan adopted by the lead agency for the Project which relates to the mitigation brought about by Section 1

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of this Agreement.

2.6. **District's Documentation, Record Keeping and Monitoring.** District shall document, keep adequate records on and monitor the emission reduction brought about as a result of this Agreement, and shall from time to time, upon written request by Developer or by the lead agency for the Project, provide to Developer or to the lead agency written reports verifying that emission reduction has been and/or is being brought about so as to fully mitigate the Project's Air Impact.

3. **Subsequent Litigation, Legislation and/or Administrative Action / Credit to Developer.**

3.1. **Subsequent Litigation.** In the event that despite this Agreement, Developer is required as a result of a final judgment or District Approved Settlement (as defined below) in any subsequent third party litigation, to pay monies in addition to the monies to be paid by Developer pursuant to Section 1 above, then, provided that the project total emissions are the same as quantified in the Verified Air Quality Assessment, District shall acknowledge and credit Developer with mitigation of the air quality impacts of the Project in such types and quantities that Developer can establish, to the reasonable satisfaction of District, will result from Developer's payment of such additional monies, and shall reduce any amounts thereafter payable by Developer under this Agreement by an amount equal to the additional monies so paid by Developer. This requirement shall not apply if the additional monies are required to mitigate emissions that exceed those set forth in the Verified Air Quality Assessment. For purposes of this Section 3.1.1, a **"District Approved Settlement"** shall mean a settlement of a lawsuit filed pursuant to CEQA, the National Environmental Protection Act or other applicable environmental law which (i) provides for Developer's payment of monies in exchange for a dismissal of such lawsuit, (ii) provides for the use of such monies by the petitioner in such lawsuit in such a manner as to mitigate adverse air quality impacts of the Project, and (iii) is approved in writing by District.

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3.2. **District Rule 9510.** The performance of Developer's and District's obligations under this Agreement will fully mitigate the Project's Air Impact. Inasmuch as the mitigation provided under this Agreement exceeds the mitigation which would otherwise have been provided under Sections 6.0 and 7.0 of District's Rule 9510, and the Project's mitigated baseline (being zero emissions) is less than the threshold stated in Section 4.3 of said Rule 9510, the Project is exempt from Sections 6.0 and 7.0 of District's Rule 9510. Accordingly, no off-site Emission Reduction Fee will be required in connection with the approval or development of the Project. For each individual project developed at the project site requiring a discretionary approval by the lead agency, Developer shall provide District with a map or diagram indicating its location within the area covered by this Agreement.

4. **Term of Agreement.** This Agreement shall be effective upon the date first written above, and shall terminate upon District's meeting its obligation to implement projects that provide necessary emissions reductions to fully mitigate the Project's Air Impact (the "**Term**"). Developer may, at any time by written notice to District, terminate this Agreement, whereupon, (i) District shall acknowledge in writing to the lead agency that Developer has mitigated air quality impacts of the Project to the extent and in the types and quantities brought about by Funding Agreements theretofore funded by Developer's Emission Reduction Proposal Advance (and if applicable pursuant to Section 1.7.1 above), (ii) District shall refund to Developer any unused portion of Developer's Emission Reduction Proposal Advance less any unpaid administrative fees incurred; and (iii) neither Developer nor District shall have any further rights or obligations under this Agreement. Developer acknowledges that in the absence of this Agreement, the project is subject to all applicable provisions of District Rule 9510 (Indirect Source Review).

5. **Payment of Administrative Fees to District.** Developer agrees to pay to District, in order to reimburse District for its general overhead required for the administration of this Agreement, an administrative fee ("***ERIP Fee***") in an amount

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equal to four percent (4%) of the Emission Reduction Proposal Advance. Such ERIP Fee shall be due and payable upon Developer's delivery of the Emission Reduction Proposal Advance pursuant to Section 1.3 above. In addition to the ERIP Fee, Developer agrees to pay to District, within thirty (30) days following Developer's receipt of District's invoice, administrative fees to reimburse District for staff time spent and materials used by District in the administration of this Agreement, other than that time associated with the ERIP program covered by the ERIP Fee above, including review, verification and preparation of documents, and staff time relating to the performance of District's obligations hereunder, based on a time and materials basis at District's average weighted labor rates.

6. **Representations, Covenants and Warranties.**

6.1. **Developer's Representations, Covenants and Warranties.** Developer represents, covenants and warrants to District, as of the date of this Agreement, and as of the date of Developer's submission to District of any documents contemplated hereunder, as follows:

6.1.1. The undersigned representatives of Developer are duly authorized to execute, deliver and perform this Agreement, and upon Developer's execution and delivery of this Agreement, this Agreement will have been duly authorized by Developer.

6.1.2. Upon execution and delivery of this Agreement by Developer, Developer's obligations under this Agreement shall be legal, valid and binding obligations of Developer, duly enforceable at law and in equity in accordance with the terms and conditions of this Agreement.

6.1.3. There is no lawsuit, legal action, arbitration, legal or administrative proceeding, legislative or quasi-legislative action or claim existing, pending, threatened or anticipated which would render all or any portion of this Agreement invalid, void or unenforceable in accordance with the terms and conditions thereof.

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6.1.4. Other than the execution and delivery of this Agreement by the undersigned representatives of Developer, there are no approvals, consents, confirmations, proceedings, or other actions required by Developer or any third party, entity or agency in order to enter into and carry out the terms, conditions and intent of the parties with respect to this Agreement.

6.2. **District's Representations, Covenants and Warranties.** District represents, covenants and warrants to Developer, as of the date of this Agreement, and as of the date of District's delivery to Developer of any documents contemplated hereunder, as follows:

6.2.1. The undersigned representatives of District are duly authorized to execute, deliver and perform this Agreement, and upon District's execution and delivery of this Agreement, this Agreement will have been duly authorized by District.

6.2.2. Upon execution and delivery of this Agreement by District, District's obligations under this Agreement shall be legal, valid and binding obligations of District, duly enforceable at law and in equity in accordance with the terms and conditions of this Agreement.

6.2.3. There is no lawsuit, legal action, arbitration, legal or administrative proceeding, legislative, quasi-legislative or administrative action or claim existing, pending, threatened or anticipated which would render all or any portion of this Agreement invalid, void or unenforceable in accordance with the terms and conditions thereof.

6.2.4. Other than the execution and delivery of this Agreement by the undersigned representatives of District, there are no approvals, consents, confirmations, proceedings, or other actions required by District or any third party, entity or agency in order to enter into and carry out the terms, conditions and intent of the parties with respect to this Agreement.

6.2.5. No lawsuit, legal action, arbitration, legal or administrative proceeding, legislative or quasi-legislative action or claim existing, pending, threatened or

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anticipated will render invalid, void or unenforceable any right or benefit Developer is to receive under the terms and conditions of this Agreement.

6.2.6. The monies paid by Developer under this Agreement shall be sufficient to ensure that the emission reduction contemplated by this Agreement shall occur, and District shall utilize such monies in such a manner as to ensure that such emission reduction shall occur.

6.2.7. Upon the approval of this Agreement by the governing board of District, the Air Pollution Control Officer of District, or equivalent representative, or a delegee of such officer, shall have the authority to approve, deliver, verify, enter into, acknowledge and/or accept any communication, notice, notification, verification, agreement and/or other document to be issued or entered into by District under the terms and conditions of this Agreement, without further approval of the governing board of District.

7. **Indemnification**. Developer agrees to indemnify, defend and hold harmless District for, from and in connection with any third party claims, losses and/or liabilities arising from or in connection with District's performance of this Agreement, excluding only such claims, losses and/or liabilities which result from or in connection with District's sole negligence, act or omission.

8. **Inurnment**. Developer's rights and obligations under this Agreement, or applicable portions thereof, shall run with the land encompassed by the Project, and shall inure to the benefit of and be binding upon the heirs, successors and assigns of Developer who take title to such lands or applicable portions thereof. Upon Developer's conveyance of all or any portion of the lands encompassed by the Project, the rights and obligations of Developer under this Agreement shall, to the extent applicable to the lands so conveyed, be transferred to the transferee thereof, and Developer shall thereupon be released by District from, all obligations and liabilities so assigned, except for such obligations and liabilities arising prior to such transfer.

9. **Assignment**. Developer shall have the right to assign all or any part of its rights and/or obligations under this Agreement. Upon any such assignment, Developer shall

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deliver to District a written assignment and assumption agreement specifying the fact and extent of the assignment, the name and address of the assignee, and the assignee's assumption of all obligations of Developer thereby assigned. Developer shall have the right to assign all or any part of its rights and/or obligations under this Agreement to a third party for use in connection with the mitigation of air quality impacts resulting from one or more projects other than the Project, so long as (i) the project is located within the District Boundaries, (ii) the air quality impacts of such project(s) will in fact be mitigated, as verified by District, by the emission reductions brought about by this Agreement, and (iii) the project(s) consist of residential, commercial, industrial and/or mixed use real estate projects which incorporate the Emission Reduction Design Features. Upon any such assignment by Developer, District shall enter into an amendment of this Agreement which acknowledges the assignment and conforms the various provisions of this Agreement as may be required to be conformed in order to provide to the assignee the rights and benefits of this Agreement as if such assignee and its project were the original party and project contemplated in this Agreement.

10. **Recitals Incorporated.** The recitals set forth hereinabove are hereby incorporated into this Agreement and acknowledged, agreed to and adopted by the parties to this Agreement.

11. **Further Assurances.** Developer and District agree to execute and deliver any documents and/or perform any acts, which are reasonably necessary in order to carry out the intent of the parties with respect to this Agreement.

12. **No Joint Venture or Partnership.** District and Developer agree that nothing contained in this Agreement or in any document executed in connection with this Agreement shall be construed as making District and Developer joint ventures or partners.

13. **Notices.** Any notices or communications relating to this Agreement shall be given in writing and shall be deemed sufficiently given and served for all purposes

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when delivered, if (a) in person, (b) by facsimile (with the original delivered by other means set forth in this Section 13), (c) by generally recognized overnight courier or (d) by United States Mail, certified or registered mail, return receipt requested, postage prepaid, to the respective addresses set forth below, or to such other addresses as the parties may designate from time to time by providing written notice of the change to the other party.

To Developer: Address & Contact Name	To District: San Joaquin Valley APCD 1990 E. Gettysburg Avenue Fresno, CA 93726 Fax: (559) 230-6061 Attn: Seyed Sadredin Executive Director/APCO
With a copy to: Address & Contact Name	with a copy to:San Joaquin Valley APCD 1990 E. Gettysburg Avenue Fresno, CA 93726 Fax: (559) 230-6061 Attn: Dave Warner Director of Permit Services with a copy to: San Joaquin Valley APCD 1990 E. Gettysburg Avenue Fresno, CA 93726 Fax: (559) 230-6061 Attn: Philip M. Jay District Counsel

14. **Entire Agreement.** The terms of this Agreement, together with all attached exhibits, are intended by the parties as the complete and final expression of their agreement with respect to such terms and exhibits and may not be contradicted by evidence of any prior or contemporaneous agreement. This Agreement specifically supersedes any prior written or oral agreements between the parties with respect to

the subject matter of this Agreement.

15. **Amendments and Waivers.** No addition to or modification of this Agreement shall be effective unless set forth in writing and signed by the party against whom the addition or modification is sought to be enforced. The party benefited by any condition or obligation may waive the same, but such waiver shall not be enforceable by another party unless made in writing and signed by the waiving party.

16. **Invalidity of Provisions.** If any provision of this Agreement as applied to either party or to any circumstance shall be adjudged by a court of competent jurisdiction to be void or unenforceable for any reason, the same shall in no way affect (to the maximum extent permissible by law) any other provision of this Agreement, the application of any such provision under circumstances different from those adjudicated by the court, or the validity or enforceability of this Agreement as a whole. The parties further agree to replace any such invalid, illegal or unenforceable portion with a valid and enforceable provision which will achieve, to the maximum extent legally possible, the economic, business or other purposes of the invalid, illegal or unenforceable portion.

17. **Construction.** Unless otherwise indicated, all Section references are to the sections of this Agreement and all references to days are to calendar days. Whenever, under the terms of this Agreement the time for performance of a covenant or condition falls upon a Saturday, Sunday or California state holiday, the time for performance shall be extended to the next business day. The headings used in this Agreement are provided for convenience only and this Agreement shall be interpreted without reference to any headings. Wherever required by the context, the singular shall include the plural and vice versa, and the masculine gender shall include the feminine or neuter genders, or vice versa. This Agreement may be executed in one or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. The language in all parts of this Agreement shall be construed as a whole in accordance with its fair meaning, and shall not be

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construed against any party solely by virtue of the fact that such party or its counsel was primarily responsible for its preparation.

18. **Governing Law.** This Agreement shall be governed by the laws of the State of California applicable to contracts made and to be performed in California.

19. **No Third-party Beneficiaries.** Nothing in this Agreement, express or implied, is intended to confer any rights or remedies under or by reason of this Agreement on any person other than the parties to it and their respective permitted successors and assigns, nor is anything in this Agreement intended to relieve or discharge any obligation of any third person to any party hereto or give any third person any right of subrogation or action over or against any party to this Agreement.

20. **Exhibits.** The exhibits attached to this Agreement shall be deemed to be a part of this Agreement and are fully incorporated herein by reference.

21. **Force Majeure.** The time within which any party shall be required to perform under this Agreement shall be extended on a day-per-day basis for each day during which such performance is prevented or delayed by reason of events reasonably outside of the control of the performing party, including, without limitation, acts of God, events of destruction, acts of war, civil insurrection, strikes, shortages, governmental delays, moratoria, civil litigation and the like, and/or delays caused by the non-performing party's act or omission.

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IN WITNESS WHEREOF, Developer and District have executed this Agreement and agree that it shall be effective as of the date first written above.

DEVELOPER: Developer Name,

a California limited liability company

By:_____

Name:_____

Title:_____

DISTRICT: **SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT**, an air pollution control district formed pursuant to California Health and Safety Code section 40150, et seq.

///

DISTRICT

San Joaquin Valley Unified Air Pollution Control District

///

By:_____

Councilmember J. Steven Worthley, Chair

Governing Board

///

Recommended for approval:

San Joaquin Valley Unified Air Pollution Control District

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_____

Seyed Sadredin

Executive Director/APCO

///

///

///

Approved as to legal form:

San Joaquin Valley Unified Air Pollution Control District

_____

Philip M. Jay

District Counsel

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Fresno, CA 93726
(559) 230-6000

Approved as to accounting form:

San Joaquin Valley Unified Air

Pollution Control District

///

_____

Roger W. McCoy

Director of Administrative Service

For accounting use only:

Program:_____

Account No.:_____

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EXHIBIT A

DESCRIPTION OF THE PROJECT

[INSERT MAP.]

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EXHIBIT B

EMISSION REDUCTION DESIGN FEATURES

The project shall incorporate the following Emission Reduction Design Features:

The project will incorporate the following on-site features:

1. Utilization of land use designs which create walkable communities and encourage pedestrian travel.
2. Utilization of interconnecting sidewalks, walking paths and/or bike paths in order to encourage travel by means other than motor vehicle.
3. Utilization of appropriate landscaping to create reasonable shade canopies for streets, parkways and parking areas.
4. Utilization of roadway designs, which enhance pedestrian safety by appropriate signaling, signage and separation from traffic.
5. Design requirements, which incorporate natural gas hookups and electrical outlets on patios.
6. Design requirements, which prohibit the installation and use of wood burning stoves and wood burning fireplaces.

Prior to issuance of grading permits for the Project, Developer shall prepare and submit to District dust control plans for the areas to be graded, in accordance with District Regulation VIII. The plan shall be prepared consistent with District Regulation VIII and must be reviewed and approved by the District prior to commencement of grading activities. Each contractor working on the Project site shall implement the dust control measures outlined in the approved dust control plan. The dust control measures selected shall be incorporated as a note on each grading plan.

District maintains New Source Review requirements that direct owners/operators of certain types of stationary equipment to obtain an Authority to Construct ("ATC") and Permits to Operate ("PTO") from the District. As part of this process, the need for emission control equipment is assessed and the District determines whether a Health Risk Assessment ("HRA") must be prepared.

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Owners/operators of all stationary sources for which such approvals are required should show proof of compliance with District Rules and Regulations prior to issuance of certificates of occupancy.

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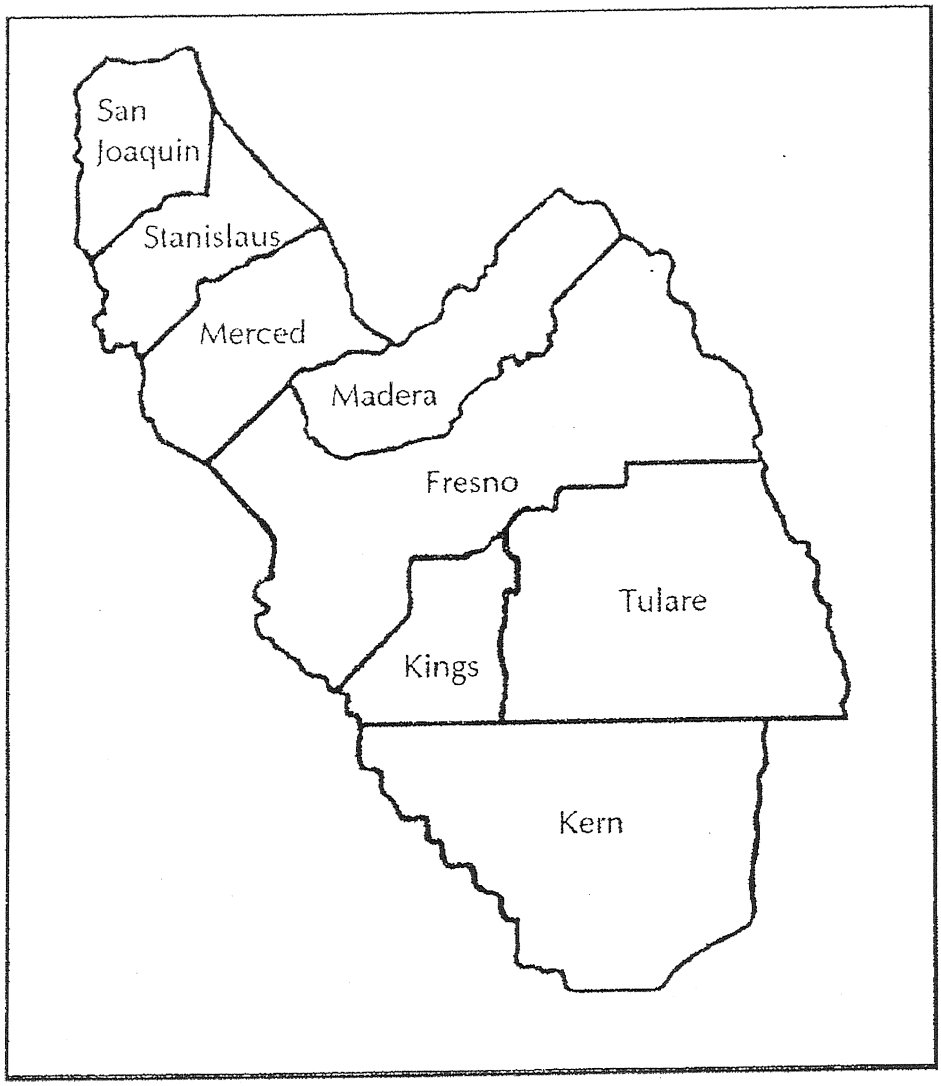
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EXHIBIT C

DISTRICT BOUNDARIES



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San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT.



AIR TOXICS

2022 Annual Report

March 16, 2023

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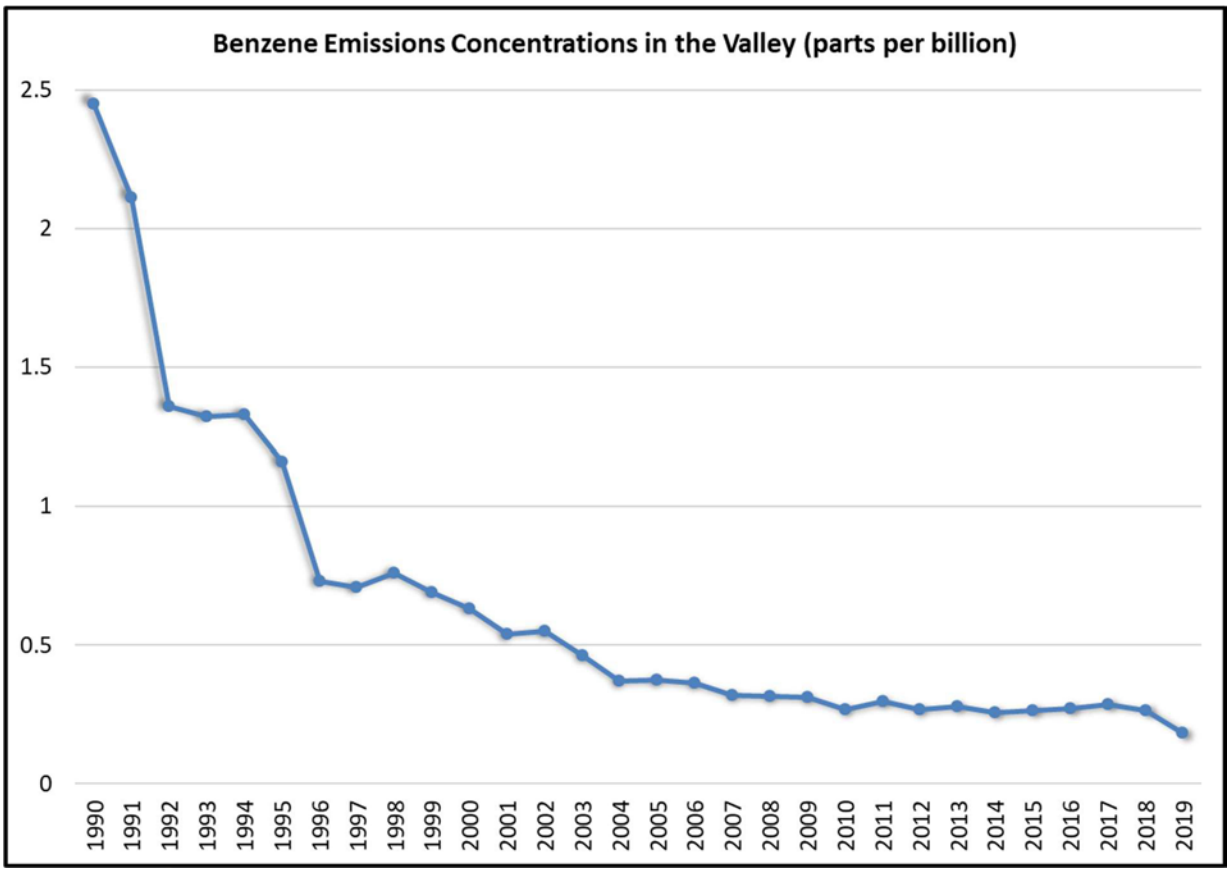
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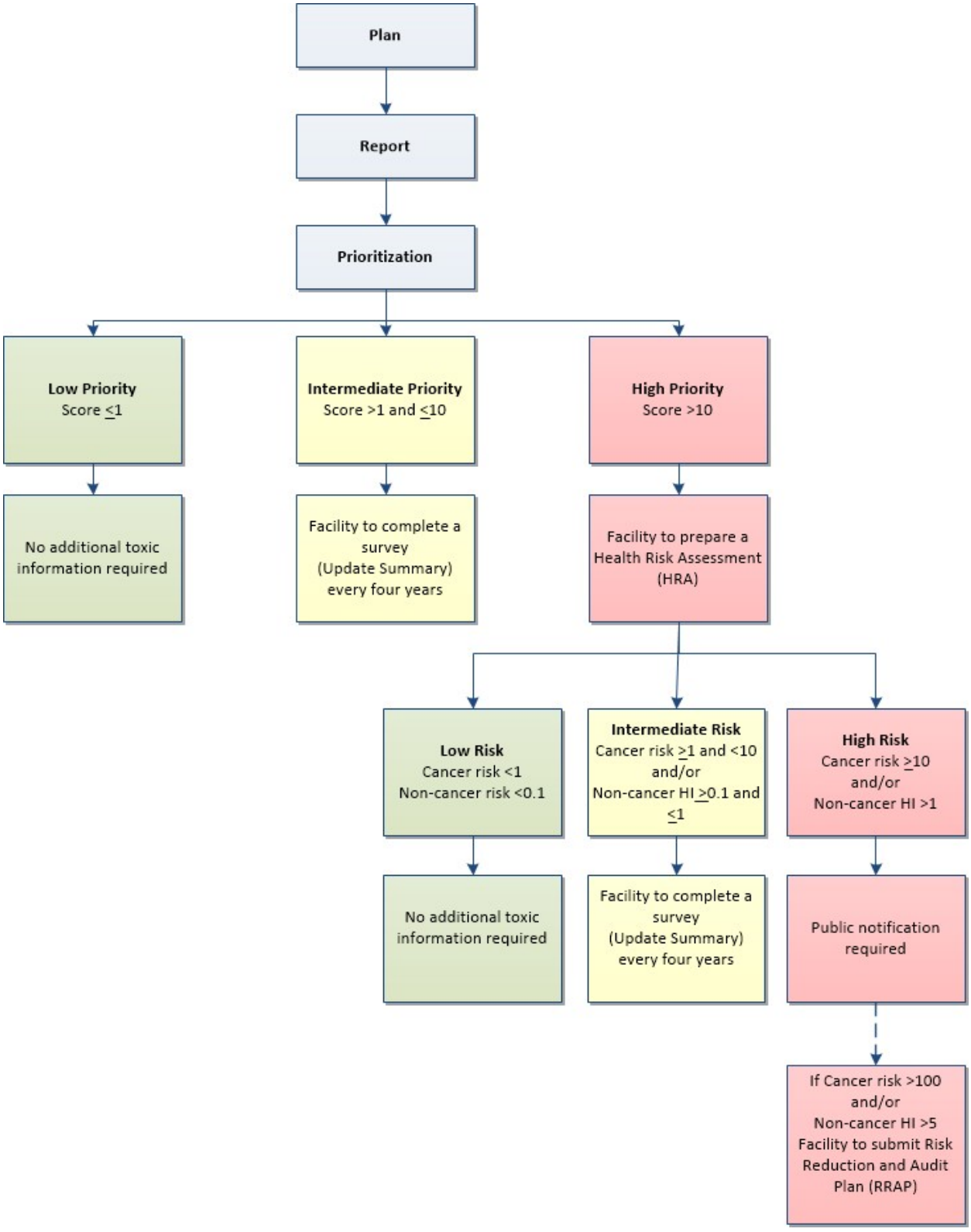
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San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

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Seyed Sadredin
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Northern Region Office
4800 Enterprise Way
Modesto, CA 95356-8718
(209) 557-6400 • FAX (209) 557-6475

Central Region Office
1990 East Gettysburg Avenue
Fresno, CA 93726-0244
(559) 230-6000 • FAX (559) 230-6061

Southern Region Office
2700 M Street, Suite 275
Bakersfield, CA 93301-2373
(661) 326-6900 • FAX (661) 326-6985

www.valleyair.org

DATE: June 19, 2008

TO: SJVUAPCD Governing Board

FROM: Seyed Sadredin, Executive Director/APCO
Project Coordinator: Arnaud Marjollet

RE: RECEIVE AND FILE THE "2008 ANNUAL REPORT ON THE DISTRICT'S INDIRECT SOURCE REVIEW PROGRAM"

RECOMMENDATION:

Receive and file the "2008 Annual Report on the District's Indirect Source Review Program" (see attachment A).

BACKGROUND:

District Rule 9510, Indirect Source Review (ISR), was adopted by the District's Board to reduce the impacts of growth in emissions resulting from new land development in the San Joaquin Valley. The rule's intent, requirements, and administrative procedures are generally described in this report, which was prepared pursuant to Rule 9510 to describe emission reductions achieved and mitigation fees received through implementation of the ISR program.

DISCUSSION:

District Rule 9510 applies to new development projects that emit emissions of at least two tons of nitrogen oxides (NOx) or two tons of particulate matter smaller than ten microns in aerodynamic diameter (PM10) per year.

Developers of projects subject to Rule 9510 must reduce emissions occurring during construction and operational phases, or pay specified mitigation fees. To minimize emissions and to minimize the applicable mitigation fee, developers have begun voluntarily incorporating many air-friendly design changes into their proposals.

For instance, significant reductions in emissions have been generated via the use of cleaner construction equipment. For large distribution centers, proponents have voluntarily proposed to use cleaner truck fleets. In addition, many lesser but still cumulatively significant reductions in emissions have been garnered by a whole range of effective design principles, like installation of solar power, integrated mixed-use development design, bike lanes, high-efficiency housing design, and many others.

If a developer does not achieve the sufficient emission reductions through onsite measures, the rule provides a mechanism by which the developer can pay an offsite mitigation fee to the District. One hundred percent of all offsite mitigation fees received by the District are to be used by the District's existing Emission Reduction Incentive Program (ERIP) to fund emission reduction projects, achieving emission reductions in behalf of the project. Additionally, if a project is subject to off-site emission reduction fees, the developer is required to pay an administrative fee equal to four percent (4%) of the required off-site fees. This fee is to cover the District's cost of administering the off-site emission reduction program.

Section III of this year's report summarizes District Implementation of Rule 9510 and Section IV summarizes funds received and expended, emission reductions realized, and overall cost-effectiveness of funded projects. Appendix A of the report provides a list of all emission reduction projects funded by the ISR program.

Attachment
2008 Annual Report on the District's Indirect Source Review Program (13 pages)

San Joaquin Valley Air Pollution Control District
Meeting of the Governing Board
June 19, 2008

RECEIVE AND FILE THE "2008 ANNUAL REPORT ON THE DISTRICT'S INDIRECT SOURCE REVIEW PROGRAM"

Attachment:
2008 Annual Report on the District's Indirect Source Review Program
(12 pages)

The above attachment has been included with the agenda packets distributed to members of the Governing Board. It has not been included with other agenda packets. A copy of this document is available for review and/or purchase from the San Joaquin Valley Unified Air Pollution Control District.



San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

2008 Annual Report on the District's Indirect Source Review Program

Reporting Period: March 1, 2007 to February 29, 2008

SAN JOAQUIN VALLEY AIR POLLUTION CONTROL DISTRICT GOVERNING BOARD
2008 Annual Report on the District's Indirect Source Review Program

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EXECUTIVE DIRECTOR / AIR POLLUTION CONTROL OFFICER

SEYED SADREDIN

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I. EXECUTIVE SUMMARY

This *"2008 Annual Report on the District's Indirect Source Review Program"* was prepared by the San Joaquin Valley Unified Air Pollution Control District. District Rule 9510, Indirect Source Review (ISR), was adopted by the District's Governing Board to reduce the impacts of growth in emissions resulting from new land development in the San Joaquin Valley. The rule's intent, requirements, and administrative procedures are described in this report, as are the emission reductions achieved and mitigation fees received during 2007-2008 through implementation of the ISR program.

District Rule 9510 applies to new development projects that emit emissions of at least two tons of nitrogen oxides (NOx) or two tons of particulate matter smaller than ten microns in aerodynamic diameter (PM10) per year. The rule contains provisions exempting traditional stationary source projects that are subject to the District's stationary source permitting requirements.

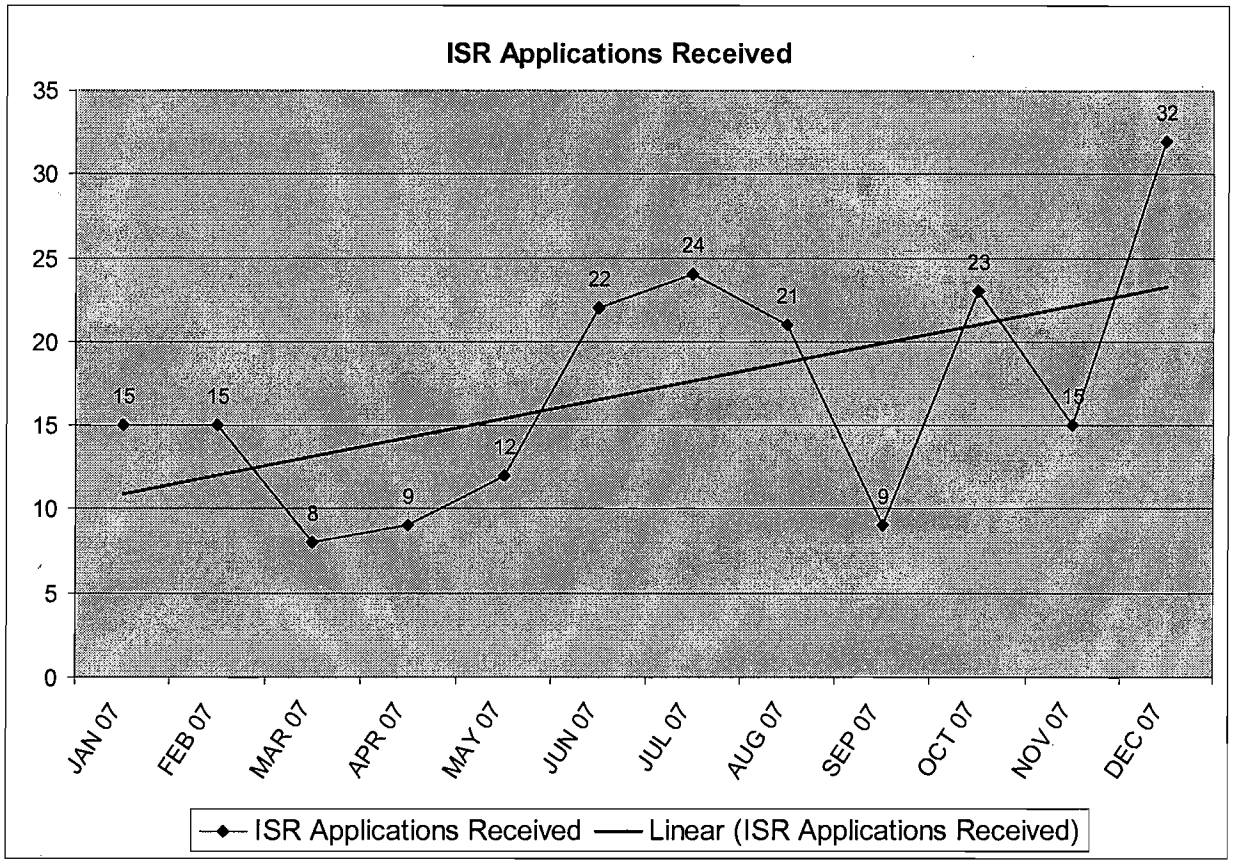
Developers of projects subject to Rule 9510 must reduce emissions occurring during construction and operational phases, or pay specified mitigation fees. To minimize emissions and to minimize the applicable mitigation fee, developers have begun voluntarily incorporating many air-friendly design changes into their proposals. For instance, significant reductions in emissions have been generated via the use of cleaner construction equipment. For large distribution centers, proponents have voluntarily proposed to use cleaner truck fleets. In addition, many lesser but still cumulatively significant reductions in emissions have been garnered by a whole range of effective design principles, like installation of solar power, integrated mixed-use development design, bike lanes, high-efficiency housing design, and many others.

If a developer cannot achieve the required emission reductions through onsite measures, the rule provides a mechanism by which the developer can pay an offsite mitigation fee to the District. One hundred percent of all offsite mitigation fees received by the District are to be used by the District's existing Emission Reduction Incentive Program (ERIP) to fund emission reduction projects, achieving emission reductions in behalf of the project. Additionally, if a project is subject to off-site emission reduction fees, the developer is required to pay an administrative fee equal to four percent (4%) of the required off-site fees. This fee is to cover the District's cost of administering the off-site emission reduction program.

Despite legal challenges[1] and slowed growth in the building industry, especially in the residential development sector, the ISR program had considerable success during this reporting period. As compared with the 2006-2007 reporting period, the ISR program experienced a 46% increase in Air Impact Assessment (AIA) applications received (194 applications received this year versus 133 last year) and a 244% increase in payment of

[1] On June 27, 2006 a lawsuit was filed by various building industries challenging the validity of District Rule 9510. On March 25, 2008 the Fresno County Superior Court ruled in favor of the District on all accounts. An appeal of that decision was filed May 22, 2008. There is a companion case pending in Federal Court which claims District Rule 9510 is preempted by federal tailpipe control standards. Initial indications of the outcome of this case may become apparent in the fall of 2008.

off-site mitigation fees ($5,716,032 received this year compared to $1,660,072 last year).



This increase continued throughout the year, as seen by the graph above, and is attributable to major efforts in District outreach and implementation of measures to improve linkages between the ISR program and District Compliance functions. Outreach included coordinating and holding multiple meetings with key planning agency staff throughout the San Joaquin Valley, conducting public workshops on how to comply with ISR and providing land use agencies training on the use of URBEMIS.

For the 2007-2008 ISR annual reporting period, the District's ISR accounts held a beginning balance of $5,090,869. During this reporting period, the District received off-site mitigation fees totaling $5,392,453 resulting in a grand total of $10,483,322 in off-site mitigation fees. The District funded off-site emission reduction projects totaling $3,125,191, leaving an unexpended balance of $7,358,131.

Implementation of District Rule 9510 resulted in projected combined on-site and off-site emission reductions totaling 2,078 tons of nitrogen oxides (NOx) and 1,087 tons of fine particulate matter (PM10). Off-site emission reduction projects funded by the ISR program achieved emission reductions representing 252 of NOx and 9 tons of PM10, with an average cost effectiveness of $11,928 per ton of reduced emissions.

II. INTRODUCTION

The District's population increased by 22% between 1990 and 2000, and California's Department of Finance has projected that the San Joaquin Valley Air Basin (SJVAB) will experience an overall increase in population of 24% between 2000 and 2010, and an additional 26% increase between 2010 and 2020. Population growth results in increased area source emissions from activities such as increased consumer product use, fuel combustion, and landscape maintenance. Additionally, the total number of vehicle miles traveled (VMT) increases at an even faster rate than the population growth rate. The District experienced a 9% increase in VMT in just three years, between 1999 and 2002, and we expect to see an additional 27% increase in VMT from 2002 to 2010.

The projected growth in these so called "indirect source" emissions erodes the benefits of emission reductions achieved through the District's stationary source program and the state and federal mobile source controls. The District has longstanding statutory authority to regulate indirect sources of air pollution. Pursuant to this authority, the District made a federally enforceable commitment to regulate indirect sources when it adopted its PM10 Attainment Plan in June 2003. Subsequently, the California State Legislature passed Senate Bill 709, Florez, in the fall of 2003, which Governor Gray Davis subsequently signed and codified into the Health and Safety Code in §40604. This additional legislation required the District to adopt, by regulation, a schedule of fees to be assessed on area wide or indirect sources of emissions that are regulated by the District.

District Rule 9510 (Indirect Source Review) was adopted by the District's Board on December 15, 2005, and became effective March 1, 2006. Rule 9510 was adopted by the District's Board to reduce the impacts of growth in emissions resulting from new land development in the San Joaquin Valley. Although the rule does not directly regulate VMT, it is designed to regulate the air impacts associated with new development. Rule 9510 applies to residential and non-residential development projects, including transportation and transit projects, which equal or exceed established applicability thresholds. Rule 9510 establishes emission reduction requirements for NOx and PM10 pollutants. Emission reductions required by the rule that are not achieved through on-site emission reduction measures are subject to off-site emission reduction fees. These fees are used by the District to fund emission reduction projects, mitigating the project's potential impact on air quality in the SJVAB.

This report was prepared pursuant to provisions of Rule 9510 that require the District to prepare an annual report regarding expenditure of received funds and achieved emission reductions. Pursuant to Rule 9520, Section 10.4, the annual report should include the following:

- Total amount of Off-Site Fees received;
- Total monies spent;
- Total monies remaining;
- Any refunds distributed;
- A list of all projects funded;

- Total emissions reductions realized; and
- The overall cost-effectiveness factor for the projects funded.

III. IMPLEMENTATION

District Rule 9510 (Indirect Source Review)

District Rule 9510 applies to new development projects that emit emissions of at least two tons of NOx or two tons of PM10 per year. Developers of projects subject to Rule 9510 are required to reduce emissions occurring during construction and operational phases. During construction, exhaust emissions of NOx and PM10 are to be reduced by 20% and 45% respectively, compared to the statewide average for construction equipment. Construction exhaust emissions can be reduced through installation and use of aftermarket devices, and through use of construction equipment that is newer than the statewide average. Operational emissions of NOx and PM10 are to be reduced by 33.3% and 50%, respectively, of the project's baseline for 10 years.

Operational emissions can be reduced by incorporating design elements that reduce onsite emissions, and the District has seen some very positive clean-air technologies and techniques employed by developers to reduce indirect emissions. For instance, significant reductions in emissions have been generated via the use of cleaner construction equipment. For large distribution centers, proponents have voluntarily proposed to use cleaner truck fleets. In addition, many lesser but still cumulatively significant reductions in emissions have been garnered by a whole range of effective design principles, like installation of solar power, integrated mixed-use development design, bike lanes, high-efficiency housing design, and many others.

If, after implementing such onsite measures, a developer cannot achieve the required emission reductions, the rule provides a mechanism by which the developer can pay an offsite mitigation fee to the District. One hundred percent of all offsite mitigation fees received by the District are to be used by the District's existing Emission Reduction Incentive Program (ERIP) to fund emission reduction projects, achieving emission reductions on behalf of the project. To recover the District's costs for administering the requirements of Rule 9510, the District's Board adopted Rule 3180 (Administrative Fees for Indirect Source Review). Provisions of Rule 3180 establish an application filing fee structure of $432 for residential and $648 for non-residential projects. Additionally, if a project is subject to off-site emission reduction fees, the developer is required to pay an administrative fee equal to four percent (4%) of the required off-site fees. This fee is to cover the District's cost of administering the off-site emission reduction program.

Development Mitigation Contracts

A Development Mitigation Contract (DMC) is an air quality mitigation measure by which a developer voluntarily enters into a contractual agreement with the District to reduce a development project's impact on air quality beyond that achieved by compliance with District Rule 9510. By fully mitigating the project's impact on air quality, a developer

can address one of the issues that have led to California Environmental Quality Act (CEQA) legal challenges to development projects within the SJVAB.

Implementation of a DMC is complementary to ISR; project emissions are characterized, mitigation funds are paid to the District, the District administers the funds to secure the required emission reduction projects. A prerequisite for the District to enter into a DMC is that the DMC will exceed the air quality benefits achieved by compliance with Rule 9510. Therefore, developers who enter into a DMC are considered in compliance with District Rule 9510. This report therefore includes revenues and emission reductions resulting from DMCs. During this reporting period, the District received no new off-site mitigation fees from development mitigation contracts. However, DMC funds carried forward from the previous reporting period were used to fund off-site emission reduction projects.

IV. 2007–2008 ANALYSIS

Table -1: Summary of ISR Program for 2007 to 2008

		Total ISR Program
Beginning Balance	**$**	**5,090,869**
Total Application Fees Received	$	115,869
Total Administrative Fees Received	$	207,710
Total Amount Off-Site Fees Received	$	5,392,453
Total Fees Received	$	5,716,032
Grand Total of Available Off-Site Fees	**$**	**10,483,322**
Total Amount Spent (Contracted)	**$**	**3,125,191**
Total Balance of Available Off-Site Fees	$	7,358,131
Total Amount Refunded	$	0
Grant Total Balance of Available Off-Site Fees	**$**	**7,358,131**

		NOx	*PM10*	*Total*
Total Off-Site Achieved Emission Reductions	***Tons***	251.56	9.09	**260.65**
Emission Reductions Cost Effectiveness *(average based on projects funded)*	*$/Ton*			**11,928**
Total ON-SITE Projected Emission Reductions	*Tons*	1,009.61	305.20	**1,314.81**
Total OFF-SITE Projected Emission Reductions	*Tons*	1,067.91	781.78	**1,849.69**
Total Projected Emission Reductions	***Tons***	2,077.52	1,086.78	**3,164.50**

Total Application Fees Received

District Rule 3180 (Administrative Fees for Indirect Source Review) establishes application fees of $432 and $648 respectively for non-residential ISR applications. The District may also charge for additional staff time required to process an application. As presented in Table-1, the District received application fees totaling $115,869.

Total Administrative Fees Received

District Rule 3180 (Administrative Fees for Indirect Source Review) establishes a four percent (4%) administrative fee to cover the District's costs of operating an off-site emissions reduction program. As presented in Table-1, the District received administrative fees totaling $207,710.

Total Amount of Off-site Fees Received

Provisions within Rule 9510 allow applicants to defer payment of off-site mitigation fees. The payment schedule must provide assurance that reductions from off-site emission reduction projects can be obtained reasonably contemporaneous with emission increases associated with the project. As presented in Table-1, the District received off-site fees totaling $5,392,453. This total does not include fees that have been deferred, nor does it include payments that have been invoiced, but not yet received. As compared to $1,543,697 presented in last year's annual report, this represents a 249% increase in off-site fees received by the District.

A balance of $5,090,869 in off-site mitigation fees was carried forward from the previous reporting period, resulting in $10,483,322 available to fund off-site mitigation projects. Please note that last year's annual report showed a remaining off-site mitigation fee balance of $3,368,308. This amount included $1,722,561 representing funds which had been committed to projects, but not contracted at the time of the annual report.

Total Expenditure of Off-site Fees Received

The District uses off-site fees to fund quantifiable and enforceable off-site emission reduction projects, reducing surplus emissions of NOx and PM10. With the exception of $131,000 voluntarily released by a developer, expenditure of off-site mitigation fees has been limited to fees collected through Development Mitigation Contracts. Of the $131,000 that was available to the District, an emissions reduction project representing $31,000 was funded, and the balance of $100,000 is currently contracted and will be reported in the next year ISR Annual Report.

As presented in Table-1, funds totaling of $3,125,191 were dispersed during this reporting period, leaving a balance of $7,358,131.

Total Emission Reductions Realized

The District funded 25 emission reduction projects for a total of 81 emission sources. These projects consisted primarily of re-powering various type of diesel powered industrial portable equipment such as top grinder, oil drill rig, plastic granulator and agricultural irrigation pumps, with either cleaner diesel engines or by conversion to electric motors. The projects funded achieved total emission reductions of 252 tons of NOx and 9 tons of PM10, with a total of 261 tons combined. The same projects also reduced emissions of Reactive Organic Gases (ROG) by 31 tons. A complete list of all projects funded is presented in Appendix B.

Projected Emission Reductions

Projected emission reductions are a combination of emission reductions to be achieved in the future through implementation of design elements at full project build out and through funding off-site emission reductions projects, using off-site mitigation fees.

For this reporting period, implementation of District Rule 9510 resulted in combined projected on-site and off-site emission reductions totaling 2,078 tons of NOx and 1,087 tons of PM10.

Overall Cost-effectiveness of Funded Projects

Average overall cost-effectiveness is calculated based on total tons of emissions reduced, NOx plus PM10, divided by total funds spent. During this reporting period, the District achieved emission reductions totaling 261 tons and expended funds totaling $3,125,191. As presented in Table-1, average cost-effectiveness is calculated to be $11,928 dollars per ton. This represents a 7% increase, as compared to last year's cost-effectiveness of $11,133 dollars per ton. The District anticipates that cost effectiveness will continue to increase as the most cost-effective projects are funded first.

Appendix A - List of all emission reduction projects funded by the ISR program

APPENDIX A

List of all emission reduction projects funded by the ISR program

EMISSION REDUCTIONS PROJECTS
ISR Annual Report / March 2007 – Feb 2008

Project Name	Date Rec'd	Date Executed	Executed Contract Amount	Amount Paid	Amount UnPaid	Balance	Status	Count Installed	Count Projected	Project Type	Nox Tons	PM10 Tons	ROG Tons
VERA													
Old River Ranch		18-May-07	$25,000	$21,992	$0	$3,008	Closed	1		AG Engine	1.70	0.06	0.21
Old River Ranch		10-Apr-07	$115,567	$0	$115,567	$0	Outstanding		6	AG Engine	1.98	-0.06	0
Old River Ranch		21-Mar-07	$90,000	$90,000	$0	$0	Closed	3		AG Engine	3.15	0.07	0.31
Old River Ranch		30-Apr-07	$22,278	$19,789	$0	$2,489	Closed	1		AG Engine	1.91	0.07	0.26
Old River Ranch		23-Apr-07	$82,719	$82,719	$0	$0	Closed	3		AG Engine	8.52	0.33	1.08
Old River Ranch		23-Apr-07	$20,000	$20,000	$0	$0	Closed	1		AG Engine	1.19	0.01	0.09
Old River Ranch		16-Apr-07	$30,000	$30,000	$0	$0	Closed	2		AG Engine	1.48	0.08	0.26
	Dec-08		**$385,564**	**$264,500**	**$115,567**	**$5,497**		**11**	**6**		**19.93**	**0.56**	**2.21**
Lennar Communities	Feb-08	26-Sep-07	**$16,496**	**$14,920**	**$0**	**$1,576**	**Closed**	**1**		Ag Engine	**1.07**	**0**	**0.18**
Castle & Cooke/ West Ming	May-08	14-Nov-07	**$131,128**	**$131,128**	**$0**	**$0**	**Closed**	**3**		Off Road - Portable Grain Grinders, Pellet Mill Equipment	**36.34**	**1.3**	**4.37**
Castle & Cooke/ Gateway Village		31-May-07	$1,232,390	$484,073			Closed	12		Ag Engine	41.84	1.46	5.42
Castle & Cooke/ Gateway Village					$748,317		Outstanding		8		18.84	0.65	2.39
	Oct-08		**$1,232,390**	**$484,073**	**$748,317**	**$0**		**12**	**8**		**60.68**	**2.11**	**7.81**
Panama 99 Prop. LLC/HWY 99		04-Apr-07	$151,421	$79,985			Closed	2		Off Road - Air Compressors, Drill Units Hydraulic Drill Equipment	4.35	0.16	0.54
Panama 99 Prop. LLC/HWY 99					$71,436		Outstanding		2		6.25	0.26	0.83
Panama 99 Prop. LLC/HWY 99		25-Jun-07	$103,274		$103,274		Outstanding		3	Off Road - Drill Service Pumps	8.26	0.35	1.07
Panama 99 Prop. LLC/HWY 99		19-Jun-07	$41,192	$39,368	$0		Closed	1		Ag Engine	4.48	0.15	0.51
Panama 99 Prop. LLC/HWY 99		14-Nov-07	$47,705	$47,705	$0		Closed	1		Off-Road - Portable Grain Equipment	12.29	0.41	1.42
	Oct-08		**$343,592**	**$167,058**	**$174,710**	**$1,824**		**4**	**5**		**35.63**	**1.33**	**4.37**
Castle & Cooke /Stockdale Ranch		11-Jun-07	$49,428	$49,428	$0	$0	Closed	1		Off Road - Plastic Granulator	4.70	0.17	0.52
Castle & Cooke /Stockdale Ranch		31-May-07	$100,987	$100,987	$0	$0	Closed	3		Off Road - Sprayer	5.22	0.18	0.6
Castle & Cooke /Stockdale Ranch		19-Jun-07	$67,025	$67,025	$0	$0	Closed	3		Off Road - Hydraulic Power Pack	6.38	0.27	0.94
Castle & Cooke /Stockdale Ranch		31-May-07	$48,394	$48,394	$0	$0	Closed	1		Off Road - Pump Engine	3.00	0.10	0.34
Castle & Cooke /Stockdale Ranch		20-Aug-07	$27,910	$0	$27,910	$0	Outstanding		1	Off Road - Drill Rig	1.10	0.05	0.15
Castle & Cooke /Stockdale Ranch		31-May-07	$275,651	$217,842	$0	$57,809	Closed	7		Off Road - Generator, Mud Pump, Drill Rig, Draw Work	24.28	0.91	2.96
Castle & Cooke /Stockdale Ranch				$0	$57,809	($57,809)	Outstanding		1		15.88	0.53	1.82
Castle & Cooke /Stockdale Ranch		31-May-07	$140,916	$0	$140,916	$0	Outstanding		4	Ag Engine	12.51	0.43	1.48
Castle & Cooke /Stockdale Ranch		02-May-07	$25,857	$25,857	$0	$0	Closed	1		Ag Engine	1.60	0.06	0.21
Castle & Cooke /Stockdale Ranch		06-Jun-07	$171,600	$0	$171,600	$0	Outstanding		5	AG Engine	17.17	0.59	2.12
Castle & Cooke /Stockdale Ranch		31-May-07	$77,253	$77,253	$0	$0	Closed	3		AG Engine	5.01	0.21	0.69
	Oct-08		**$985,021**	**$586,786**	**$398,235**	**$0**		**19**	**11**		**96.85**	**3.50**	**11.8**
ISR													
ISR Mitigation		02-Oct-07	$31,000	$0	$31,000	$0	Outstanding		1	Park and Ride Subsidy	1.06	0.29	0.34
	Sep-08		**$31,000**	**$0**	**$31,000**	**$0**			**1**		**1.06**	**0.29**	**0.34**
		Totals	**$3,125,191**	**$1,648,465**	**$1,467,829**	**$8,897**		50	Projects	Achieved	**168.51**	**6.00**	**20.91**
								31	Projects	Projected	**83.05**	**3.09**	**10.20**
											251.56	**9.09**	**31.1**

AIR QUALITY EMISSION REDUCTION AGREEMENT

This Air Quality Emission Reduction Agreement ("Agreement") is entered into as of _____, 2007 by and between Developer Name ("Developer") and the SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT, an air pollution control district formed pursuant to California Health and Safety Code section 40150, et seq. ("District").

RECITALS

WHEREAS, Developer is presently seeking governmental approval of land use entitlements ("Entitlements") which will permit the development of a Project located in the City/County, California, as more particularly described on Exhibit A attached hereto (the "Project"); and

WHEREAS, the Project incorporates the design features specified on Exhibit B attached hereto ("Emission Reduction Design Features"), in order to significantly reduce the air quality impacts associated with the Project; and

WHEREAS, despite incorporation of the Emission Reduction Design Features, without additional emission reductions, the Project would cause impacts on air quality within the geographical boundaries of the San Joaquin Valley Unified Air Pollution Control District, as depicted on Exhibit C attached hereto (the "District Boundaries"); and

WHEREAS, Developer anticipates that mitigation of impacts on air quality resulting from the Project will be either required as a condition to the approval of Developer's Entitlements, or voluntarily imposed by Developer as a means of reducing such impacts; and

WHEREAS, Developer desires to fully comply with all requirements of the California Environmental Quality Act codified at California Public Resources Code section 21000, et seq. ("CEQA"), including all requirements relating to the mitigation of air quality impacts arising from or in connection with the Project; and

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WHEREAS, District is an air pollution control district formed by the counties of Fresno, Kern, Kings, Madera, Merced, San Joaquin, Stanislaus and Tulare, pursuant to California Health and Safety Code section 40150, et seq.; and

WHEREAS, District is responsible for developing and implementing air quality control measures within the District Boundaries, including air quality control measures for stationary sources, transportation sources, and indirect sources; and

WHEREAS, District has determined that with appropriate funding, District can bring about a reduction of emissions from certain projects in types and in sufficient quantities to fully mitigate the net air quality criteria pollutant impacts of the Project as quantified in the Verified Air Quality Assessment (as defined in Section 2.2 below) ("Project's Air Impact"); and

WHEREAS, Developer and District desire to enter into this Agreement in order to develop and implement air quality control measures which will fully mitigate the Project's Air Impact to the extent that the development of such Project will result in no net increase in criteria pollutant emissions over the criteria pollutant emissions which would otherwise exist without the development thereof.

AGREEMENT

NOW THEREFORE, in exchange of the mutual covenants herein contained, Developer and District hereby agree as follows:

1. **Emission Reduction by Developer and District.**

1.1. **Emission Reduction Proposals**. Developer shall identify and propose to District opportunities to reduce emissions to fully mitigate Project's Air Impact, including but not limited to opportunities for removal or retrofitting of stationary, transportation, indirect, and/or mobile pollution source equipment, and/or other opportunities therefore (each, an "**Emission Reduction Proposal**"). Each Emission Reduction Proposal shall be submitted in writing to District, using District approved forms, and shall contain a representation by Developer that the owner/operator of the identified Pollution Source Equipment has expressed interest in entering into a written funding agreement with

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District in District's then standard form ("**Funding Agreement**") requiring removal or replacement of the identified equipment with new equipment under District's "Heavy Duty Engine Emission Reduction Incentive Program", or another emission reduction program adopted by District ("**District Emission Reduction Program**"). Developer shall submit Emission Reduction Proposals to District in sufficient amounts to fully mitigate emissions from each distinct phase of the project. For each phase of the project, Developer shall submit Emission Reduction Proposals to District no later than application for grading permits for, and before generating emissions from, that phase. Any Emission Reduction Shortfall for a given phase shall be addressed according to Section 1.7.2 of this Agreement.

1.2. **District's Verification of Emission Reduction.** As quickly as practicable upon Developer's submission to District of an Emission Reduction Proposal, District shall determine the types and quantities of permanent reduction in emissions which would be realized by the proposed removal or retrofit and shall advise Developer of such determination in writing ("**Emission Reduction Verification**") thereby verifying that in District's considered opinion the removal or retrofit proposed in the Emission Reduction Proposal would result in permanent emission reduction in the locality of the Project in the types and quantities so determined by District.

1.3. **Emission Reduction Proposal Advance.** Developer shall advance to District, on the date of submittal of each Developer's Emission Reduction Proposal, a monetary sum equal to the total estimated cost (as specified in each Developer's Emission Reduction Proposal), until sufficient advance is received by District to fully mitigate the Project's Air Impact ("**Emission Reduction Proposal Advance**").

1.4. **Funding Agreements.** As soon as practicable after District's receipt of Developer's Emission Reduction Proposal Advance, District shall use diligent efforts to enter into Funding Agreements with the owners and/or operators of the pollution source equipment identified in Developer's Emission Reduction Proposal, thereby providing for the removal and/or retrofit of all of such Pollution Source Equipment, and

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providing for District's payment (from the Emission Reduction Proposal Advance) to such owner or operator, of an amount equal to the estimated cost of such opportunity, as specified in Developer's Emission Reduction Proposals. District shall use diligent efforts to enter into Funding Agreements with all of the owners or operators identified in Developer's Emission Reduction Proposals within one hundred eighty (180) days following District's receipt of a complete Emission Reduction Proposal and the Emission Reduction Proposal Advance from Developer.

1.5. **Use of Emission Reduction Proposal Advance**. District shall use the Emission Reduction Proposal Advance to meet its monetary obligations under the Funding Agreements that District shall enter into with the owners of the Pollution Source Equipment identified in Developer's Emission Reduction Proposals.

1.6. **Use of Unused Portions of Emission Reduction Proposal Advance.** In the event Developer is unable to submit to District Emission Reduction Proposals providing for emission reduction in the types and quantities necessary to fully mitigate the Project's Air Impact, or in the event District is unable to enter into Funding Agreements with any of the owners or operators identified in Developer's Emission Reduction Proposals, District shall notify Developer in writing of the additional emission reductions needed to fully mitigate the Project's Air Impact, and Developer shall have a reasonable time, not to exceed one hundred eighty (180) days within which to submit to District additional or supplemental Emission Reduction Proposals in order to provide the necessary additional emission reduction.

1.7. **Unused Advance / Emission Reduction Shortfall / Additional Payment.**

1.7.1. **Unused Advance.** If, despite District's diligent efforts to enter into Funding Agreements with all of the owners or operators identified in Developer's Emission Reduction Proposals (and, if applicable, supplemental Emission Reduction Proposals submitted by Developer), District is unable to enter into Funding Agreements sufficient to fully mitigate the Project's Air Impact, then District shall use any unused portion of Developer's Emission Reduction Proposal Advance to fund emission

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reduction opportunities to mitigate the balance of the Project's Air Impact at District's actual cost of doing so, provided that such actual costs shall not exceed the costs set forth in the following Emission Reduction Cost Schedule:

Emission Reduction Cost Schedule		
Year Paid	NOx or ROG ($/ton)	PM10 ($/ton)
2007	$49,700	$55,940
2008	$65,450	$90,110
Beyond	Prevailing Costs	Prevailing Costs

District is of the considered opinion that the emission reductions listed in the above schedule can be achieved at the corresponding times and costs shown in said schedule. If, at the time of invoicing, the District has not identified Prevailing Costs for post-2008 payments, 2008 costs shall apply.

1.7.2. **Emission Reduction Shortfall/Additional Payment.** In the event the emission reduction brought about by the Funding Agreements entered into between District and the owners or operators identified in Developer's Emission Reduction Proposals (and, if applicable supplemental Emission Reduction Proposals), and that brought about pursuant to Section 1.7.1 above, are not sufficient to fully mitigate the Project's Air Impact ("**Emission Reduction Shortfall**"), then Developer shall be credited for the emission reduction brought about as a result of Funding Agreements entered into between District and the owners or operators identified in Developer's Emission Reduction Proposals and for the emission reduction brought about pursuant to Section 1.7.1 above, and Developer thereafter shall deposit with District, within 30 days of receiving notice of the Emission Reduction Shortfall from District, an additional amount equal to the product of (i) District's cost per ton of emission reduction as shown in the Emission Reduction Cost Schedule set forth in Section 1.7.1 above, multiplied by (ii) the total number of tons of emission reduction necessary to fully mitigate the Project's Air Impact less the total number of tons of emission reduction so credited to Developer. However, in no case shall the amount paid to District and the

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amount of emission reductions achieved per this agreement be less than the amount that would be paid to District or the amount of emission reductions that would be required for this Project according to District Rule 9510 (Indirect Source Review). To allow verification of equivalency of emission reductions and off-site mitigation fee amounts, according to District Rule 9510, Developer shall submit to District an ISR Air Impact Assessment Application, using District forms, no later than concurrent with the Developer's submission of the air quality assessment, as set forth in Section 2.2.

1.8. **Surplus Mitigation.** In addition to the amounts payable under paragraph 1.3, Developer shall deliver to District an additional sum equal to five percent (5%) of the Emission Reduction Proposal Advance. Said additional sum shall be paid under the same schedule as set forth in paragraph 1.3. District shall utilize such additional sum to fund further localized emission reduction opportunities in quantities consistent with the schedule set forth in paragraph 1.7.1.

1.9 **Time of Use**. Any emission reductions brought about by this Agreement prior to the date Developer receives final approval of the Project from all applicable Governmental Authorities shall be credited to the total amount of emission reductions achieved per this agreement.

1.10. **District's Obligation**. The monies paid by Developer under this Agreement shall be used by District to obtain localized emission reductions in the types and quantities necessary to fully mitigate the Project's Air Impact as quantified in the Verified Air Quality Assessment. If necessary, District shall assist Developer in securing emission reductions, consistent with the provisions established in Section 1.7.2.

1.11. **Developer's Obligation**. District acknowledges that, if the Project is not finally approved so that such development is allowed to proceed, Developer has no obligations under this Agreement relative to the respective Project. Developer acknowledges that it must satisfy the terms of this Agreement in order to develop the Project.

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2. **CEQA Compliance/Full Mitigation.** For and in exchange of Developer's payment of funds pursuant to Section 1 above, District shall ensure, by way of entering into, funding and enforcing the Funding Agreements in accordance with the provisions of Section 1.4 above, that the Project's Air Impact is fully mitigated, such that the Project, combined with the emission reductions brought about in accordance with Section 1 above, shall result in no net increase in air quality impacts over those air quality impacts which would otherwise exist without the development of such Project. For the purpose of this agreement, full mitigation means the sum of all NOx, ROG, and PM10 emission reductions achieved by the Emission Reductions Proposals equals, or is greater than, the sum of all NOx, ROG, and PM10 emissions increases calculated as the average annual construction and the peak annual area source and mobile source emissions of NOx, ROG, and PM10 less the average annual emissions that have occurred at the project site during the three years prior to release of the Notice of Preparation. In addition to entering into, funding and enforcing the Funding Agreements in accordance with the provisions of Section 1.4 above, District shall do all of the following:

2.1. **District's Verification of Air Assessment Protocol.** Within ten (10) business days following the date of this Agreement, Developer shall submit to District an air assessment protocol prepared by Developer's air quality consultant reflecting the methodology, including air quality impact modeling, to be utilized in the preparation of the air quality assessment for the Project. Within twenty-one (21) business days following District's receipt of Developer's air assessment protocol, District shall review and comment upon such air assessment protocol, and, after Developer's incorporation of any revisions suggested by District, District shall verify in writing to Developer the correctness of the air assessment protocol which will be utilized in the preparation of the air quality assessment for the Project.

2.2 **District's Verification of Air Quality Assessment.** Following District's Verification of Air Assessment Protocol, Developer shall submit to District an air quality

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assessment prepared by Developer's air quality consultant assessing the air quality impacts of the Project. District shall use its best efforts to review and comment upon Developer's air quality assessment within thirty (30) days following District's receipt of Developer's complete air quality assessment, and, after Developer's incorporation of any and all revisions suggested by District, District shall verify in writing to Developer the correctness of the air quality assessment to be utilized in connection with the CEQA documents for the Project, including (i) the methodology utilized in the preparation of the CEQA document, (ii) the types and quantities of any net air quality impacts associated with the Project, (iii) the appropriateness of the mitigation measures proposed in the CEQA document, and (iv) any other matters which may pertain to such CEQA document and/or any air quality impacts or air quality mitigation measures referenced therein (the "**Verified Air Quality Assessment**").

2.3. **District's Verification of Administrative Draft Environmental Impact Report**. Upon request by Developer, and submission by Developer to District of any administrative Draft Environmental Impact Report, or other applicable CEQA documents for the Project, District shall review, comment upon and, after incorporation of any and all revisions made by District, verify in writing to Developer the correctness of all portions thereof which pertain to air quality impacts, including, (i) the methodology utilized in the preparation of the CEQA document, (ii) the types and quantities of any net air quality impacts associated with the Project, (iii) the appropriateness of the mitigation measures proposed in the CEQA document, and (iv) any other matters which may pertain to such CEQA document and/or any air quality impacts or air quality mitigation measures referenced therein.

2.4 **District's Acknowledgment Regarding Full Mitigation**. At such time as District is provided an opportunity as a commenting agency to comment upon the Draft Environmental Impact Report and Final Environmental Impact Report for the Project, District shall comment in writing as to the correctness of all portions thereof which pertain to air quality impacts, including (i) the methodology utilized in the

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preparation of the CEQA document, (ii) the types and quantities of any net air quality impacts associated with the Project, (iii) the appropriateness of the mitigation measures proposed in the CEQA document, and (iv) any other matters which may pertain to such CEQA document and/or any air quality impacts or air quality mitigation measures referenced therein. District shall at all times fully perform its duties and obligations as a commenting agency, and the provisions of this Section 2.4 shall not be interpreted to the contrary. At such time as District has entered into Funding Agreements pursuant to Section 1.4 above and the owners/operators of equipment to be removed and/or replaced under such agreements have removed and replaced such equipment in accordance with the provisions thereof, District shall verify in writing to Developer and to the lead agency that full mitigation of the Project's Air Impact has been achieved, upon successful fulfillment of all Funding Agreements. District shall ensure that the owners/operators of equipment to be removed and/or replaced pursuant to such Funding Agreements perform all obligations to be performed on the part of such parties under said Funding Agreements. District acknowledges that the Verified Air Quality Assessment and its quantification of the Project's Air Impact will be based on the pending applications for development of the Project and that actual approvals may be for a lesser amount of development. District agrees that Developer's obligations under this Agreement shall be based on the amount of development actually approved, and the final quantification of the Project's Air Impact will be revised accordingly.

2.5. **District's Oversight of Air Quality Mitigation Monitoring Plan.** Upon request of the lead agency having jurisdiction over the Project, District shall oversee that portion of the mitigation monitoring plan adopted by the lead agency for the Project which relates to the mitigation brought about by Section 1 of this Agreement. Alternatively, upon request of that lead agency, District shall cooperate with the lead agency in the oversight of that portion of the mitigation monitoring plan adopted by the lead agency for the Project which relates to the mitigation brought about by Section 1

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of this Agreement.

2.6. **District's Documentation, Record Keeping and Monitoring**. District shall document, keep adequate records on and monitor the emission reduction brought about as a result of this Agreement, and shall from time to time, upon written request by Developer or by the lead agency for the Project, provide to Developer or to the lead agency written reports verifying that emission reduction has been and/or is being brought about so as to fully mitigate the Project's Air Impact.

3. **Subsequent Litigation, Legislation and/or Administrative Action / Credit to Developer**.

3.1. **Subsequent Litigation**. In the event that despite this Agreement, Developer is required as a result of a final judgment or District Approved Settlement (as defined below) in any subsequent third party litigation, to pay monies in addition to the monies to be paid by Developer pursuant to Section 1 above, then, provided that the project total emissions are the same as quantified in the Verified Air Quality Assessment, District shall acknowledge and credit Developer with mitigation of the air quality impacts of the Project in such types and quantities that Developer can establish, to the reasonable satisfaction of District, will result from Developer's payment of such additional monies, and shall reduce any amounts thereafter payable by Developer under this Agreement by an amount equal to the additional monies so paid by Developer. This requirement shall not apply if the additional monies are required to mitigate emissions that exceed those set forth in the Verified Air Quality Assessment. For purposes of this Section 3.1.1, a "**District Approved Settlement**" shall mean a settlement of a lawsuit filed pursuant to CEQA, the National Environmental Protection Act or other applicable environmental law which (i) provides for Developer's payment of monies in exchange for a dismissal of such lawsuit, (ii) provides for the use of such monies by the petitioner in such lawsuit in such a manner as to mitigate adverse air quality impacts of the Project, and (iii) is approved in writing by District.

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3.2. **District Rule 9510.** The performance of Developer's and District's obligations under this Agreement will fully mitigate the Project's Air Impact. Inasmuch as the mitigation provided under this Agreement exceeds the mitigation which would otherwise have been provided under Sections 6.0 and 7.0 of District's Rule 9510, and the Project's mitigated baseline (being zero emissions) is less than the threshold stated in Section 4.3 of said Rule 9510, the Project is exempt from Sections 6.0 and 7.0 of District's Rule 9510. Accordingly, no off-site Emission Reduction Fee will be required in connection with the approval or development of the Project. For each individual project developed at the project site requiring a discretionary approval by the lead agency, Developer shall provide District with a map or diagram indicating its location within the area covered by this Agreement.

4. **Term of Agreement.** This Agreement shall be effective upon the date first written above, and shall terminate upon District's meeting its obligation to implement projects that provide necessary emissions reductions to fully mitigate the Project's Air Impact (the "**Term**"). Developer may, at any time by written notice to District, terminate this Agreement, whereupon, (i) District shall acknowledge in writing to the lead agency that Developer has mitigated air quality impacts of the Project to the extent and in the types and quantities brought about by Funding Agreements theretofore funded by Developer's Emission Reduction Proposal Advance (and if applicable pursuant to Section 1.7.1 above), (ii) District shall refund to Developer any unused portion of Developer's Emission Reduction Proposal Advance less any unpaid administrative fees incurred; and (iii) neither Developer nor District shall have any further rights or obligations under this Agreement. Developer acknowledges that in the absence of this Agreement, the project is subject to all applicable provisions of District Rule 9510 (Indirect Source Review).

5. **Payment of Administrative Fees to District.** Developer agrees to pay to District, in order to reimburse District for its general overhead required for the administration of this Agreement, an administrative fee ("***ERIP Fee***") in an amount

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equal to four percent (4%) of the Emission Reduction Proposal Advance. Such ERIP Fee shall be due and payable upon Developer's delivery of the Emission Reduction Proposal Advance pursuant to Section 1.3 above. In addition to the ERIP Fee, Developer agrees to pay to District, within thirty (30) days following Developer's receipt of District's invoice, administrative fees to reimburse District for staff time spent and materials used by District in the administration of this Agreement, other than that time associated with the ERIP program covered by the ERIP Fee above, including review, verification and preparation of documents, and staff time relating to the performance of District's obligations hereunder, based on a time and materials basis at District's average weighted labor rates.

6. **Representations, Covenants and Warranties.**

6.1. **Developer's Representations, Covenants and Warranties.** Developer represents, covenants and warrants to District, as of the date of this Agreement, and as of the date of Developer's submission to District of any documents contemplated hereunder, as follows:

6.1.1. The undersigned representatives of Developer are duly authorized to execute, deliver and perform this Agreement, and upon Developer's execution and delivery of this Agreement, this Agreement will have been duly authorized by Developer.

6.1.2. Upon execution and delivery of this Agreement by Developer, Developer's obligations under this Agreement shall be legal, valid and binding obligations of Developer, duly enforceable at law and in equity in accordance with the terms and conditions of this Agreement.

6.1.3. There is no lawsuit, legal action, arbitration, legal or administrative proceeding, legislative or quasi-legislative action or claim existing, pending, threatened or anticipated which would render all or any portion of this Agreement invalid, void or unenforceable in accordance with the terms and conditions thereof.

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6.1.4. Other than the execution and delivery of this Agreement by the undersigned representatives of Developer, there are no approvals, consents, confirmations, proceedings, or other actions required by Developer or any third party, entity or agency in order to enter into and carry out the terms, conditions and intent of the parties with respect to this Agreement.

6.2. **District's Representations, Covenants and Warranties.** District represents, covenants and warrants to Developer, as of the date of this Agreement, and as of the date of District's delivery to Developer of any documents contemplated hereunder, as follows:

6.2.1. The undersigned representatives of District are duly authorized to execute, deliver and perform this Agreement, and upon District's execution and delivery of this Agreement, this Agreement will have been duly authorized by District.

6.2.2. Upon execution and delivery of this Agreement by District, District's obligations under this Agreement shall be legal, valid and binding obligations of District, duly enforceable at law and in equity in accordance with the terms and conditions of this Agreement.

6.2.3. There is no lawsuit, legal action, arbitration, legal or administrative proceeding, legislative, quasi-legislative or administrative action or claim existing, pending, threatened or anticipated which would render all or any portion of this Agreement invalid, void or unenforceable in accordance with the terms and conditions thereof.

6.2.4. Other than the execution and delivery of this Agreement by the undersigned representatives of District, there are no approvals, consents, confirmations, proceedings, or other actions required by District or any third party, entity or agency in order to enter into and carry out the terms, conditions and intent of the parties with respect to this Agreement.

6.2.5. No lawsuit, legal action, arbitration, legal or administrative proceeding, legislative or quasi-legislative action or claim existing, pending, threatened or

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anticipated will render invalid, void or unenforceable any right or benefit Developer is to receive under the terms and conditions of this Agreement.

6.2.6. The monies paid by Developer under this Agreement shall be sufficient to ensure that the emission reduction contemplated by this Agreement shall occur, and District shall utilize such monies in such a manner as to ensure that such emission reduction shall occur.

6.2.7. Upon the approval of this Agreement by the governing board of District, the Air Pollution Control Officer of District, or equivalent representative, or a delegee of such officer, shall have the authority to approve, deliver, verify, enter into, acknowledge and/or accept any communication, notice, notification, verification, agreement and/or other document to be issued or entered into by District under the terms and conditions of this Agreement, without further approval of the governing board of District.

7. **Indemnification**. Developer agrees to indemnify, defend and hold harmless District for, from and in connection with any third party claims, losses and/or liabilities arising from or in connection with District's performance of this Agreement, excluding only such claims, losses and/or liabilities which result from or in connection with District's sole negligence, act or omission.

8. **Inurnment**. Developer's rights and obligations under this Agreement, or applicable portions thereof, shall run with the land encompassed by the Project, and shall inure to the benefit of and be binding upon the heirs, successors and assigns of Developer who take title to such lands or applicable portions thereof. Upon Developer's conveyance of all or any portion of the lands encompassed by the Project, the rights and obligations of Developer under this Agreement shall, to the extent applicable to the lands so conveyed, be transferred to the transferee thereof, and Developer shall thereupon be released by District from, all obligations and liabilities so assigned, except for such obligations and liabilities arising prior to such transfer.

9. **Assignment**. Developer shall have the right to assign all or any part of its rights and/or obligations under this Agreement. Upon any such assignment, Developer shall

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deliver to District a written assignment and assumption agreement specifying the fact and extent of the assignment, the name and address of the assignee, and the assignee's assumption of all obligations of Developer thereby assigned. Developer shall have the right to assign all or any part of its rights and/or obligations under this Agreement to a third party for use in connection with the mitigation of air quality impacts resulting from one or more projects other than the Project, so long as (i) the project is located within the District Boundaries, (ii) the air quality impacts of such project(s) will in fact be mitigated, as verified by District, by the emission reductions brought about by this Agreement, and (iii) the project(s) consist of residential, commercial, industrial and/or mixed use real estate projects which incorporate the Emission Reduction Design Features. Upon any such assignment by Developer, District shall enter into an amendment of this Agreement which acknowledges the assignment and conforms the various provisions of this Agreement as may be required to be conformed in order to provide to the assignee the rights and benefits of this Agreement as if such assignee and its project were the original party and project contemplated in this Agreement.

10. **Recitals Incorporated**. The recitals set forth hereinabove are hereby incorporated into this Agreement and acknowledged, agreed to and adopted by the parties to this Agreement.

11. **Further Assurances**. Developer and District agree to execute and deliver any documents and/or perform any acts, which are reasonably necessary in order to carry out the intent of the parties with respect to this Agreement.

12. **No Joint Venture or Partnership**. District and Developer agree that nothing contained in this Agreement or in any document executed in connection with this Agreement shall be construed as making District and Developer joint ventures or partners.

13. **Notices**. Any notices or communications relating to this Agreement shall be given in writing and shall be deemed sufficiently given and served for all purposes

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when delivered, if (a) in person, (b) by facsimile (with the original delivered by other means set forth in this Section 13), (c) by generally recognized overnight courier or (d) by United States Mail, certified or registered mail, return receipt requested, postage prepaid, to the respective addresses set forth below, or to such other addresses as the parties may designate from time to time by providing written notice of the change to the other party.

To Developer: Address & Contact Name	To District: San Joaquin Valley APCD 1990 E. Gettysburg Avenue Fresno, CA 93726 Fax: (559) 230-6061 Attn: Seyed Sadredin Executive Director/APCO
With a copy to: Address & Contact Name	with a copy to:San Joaquin Valley APCD 1990 E. Gettysburg Avenue Fresno, CA 93726 Fax: (559) 230-6061 Attn: Dave Warner Director of Permit Services with a copy to: San Joaquin Valley APCD 1990 E. Gettysburg Avenue Fresno, CA 93726 Fax: (559) 230-6061 Attn: Philip M. Jay District Counsel

14. **Entire Agreement.** The terms of this Agreement, together with all attached exhibits, are intended by the parties as the complete and final expression of their agreement with respect to such terms and exhibits and may not be contradicted by evidence of any prior or contemporaneous agreement. This Agreement specifically supersedes any prior written or oral agreements between the parties with respect to

the subject matter of this Agreement.

15. **Amendments and Waivers.** No addition to or modification of this Agreement shall be effective unless set forth in writing and signed by the party against whom the addition or modification is sought to be enforced. The party benefited by any condition or obligation may waive the same, but such waiver shall not be enforceable by another party unless made in writing and signed by the waiving party.

16. **Invalidity of Provisions.** If any provision of this Agreement as applied to either party or to any circumstance shall be adjudged by a court of competent jurisdiction to be void or unenforceable for any reason, the same shall in no way affect (to the maximum extent permissible by law) any other provision of this Agreement, the application of any such provision under circumstances different from those adjudicated by the court, or the validity or enforceability of this Agreement as a whole. The parties further agree to replace any such invalid, illegal or unenforceable portion with a valid and enforceable provision which will achieve, to the maximum extent legally possible, the economic, business or other purposes of the invalid, illegal or unenforceable portion.

17. **Construction.** Unless otherwise indicated, all Section references are to the sections of this Agreement and all references to days are to calendar days. Whenever, under the terms of this Agreement the time for performance of a covenant or condition falls upon a Saturday, Sunday or California state holiday, the time for performance shall be extended to the next business day. The headings used in this Agreement are provided for convenience only and this Agreement shall be interpreted without reference to any headings. Wherever required by the context, the singular shall include the plural and vice versa, and the masculine gender shall include the feminine or neuter genders, or vice versa. This Agreement may be executed in one or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument. The language in all parts of this Agreement shall be construed as a whole in accordance with its fair meaning, and shall not be

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construed against any party solely by virtue of the fact that such party or its counsel was primarily responsible for its preparation.

18. **Governing Law**. This Agreement shall be governed by the laws of the State of California applicable to contracts made and to be performed in California.

19. **No Third-party Beneficiaries**. Nothing in this Agreement, express or implied, is intended to confer any rights or remedies under or by reason of this Agreement on any person other than the parties to it and their respective permitted successors and assigns, nor is anything in this Agreement intended to relieve or discharge any obligation of any third person to any party hereto or give any third person any right of subrogation or action over or against any party to this Agreement.

20. **Exhibits**. The exhibits attached to this Agreement shall be deemed to be a part of this Agreement and are fully incorporated herein by reference.

21. **Force Majeure**. The time within which any party shall be required to perform under this Agreement shall be extended on a day-per-day basis for each day during which such performance is prevented or delayed by reason of events reasonably outside of the control of the performing party, including, without limitation, acts of God, events of destruction, acts of war, civil insurrection, strikes, shortages, governmental delays, moratoria, civil litigation and the like, and/or delays caused by the non-performing party's act or omission.

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IN WITNESS WHEREOF, Developer and District have executed this Agreement and agree that it shall be effective as of the date first written above.

DEVELOPER: Developer Name,

a California limited liability company

By:_____

Name:_____

Title:_____

DISTRICT: **SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT**, an air pollution control district formed pursuant to California Health and Safety Code section 40150, et seq.

///

DISTRICT

San Joaquin Valley Unified Air Pollution Control District

///

By:_____

Councilmember J. Steven Worthley, Chair

Governing Board

///

Recommended for approval:

San Joaquin Valley Unified Air Pollution Control District

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_____

Seyed Sadredin

Executive Director/APCO

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Approved as to legal form:

San Joaquin Valley Unified Air Pollution Control District

_____

Philip M. Jay

District Counsel

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Fresno, CA 93726
(559) 230-6000

Approved as to accounting form:

San Joaquin Valley Unified Air

Pollution Control District

///

_____

Roger W. McCoy

Director of Administrative Service

For accounting use only:

Program:_____

Account No.:_____

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EXHIBIT A

DESCRIPTION OF THE PROJECT

[INSERT MAP.]

EXHIBIT B

EMISSION REDUCTION DESIGN FEATURES

The project shall incorporate the following Emission Reduction Design Features:

The project will incorporate the following on-site features:

1. Utilization of land use designs which create walkable communities and encourage pedestrian travel.
2. Utilization of interconnecting sidewalks, walking paths and/or bike paths in order to encourage travel by means other than motor vehicle.
3. Utilization of appropriate landscaping to create reasonable shade canopies for streets, parkways and parking areas.
4. Utilization of roadway designs, which enhance pedestrian safety by appropriate signaling, signage and separation from traffic.
5. Design requirements, which incorporate natural gas hookups and electrical outlets on patios.
6. Design requirements, which prohibit the installation and use of wood burning stoves and wood burning fireplaces.

Prior to issuance of grading permits for the Project, Developer shall prepare and submit to District dust control plans for the areas to be graded, in accordance with District Regulation VIII. The plan shall be prepared consistent with District Regulation VIII and must be reviewed and approved by the District prior to commencement of grading activities. Each contractor working on the Project site shall implement the dust control measures outlined in the approved dust control plan. The dust control measures selected shall be incorporated as a note on each grading plan.

District maintains New Source Review requirements that direct owners/operators of certain types of stationary equipment to obtain an Authority to Construct ("ATC") and Permits to Operate ("PTO") from the District. As part of this process, the need for emission control equipment is assessed and the District determines whether a Health Risk Assessment ("HRA") must be prepared.

Owners/operators of all stationary sources for which such approvals are required should show proof of compliance with District Rules and Regulations prior to issuance of certificates of occupancy.

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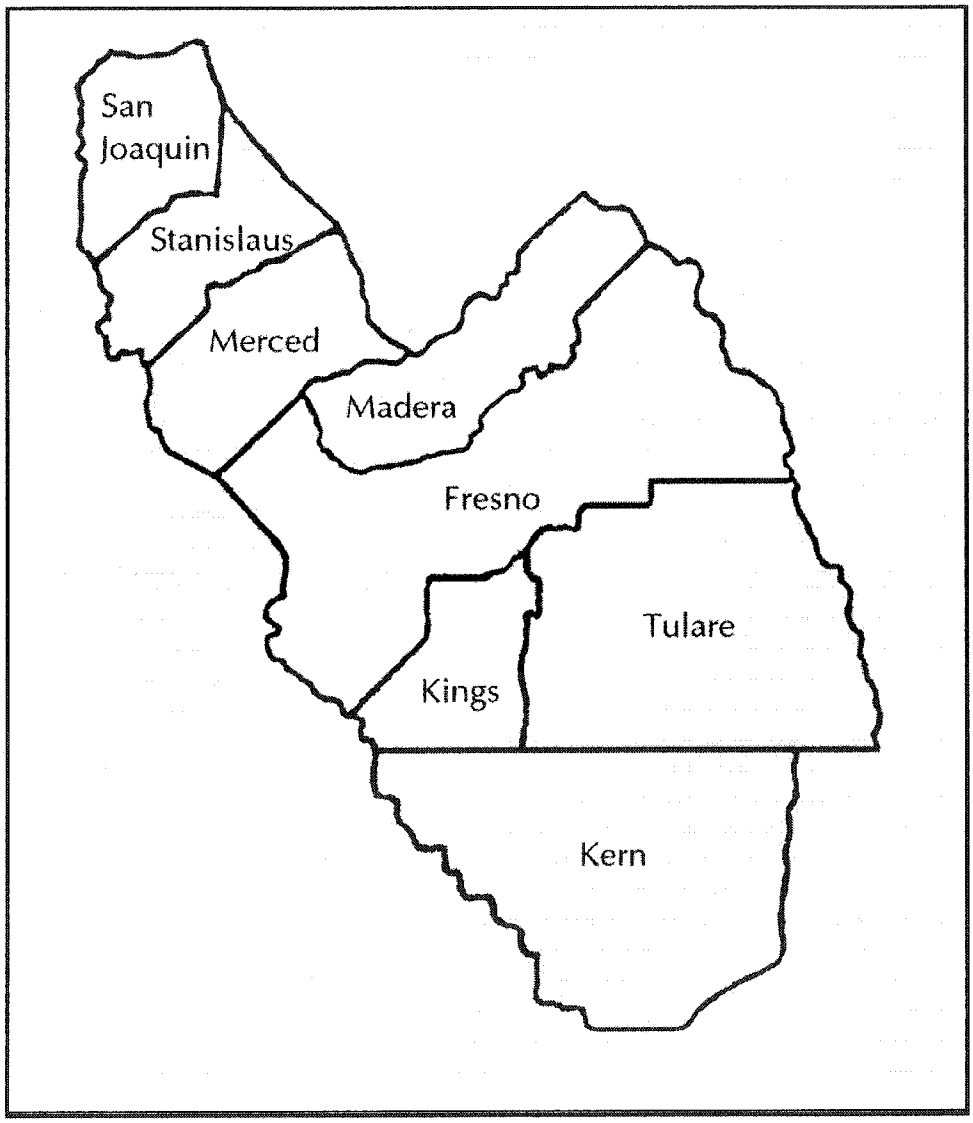
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EXHIBIT C

DISTRICT BOUNDARIES



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SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT

FINAL DRAFT STAFF REPORT

December 15, 2005

Rule 9510 – Indirect Source Review (ISR)
Rule 3180 – Administrative Fees for Indirect Source Review

Prepared by: Chrystal Meier, Air Quality Specialist
Jennifer Barba, Senior Air Quality Specialist
Dave Mitchell, Planning Manager
Tom Jordan, Special Projects Administrator
Scott Nester, Planning Director

I. SUMMARY

A. Reasons for Rule Development and Implementation

The San Joaquin Valley Air Basin (SJVAB) is classified as a nonattainment area for the state and federal health based ambient ozone and PM10 standards by the California Air Resources Board (ARB) and the U.S. Environmental Protection Agency (EPA). The SJVAB is currently classified as serious nonattainment for the 24-hour and annual National Ambient Air Quality Standards (NAAQS) for particulate matter 10 microns in size and smaller (PM10), serious nonattainment for the new federal 8-hour ozone standard, non-attainment for the new federal PM2.5 standard, and severe nonattainment for the 1-hour state ozone standard.

Legislation

SB 709, Florez, was passed by the state legislature, was signed by Governor Gray Davis, and codified into the Health and Safety Code in §40604 in 2003. This requires the San Joaquin Valley Air Pollution Control District to adopt, by regulation, a schedule of fees to be assessed on areawide or indirect sources of emissions.

PM10 Plan Commitment.

The San Joaquin Valley Unified Air Pollution Control District (District) adopted its 2003 PM10 Plan on June 19, 2003, which projects attainment of the NAAQS for PM10 at the earliest practicable date of December 31, 2010. As part of its PM10 attainment strategy, the District is required to reduce directly emitted PM10 and the PM10 precursor oxides of nitrogen (NOx). The 2003 PM10 Plan commits the District to develop new rules or amend existing rules to achieve these emission reductions. The Indirect Source Rule (ISR) is one of the commitments contained in the 2003 PM10 Plan

to meet these requirements. The ISR commitment will be implemented through Rule 3180 and Rule 9510. Indirect sources are land uses that attract or generate motor vehicle trips.

Ozone Plan Commitment.

Emission reductions from Rule 9510 are also important for attaining state and federal ozone standards. As an extreme nonattainment area, the SJVAB was required by the Federal Clean Air Act (CAA) to attain the NAAQS for ozone by November 15, 2010. In order to achieve attainment by 2010, the Extreme Ozone Attainment Demonstration Plan contained commitments to reduce a precursor of ozone, NOx and volatile organic compounds (VOC). These commitments included NOx reductions from indirect sources. Although the federal one-hour standard has been revoked, the plan commitments must still be implemented to ensure progress is made toward attaining the new more stringent 8-hour ozone standard. By 2007, the District will be required to prepare a plan to comply with the federal 8-hour ozone standard that is expected to require additional reductions. Additionally, the California Clean Air Act (CCAA) requires the District to adopt all feasible control measures to attain the standards.

Health Impacts of Non-Attainment

Since 1996 there have been more than 800 new scientific studies published that associate the effects of airborne particulates on human health. Overall the studies validate earlier research and confirm the relationship between particulate air pollution, illness, hospitalization and premature death. Infants and children, particularly asthmatic children, are especially sensitive to the effects of fine particulate pollutions. For additional information on particulate health impacts see the 2003 PM10 Plan, Chapter 1.

Ozone research has produced strong evidence that correlates exposure to ozone and adverse health effects. In humans, ozone can irritate and inflame the respiratory tract, particularly during heavy physical activity, which results in heavy coughing, throat irritation, and breathing difficulties. For additional information on ozone health impacts see the District's Extreme Ozone Attainment Demonstration Plan, Section 2.3.

B. District Authority and Limitations

Authority

The primary provision of state law giving the District authority to regulate indirect source emissions is part of the California Clean Air Act legislation adopted in 1988. The provision, incorporated into Health and Safety Code, Section 40716, states that "a district may adopt and implement regulations to … reduce or mitigate emissions from indirect and areawide sources of air pollution." To further clarify, a California Attorney General opinion issued in 1993 states that

> *"a district's regulations may require the developer of an indirect source to submit the plans to the district for review and comment prior to the issuance of a permit for construction by a city or county. A district may also require the owner of an indirect source to adopt reasonable post-construction measures to mitigate particular indirect effects of the facility's operation. Such regulations could be enforced through an action for civil penalties…"*

Indirect source mitigation programs are also consistent with ARB's interpretation of the CCAA all feasible measures requirement:

> *"every feasible measure to mean that, at a minimum, a district consider regulations that have been successfully implemented elsewhere. They should also consider going beyond what has already been accomplished by evaluating new technologies and innovative approaches that may offer potential emission reductions. Further, districts should consider not only technological factors, but also social, environmental, economic (e.g., cost-effectiveness), and energy factors which prevail in the district, along with the resources realistically available to the district to adopt, implement, and enforce the measures."*

Health and Safety Code 42311(g) allows districts to adopt a schedule of fees on areawide or indirect sources which are regulated, but for which permits are not issued, to cover the costs of District programs related to this source. SB 709, Florez, was passed by the state legislature, was signed by Governor Gray Davis, and codified into the Health and Safety Code in §40604 in 2003. This requires the San Joaquin Valley Air Pollution Control District to adopt, by regulation, a schedule of fees to be assessed on areawide or indirect sources of emissions.

Finally, the District has the authority to control indirect sources, defined in the Clean Air Act (CAA §110(a)(5)(C)) as, "… a facility, building, structure, installation, real property, road, or highway which attracts, or may attract, mobile sources of pollution"(emphasis added). This authority comes from the CAA §110(a)(5)(A)(i):

> *"Any State may include in a State implementation plan … any indirect source review program."*

Analysis of Nexus Applicability

The District analyzed the applicability of Nexus requirements for Rule 9510 and 3180. The District's legal council's analysis found that the Rule and supporting documentation likely meets the federal 'reasonable relationship test'. In addition, the analysis found that the California Mitigation Fee Act (CGC §66000 et seq.) does not apply to Rule 9510 and 3180. The analysis similarly found that California Proposition 13 and 218 do not apply to Rules 9510 and 3180.

California's Mitigation Fee Act (CGC §66000 et seq.) establishes authority and limitations on fees or taxes charged, "by a local agency to the applicant in connection *with approval of a development project*." CGC §66001 (a) states, "In any action establishing, increasing, or imposing a fee *as a condition of approval* of a development project by a local agency on or after January 1, 1989, the local agency shall do all of the following," and §66001 (b), "In any action imposing a fee *as condition of approval* of a development project. (Italics added)." The District cannot impose on the local land-use authority and will not be approving or disapproving development projects. As such, the District cannot place 'conditions of approval' on a project. Therefore, the Mitigation Fee Act does not apply to the ISR Rule. The District does not consider the action of approving or disapproving an air quality analysis and assessment of fees as a discretionary action.

Limitations

The District will not be approving development projects, but the air impact assessments associated with development projects. In this approval, the District will assess air impacts, the amount of reduction required by the rule, the amount of applicant-specified on-site emission reductions, and the amount of off-site emissions reductions needed, if any. The District recognizes the land-use authority of SJVAB Cities and Counties and does not have land-use authority itself.

II. RULE DEVELOPMENT PROCESS

As part of the rule development process for this project, District staff held public scoping meetings in Fresno, Modesto, and Bakersfield in October 2003. At the scoping meetings, District staff presented the objectives of the proposed rulemaking project, collected information, and received comments from interested parties, local agencies, the building industry, real estate associations, consultants, and trade associations. The comments received were incorporated into the draft rules and staff report. In March of 2004, the District presented a draft Rule 9510, and several other documents. In June of 2005, the District presented draft Rule 9510 and draft Rule 3180, as well as associated appendices. The comments received were incorporated into the draft rules and staff report. In addition, District staff held a public workshop September 1, 2005 and solicited input on the draft rule and associated documents. The District received comments from interested parties and affected entities. Information obtained throughout this workshop process was used to develop and modify the draft rules and staff report.

Pursuant to state law, District staff is required to perform an assessment of the socioeconomic impacts prior to the adoption, amendment, or repeal of a rule that will have significant air quality benefits or that will strengthen emission limitations. As a part of the District's socioeconomic analysis process, District staff held a Focus Group meeting on August 11, 2005 to assist in the collection of socioeconomic data for the

implementation of the new proposed program. The Focus Group consisted of a limited number of representatives from interested groups.

Final drafts of the proposed rules, staff report, emission reductions analysis, cost effectiveness analysis, on-site emission reduction checklist, socioeconomic analysis, and rule consistency analysis, will be published prior to a public hearing by the Governing Board to consider the adoption of proposed Rules 3180 and 9510. The tentative schedule for the public hearing to consider the adoption of the newly proposed rules by the District Governing Board is for December 15, 2005.

III. BACKGROUND

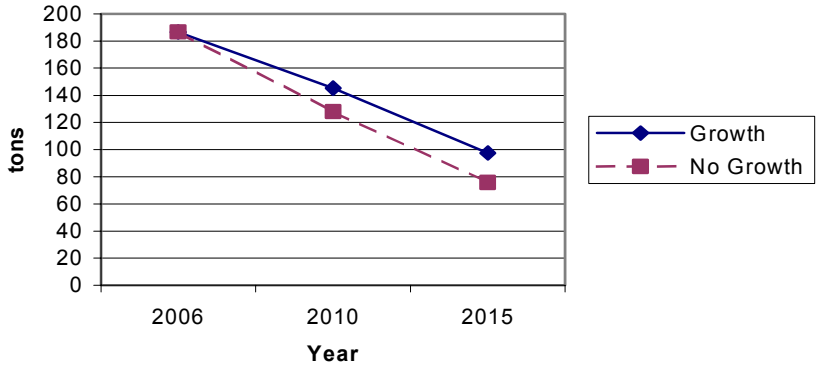
A. Growth and Emissions

The District exceeds state and federal air quality standards for ozone and PM10, despite significant reduction of air pollution from both mobile and stationary sources, primarily because of increases in population and vehicle miles traveled (VMT) in the SJVAB.

Reductions

Federal, state and local efforts have led to approximately 30 percent reduction in smog precursors and a ten percent reduction in PM10 (overall) in the SJVAB since 1990[1]. Significant reductions from stationary sources have been achieved, so that mobile sources now produce 69 percent of all NOx emissions in the District. Today's new cars pollute about 90 percent less than models produced 25 years ago due to California's strict vehicle emissions standards. By 2003, the average new car in California will pollute 75 percent less than 1994 models[2]. Although these standards will continue to greatly improve air quality, large increases in population and driving partially reduce the benefits of cleaner motor vehicles. The following chart shows how much lower the emissions from motor vehicles would be if growth were not to occur.

Figure 1
Difference in NOx Emissions for All Vehicle Types



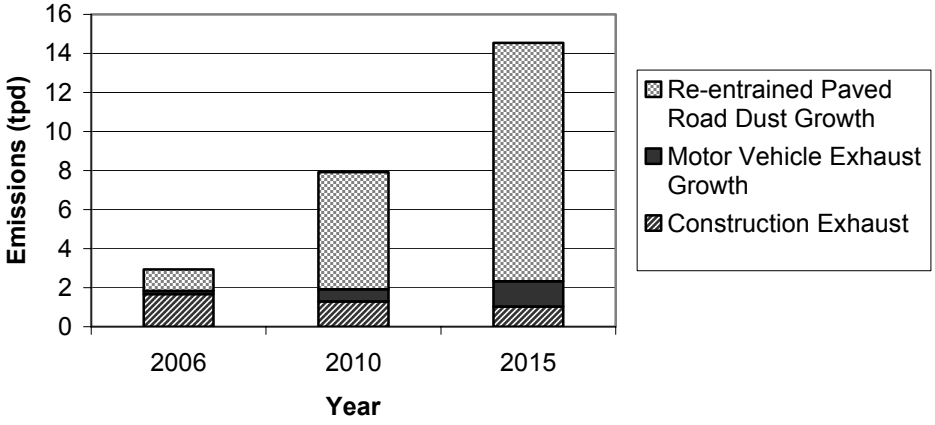
Population Growth

The SJVAB has experienced a large increase in population in the past several decades. The total population in the District increased by 22% between 1990 and 2000, and California's Department of Finance is projecting that the SJVAB will see an overall increase in population of 24% between 2000 and 2010. Each county varies, with the highest expected growth in terms of percentage increase in Madera, and the lowest expected growth in Fresno, but in terms of numbers of people, Fresno is expected to see the largest increase[3]. With increased population there is an increase in emissions from area sources, such as consumer products, fuel combustion, landscape maintenance equipment, etc.

VMT Growth

The total number of vehicle miles traveled (VMT) in the District has increased at a faster rate than population growth. The District witnessed a nine percent increase between 1999 and 2002, and is expecting a 27 percent increase from 2002 to 2010[4]. Entrained and re-entrained paved road dust and corresponding PM10 emissions, increase as VMT increases. The ozone and PM10 precursor NOx, also increases as VMT increases.

Figure 2
PM10 Emissions from Development



Increased Emissions From Growth

The past and projected increases in population, associated development and construction emissions and vehicle miles traveled, and the slower than expected introduction of technological advances in automobile and truck emission controls, have significantly slowed progress toward attainment. The ISR program can reduce and offset some of the growth in emissions and is required for attainment of the federal ozone and PM10 standards by the dates required in ozone and PM10 attainment plans.

B. Existing Indirect Source Programs

The District identified several examples of air pollution agencies in California that are currently reviewing land use projects for indirect source impacts and/or collecting mitigation fees in their districts. Five air pollution agencies have adopted and implemented an indirect source rule or policy. The methods and authority over development projects vary from air district to air district. Brief descriptions of these programs are provided below.

Mendocino County Air Quality Management District (AQMD) outlines their permitting process for indirect sources in Rule 1-200. The rule requires any indirect source to obtain an Authority to Construct (ATC) prior to starting construction. When Mendocino AQMD receives an application, they perform a California Environmental Quality Act (CEQA) determination. The ATC is not issued until a Notice of Determination is completed and filed.

Great Basin Unified Air Pollution Control District (APCD) also has an indirect source permit rule in place, Rule 216. This rule defines indirect sources as a secondary source, which is any structure, building, facility, equipment, installation, operation, or aggregation thereof. The application and associated informational documents are reviewed, and an analysis on expected emissions and air quality impact is performed. Public notice is published, and the general public is allowed to review and comment. The District then considers comments and imposes conditions on the approval of the permit or denies a permit if it is determined that the secondary source will contribute to a violation of any air quality standard. The fees imposed on secondary sources in Great Basin are outlined in Rule 301. Those fees are based on the size of the commercial unit and the number of parking spaces, or the number of residential dwelling units.

Colusa County APCD has an indirect source fee rule, Rule 4.8. The fees are assessed for building permit applicants during the city or county's permit process. The fees are based on the square footage of commercial or industrial projects, or by residential unit. The city or county may retain an administrative fee of ten percent. The fees are used to offset the District's costs, and any excess is used to mitigate air quality impacts.

Placer County APCD has instituted a "Policy Regarding Land Use Air Quality Mitigation Funds." During CEQA review, the APCD assesses total emissions that are estimated to occur during the ozone season from a particular project. The emissions are estimated by utilizing URBEMIS, which will be mentioned later in this staff report. After estimating emissions during the ozone season from URBEMIS, Placer County APCD requires 40% mitigation of a project's impact or to below a significance threshold, either on-site, off-site, by paying a fee, or a combination of those options.

Shasta County AQMD has adopted Rule 3:16, which allows Shasta County to place reasonable conditions on any fugitive, indirect or non-traditional source. At the current time, Shasta County utilizes the rule to mitigate the impact of new residential dirt roads by requiring paving or paying a fee. Their Resolution 84-2 authorizes an in-lieu buy out schedule for road paving, which is currently set at $800 per parcel below 1,000 feet in elevation.

In addition to the above examples, numerous government agencies in the SJVAB have created impact fee programs that have proved useful in drafting this program. The most common are transportation/transit impact fees for cities such as Bakersfield, Lathrop, and Visalia. The City of Stockton and the City of Turlock also have air quality impact fee programs in place.

C. Program Options

The District considered several options for the initial approach to the ISR program. The options were developed to coincide with the normal development process as a condition of application completeness during the environmental review with a city/county, or while compiling conditions of permit approval as part of the cities/counties development processes.

District Permit Program: This option would require permit applicants to obtain a permit from the District prior to paying the city/county's building permit fees. The District could require applicants to provide specific documents needed to determine the emissions from the project using URBEMIS. The District could then require on-site emission reduction measures as conditions of approval of the permit and/or calculate a fee. Under this option, the District could collect the off-site fee prior to issuing the District permit or defer the fee until the city/county issued the building permit.

City/County Review & Administration: This option would allow the city/county to review the emissions generation of an applicant's project, likely using URBEMIS. Under this option, the city/county would collect the off-site fee, if any, and transfer the fee to the District's off-site fund account(s). The city/county could also operate the entire program including expenditure of funds on emission reduction projects if the city/county adopted a program at least as effective at reducing emissions as the District's rule.

District Review & City/County Administration: Under this option, the District would require the applicant to provide documents necessary to perform an emissions generation analysis, likely using URBEMIS. The District would calculate the off-site fee amount based on total emissions and identify credits for specific on-site emission reduction measures included in the project. Prior to authorization of a building permit, the city/county would review the list, check which on-site measures have been incorporated into the project, and collect the fee, if any.

Simple Fee: This option would allow cities/counties to charge an off-site fee based on certain criteria, such as size or number of units. If this option was pursued, most likely the per unit fee would be based on the Institute of Transportation Engineers (ITE) trip generation rates for the different land uses and emissions calculated by URBEMIS. Under this option, the city or county would assess and collect the fee. An appeal program or a rebate program would be a possibility to give credit for any on-site measures that were performed or incorporated into the design of the project.

District Review & Administration: Under this option, the District would require the applicant to provide documents necessary to perform an emissions generation analysis, likely using URBEMIS. The District would calculate a required reduction amount based on total emissions and identify credits for specific on-site emission reduction measures included in the project. Required reductions not achieved by voluntary on-site measures would be achieved off-site through an offset fee. Offsite reductions would be subject to criteria including (but not limited to) being quantifiable and surplus. The District would conduct annual reporting to analyze the effectiveness of the off-site emission reduction program.

The District chose to pursue the 'District Review & Administration' option for several factors. Primarily, the District chose to craft the ISR rules to be compatible with local land-use authorities decision-making processes, and to have the ability to be worked into CEQA documents at the Lead Agencies' discretion. The District includes the options for voluntary on-site emission reduction measures that would allow a reduction in off-site fees.

IV. PROPOSED REGULATIONS

A. Proposed Rule 9510

The purpose of proposed Rule 9510 is to reduce emissions of NOx and PM10 from new development projects. The rule applies to development projects that will seek to gain a discretionary approval for projects that, upon full build-out will include any one of the following: 50 residential units, 2,000 square feet of commercial space, 25,000 square feet of industrial space, 20,000 square feet of medical office space, 39,000 square feet of general office space, 9,000 square feet of educational space, 10,000 square feet of government space, 20,000 square feet of recreational space, or 9,000 square feet of uncategorized space. The rule also applies to transportation projects whose construction exhaust emissions will result in a total of two tons per year of NOx and PM10 combined. However, there are several sources that are exempt. These include transportation projects that meet certain conditions, reconstruction projects that result from a natural disaster, development project's whose primary functions are from District permitted stationary sources. Also, development projects that have a mitigated baseline below two tons per year for NOx and PM10 shall be exempt from the

mitigation requirements of the rule. Anti-circumvention language was added to prevent piecemealing of development projects.

Applicability

Rule 9510 applies to any applicant that applies for a final discretionary approval for a development project which will include any of the following: 50 residential units; 2,000 square feet (sf) of commercial space; 25,000 sf of light industrial space; 100,000 sf of heavy industrial space; 20,000 sf of medical office space; 39,000 sf of general office space; 9,000 sf of educational space; 10,000 sf of government space; 20,000 sf of recreational space; 9,000 sf of space not identified, and; transportation and transit projects where construction exhaust emissions results in a total of 2 tons of NOx and PM10 combined.

Exemptions

Transportation and Transit projects are only subject to the construction emission reduction requirements of the rule. Development projects subject to the rule that reduce their operational emissions to less than 2 tons per year of NOx and PM10 each not subject to the rule's operational or construction emission reductions requirements.

Reconstruction of a development that was damaged or destroyed that is rebuilt to essentially the same use and intensity is similarly not subject the rule's requirements. In addition, development projects whose primary functions are regulated by District permits are exempt. Those stationary source projects are exempted because the projects' primary emissions are from stationary sources that are currently regulated by District rules and permitting requirements.

Application

Rule 9510 requires applicants of new development projects to submit an Air Impact Assessment (AIA) application to the District prior to or at the project's application for a final discretionary approval with a public agency. The application would include the information necessary for the District to perform an assessment, project location and description, an on-site emission reduction checklist, and an assessment by the applicant (if desired). An AIA would consist of inputting project data into an APCO-approved model to estimate emissions, and inputting on-site emission reduction measures that are components of the project design and/or other project specifics to calculate emissions reductions. This will be performed by the District and may be performed by the applicant. The emissions and emissions reduction outputs will be used to calculate the amount of on-site emission reduction is achieved, and what the off-site emission reduction fee would be, if any. Proposed Rule 9510 specifies the use of an APCO-approved model (Draft Rule 9510 Section 3.2), which in most cases will be URBEMIS. In the event that URBEMIS is not suitable for the proposed land use (i.e. does not have ITE trip rate), the District may approve another model, or review and approve off-line with project-specific calculations. If project-specific data is entered into

the APCO-approved model and overrides defaults, the applicant shall document and justify those project-specific inputs.

On-Site Emission Reduction Checklist
The measures listed in the checklist have a known quantification methodology in URBEMIS 8.7. The methodologies can be found in the URBEMIS User's Guide, available at South Coast AQMD's website http://www.aqmd.gov/ceqa/urbemis.html. The on-site emission reduction checklist shall identify which measures have been voluntarily selected by the applicant, the enforcement mechanisms available for those measures, and the reasons for not selecting the remaining measures. All measures selected that are above District or State requirements, regardless of enforcement mechanism, will count towards emission reductions for the project, in accordance with the methodologies in URBEMIS. The measures for the On-Site Emission Reduction Checklist can be found in Appendix C.

On-Site Enhancing Measures
The District has identified several measures that are known to have an air quality benefit. However, at this time they do not have a quantification methodology for project-level emission reductions. These measures still have a beneficial air quality impact. For this reason, the District will maintain a list of 'On-Site Enhancing Measures' and make it available to applicants. There are no requirements on selection of measures from the On-Site Enhancing Measures list. As emission reduction methodologies are determined for these and other new measures, they can be incorporated into URBEMIS. The list is available in Appendix C.

Monitoring and Reporting Schedule
For projects that select on-site measures that do not already have an enforcement mechanism, a proposed SJVAPCD On-Site Monitoring and Reporting Schedule (MRS) will be completed. The District will provide a standard form for the MRS, and the applicant is responsible for completing the MRS. The District will then work with the applicant to finalize the MRS. Draft Rule 9510 §5.4 discusses the components of a MRS.

Fee Deferral Schedule
In addition to the AIA application, the applicant may propose a Fee Deferral Schedule at the time of application or during application review in anticipation of a possible off-site fee, or within 15 days of receiving an off-site fee invoice. The District will provide the Fee Deferral Schedule format. The applicant can choose the schedule of payments, but all fees for a development or phase thereof must be received *prior* to construction of that development or phase thereof. Draft Rule 9510 §5.5 discusses the components of a FDS.

Completeness Finding
The District will have 10 days to determine whether or not the application is complete. After the District deems the application complete, the District has 30 days to approve

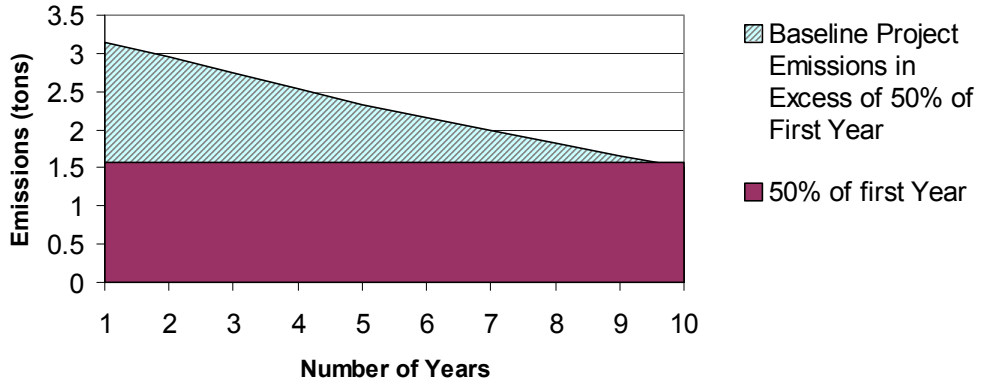
the application and notify the applicant of the estimated fee amounts. In addition, the application and MRS will be submitted to the applicable public agency for voluntary review. The public agency may provide comment at their discretion. The applicant may have the assessment modified to incorporate more on-site measures, if desired. Once the proposed MRS is approved, the District and the applicant shall finalize the MRS. If there are changes to the project that will impact the emissions total or schedule of build-out, the applicant shall notify the District of that change within 60 days of said changes, or prior to the start of project construction, whichever is first. As stated above, if a project mitigates to less than two tons of operational NOx and PM10, it will not be subject to the required emission reductions stated in the draft Rule 9510 §4.3.

Required Emission Reductions

Proposed Rule 9510 would require applicants to reduce NOx and PM10 emissions. The rule is designed to reduce the impact of the development projects to the extent needed for the District to reach attainment of ozone and PM10 standards. The District calculated the level of reduction needed on a per-project basis that would achieve the emission reduction committed to in the PM10 and ozone attainment plans. Draft Rule 9510 Section 6.0, et seq., describes the required emission reductions.

Although the majority of the NOx emissions associated with a project are due to motor vehicles, there is a decline in NOx emissions over time due to ARB's tailpipe controls. The NOx mitigation fee is structured to account for a 50% decline in annual NOx emissions from motor vehicles over ten years. Thus, the rule requires mitigation of the cumulative NOx emissions in excess of 50% of the project's operational baseline emissions (the emissions at the first year of buildout) until the project's emissions reach half of the project's first-year baseline emissions, which is approximately 10 years. This method ensures that a project does not over-mitigate its emissions. Draft Rule 9510 Sections 3.8 defines baseline emissions. Rule 9510 Sections 3.10 and 3.27 define construction baseline and operational baseline, respectively. Rule 9510 Section 3.20 defines 'mitigated baseline'. Project emissions and the required mitigation can be visually represented as follows:

Figure 3
NOx Project Emissions and Reductions Compared to 50% of the First Year Emissions



In essence, the NOx mitigation required for Rule 9510 is represented above by the triangle, which is equal to one third of total project emissions during the first ten years. The applicant can reduce the emissions represented by that triangle by using on-site mitigation measures, by paying the District a fee to fund emission reduction projects off-site, or through a combination of the two. The fee amount would decrease or be eliminated depending on the amount of on-site mitigation incorporated by the applicant into the design of the project.

The PM10 mitigation requirement is different from NOx. Operational PM10 emissions from a project do not decline over time – they remain constant. Accordingly, Rule 9510 will require mitigation equal to half of the emissions for the first year after build-out for 10 years (the same period of time required for NOx mitigation).

Proposed Rule 9510 would also require applicants to reduce NOx and PM10 construction equipment emissions. The rule requirement is to reduce construction NOx emissions by 20% and PM10 emissions by 45% beyond the statewide average. In determining the level of reduction for construction emissions, the District researched what other air districts had set, and found those targets are achievable. There are several options available for controlling NOx and PM10 emissions from equipment used for construction on-site. Options can include, utilizing newer equipment, altering fuel type, modifying an engine, or using exhaust after-treatment devices, to meet the rule requirements. New equipment can provide a high percentage of emissions reductions, depending on the horsepower and the year of the equipment. The reductions are achievable with existing technology with a mix of newer equipment and retrofit devices, and will allow applicants applying moderate effort to pay no fee on construction.

Achieving Emission Reductions

If on-site mitigation measures are chosen by the applicant, the applicant shall submit a MRS to the District for the those on-site mitigation measures that do not have built in enforcement mechanisms. All on-site emission reductions measures that are above District and State requirements will be credited to emission reductions for the project. The MRS will identify enforcement mechanisms, which may include identifying specific funding mechanisms, as well as monitoring, recordkeeping and reporting. The Proposed MRS shall be forwarded by the District to the public agency for review. It is important to note that the percent reduction achieved onsite results in a greater reduction of the NOx fee. While on-site mitigation is not required, the "bigger bang for the buck" is achieved with as much on-site mitigation as possible. For example, when onsite NOx reductions exceed the excess emissions above 50% of the first year's baseline, the NOx fee becomes zero. Additionally, if the onsite measures reduce the NOx and PM10 to less than 2 tons per year each at buildout (baseline), no additional reductions are required. See Table 1 for examples of on-site emission reductions and the associated off-site fee reduction. See Table 2 for a list of simple measures that small projects can achieve, and a list for larger projects. If the emission reductions required by the rule are not fully achieved on-site, off-site fees would be required.

The use of off-site fees is strictly limited to procurement of off-site emission reductions. Absolutely no off-site funds may be used for District staffing or budget. The District shall provide annual reporting per draft Rule 9510 Section 10.4. Annual reports shall include, at a minimum: the total amount of off-site fees received; the total monies spent; total monies remaining; any refunds distributed; a list of all projects funded; the total emission reductions realized, and; the overall cost-effectiveness factor for the projects funded.

Off-site mitigation would consist of paying a fee to fund emission reduction projects for required emission reductions that are not reduced on-site. Rule 9510 contains pollutant-specific fee formulas in Section 7.0, et seq. Appendix B shows how those formulas were developed. The off-site fees are strictly tonnage based. This means that all projects are treated equally, and assessed on the amount of emissions associated with the project. The fee formula applies equally to all applicable projects, accounts for the amount of on-site emission reductions. The fee would be payable in 60 days upon notification of fee amount, unless the applicant has arranged a FDS with the District.

Both the NOx and the PM10 fee formulas include a Cost of Reductions for one ton of that pollutant. These values were determined based on historical grant programs with the district and project fund use, and represents an average value for a range. Appendix E contains a greater description of how those values were derived.

Rule 9510 directs the District to administer the fee use to achieve emissions reductions that the fees were based on, in a cost-effective manner. There are numerous emissions

reduction projects available. Potential projects are as follows: projects currently qualifying for the District's Heavy-Duty Engine Incentive Program including, alternative fuel low-emission school buses, transit buses, and other vehicles, diesel engine retrofits and repowers for trucks, PM efficient street sweepers powered by natural gas, agricultural water pumping engine replacements, locomotive repower/retrofits, electric forklifts, etc. Other potential projects include gross polluter replacement, biomass subsidies, electric vehicle or lawn equipment rebates, truck refrigeration unit plug-ins at distribution centers, woodstove replacement/retirement, video-teleconferencing systems, and telecommuting start-up costs. Potential PM10 reduction programs include paving or treating unpaved traffic surfaces and shoulders and PM10 efficient street sweeper purchases. Some projects will achieve reductions of NOx and PM10. The funds will be managed by a grant-like program and allocated as applications are received. If a sufficient amount of applications to fund projects are not received, the District will consider a directive program that would be approved by the Governing Board. The District recognizes the sensitivity of the geographic distribution of the funds. Any emissions reduction project will provide a localized benefit to the area of fee origin.

Table 1
On-Site Reductions and Associated Operational Off-Site Fee Reductions.

Example Project 150 Single-Family Units in 2006 <u>On-Site Package</u> - Increased Density (from 50 to 30 acres) - No Wood Stoves - Increased Energy Efficiency by 10% - Located near local-Serving Retail - Bus Service Nearby - Traditional Street Design - Sidewalks on Both Sides of Street - Bikelanes on 20% of streets - 10% of units Deed-Restricted Below Market Rate	On-Site Emission Reduction (%)		Operational Off-Site Fee Reduction (%)	
	NOx 12%	PM10 36%	NOx 36%	PM10 72%
Example Project 200 Multi-Family Units 40,000 sf Strip Mall 60,000 sf General Office <u>On-Site Package</u> - No Wood Stoves - Increased Energy Efficiency by 10% - Located near local-Serving Retail - Bus Service Nearby - Traditional Street Design - Sidewalks on Both Sides of Street - Bikelanes on 20% of streets - 5% of units Deed-Restricted Below Market Rate - Commercial and Retail implement Transportation Demand Measures - Commercial and Retail Reduce Parking Supply	On-Site Emission Reduction (%)		Operational Off-Site Fee Reduction (%)	
	NOx 23%	PM10 29%	NOx 68%	PM10 59%

Table 2
Basic On-Site Measures for Small and Large Projects.

Small Projects	**Large Projects**
All Land Uses: Traditional Street Design Increased Energy Efficiency Include Sidewalks on all streets Locate near mass transit stops Locate near a mix of uses Residential: No Fireplaces or Woodstoves Locate near local serving retail Locate near jobs Non Residential: Reduce parking supply Locate near residences Implement Transportation Demand Measures Include Bike Racks	Same as Small Projects, Plus: All Land Uses: Include a mix of uses Install Bike Paths or Bike Lanes and/or Pedestrian paths

AIA Approval

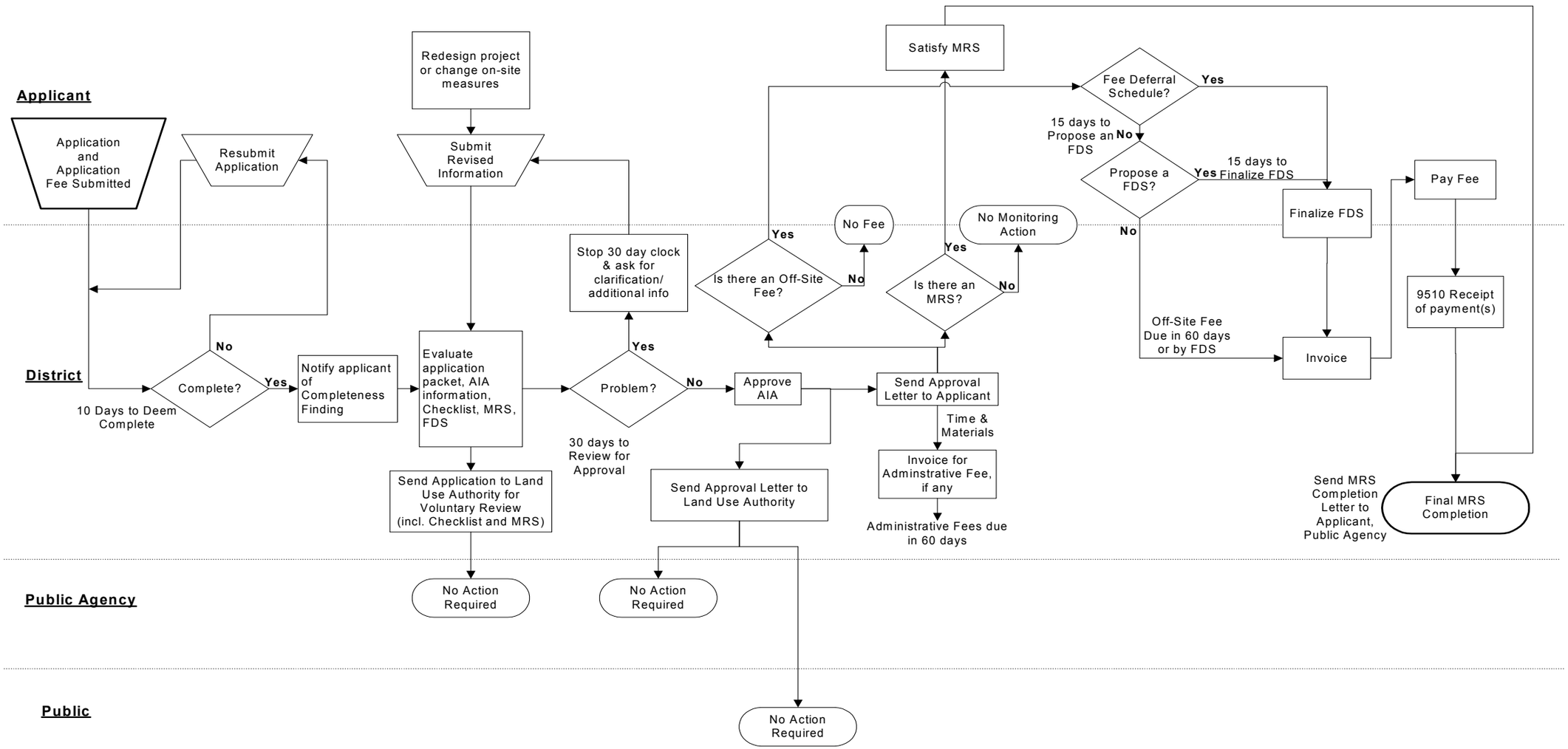
The District will provide a decision on the AIA application within 30 days of finding the application complete. The District will approve the AIA application or disapprove the AIA application. It is important to note that the District will not be approving a permit or other discretionary action as a result of Rule 9510. In addition, the District will not be approving or disapproving the development project itself, but the Air Impact Assessment application for that project. The authority for land-use decisions lies with the local land-use agency. The AIA application approval is ministerial and will not involve conditions of approval.

MRS Maintenance

For those projects that have a MRS with the District, the applicant is responsible for implementing those measures identified. The District is responsible for monitoring and receiving reports for on-site emission reduction measures. The District shall provide a tentative compliance letter to the applicant, public agency and public upon request. Upon completion of the last MRS requirement, the District shall provide a letter of MRS completion to the public agency and applicant. The District shall also make the letter available to the public.

If the applicant committed to on-site construction emission reductions, the applicant is responsible for submitting the construction equipment schedule to the District prior to applying to the public agency for a grading permit. At that time, the District will verify construction emissions for the project. If the on-site emission reductions specified by the applicant are not achieved, the District shall assess and invoice for off-site fees required by the rule.

ISR Application Flow Chart



B. Proposed Rule 3180

The purpose of proposed Rule 3180 is to recover the costs of administering Rule 9510. The proposed rule includes a non-refundable application-filing fee to be paid when an application is submitted to the District. Once an application and the application fee are received, district staff will log the total staff hours spent on the project using the District's automated Labor Information System. The application evaluation fee will comprise those hours at a weighted average labor rate, minus the application-filing fee, so that only the cost of the actual hours spent on the project will be recovered.

Rule 3180 also contains a fee equal to 4% of the offsite emission reduction fees to recover the cost of administering off-site emission reduction projects. The 4% would be payable when the offsite emission reduction fees are collected.

C. Program Implementation - Streamlining

The process identified in Rule 9510 may be completed prior to or concurrent with the City/County permit review process. Specifically, Rule 9510 has been designed for non-interference with the City/County land-use and California Environmental Quality Act (CEQA) processes. However, information from the ISR process may be used by a Lead Agency in environmental documents, at their discretion. Currently, air quality impact assessments are usually required for projects with potentially significant air impacts. Since the NOx and PM10 pollutants will be addressed through ISR, it will not place an added burden to the applicant, and should provide a foundation for or replace the ozone precursor and PM10 emission analysis included in that environmental document. The On-Site Emission Reduction Checklist will help applicants identify quantifiable mitigation alternatives and provide justification for feasibility or infeasibility. The MRS will identify enforcement mechanisms for on-site emission reduction measures that were selected by the applicant.

The District will provide information on the District's website, such as application forms and guidance documents. The District will revise its Guidelines for Assessing and Mitigating the Air Quality Impacts (GAMAQI) document as needed. In addition, the District will work with Cities and Counties on additional measures to facilitate communication and streamlining of the application and review process.

Finally, the ISR program is set up to allow the applicant to provide the AIA. However, the applicant is not required to provide modeling or emissions calculations. The District will prepare the AIA based on the project-specific information provided in the AIA application. The District will not charge a specific fee for modeling, but will invoice for any time and materials beyond that covered by the application filing fee. The application filing fee was estimated based on the average time expected to review and AIA application and conduct emissions calculations/modeling for the project.

D. Use for Environmental Review – CEQA

The ISR program operation is not subject to CEQA requirements. The review conducted on applications for the program is a ministerial action not subject to CEQA, per PRC §21080 *Division Application to Discretionary Projects; Nonapplication; Negative Declarations; Environmental Impact Report Preparation* (b)(1):

> *(b) This division does not apply to any of the following activities:*
> *(1)Ministerial projects proposed to be carried out or approved by public agencies.*

The ISR Program will require an amount of emission reductions from certain development projects subject to the rule. Implementation and compliance with the rule will reduce the cumulative NOx and PM10 impacts of anticipated growth to less than significant because the reductions attributed to this program were identified in two attainment plans as necessary to achieve the applicable standards. CEQA Guidance document § 15064 (h)(3) states-

> A lead agency may determine that a project's incremental contribution to a cumulative effect is not cumulatively considerable if the project will comply with requirements in a previously approved plan … which provides specific requirements that will avoid or substantially lessen the cumulative problem (e.g. … air quality plan).

The GAMAQI will be updated with any necessary changes to District CEQA policy and provides a suitable location for changes to defaults and guidance on model usage.

E. APCO- Approved Models

Proposed Rule 9510 specifies the use of an APCO-approved model, which in most cases will be URBEMIS. URBEMIS stands for "Urban Emissions Model." URBEMIS was originally developed by the California Air Resources Board (ARB) as a modeling tool to assist local public agencies with estimating air quality impacts from land use projects when preparing a CEQA environmental analysis. The model was developed to estimate construction, area source, and operational air pollution emissions from vehicles from a wide variety of land use development projects in California, such as residential neighborhoods, shopping centers, office buildings, etc. Originally designed as a 'sketch planning' tool for CEQA project review, it has been continuously enhanced with each new version to provide greater capability and accuracy. URBEMIS is used statewide by air agencies and public agencies and contains air basin-specific information. URBEMIS has substantial flexibility to accommodate project specific travel and vehicle information when available. The model also includes a mitigation component that allows the user to select specific measures and quantify emission reductions associated with the selected measures[5].

The District undertook an extensive effort to ensure that URBEMIS is the right tool for this program. The District hired a consultant, TY Lin International/CCS, to review

available land use emissions models, recommend which model is most suitable for this program, and identify areas of improvement. The consultant recommended URBEMIS as the best tool for ISR for several reasons, including:

- URBEMIS contains the latest California-specific emission factors with motor vehicle emission factors based on EMFAC2002,
- URBEMIS is the only model that contains emissions calculations for PM10
- URBEMIS contains emissions calculations for area sources
- URBEMIS contains motor vehicle activity based on trip rates from the Institute of Transportation Engineers (ITE)
  ITE rates are nationally accepted, are widely used and have withstood legal challenges.
- URBEMIS does not require large amounts of input for an emissions estimate (it is easy to use)
- URBEMIS inputs are objective and quantifiable.
  For Example- For sidewalk coverage, the input fields include percent of streets with sidewalks on both sides and the percent of streets with sidewalks on one side.
- URBEMIS contains the flexibility to modify defaults if project-specific information is known.
- URBEMIS is free.

TY Lin International/CCS made recommendations on the improvements to the area-wide mitigation component and hired a sub consultant, Nelson/Nygaard, to make detailed recommendations for improvements to the operational mitigation component. Nelson/Nygaard researched the latest studies on land use, what design features consistently reduced vehicle activity (and consequently emissions) in the real world and by how much. Nelson/Nygaard then created emissions reduction calculation methodologies based on those studies and submitted a report to the District. The District then initiated an extensive statewide effort to update the URBEMIS model with the resulting recommendations. The District, TY Lin International/CCS, and Nelson/Nygaard met with the URBEMIS working group, which is a group of representatives from air districts throughout the state of California, as well as the California Department of Transportation (CalTrans), and presented the recommended changes to URBEMIS. Once the URBEMIS Working Group made recommendations that were incorporated into the report, the report was then peer reviewed by several well respected researchers in the field of land use and travel activity. The peer review comments were incorporated into the report and approved. The final report was incorporated into URBEMIS 8.7, released to the public, and is included in this document as Appendix D.

The URBEMIS model would require, at minimum, the following inputs: type of land use, number of units, and any mitigation measures selected. However, there are numerous defaults that can be modified if more precise information on the project is available.

These can include: trip rate(s), emission factors and usage rates for specified area source emissions, year of project use, fleet characteristics in terms of percentage of and fuel use of vehicle types, trip speeds, trip lengths, trip percentages, ambient seasonal temperatures, variable start percentages, and emission reduction inputs. Emission reduction inputs can include increased density, zero hearth options, percent energy efficiency beyond Title 24, percent of landscape equipment electrically powered, number of housing units and study area employment (job to housing ratio), the presence of local serving retail, the number of transit stops, intersections per square mile, percentage of streets with sidewalks, percentage of bike lane coverage, percentage of housing units below market rate, numerous transportation demand management measures, number of actual parking spaces, and controls on fleets. Based on those inputs, the model calculates total area source emissions, total vehicle emissions, total overall emissions and total reduced emissions in terms of lbs/summer day, lbs/winter day, or tons/year.

In addition to the benefits of URBEMIS, this model was chosen over other potential models for various reasons. A different option was to use transportation models used by the COGs for conformity purposes. Transportation models, while appropriate for their current use, are not appropriate for ISR for the following reasons:

- There is not one model used valley-wide.
    - *There are eight different models. Some cover only one county, others cover multiple counties.*
- The eight models do not use the same modeling basis, making for inconsistencies of software if multiple models are used.
- The analysis requires subjective inputs.
- Certain trips are not accounted for in the transportation model.
  For example- While URBEMIS will account for the very-short trips associated with new gas stations (passby trips), transportation models do not include the short drives into gas stations.
- The transportation models include deviations from known trips.
    - *They do not account for 10-15% of trips on Arterial Streets*
    - *They do not account for 15-35% of trips on Collector Streets*
    - *Trips on local streets are not included*
- The trip types come from old, 1970's data that is only periodically updated.
- Does not include new area emissions, which are wholly attributable to new developments.
- Transportation modeling requires many inputs, and is not easily used by an average applicant.
- Transportation modeling is not free

It is the view of the District that URBEMIS is the best tool available. As stated above, URBEMIS has a solid, proven basis (EMFAC2002, ITE, peer-reviewed quantification), is flexible and allows changes to various calculation inputs when project-specific information is known. Comments received by the District pointed out that URBEMIS

contains some information that may need refinement. Particularly, the fleet mix and the on-road silt-loading factor. The District agrees that new, more accurate information should be incorporated into URBEMIS when that information becomes available Concerning the on-road silt-loading factor, the District concurs with the air basin specific factor received in comments and will be recommending using the factor of .031 for analyses prepared for the rule and will incorporate that factor into the San Joaquin Valley portion of URBEMIS. To remedy the fleet-mix issue, the District has hired a consultant (VRPA) to investigate and recommend new land-use specific fleet mixes. In addition, the District is participating in a statewide effort to improve the construction portion of URBEMIS. In the interim detailed guidance and sample construction inputs will be provided by the District to assist applicants.

F. Other Issues

The 2003 PM10 Plan also included a one-ton per day PM10 emission reduction commitment for Metropolitan Bakersfield by 2010. That commitment is being addressed through a "task force" composed of staff from the City of Bakersfield, Kern County, and the District. The task force is identifying the projects that would provide the greatest impact on ambient PM10 levels in the area.

Input from the public during the scoping meetings and from written comments suggested that the proposed indirect source rules should include existing sources as well. There are several types of land uses that generate significant trips that could be considered: event centers, distribution centers, and regional shopping centers. The District has performed some preliminary research on distribution centers and warehouses. There are well over 2600 distribution facilities in the SJVAB, with an average size of 800,000 sq ft, according to District estimates. The District will continue to consider regulations on these types of sources for some time in the near future.

The District will work to coordinate the ISR program with the public agency land-use approval process. The District will be coordinating review with the public agency through-

1. Making the ISR process concurrent with or prior to the public agency process;
2. Forwarding a copy of the AIA application (upon determination of completeness), a copy of the AIA approval package (upon approval), and a letter of Final Compliance to the public agency for voluntary review and commenting;
3. Communicating with the public agency when necessary during the application review process; and
4. Incorporating ISR AIA data into the District's CEQA commenting process.
5. Providing a letter of project status to the public agency upon request.

In addition, the application and approval will be made available to the public.

V. EMISSIONS AND EMISSIONS REDUCTIONS

The District committed to reduce the PM10 and NOx emissions from indirect sources in the 2003 PM10 Plan and the Extreme Ozone Attainment Demonstration Plan, which could be achieved by on-site emission reduction and/or emission based fees that would be used to fund off-site emissions reduction projects. Both plans contained emissions reduction commitments from growth that were necessary to demonstrate attainment. Appendix B contains an estimate of total emissions and emissions reductions expected from new development projects by 2010, which are 5.4 tons per day of NOx and 5.8 tons per day of PM10.

The ISR program is expected to achieve the emission reductions committed to in the PM10 and ozone plans. However, the District realizes that those emission reductions may not be achieved for a variety of reasons. If the emission reductions are not achieved because growth becomes less than that forecast in the emission inventories, the District will not need to adjust the program to make up the reductions. This is because the need for emission reductions was based on the projected growth. If growth occurs at a level less than that predicted, then the level of emission reductions needed will similarly be reduced. However, if other circumstances are encountered and the emission reductions are not achieved, the District will have to make a SIP revision, possibly substituting another measure for the remainder of emission reductions required or adjusting the off-site mitigation fee program to obtain greater reductions.

The District based its estimate of emission reductions achievable by the ISR program on total growth in the emission inventory that is subject to the rule accounting for rule mitigation requirements, exemptions and applicability thresholds. The District considered using a bottoms-up estimate of emissions based on the number of projects and units expected each year. Statistics on residential development were available for this type of analysis; however, due to the wide variety of uses and limited data on the numbers and sizes of non-residential uses, a comprehensive bottom-up analysis was not feasible.

VI. COST EFFECTIVENESS – OFF-SITE EMISSION REDUCTION PROJECTS

District staff has prepared a draft cost effectiveness analysis of the estimated costs of emission reductions required in the proposed Draft Rule 9510. The cost effectiveness analysis is attached to this staff report and labeled Appendix E. This analysis details the types, quantities and costs of projects available for funding from the off-site fees collected by the District, and provides an example mix of projects to demonstrate how the fees may be used. The District shall use 100% of the off-site funds received for

emission reduction projects. No off-site funds may be used for the District's budget, staffing or other administration.

Off-Site fund use accountability is written into the Draft Rule 9510. The District shall provide annual reporting per draft Rule 9510 Section 10.4. Annual reports shall include, at a minimum: the total amount of off-site fees received; the total monies spent; total monies remaining; any refunds distributed; a list of all projects funded; the total emission reductions realized, and; the overall cost-effectiveness factor for the projects funded. Annual reports shall be made available to the public.

For off-site emission reduction projects, the duration of the contract will vary depending on the project. Some contracts will be completed upon installation, while others may require reporting for 5 years or longer. For example, a road-paving project would have a contract that is completed upon installation, whereas an engine contract typically contains a 5-year reporting requirement.

VII. SOCIOECONOMIC IMPACT ANALYSIS

Pursuant to state law, the District is required to analyze the socioeconomic impacts of any proposed rule or rule amendment that significantly affects air quality or strengthens an emission limitation. The provisions of Draft Rules 9510 and 3180 will reduce PM10 and NOx, emissions by requiring pollutant specific mitigation through measures incorporated in to the design of a new project, and/or paying a fee to fund emissions reduction projects; therefore, District staff solicited volunteers from affected entities to participate as members of the socioeconomic focus group for these rules. District staff held a focus group meeting, to identify the socioeconomic impacts of the draft rules. District staff will use the socioeconomic analysis to further refine the draft rules. The socioeconomic report was released to the public for comment and review and was presented at the final workshop. The report was incorporated into this staff report as Appendix F. The final socioeconomic report will be presented to the District Governing Board at the public hearing for adopting the proposed rules.

The implementation of ISR fees may have socioeconomic impacts on certain development types that are summarized below and described in the socioeconomic impact analysis. Although impacts may occur, the program has been designed to minimize economic impacts and to allow options to developers that minimize their fees. However, the District recognizes that some businesses and individuals will be impacted, but believes that the impact is justified by the benefits of the rule to the Valley. The rule is designed to reduce emissions of pollutants contributing to poor air quality in the entire air basin and will provide a health benefit through its implementation. The District is required to attain federal air quality standards by specific dates with reductions contained in District attainment plans. These plans rely on reductions from ISR that if not achieved will result in sanctions that would cause a far greater impact to the Valley's economy than

implementing the rule. If ISR were not adopted, rules on other industries with as great or greater economic impacts would still be required.

A. RESULTS

SINGLE-FAMILY RESIDENTIAL. The Socio found a less-than-significant impact on Single-Family Residential project applicants for 2006, 2007 and 2008. The Socio found a minor increase in the price Single-Family Residential buyers would find in the average Valley City for 2006, 2007 and 2008. See Appendix F Tables 19-21 and associated text.

MULTI-FAMILY RESIDENTIAL. The Socio found a less-than-significant impact on Multi-Family Residential project applicants for the average Valley city for 2006, 2007 and 2008. The Socio found a minor increase in the price Multi-Family Residential buyers and renters would find in the average Valley City for 2006, 2007 and 2008. Multi-family residential development in small and medium sized bedroom communities is projected to experience a significant impact in 2007 and 2008. Small rural/farming communities could have a significant impact in 2008. The reason for the greater impact in these particular areas is the lower overall cost of housing in those areas making the fee a higher percentage of the housing cost. This impact is mitigated to some extent by the rule threshold of 50 units and 2 tons per year of emissions. Many projects in those areas are small. Some locations qualifying as bedroom communities are seeing very rapid growth in housing stock that is as expensive or more expensive than in the large urban areas. This trend may also limit the areas of impact. Due to the ability of the developer to pass on or absorb at least part of the cost and for consumers to amortize the cost in a mortgage or through rents, the District believes that this impact is not significant. See Appendix F Tables 23-25 and associated text.

INDUSTRIAL. The Socio found a less-than-significant impact on industrial project applicants for 2006 and 2008. The Socio found a less-than-significant impact on industrial renters in 2006 and 2008. See Appendix F Tables 28 and 29 and associated text.

OFFICE. The Socio found a less-than-significant impact on office project applicants for 2006 and 2008. The Socio found a less-than-significant impact on office renters in 2006 and 2008. See Appendix F Tables 28 and 29 and associated text.

COMMERCIAL. The Socio found a less-than-significant impact on industrial project applicants for 2006, but a significant impact in 2008. The Socio found a less-than-significant impact on commercial renters in 2006, but a significant impact in 2008. Commercial uses with a small footprint but high trips due to customer turnover experience the greatest impact. Commercial and other development types may reduce their fees with on-site measures. Many measures are available that may be required for other purposes and add no cost to the development, but can add amenities and value to the project. This would provide a mechanism to reduce the impact of the fee. Overall, the District concludes that with mitigation options and the ability to pass costs

on to project tenants, this impact should not be considered significant. See Appendix F Tables 28 and 29 and associated text.

PROSPECTIVE HOME-BUYERS AND SMALL BUSINESSES. Socio Section 6.4 addresses the impact on small business and includes a discussion of potential disproportionate impact on home-buyers and small business. The socio concludes that the increased costs due to the fees would have a temporary impact while the consumer responds to the costs with changes in purchasing decisions or increases income.

VIII. ENVIRONMENTAL IMPACTS

Pursuant to state law, District staff has conducted an initial study to identify any possible environmental impacts of this program and prepared a proposed negative declaration for draft Rules 9510 and 3180. The 30-day comment period for the proposed negative declaration ends on December 5, 2005. The District Governing Board will consider approving the negative declaration at the December 15, 2005 public hearing for the rules.

IX. RULE CONSISTENCY ANALYSIS

Pursuant to the California Health and Safety Code, Section 40727.2, District staff has prepared a rule consistency analysis of the program and is included in this staff report as Appendix G. The Rule consistency analysis shows the rule is non-duplicative, and consistent with existing District, state and federal rules.

X. REFERENCES

1. California Air Resources Board, Emissions Inventory, www.arb.ca.gov.

2. California Air Resources Board, *Status Report,* 1994

3. California Department of Finance, Population Projections, www.dof.ca.gov/HTML/DEMOGRAP/projco.pdf

4. 2003 PM10 Plan, Appendix B

5. South Coast AQMD website, Frequently Asked CEQA Questions, http://www.aqmd.gov/ceqa/faq.html

APPENDIX A

Responses to Comments on Proposed Rule 9510 (Indirect Source Review) and Rule 3180 (Administrative Fees for Indirect Source Review)

December 15, 2005

SUMMARY OF COMMENTS AND RESPONSES ON THE RECEIVE AND FILE OF DRAFT RULE NOVEMBER 17, 2005

Public Comment
Date November 5, 2005
Multiple Letters- Signed by

Kaaren Page	Betty Sanderson	Theresa Stump
Stephen Page	J Wesley Sanderson	Bill Moffit
Warren A. Minna	Georgette Theotig	Deb See
Nancy Faisselman	Isabel Stierle	Rosmarie Grabski
Nany Bacon	Li?? Wa???	Monte Harper
		Emid Harper

As a resident of the San Joaquin Valley, I am very well aware that the Valley is rated as '*extreme non-attainment*' when it comes to meeting federal air quality standards. We must take bold steps to clean up our air while allowing reasonable housing growth.

The best way to reach this goal is through your proposed Indirect Source Rule Package (Rules 9510 and 3180) that the District is sponsoring. This is accomplished two ways: allowing housing and commercial developments to be designed to reduce air pollution and to charge a fee for that air pollution that cannot be eliminated, with the fees being used to fund other projects that reduce air pollution.

1. **COMMENT:** I support a strong version of the rule that offers a real chance to improve the air in the valley and at the same time allow developers to use innovative design features to reduce our dependency on automobile transportation.

   Our lungs, our health, and our children deserve no less.

   RESPONSE: Comment Noted

California State Department of Housing and Community Development:
Date: November 29, 2005

Thank you for the continued opportunity to comment on the San Joaquin Valley Air Pollution Control District's (District) proposed Draft Rules 9510 and 3180 (Rules). The Department has reviewed the draft Rules as revised November 17, 2005 and the District's "Response to Comments" found in Appendix A of the draft Rules. The Department appreciates the District addressing some of the issues raised in the

comment letters of July 25, 2005 and September 15, 2005. However, as discussed below, the Department continues to have a number of concerns with the revised draft of the Rules.

Proposed Rule 9510 does not comply with the "clarity," "consistency," and "nonduplication" requirements set forth in Health and Safety Code Section 40727, and an adequate nexus has not been established to support these rules. In addition,

2. **COMMENT: The proposed inclusion, followed by the deletion of, an exemption for housing directly assisted by federal, State, or local government is of particular concern.** The District's response to comment #92 indicated the government supported housing exemption (affordable housing) was removed "based on the District's internal analysis of applicability and impacts….". Although affordable housing qualifies as a mitigation measure, it is unclear how the URBEMIS model assesses and credits affordable housing. Affordable housing is often a catalyst for the type of transit-oriented development that is encouraged by the District's policy recommendations as described in District's *Air Quality Guidelines for General Plans*. According to the Air Resources Board's study, *The Land Use – Air Quality Linkage*, densities found in affordable housing developments are generally high enough to provide the ridership needed to support transit service (page 15).

   RESPONSE: As stated in the November 17th Staff Report (p. 11) and in the September 1, 2005 Response to Comments, the methodology for emission reduction is detailed in the URBEMIS User's Guide (http://www.aqmd.gov/ceqa/urbemis.html). Basically, the trip reduction benefit of below-market-rate housing will be credited to a development that includes this feature. In addition, Appendix D- Recommended Changes to URBEMIS details the research supporting the emission reduction and the methodology for the reduction on pages D-38 through 39 and includes the following statement:

   … Thus, the total reduction is as follows:

   *Trip reduction = % units that are BMR * 0.04*

   A development with 20% BMR units would thus gain a 0.8% reduction. A development with 100% BMR units would gain a 4% reduction.

3. **COMMENT:** There is also insufficient information in the draft Rule analyses to discern whether and to what extent affordable housing developments, despite qualifying for some mitigation credits, might be subject to fees for off-site emissions reductions. This has the potential to render projected affordability levels or the projects themselves, infeasible as proposed. Affordable housing development proposals, are already subject to significant development constraints despite their acknowledged benefit potential relative to air quality.

Applying Rule 9510 to these projects would subject them to an additional and ambiguous permit requirement. This effect would be inconsistent with State laws which require affirmative actions to promote affordable housing opportunities. Accordingly, the Department urges the District to reinstate the exemption for housing projects in which at least 49 percent of the units are reserved for lower-income households and which are directly assisted by federal, State, or local government.

RESPONSE: The staff report and socio-economic impact analysis recognize that any fee would increase costs, but that market forces so far outweigh the effect of the fee that they render it insignificant. The District disagrees that the rule is contrary to state law promoting affordable housing. Rule 9510 is being adopted to reduce the air quality impacts of new development, including housing projects serving all market segments. Since the rule contains provisions to reduce potential fees for developments that contain affordable housing, it encourages affordable housing to be included in more projects.

4. **COMMENT:** Having deleted the exemption, the District must now amend those documents that were based on the exemption being part of the project. This includes the CEQA initial study which describes the project as exempting some sources including “certain low-income housing projects” (page 4). By removing the exemption, the District has redefined the project.

RESPONSE: The District does not concur that removing the low-income housing exemption substantially changes the project analyzed in the CEQA initial study. First, the socioeconomic impact analysis that is the basis of the initial study discussion on impacts on housing and population indicated that low-income households were already unable to afford new homes and rental units affected by the rule. The revised socioeconomic impact analysis was based on the latest rule version and arrived at the same conclusions regarding impacts with and without the exemption. Therefore, the impacts examined in the initial study are also the same. Second, by removing the exemption for "certain low-income housing projects", the language of the Rule would result in a slight reduction in air quality impacts, as some additional housing projects would now be subject to the Rule. The change in language does not substantively affect the analysis of environmental impacts. On the contrary, the language change would result in an environmental benefit.

5. **COMMENT: Although the District does have the authority to implement regulations to accomplish the reduction or mitigation of emission from indirect sources, it does not have the authority to operate a permitting system for the operation or construction of these sources and has failed to show the required nexus.** The proposed Rules would impose an (off-site) fee

on development projects which are unable to incorporate on-site measures adequate to reduce indirect emissions to a specified level. The fee is determined via an application (Air Impact Assessment Application (AIA)) which is required to be approved by the District before a final discretionary permit is issued for the construction of the development project. Unless the AIA application is submitted, the project cannot go forward without the developer incurring civil penalties. In such circumstances, contrary to the assertions of the staff analyses, a fee is being imposed as a condition of approval of a development project. A 1993 Attorney General Opinion explained that "the Legislature has recognized indirect sources as essentially different from other sources of pollution and consequently has made them exempt from ordinary permitting requirements" (Ops. Cal. Atty. Gen. 92-519). The opinion goes on to clarify that "permits may not be required of indirect sources under either the general permitting authority (Government Code Section 42300) or the special permitting authority provision relating to the attainment of State ambient air quality standards (Government Code Sections 40910-40926). Further, the imposition of fees as a condition of permit approval is subject to the nexus requirements of Government Code Section 66000 et. seq. and the District has failed to show the "reasonable relationship" nexus as required.

RESPONSE: The author is mistaken about the nature of the ISR program and how the rule is designed to be implemented. The rule is consistent with the Attorney General opinion cited in that it does not require permits. Under the commenters theory, any fee is a de facto permit. Developers are subject to civil penalties if they fail to follow any District regulation. For example, failure to comply with Regulation VIII – Fugitive Dust Rules during construction or Rule 4901 – Residential Wood Combustion fireplace installation limitations may result in civil penalties. Similarly, failure to comply with the mitigation requirements of Rule 9510 may result in civil penalties, but cannot stop a development from being constructed. The District will not be implementing a permitting system for the operation or construction of projects. The ISR program will not be a permitting system, have discretionary actions, or have any land-use authority. The author states:

> The fee is determined via an application (Air Impact Assessment Application (AIA)) which is required to be approved by the District before a final discretionary permit is issued for the construction of the development project.

However, this is not the case. The application is required, but is not tied to the *issuance* of a discretionary permit. The purpose of the application is to provide information necessary to determine if a fee must be paid and the amount of the payment if one is required. The application must be submitted concurrent with the *application* to the local land use authority for a final discretionary permit. This timing is to allow the applicant to take credit for reducing project air impacts during the local agencies approval process. The District does not require completion *prior to* issuance of a permit by the local agency, nor does the District

have the authority to stop the project from being issued a final discretionary permit by the local agency.

The District's action is ministerial, and does not involve conditions of approval. All projects are subject to the same requirements, and must fulfill the requirements. The District does have the authority to enact penalties for non-compliance; however, this does not make the actions of the District discretionary or make the program a permitting program. Further, the fee is only enacted if a project is, "unable to incorporate on-site measures adequate to reduce indirect emissions to a specified level". The required emission reduction applies to all applicable projects equally, and must be satisfied. The project applicant has the *option* to reduce the fee through on-site measures. There is no discretion on the part of the District. The author's statements on applicability of laws regulating permitting actions do not apply to the ISR program, as it is not a permitting program.

The District continues to assert that Rule 9510 is not subject to Government Code Section 66000 et. Seq. Regarding the reasonable relationship requirement, the District has clearly made this demonstration. The air quality impacts of construction, area source and indirect source emissions from development projects and the methods used to quantify these impacts are clearly identified in the staff report and are undeniably contributing to the air basin's serious air quality problems. The emission reduction projects that will be utilized to mitigate a portion of these impacts are also clearly identified. Sufficient checks and balances are in place in the rule through an elected Governing Board and EPA oversight of this state implementation commitment to ensure that the mitigation funds will be used effectively on the impacts created by the development projects.

6. **COMMENT: The consistency analysis (Appendix G) fails to include analysis and findings relative to other State laws and regulations, including directly related provisions of the California Environmental Quality Act (CEQA).** The District already has existing procedures for permit review pursuant to CEQA, which are put forth in its "Guide for Assessing and Mitigating Air Quality Impacts". Proposed Rule 9510 should be subjected to a rule consistency analysis with this guide, as well as requirements for air quality analysis and mitigation pursuant to CEQA which is undertaken in the permitting process of local governments. The Department remains concerned about the duplication of assessment and potential duplication of mitigations pursuant to CEQA and the proposed Rule 9510. The District's decision to modify its CEQA handbook *after* the adoption of the proposed rules (G-2) is inconsistent with the requirement of Health and Safety Code 40727.

RESPONSE: The Guide for Assessing and Mitigating Air Quality Impacts (GAMAQI) identified by the author is a voluntary guidance document for use by lead agencies addressing air quality in CEQA documents and is in no way regulatory. Under CEQA, for most development projects the District is a commenting agency. As a commenting agency the District provides comments to the Lead Agency to the following aspects: the potential significance of air quality impacts of a project; applicable District Rules; potential mitigation measures; and if an analysis is provided to the District, the adequacy and accuracy of that analysis. Requesting comments from the District is voluntary by the Lead Agency, and comments and mitigation measures suggested by the District are non-binding. CEQA requires *disclosure* of environmental effects for discretionary actions by a public agency, and requires reasonable and feasible mitigation of effects that are determined to be significant. Nowhere within CEQA can the District require a reduction in emissions from a development project. Voluntary CEQA commenting is not parallel to an ISR program. Mitigation required by CEQA is not the same in intent, requirements, or in practice with the emission reduction requirements of the ISR program. ISR is not duplicative of any mitigation required by the lead agency since the rule provides for credit for all measures and features included in the project that reduce emissions when project emissions are calculated. The District disagrees that modifying the District's GAMAQI after adoption is inconsistent with the California Health and Safety Code (CH&SC) Section 40272 for all the reasons stated above.

CH&SC Section 40272(b)(4) states:

> **"Consistency" means that the regulation is in harmony with, and not in conflict with or contradictory to, existing statutes, court decisions, or state or federal regulations.**

CH&SC Section 40272(b)(5) states:

> "Nonduplication" means that a regulation **does not impose the same requirements** as an existing state or federal regulation unless a district finds that the requirements are necessary or proper to execute the powers and duties granted to, and imposed upon, a district.

CH&SC Section 40727.2(a) states:

> **…** the district shall identify all existing **federal air pollution control requirements,** including, but not limited to, emission control standards constituting best available control technology for new or modified equipment, **that apply to the same equipment or source type as the rule or regulation proposed for adoption or modification by the district…**
>
> ***And***
>
> **…**The analysis shall also identify **any of that district's existing or proposed rules and regulations that apply to the same equipment or source type, and all air pollution control requirements and guidelines that apply to the same**

equipment or source type and of which the district has been informed pursuant to subdivision (b)

CH&SC Section 40727.2(h) states:

Nothing in this section limits the existing authority of districts to determine the form, content, and stringency of their rules and regulations. In implementing this section, it is the intent of the Legislature that the districts retain their existing authority and flexibility to tailor their air pollution emission control requirements to local circumstances.

The District has performed the analysis required by CH&SC 40727 et. seq, in Appendix G: Rule Consistency Analysis. First, no person has identified any existing federal or state requirement or guideline that applies to the same type of source that the District is proposing to regulate per CH&SC Section 40272(b). Second, the District identified few District rules for consistency analysis, and no US EPA rules or guidelines that apply to development projects in terms of New Source Performance Standards, Control Technique Guidelines, Maximum Achievable Control Technology or National Emission Standards for Hazardous Pollutants.

The District has found that the proposed ISR program is consistent with existing District rules, and has determined that there is no conflict or duplication with existing state law and CEQA.

7. COMMENT: The direct and indirect costs imposed by the Rules on the residential development process will result in increased housing costs. The preparation of the AIA (which not only calls for a detailed Urban Emissions analysis (URBEMIS)), but also for ongoing monitoring of selected mitigation measures), is likely to result in increased costs. In some instances, despite the assessment of the socio-economic analysis, the mitigation fees could have a detrimental impact on the economic feasibility of developers of market-rate mixed-use and workforce housing. These types of developments are already financially burdened since they typically have a more difficult time obtaining financing and quickly bringing a project into the market place.

RESPONSE: The cost of the preparation of a typical AIA is included in the application-filing fee— $400 for residential projects and $600 for non-residential projects, regardless of number of units. Worst case for a 50 unit residential subdivision would be $80 per housing unit. The modeling required for an AIA will be done by the District if not provided by the applicant. Monitoring of mitigation measures selected will only occur for measures that are not already required by another public agency, and the costs will be born out of the administrative fees from the rule (assessed at 4% of the off-site fee amount). Therefore, there are no costs additional to those discussed in the Socioeconomic Analysis.

8. **COMMENT: By proposing to control emissions through fees that will be used to fund other projects, the District would be treating housing developments as direct sources when they are in fact indirect sources**. The CEQA initial study for the proposed rules describes the project's purpose as being to "reduce emissions of NOx and PM 10 from new development projects" (page 4). If the fees collected under the Rules are a mechanism to control emissions from new development projects, then the District is adopting a market-based incentive program and is subject to the Economic Incentive Program (EIP) requirements, as was asserted by the Environmental Protection Agency (EPA) in their comments. Market-based programs may only be used for direct sources. "An EIP is a regulatory program that achieves an air quality objective by providing market-based incentives or information to ***emission sources*** (emphasis in original). By providing information or flexibility in how sources meet an emission reduction target, an EIP empowers sources to find the means that are most suitable and most cost-effective for their particular circumstances. By setting a price on pollution and pollution reductions through a fee-based approach or a trading program, some sources can realize an economic reductions for less than the cost imposed by a fee (*Improving Air Quality with EIP, EPA-452/R-01-001, January 2001 at 23)*. The proposed Rules allow a developer to either use the on-site emissions controls or to pay a fee and thus "realize an economic gain or avoid additional costs by making the reductions for less than the cost imposed by a fee." The District has failed to show the proposed Rules are consistent with EPA's EIP guidance and is treating new developments as direct sources.

RESPONSE: The District disagrees that EIP guidance applies. Although there are similar elements in EIPs, Rule 9510 contains both voluntary elements (onsite mitigation) and mandatory elements (mitigation fees) that preclude the use of the EIP guidance in its entirety. Still, the rule meets the SIP submittal criteria that apply to all rules of being surplus, enforceable, quantifiable, and permanent for the time required in the SIP and meets the fundamental EIP principles of integrity, equity, and environmental benefit.

9. **COMMENT: It is impractical, and an excessive and unnecessary burden for applicants to be required to include justification of mitigation measures not selected, as is proposed by Section. 5.3.2.** The on-site checklist contains a number of emission reduction measures, which will often be inapplicable. As a result, Section 5.3.2 should be deleted. As proposed, the provision implies, for example, that all 18 of the on-site measures listed in Appendix C for residential projects (or 39 if the "on-site enhancing measures" also required justification) could be applicable for all projects. Measures which would not be routinely feasible or applicable, include but are not limited to:

- An on-site bike lane would not likely be warranted or feasible on the site of a 50-unit apartment building (R-7) nor would an apartment building involve the design of street patterns (R-10).

- "Reduce Wood Fireplaces and/or Woodstove above that required by District Rule 4901" would not be applicable to most new apartment buildings (R-14).

- All new subdivisions cannot be sited within half a mile of an existing transit stop, and it is beyond the ability of applicants to have a transit stop added within a half a mile of a new subdivision (R-2), independent of where the project is located.

RESPONSE: The District does not agree with the author's statement that it is impractical, excessive and/or an unnecessary burden to include justification. The purpose of the justification is to encourage developers to examine the potential measures more closely and not immediately reject a measure without considering its feasibility. Onsite measures have permanent air quality benefits and typically create value and provide other benefits to the development. Measures included as mitigation measures in the lead agencies CEQA document, as most are expected to be, will not require District long term monitoring. If a measure is impractical or not applicable to a project, the applicant needs only to state that in the justification. The District does not see how this is an undue burden. Finally, onsite measures are implemented voluntarily by the developer and are not required by Rule 9510.

10. **COMMENT:** As a result of these concerns, the Department respectfully requests that the District not adopt the Draft Rules as proposed and continue to work with all interested parties on needed revisions. Thank you for your consideration of these concerns. For further discussion or to set-up a meeting, please contact Linda Wheaton, Assistant Deputy Director, at (916) 327-2642.

RESPONSE: Comment Noted.

City of Porterville
Date: November 29, 2005

11. **COMMENT:** The City of Porterville appreciates and encourages the District's efforts to improve air quality in our Valley, however, the District staff report does not clearly define how the additional fees acquired through adoption of the DESIGN program would result in a quantifiable improvement to air quality in the San Joaquin Valley air basin beyond the measures already in place. Further, neither rule dictates a funding source to compensate local jurisdictions for the

additional efforts resulting from approval. Please provide clarification of these points in the final rules. Thank you for the opportunity to comment.

RESPONSE: First, Appendix B – Emission Reduction Analysis, Attachments 2 and 3 show the tonnage of offsite reductions that are estimated to occur as a result of the adoption of the ISR rules. By 2010, it is estimated that the ISR will achieve 5.4 tons per day (tpd) reduction of NOx, and 5.8 tpd reduction of PM10 from growth. The amount of off-site reductions (from the fees) are 4.7 tpd and 4 tpd of NOx and PM10, respectively. These estimates are based on the amount of reduction required by the rule, and assume an amount of that reduction is achieved on-site. The off-site fees will be used to achieve this reduction, as specified in Appendix E: Cost Effectiveness Analysis, which states how much in off-site fees is expected and how that money will be spent to achieve quantifiable reductions. Specifically, Appendix E: Cost Effectiveness Analysis, Attachment 1 (p. E-13 through E-33) details potential projects, the amount of reduction achievable, the cost of those reductions and a potential spending plan.

Second, the rule does not dictate a funding source to compensate local jurisdictions because there are no requirements placed on local jurisdictions. The local jurisdiction is not required to review, assess or otherwise act on ISR projects. The District is committed to including local jurisdictions in the process through informing them of projects and project-specific information received by the District, and District actions on those projects just as it does now when it provides comments on local agency CEQA referrals. However, neither the ISR rules nor the administrative process require 'additional efforts' from local agencies.

Visalia Unified School District

Date: October 25, 2005

On behalf of the Visalia Unified School District ("the School District"), I respectfully submit the following comments and questions to Draft Rules 9510 and 3180 of the San Joaquin Valley Air Pollution Control District ("the Valley Air District"). I am unclear about several items in the Valley Air District's proposed fee and plan to decrease emissions' impact from new development in the area. The School District's main concern is that the Draft Rules lack sufficient clarity to allow the School District to analyze what the potential impact of the new fees may be and whether the fees would actually be applicable to our projects. The School District is particularly concerned because any fees that must be paid as a result of the enactment of the Draft Rules will reduce the School District's financial ability to provide classrooms to students in these newly developed areas.

12. COMMENT: Applicability of Draft Rules to the School District

It is unclear whether the Draft Rules apply to the School District's construction of new schools. Section 2.1 of Draft Rule 9510 states that the rule applies "to any developer that seeks to gain a final discretionary approval for a development project… of … 9,0000 square feet of educational space." The Draft Rules define "developer" as any person or entity that undertakes a development project. Also, the definition of a "development project" includes any project that it "subject to a discretionary approval by a public agency" where the discretionary approval "requires the exercise of judgment or deliberation."

The school District takes the position that the Draft Rules do not apply to it because it does not operate as a "developer" and the School District school construction projects are not development projects since they are not "subject to the discretionary approval by a public agency." However, according to the Draft Rules, if a developer is constructing a school facility on behalf of the School District, then due to the definitions in the Draft Rules, the fee may be applicable.

RESPONSE: If the approval to site and construct a new school is not subject to a discretionary permit, then the author is correct that the ISR rules would not apply. Otherwise, schools have many options available in onsite measures that would substantial reduce any potential fee.

13. COMMENT: <u>Fee Calculation</u>

In addition to the question of the fee's applicability, the formula to be used in calculating the air impact mitigation fee is extremely confusing. A more straightforward formula from which the estimates of fees can be made would prove beneficial to those impacted by the Draft Rules. If these Draft Rules are intended to apply to the School District's development of new schools, a more concise formula would help us in the planning and estimating process.

RESPONSE: Although the fee formula is somewhat complex, it is the most accurate and equitable way to assess fees based on emissions to achieve the emission reduction committed to in the District's SIP. The District has found that using an excel file to calculate fees is easy and accurate. The District will make a calculator with the formula built in available to the public prior to implementation. Prior to that, the District is willing help applicants and agencies create an excel file that calculates emission reductions required and fees required.

14. COMMENT: <u>Requirement of Nexus</u>

The School District has reviewed comments to the Draft Rules submitted by other associations that are impacted by these rules. One major problem noted by many of the commentators related to the fact that the Draft Rules fail to comply with the nexus test required by AB 1600, enacted as Government Code

Sections 66000 et seq, and as required by case law such as in *Ehrlich v. City of Culver City* (1996) 12 Cal4th 854.

Similarly, we would like to express our concerns that the fees proposed do not appear to demonstrate a reasonable relationship to the cost of implementing the air pollution mitigation program. It appears to us that there is a huge disparity between the cost of implementing the mitigation program and the fees to be collected. Further, the Draft Rules and supporting analyses are largely silent on the actual mitigation measures to be funded that will reduce emissions' impact resulting from a given project. It would be helpful if the Valley Air District provided details of the actual measures and projects that will be undertaken to reduce emissions' impact as well as the benefits accruing to the public as a result of these measures.

RESPONSE: Please refer to the September 1, 2005 Response to Comment #125 about the analysis of nexus applicability that the District performed. The District disagrees that there is a disparity between the fees to be collected, estimated as up to $103 million between 2006 and 2008, and the cost of achieving off-site reductions. In Appendix E: Cost Effectiveness Analysis, Attachment 1 (p. E-13 through E-33) details potential projects, the amount of reduction achievable, the cost of those reductions and a potential spending plan.

15. COMMENT: Notice to Those Impacted by Draft Rules

Although the School District is within the San Joaquin Valley Air Basin and is subject to the jurisdiction of the Valley Air District, we feel we were not provided with adequate notice of the Draft Rules. If the Draft Rules are held to apply to the School District, the fees imposed will greatly impact our ability to plan for the development of new classrooms and educational facilities. Therefore, in the future, we request written notice of proposed rules and regulations that are intended to apply to the School District.

RESPONSE: The District regrets that the School District did not receive notice of the proposed rules; however, this rule was noticed in accordance with all legal requirements. The District will add the School District to the ISR mailing list. In addition, the District suggests that the School District visit the District website at http://www.valleyair.org/lists/list.htm. The School District can receive District news, workshop notices, and other important information for this or other plans via e-mail by subscribing to one of the District's e-mail notification lists. The e-mail notification lists are setup and maintained by the end user and not by District staff. Individuals may add or delete their names from these lists at anytime.

California League of Food Processors (CLFP)
Date: November 22, 2005

16. **COMMENT:** First, CLFP supports the amendments proposed by the District that would exempt canning and food processing from Rule 9510. Most of the primary activities performed by food processors are already regulated by the District and are subject to Rule 2201 (New and Modified Stationary Source Review Rule) and Rule 2010 (Permit Rule), so the proposed exemption will avoid redundant or confusing new regulations.

RESPONSE: Comment Noted

17. **COMMENT:** Second, CLFP and other organizations have expressed concern to the District regarding the cumulative cost of complying with the various new air pollution control requirements imposed on manufacturers in recent years. The food processing industry is one of the major sources of employment in the San Joaquin Valley and the firms operate in a very competitive economic environment. The financial resources available for complying with new regulations are very limited. CLFP appreciates that the District has responded to industry concerns by recognizing the cumulative impact of air regulations and the major investments made in stationary source emission controls.

RESPONSE: Comment Noted

California Building Industry Association
Date: November 29, 2005

On behalf of the California Building Industry Association (CBIA) and its Affiliate Associations located in the San Joaquin Valley, I am entering into the formal record comments on the proposed Draft Rules 9510 and 3180 (the "ISR"). CBIA member companies provide housing that is the cornerstone of quality of life in the San Joaquin Valley.

18. **COMMENT:** The Federal Clean Air Act, 42 U.S.C. Section 7410 (a)(2)(F), requires that approvable control measures provide quantifiable, surplus, enforceable, permanent, and adequately supported reductions in air emissions. The proposed Draft ISR does not provide sufficient analysis or findings to establish that the proposed Indirect Source Mitigation Program meets these criteria. Indeed, the document barely addresses these fundamental topics. Because these criteria have not been met, the Indirect Source Mitigation Program does not meet the Federal Clean Air Act test for full approval and inclusion in the State Implementation Plan ("SIP").

Indirect Source programs, on the scale proposed by the San Joaquin Valley Air District, have not been adopted or implemented successfully anywhere in the United States. We note that USEPA has never approved a proposed indirect source rule for emission reduction credit.

RESPONSE: The District has complied with the cited Clean Air Act section. EPA has recognized that areas with a long history of air regulation must pursue new and innovative ways to reach emission reduction requirements since the stationary sources in many cases are already in their second or third retrofit requirement with rapidly diminishing air quality returns. This had led EPA to produce guidance on voluntary and emerging measures and for taking SIP credit for mobile source incentive programs. Although Rule 9510 is unique, it still meets all control measure approvability criteria. See also the District's response to EPA's comment letter on the September 1, 2005 draft.

19. COMMENT: The expected emissions benefits are not properly quantified. The URBEMIS model-based approach proposed to calculate project travel and emission impacts is inconsistent with the SIP inventory methodology. The SIP emissions inventory used the California Air Resources Board's EMFAC-2002 model to establish the NOX and PM10 emission reductions targeted by the ISR rules. One of the key components of EMFAC is a regional travel demand model ("TDM"). The TDM is used to calculate regional travel impacts such as vehicle miles traveled ("VMTs") and trips within the SIP inventory. The SIP calculations that identify further emission reductions needed for the San Joaquin Valley to attain federal ambient air quality standards are, in turn, based on vehicle travel activity forecasts from TDMs.

New project impacts determined under the ISR rules should be calculated in a manner consistent with the SIP targets to ensure no over- or under-compliance. There is an inconsistency between the way URBEMIS and TDMs calculate new or net added vehicle miles traveled (VMT) and vehicle trips. The fundamental difference between TDMs and URBEMIS is that TDMs robustly account for the interaction effects between multiple land uses, while URBEMIS does not.

Interaction effects refer to the fact that when considered together, each individual land use (or project) "competes" with others for vehicle trips. Where these land uses are located within a metropolitan area or county and how well the regional roadway network provides access to each land use affects the number of trips taken and their length (and thus VMT). For example, locating a new shopping center near an existing residential area would likely shorten the length of existing shopping trips taken from the residential area (and thus reduce VMT). It may also increase the number of shopping trips from the residential area due to its proximity compared to the location of existing shopping centers.

The Draft ISR relies primarily on URBEMIS to calculate project level impacts, even though the District's own modeling consultant has stated that this model was designed to be a "sketch planning" tool, and was never intended to provide a detailed numerical analysis of project level air quality impacts. If the travel activity (VMT and trips) of all the URBEMIS-based individual ISR project analyses were added together, they would overstate the net travel impacts determined when jointly simulating the same new projects using a TDM. This conclusion is based on a side-by-side comparison of impacts of a hypothetical but typical new residential project performed by Sierra/Dowling using URBEMIS and the Fresno County TDM. Correcting the existing biases in the URBEMIS default assumptions does not change this result because URBEMIS treats each new project and its interaction with existing land uses and other new projects separately.

The District has attempted to account for this fundamental difference between TDMs and URBEMIS by applying a 50% discount factor in the NOx and PM10 fee formulas to require mitigation of only half or one direction of two way trips between a new project and existing land uses. While in concept this approach could eliminate the double counting problem, simply slicing URBEMIS impacts in half does not demonstrate SIP consistency.

On top of this fundamental discrepancy with the SIP methodology, URBEMIS overstates residential project emissions by over 70% as a result of multiple technical shortcomings. On this basis alone, URBEMIS cannot be considered a reliable and accurate gauge of project emissions. URBEMIS' technical problems as an emission estimation tool are documented in detail in Sierra Research's comment letter of July 22, 2005.

RESPONSE: The author states that the "emission reduction benefits are not properly quantified". The District assumes the author is discussing the emission reduction benefits from implementation of the rule, which were properly quantified in Appendix B: Emission Reduction Analysis, using the known growth data (provided to the state by the COGs), and applying a standard rule penetration, estimated on-site emission reduction achievement, and applying the emission reduction requirements to the growth emissions. This analysis is considered 'top-down' and is standard practice. The analysis did not rely on URBEMIS, a project-level model or 'bottom-up' analysis, for valley-wide emissions estimates from valley-wide growth.

The District has repeatedly addressed the "70%" overestimation cited by the author as a distortion of fact. The District has stated that project-specific data is acceptable when available and has committed to addressing the few issues that have been raised concerning URBEMIS default values, and will provide guidance on those items prior to ISR implementation.

The District could not find any reference in the Clean Air Act or in EPA guidance that prescribes implementation to use the same methodology as the SIP. Indeed, the District did not find any reference prescribing a model or methodology to assess mobile and area emissions from development projects. The author's assertion that the methodology itself must be the same for the SIP and implementation is not based on any statute, guidance, or on historical methods of rule implementation. What is important is that the rule achieves the amount of reduction committed to in the SIP, and that the model produce consistent and repeatable results and be based on widely accepted inputs and methods, all of which apply to URBEMIS.

The author mischaracterizes the fee formula's use of a 50 percent baseline as a discount factor used to correct a deficiency in URBEMIS. URBEMIS correctly uses ITE trip generation rates to show the impact of all trips associated with a development project including those generated and those attracted to the site. The purpose of the 50% of the baseline in the fee formula is to meet the nexus requirements and to meet the intent of Health and Safety Code 40717.5(a)(1) for Districts to… "make reasonable and feasible efforts to assign responsibility for existing and new vehicle trips in a manner that equitably distributes responsibility among indirect sources." By basing the fee on half the emissions, the District is ensuring that only trips from the project site are assigned responsibility. Furthermore, URBEMIS has the capability to account for reductions for passby trips where someone stops on their way to their primary destination and diverted linked trips where the trip length is shortened to account for trips that although not directly on the route to the primary destination, still result in a shorter trip length than would occur if someone went there directly. Finally, URBEMIS can accept project specific trip generation information based on market studies and local traffic studies when a proposed project may produce different results than would be expected using default trip information. We believe this a reasonable and feasible effort to meet the Health and Safety Code requirements.

The District believes the best model should be used based on the needs and parameters of the project. For SIP inventory purposes, regional TDMs are the most appropriate model for estimating emissions. However, as admitted by Sierra Research (letter November 29, 2005, Comment #29 below), TDMs are regional models that are inappropriate for project-level analysis and TDMs contain their own flaws. These flaws are ignored in the author's 'URBEMIS vs. TDM' discussion. For instance, TDMs do not account for some trips on arterial and collector streets. TDMs require a large amount of data input, are not easily used, were not developed to estimate land-use impacts, and are not available to the public. Simply, TDMs are too broad of tools to accurately estimate the emissions from individual projects. A side-by-side comparison of a project-level analysis using URBEMIS and a TDM would be misleading, as a regional TDM was never meant to be, nor should be, used to estimate and individual project's emissions.

URBEMIS uses emissions factors derived from EMFAC2002, the same model used in the SIP. Several issues raised with URBEMIS (silt loading, fleet mix) will be remedied prior to implementation. URBEMIS is maintained by a statewide working group of technical experts and air districts. URBEMIS is used in CEQA analysis across the state, and is commonly used for Environmental Impact Reports (EIRs) to assess project-specific air quality impacts. URBEMIS has been used by the District and applicants in assessing air emissions for Mitigation Agreements, as well as other agencies to assess air impacts for mitigation settlements. The District has more than adequately shown URBEMIS to be the best model for the job.

The 'fundamental flaw' raised by the author simply does not exist. It has been well demonstrated that URBEMIS is the best program for ISR's needs, and it is widely recognized across the state by other air districts, local land use agencies, and other agencies as an appropriate tool for assessing specific project-level air impacts. It is the District's assessment that the author compares TDMs to URBEMIS in raising 'SIP methodology consistency' as a 'fundamental flaw' to discredit URBEMIS; and, since TDM's are inappropriate for project-level analysis, leave the District with no available model to use.

20. COMMENT: There is no discussion of whether the emissions are surplus. New development is already controlled by existing and proposed District rules, some of which overlap the ISR proposal. Dozens of cities and counties with the San Joaquin Air Basin have adopted ordnances creating local traffic mitigation and congestion relief programs, funded by fees on new development and, in the case of several counties, increased sales taxes. In addition, large scale developments, such as planned communities, are increasingly entering into air quality mitigation agreements within the context of the environmental review process mandated by the California Environmental Quality Act ("CEQA"). All of these measures address the same concerns as the Draft ISR, improved traffic flow and reduction of tail pipe emissions.

The failure of the Draft ISR and the supporting documentation to discuss or quantify the emissions reductions attributable to these other programs undercut the ability of the measure to provide surplus and quantifiable emission reductions as required by statute.

RESPONSE: The emissions growth estimates used to develop the rule are from the District's emission inventory that includes the benefit of all adopted local, state, and federal regulations and so are surplus to adopted control programs and regulations. Local regulations that have been adopted as transportation control measures currently have no emission reductions claimed in the District's SIP. Congestion relief measures and other transportation impact fees are

required just to keep emissions from exceeding emission budgets and do not provide additional SIP creditable reductions. Local programs and ordinances that do provide a surplus benefit will now be able to provide credit to their communities through the onsite mitigation component of the rule and will reduce the fees paid by developments contributing to those programs. In addition, reductions obtained through CEQA measures and Development Mitigation Agreements will be credited toward the emission reduction requirements of the rule.

There are no existing or proposed District rules that overlap the proposed ISR program. Appendix G: Rule Consistency Analysis describes other District rules and analyzes potential for inconsistency—none were found.

21. COMMENT: The proposed Indirect Source Mitigation Program does not contain an enforceable commitment. The permitting process in the Draft ISR operates independently of any other relevant regulatory process. Numerous parties have commented that the air quality impacts attributable to new development are also subject to CEQA. Early attempts by the Air District to reconcile or streamline the ISR with the normal environmental review process have been abandoned for the time being, replaced with a statement that the Air District will revise its existing Air Quality CEQA Guidelines at some future date to minimize conflicts between the two processes. By separating the Air District permit process from CEQA, the Air District has removed any responsibility for enforcement from local agencies with the land use authority necessary to enforce on-site mitigation measures.

RESPONSE: First, the ISR program is not a permitting program. Second, the ISR program is enforceable, the same as all other District Rules, and does not need to rely on 'other relevant regulatory process' and does not conflict with other regulatory processes. This enforcement authority comes from state law. In fact, most of the District's rules "operate independently of any other relevant regulatory process" as they are stand-alone rules not dependant on other regulations. Please see District Rule 1040 (Enforcement).

The District does not need to revise the Guide for Assessing and Mitigating Air Quality Impacts (GAMAQI) in order to make the rule enforceable. The District will be revising the GAMAQI in order to clarify for those undergoing the CEQA process how ISR will affect their projects. This is no different than how the GAMAQI currently addresses other applicable rules. For instance, Regulation VIII (Fugitive PM10 Prohibitions) is discussed in the text of the GAMAQI. However, the GAMAQI discussion does *create* the enforcement of Regulation VIII, but acts to inform lead agencies, consultants, project applicants, and the public.

22. **COMMENT:** In addition, no legal nexus between the proposed mitigation program and the fees imposed on individual development projects has been established. The cost and ultimate success of the mitigation measures are speculative. The Air District's proposed mitigation program, based upon after-the-fact grant applications and the funding of primarily off-site mitigation, has not worked well in other situations, such as the South Coast Air Quality Management District's Mobile Source Reduction Commitment program. Until nexus can be demonstrated, no enforceable commitment is possible. The language of SB 709 did not repeal the independent, Constitutionally-based requirement that that "rough proportionality" between the impact created and the cost of its mitigation be established. This comment has been made several times, both in writing and testimony, and the Air District has never fully responded to this issue.

The Air District cites the USEPA approved PM10 and Ozone Attainment Plans along with SB 709 as authority that it must impose ISR. In doing so, the District is arguing backward from a conclusion, sidestepping the fundamental issue of whether an enforceable commitment exists. Such backstops are not a substitute for establishing whether an enforceable commitment exists for purposes of the Federal Clean Air Act.

RESPONSE: Although the District believes it has adequately responded to each comment regarding nexus 'rough proportionality', here is a synopsis of how the District makes this demonstration:

> The District developed an estimate of growth in mobile source emissions from new development by using the SIP emission inventory growth-only projections. This allows us to estimate the amount future emissions will increase only accounting for growth. This information was used as the basis for the ISR control measure in the 2003 PM10 Plan. Construction and area source emissions are entirely the responsibility of the development project. The emissions attributable to growth were then reduced to account for projects that will be exempt from the rule. The mitigation requirements were then applied to the emissions subject to the rule to determine the potential emission reductions. The emission reductions are cumulative since each year additional mitigation is accomplished and the benefits from prior years continue to provide a benefit. This information is provided in Appendix B of the staff report.
>
> Once the overall emission reduction target for the ISR control measure was identified, the next step was to determine the method to calculate the fair share of the emissions attributable to individual projects. As has been thoroughly discussed elsewhere, it is not appropriate to use the SIP inventory method to calculate emissions from individual projects. URBEMIS was identified as the best tool for conducting project level estimates. See Appendix D of the staff report.

With the emission estimation tool selected, the District then used URBEMIS to estimate emissions from a variety of different land use projects using basic default inputs. The basic factors used to estimate project mobile emissions are the number of vehicle trips, the length of the trips, and the average vehicle fleet emission rates. Based on comments received on early drafts, the District replaced default values for PM10 silt loading values, and activated the commercial passby trips component. The purpose of this analysis was to estimate the potential emissions and fees from an individual development. The results were then used in socioeconomic impact analysis to determine the potential impacts of worst-case fee amounts.

The next step in determining rough proportionality is to verify that the individual project impact is roughly proportional to the mitigation achieved with the fees that are collected. This is accomplished by using an emission based fee formula to determine the amount of funds collected and a fixed cost of reductions for the emission reductions to be purchased by the District. The cost of reductions was developed for future years based on recent cost-effectiveness history with District grant programs, a determination that the reductions will be continue to surplus to any adopted regulations, the emission inventory for the sources, and the technical and economic feasibility of the projects. This analysis is adequate to confirm that the District will be able to maintain rough proportionality between the emissions generated and the emissions reduced through the fees.

The District has several options for corrective actions should the average cost of reductions achieved by the ISR Program be significantly higher or lower than predicted. Since staff will be continuously monitoring the projects funded, we will be able to identify early if costs are on target. If costs of reductions are coming in high, the first option would be to focus the project mix on more cost-effective projects until the average approaches the target amount. If insufficient low cost off-site projects are available, the cost of reductions could be increased by amending the rule. If costs of reductions are coming in low and it appears that the lower-than-expected cost-effectiveness can be sustained, the fee amount may be lowered. The District may also modify the incentive amounts offered to attract preferred, highly cost-effective projects where potential applicants may be reluctant to participate when the incentive amount offered may be inadequate to cover costs of implementing the project. Modified incentive amounts could also be used if the District has difficulty attracting sufficient projects.

The comparison to mobile source emission reduction credit programs is not valid. The reason those programs have not been highly successful is because stationary sources needing ERCs have been able to obtain those reductions at lower costs using traditional banked ERCs than could be achieved by mobile source reductions. Grant programs throughout the state have been extremely successful in obtaining emission reductions from a wide variety of sources. Since ISR reductions can be obtained from any source of surplus, quantifiable, and enforceable reductions, it can be expected to do even better than the existing grant programs in attracting projects.

23. COMMENT: There is no finding that the benefits of the proposed measures will be permanent.

The Draft ISR assumes that the measures will be in effect for ten years. Because of the passive nature of many of the on-site mitigation measures, there is no guarantee that purchasers of newly developed property will leave those mitigation measures in place. Likewise, there is no documentation that the emission reductions associated with the proposed control measures will persist throughout the life of the SIP. As discussed previously, the benefits are speculative, have not been quantified and documented, and as a result the longevity of the benefits are equally speculative.

RESPONSE: The ISR program differentiates between onsite and off-site measures when demonstrating the permanence of the reductions for SIP purposes. The onsite measures are most closely related to measures covered by EPA's Voluntary and Emerging Measures Policy. This policy recognizes that land use measures are highly desirable, but more difficult to quantify than traditional measures. Once the project is constructed with the onsite features in place, the benefits continue indefinitely into the future. Measures like density, mix of uses, and pedestrian infrastructure are not likely to be eliminated after development. All on-site measures that are not required by the lead agency will be enforced by the District to ensure that the emission reduction benefits will occur for the full duration of ten years. Offsite projects funded with mitigation fees only take credit for SIP reductions during the life of the project. This is accounted for in the emission reduction spreadsheet in Appendix B. Offsite projects meet EPA SIP criteria for permanence. Applicants are under contract to utilize the cleaner equipment through the term of the contract. When the new equipment, device, or paved road reaches the end of its useful life, the new purchase must comply with regulations in place at that time and will use cleaner technology in many cases.

As the District has repeatedly demonstrated, the benefits are not speculative, have been quantified and documented. Please refer to the *entire* Staff Report, Appendix B: Emission Reduction Analysis, Appendix D: Recommended Changes to URBEMIS, and Appendix E: Cost Effectiveness Analysis.

24. COMMENT: The proposed Indirect Source Mitigation Program is not adequately supported. The Air District's socio-economic analysis focused on the narrowest viewpoint available, the impact on residential builders, and did not even attempt to analyze the larger impacts on other business sectors, employment, public services, etc. The proposed rulemaking provides no information on the commitments from other agencies that are necessary to implement the various measures. Finally, there is no indication that the proposed requirements have been integrated into local development plans.

RESPONSE: First, there are no "commitments from other agencies that are necessary" to implement ISR. Therefore, the District did not include "commitments from other agencies" as there are none.

The author mistakenly states that the socioeconomic analysis, "focused on the narrowest viewpoint available." The author is posing that the District did not thoroughly or adequately address the socioeconomic impacts of the ISR program, which is untrue. The socioeconomic analysis included analysis on the impacts to homebuilders, homebuyers, renters, low-income housing and housing affordability. In addition it analyzed the impacts to commercial, office and industrial builders, buyers and renters, and small businesses. The mitigation fees are spent on projects in the San Joaquin Valley that provide benefits to the Valley's economy as described in the revised socioeconomic impacts report.

ISR has been designed to work synergistically with the local development approval process. Developers may use mitigation measures and local requirements of the local development process to reduce their Rule 9510 fees, but are not required to do so. The proposed requirements of ISR, a prescribed amount of emission reduction for particular development projects, do not need to be integrated into local development plans, but may be used to demonstrate that air quality impacts of the project have been reduced. Developers wanting to use Rule 9510 as support for their air quality impact study for the local development approval process can time their application to the District such that it will fit seamlessly with the normal CEQA timelines. For the 'mitigation program', there are no up-front requirements for all projects. Applicants that voluntarily commit to certain measures that are not already requirements by other agencies must enter into an agreement with the District that details the schedule of monitoring and reporting for the District to enforce implementation of those measures. The 'mitigation program' requirements are to implement those measures the applicant has voluntarily committed to. The only possible conflict with local development plans is if a measure is not allowed by the local agency: in that instance, the District would remove that measure from the ISR project, and reassess emissions. Thereby avoiding conflicts with the local agency.

25. COMMENT: In summary, for the reasons stated above, the Draft ISR continues to be fundamentally flawed, and is unlikely to satisfy the requirements of the Federal Clean Air Act. As a result, the Air District will have a difficult time convincing USEPA that the ISR control measure will contribute to the emission reduction goals set forth in the SIP and the District should look to other measures to obtain PM10 and NOx reductions.

RESPONSE: As stated in Response to Comment #18, the EPA is supportive of the rule, and has not raised the 'flaws' that the author claims are present. The emission reduction goals in the SIP will primarily be achieved through grant and incentive programs that have been in operation for over a decade and that meet all SIP submittal criteria. Credit for new grant and incentive programs will follow the same SIP criteria and will comply with the same standards for quantification and verification as the existing programs. Each new program will go through a public review process and be approved by the District's Governing Board. The voluntary onsite measures will only be credited to the extent that they meet the criteria of EPA's Voluntary and Emerging Measures Policy.

Sierra Research – On Behalf of CBIA

Date: November 29, 2005

On behalf of the California Building Industry Association (CBIA), Sierra Research (Sierra) is pleased to submit the following comments on the revised draft Indirect Source Rules (ISR) 9510 and 3180 released by the San Joaquin Valley Unified Air Pollution Control District (District) earlier in November.

Our comments in this letter rebut District responses to earlier comments submitted by Sierra in September. As directed by CBIA, our comments focus on technical and modeling issues related to the use of the URBEMIS model under the proposed rules based on our independent review of the model and its underlying assumptions. In this review we were assisted by Dowling Associates, Inc. (Dowling), a transportation planning firm with extensive travel demand modeling experience supporting a number of the San Joaquin Valley Transportation Planning Agencies (TPAs).

Our rebuttal covers the following two issues:

1. URBEMIS modeling assumptions substantially overestimate residential project emissions. A combination of unresolved technical problems result in overstating both residential PM10 and NOx project emissions, and therefore ISR fees, by over 70%.

2. Rule 9510 consistency with SIP emissions inventory has not been demonstrated. The SIP travel model projects a different amount of travel (and therefore emissions and fees) from each project than URBEMIS calculates. Our Fresno County test case shows that URBEMIS produces higher project emissions than does the SIP methodology.

A detailed discussion of each of these unresolved issues is provided in Attachment A.

26. COMMENT: Summary

The following table summarizes each of the technical modeling issues identified by Sierra/Dowling during the ISR rulemaking process, their impacts, and the District's response to each issue.

Status of District Responses to Sierra/Dowling ISR Comments		
Issue	Emissions Bias	District Response
Residential Fleet Mix	NOx high by **20%**	Will fix, revised fleet mix to be determined
Silt Loading Factors	PM_{10} high by **50%**	Will fix
Average Vehicle Trip Lengths	NOx and PM_{10} high by **20-30%**	Will fix, unsure of approach
Residential Fleet Age Distribution	Exhaust NOx and PM_{10} high by over **20%**	Not convinced data provided warrant a revision
SIP Consistency	NOx and PM_{10} likely **high by unknown amount**	Handled by 50% fee discount?

Although the District has indicated a willingness to address some of the modeling issues we have identified, we believe the responses to our earlier comments on URBEMIS model issues are incomplete (in that corrections will not be made until after ISR adoption) or mildly dismissive (e.g., not willing to consider how revised residential age distribution impacts will be addressed). Some of the unresolved issues are fundamental and still need to be addressed before these rules can go forward

Furthermore, the District has not proven that the URBEMIS-based ISR approach will result in emission reductions that match SIP targets. From a policy standpoint, we believe this burden-of-proof lies with the District and that SIP consistency cannot simply be asserted.

These technical problems result in major discrepancies in estimating emissions and corresponding fees under Rule 9510. Thus, we respectfully recommend that the District delay its scheduled December 15 hearing on ISR adoption until these issues are fully resolved.

If you have any questions about the information presented above or in Attachment A, please feel free to contact Bob Dulla or me at (916) 444-6666.

RESPONSE: The District has determined that all items that the author raises have been adequately addressed. See the following Comments and Response to Comments #27 through #29.

ATTACHMENT A
UNRESOLVED RULE 9510 TECHNICAL ISSUES
THAT RESULT IN OVERSTATED EMISSIONS

27. COMMENT: URBEMIS Modeling Assumptions Substantially Overestimate Residential Project Emissions - In responses to our comments, the District acknowledged that many of the default modeling assumptions in the URBEMIS model do not accurately represent conditions in the San Joaquin Valley when applied to residential projects. These incorrect model defaults identified by Sierra and Dowling substantially overestimate residential project emissions by a minimum of 70% for both pollutants targeted under the ISR rules, oxides of nitrogen (NOx) and "fine" particulate matter (PM10).

The District's response to these URBEMIS model default issues is incomplete. In acknowledging these problems, the District responds only that these faulty model assumptions will be corrected in a future version of URBEMIS that will be released (presumably without opportunity for public review) after the ISR rules are adopted.

Although the District has indicated that a small part of these model corrections will be made prior to rule implementation, no timetable has been provided for revising URBEMIS, nor has it been made clear that these revisions will be publicly reviewed. The District has been aware of these modeling issues since July, yet no further action has been taken. The District's approach does not guarantee the release of a revised and fully reviewed model before implementation.

RESPONSE: The District does not "acknowledge that ***many*** (emphasis added) of the defaults… do not accurately represent conditions in the San Joaquin Valley". The District does acknowledge that a there are a few items that need refinement, specifically the on-road silt loading factor (easily adjusted by a known amount) and the fleet mix (less easily adjusted). The District had already hired a consultant to analyze and recommend a revised fleet mix, and results are expected prior to rule implementation. The author's assertion that "no further action has been taken" is misinformed and false. In addition to researching the fleet mix, the District is participating in the URBEMIS statewide working group (see paragraph below for more information). The model defaults ***do not*** overestimate residential project emissions "by a minimum of 70% for both pollutants". This claim is false, and the District has repeatedly addressed this claim.

The author is incorrect in his assertion that the District will make changes to URBEMIS "without opportunity for public review" and therefore without any review or safeguards. Changes to URBEMIS are made through a statewide working group that includes other air districts, model experts, technical experts and other public agencies such as CalTrans. As consultants such as Sierra Research use URBEMIS, they often find areas for improvement and correction. Any proposed changes impacting the statewide use of the model must be vetted through this group. The District cannot, nor does it propose to, make 'closed door', questionable changes to the URBEMIS model. If an applicant or a consultant can find better input data or another model that more accurately characterizes the emissions from their project, the District will consider them. If they apply broadly, the District is committed to make those changes available to all users. Sierra should recognize that all modeling is based on incremental improvement. The District will use the best information currently available and commits to continuous improvement in its emission estimating techniques and models.

The author states that a "small part" of issues will be addressed. The District finds only three items raised that are legitimate and only two that are substantial, one of which (silt loading) has been resolved, and the other (fleet mix) is currently being researched. As for a "guaranteed release" of a revised program prior to implementation, these *two* issues can be addressed through guidance. A revised program is not necessary to account for the refined default changes. As stated above, the District is participating in the URBEMIS statewide working group, which is currently expecting to release a revised program in more than one year. The District is committed to making URBEMIS as accurate as possible, and is working towards that goal. Any change that can be made through District guidance will be implemented quickly.

In addition, the silt loading factor issue was raised by Sierra Research, which proposed a new factor, and the District agreed that the proposed factor was more accurate. This revised factor has been publicly discussed, and has been included in ISR documentation.

28. COMMENT: In addition, the District did not act on the evidence presented by Sierra/Dowling based on U.S. Census and Caltrans Travel Survey data—that new residential developments exhibit newer vehicle fleet age distributions (and therefore have lower average emissions). The District's response indicates a need for further survey data to warrant revising the URBEMIS default vehicle age distribution when applied to new residential projects.

Would data from a third-party survey that gathered information on vehicles per household and age from a random sample of "new" residential households in the

San Joaquin Valley be sufficient to warrant a revision if it showed a similar shift toward newer vehicles in the existing Sierra/Dowling analysis? And if so, how will this be accomplished? The District suggests the possibility of an age correction factor to address the fact that the EMFAC model emission factors used by URBEMIS cannot easily be modified to account for a revised age distribution. Who would develop this age correction factor and how would it be developed?

RESPONSE: The District did not act on the survey data because we are not yet convinced that it is more accurate than the information currently used in URBEMIS, which is an age distribution from EMFAC2002 (See September 1, 2005 Response to Comments #121 through #153). As pointed out in your previous comment letter, providing a project-specific fleet-mix age for each land use type would not be easy and would not be possible to automate in the current models used to quantify project emissions. We are not sure if the survey data described is adequate for this purpose. Since Sierra previously stated that it wants any changes vetted through a public process, the District will first pass this information to the URBEMIS Working Group for assessment. If consensus is reached that a major overhaul to URBEMIS is needed to account for fleet age differences, then the District will work to raise the necessary resources to develop the model. The new model would need to be submitted to EPA for approval. The fleet age distribution currently in use is adequate for the ISR program until such a time as a model capable of using this information becomes available.

29. COMMENT: Rule 9510 Consistency with SIP Emissions Inventory Has Not Been Demonstrated We continue to disagree with the District's assertion that the URBEMIS model-based approach proposed to calculate project travel and emission impacts is consistent with the Statewide Implementation Plan (SIP) inventory methodology. This SIP emissions inventory and its underlying methodology were used to establish the NOx and PM10 emission reductions targeted by the ISR rules. Thus, it is critically important to ensure that new project impacts determined under the ISR rules are calculated in a manner consistent with the SIP targets to ensure no over- or under-compliance.

Our disagreement centers on the inconsistency between URBEMIS and regional travel demand models (TDMs) in calculating new or net added vehicle miles traveled (VMT) and vehicle trips. The TDM models are used to calculate regional travel impacts (i.e., VMT and trips) within the SIP inventory. The fundamental difference between TDMs and URBEMIS is that TDMs robustly account for the interaction effects[1] between multiple land uses; URBEMIS does not.

1 Interaction effects refer to the fact that when considered together, each individual land use (or project) "competes" with others for vehicle trips. Where these land uses are located within a metropolitan area or county and how well the regional roadway network provides access to each land use affects the number of trips taken and their length (and thus VMT). For example, locating a new shopping center near an existing

If travel activity (VMT and trips) were totaled across all the URBEMIS-based individual ISR project applications, we believe they would overstate the net travel impacts determined when jointly simulating the same new projects using a TDM. This conclusion is based on a side-by-side comparison of impacts of a hypothetical but typical new residential project performed by Sierra/Dowling using URBEMIS and the Fresno County TDM. Further, we believe this conclusion remains valid even after correcting existing bias in URBEMIS default assumptions. This is because URBEMIS treats each new project and its interaction with existing land uses and other new projects separately.

We understand and agree with the District that it is not practical to make developers run TDM simulations under each ISR application, and readily acknowledge that TDMs are not without flaws of their own. However, calculations performed within the SIP that identify further emission reductions needed for the San Joaquin Valley to attain federal ambient air quality standards (a portion of which are targeted by the ISR rules) are based on vehicle travel activity forecasts from TDMs.

The District suggests that this fundamental difference between TDMs and URBEMIS is accounted for by applying a 50% discount factor in the NOx and PM10 fee formulas to require mitigation of only half or one direction of two-way trips between a new project and existing land uses. We understand the concept in principle, but strongly believe that by simply slicing URBEMIS impacts in half, SIP consistency has not been demonstrated. We believe the acid test of SIP consistency consists of an analysis that compares summed URBEMIS vs. TDM simulated travel impacts for a package of specific projects that have been developed in recent years. We are not aware that this type of URBEMIS analysis has ever been done and is likely one of the key reasons why ISR rules have never been successfully adopted and implemented on this scale.

RESPONSE: Please see Response to Comment #19 above. The District agrees that the model used for the ISR program should be carefully chosen as to not over- or under-comply with the SIP reduction targets. However, the District maintains that the methodology for implementation does not need to be identical to the SIP methodology to achieve this. The author states that for the Valley, if URBEMIS is compared side by side to a TDM, URBEMIS over-estimates net travel impacts. However, a regional TDM was never meant to be, nor should it be, used to estimate emissions from an individual project. To take a project-level model and try to compare it 'side-by-side' to a regional model is inappropriate and misleading.

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residential area would likely shorten the length of existing shopping trips taken from the residential area (and thus reduce VMT). It may also increase the number of shopping trips from the residential area due to its proximity compared to the location of existing shopping centers.

Stop the Air Board Tax *We'll All Pay!*
Date: November 16, 2005
Signed by
City of Clovis – Mayor Nathan Magsig
San Joaquin Busniess Council – President Ron Addington
Visalia Chamber of Commerce – President and CEO Mike Cully
Kern County Taxpayers Association – Executive Director Michael Turnipseed
Greater Merced Chamber of Commerce – CEO Will Lee

30. COMMENT: A broad-based coalition of local chambers of commerce, local government officials, homebuilders, taxpayer organizations, agricultural groups, ethnic and community groups are formally opposing Rules 9510 and 3180 proposed by the San Joaquin Valley Air Pollution Control District (the District). These Rules will collect hundreds of million of dollars by imposing fees on every new home, small and large business, public facilities and other new construction projects within the Central Valley, with questionable air quality benefit.

Indeed, as Rules 9510 and 3180 are currently proposed, the District is proposing to collect more than $670 million in fees over the next five years- taken right out of the regional economy.

RESPONSE: First, the proposed rule does not apply to all new development nor does it impose fees on all new development. For instance, the following projects are exempt from the rule or the fees:

- Projects below the applicable size thresholds in the rule (e.g., 50 residential homes)
- Projects at stationary source businesses already regulated by the District
- New projects and expansions that do not require a new discretionary approval by the local land-use agency
- Projects that employ enough control features to reduce emissions to less than 2 tons per year

The District's most up to date estimate of the offsite mitigation fees is $103 million over the next 3 years. The authors' estimate of $670 million in five years is erroneous. The authors' estimate is based on incorrect use of the fee formulas and emissions estimates and record setting development rates. The District believes that it is not prudent to base revenue estimates on record development rates that would result in SIP commitments that fall short if not realized. Although the authors' estimates are overstated, it should be recognized that solving the Valley's air pollution problems is very costly as can confirmed by industrial sources that have invested billions of dollars on pollution control in the last three decades. The funds will not be taken out of the regional economy. All offsite mitigation fees will be used to purchase emission reductions here and will

result in the funds being reinvested in the Valley. The cost of administering the program is assessed at only four percent of the offsite emission fees.

Finally, the District has thoroughly documented, described and demonstrated that the proposed rules will have a real and substantial beneficial impact on air quality. For more information on the emission reduction analysis or spending plan, please see Staff Report Appendix B: Emissions Reduction Analysis (which used a standard, accepted emission reduction methodology) and Appendix E: Cost Effectiveness Analysis (which thoroughly demonstrates the availability of off-site reductions and a plan for off-site fee use).

31. **COMMENT:** As you are probably aware, the Air District recently released a revised version of these Rules and accompanying documents. In our opinion, the changes have failed to address some of the fundamental concerns of our coalition. Namely, the Rules continue to unfairly target new homeowners and businesses to disproportionately fund air emissions cleanup; the methodology and science remain flawed and they still significantly overestimate emissions and result in inflated fees; the fees still seek to impose enormous and unjustified new costs on businesses, new homeowners, public entities and ultimately all Valley consumers and our economy; and the rules still fail to provide for full accountability.

We all support the goal of cleaner air, but there are better and more effective ways to reduce air pollution in a manner that is balanced and less costly for residents and our economy.

As representatives of the coalition, we feel compelled to share the following key reasons we are respectfully urging you and other Governing Board members to oppose Rules 9510 and 3180 when they come up for a vote on December 15, 2005.

RESPONSE: Please see Response to Comments #32 through #42 below.

32. **COMMENT:** ISSUE #1 – LACK OF FAIRNESS, EFFECTIVENESS OR EFFICIENCY
Indirect source rules place a disproportionate burden on new housing, new businesses and new public facilities to pay for a regional problem that is the responsibility of ALL residents. Indirect source rules are just that – *indirect, unproven* and *inefficient* ways to go about calculating and mitigating air quality emissions. For this reason, no other air district in the nation has adopted this type of indirect source rule. The District should be pursuing more balanced solutions that equally apply to all residents and rules that more directly go after

the true source of emission – namely tail pipe emissions and the dirtiest pollution sources like diesel.

RESPONSE: The authors claim that new homeowners and businesses are being singled out unfairly for controls by this rule. This rule would be only one of many measures that the District has implemented and proposes to implement to control emissions from nearly every possible source category. The District has produced two comprehensive plans, one for ozone and one for PM10, that analyze current and future emissions, and lay out a strategy for emission reductions by a variety of controls and actions. For example, the ISR program is one of more than 20 rules identified in the 2004 Extreme Ozone Attainment Demonstration Plan.

The authors indicate that the ISR program attempts to 'burden' new development to pay for a regional problem. The ISR program only assesses and places requirements on the fair share of the emissions from new development to solve regional ozone and PM10 problems. Each project that would go through the ISR program would be responsible *only* for their own emissions.

In addition, the District has successfully and aggressively regulated existing sources of air pollution. Existing homeowners have contributed in the form of DMV surcharges to the tune $7 per year per vehicle, compliance with fireplace regulations, low-VOC architectural coatings, and smog check programs. New stationary sources must employ Best Available Control Technology and mitigate their new emissions with offsets.

33. COMMENT: ISSUE #2 – THE COST OF THE PROPOSED RULES
Two years into the rule-making process, the District still has failed to provide the public with a comprehensive estimate of the cost of the proposed Rules. Specifically, the socioeconomic analysis fails to address the cumulative impact on housing costs, on business costs, and on economic growth and job creating. The analysis discusses impact on only select segments of the business community, ignoring the full economic impacts of the rule. Our coalition has reviewed what information is available in the District's socioeconomic analysis and we were able to determine that the District will collect as much as $670 million in fees over the next five years.

RESPONSE: Concerning the adequacy of the District's analysis of economic impacts, please refer to Response to Comment #24 above. Concerning the '$670 million' in purported fees, please refer to Response to Comments #30 and #34.

34. COMMENT: Housing:

The District's analysis shows the fees will average more than $1,700 on every home by 2008. Cumulatively, we estimated that the cost on all new housing projects in the eight county region will exceed $225 million over the next 5 years, assuming the current pace of housing permits. That's why the State Department of Housing and Community Development warned that these Rules will negatively impact housing affordability in our region.

RESPONSE: The author has misstated the facts provided in the District's analysis and in the Socioeconomic Analysis. The fee estimates of $1,700 per home and the various numbers sited for industrial and commercial projects represent maximum worst-case fees that may apply if the developers choose to employ no on-site controls. Even so, this amount was found to not have a significant impact on the housing market in the socioeconomic impact analysis. If the high rates of development continue, the air impacts from housing will also be greater than predicted, and so those funds will be needed to offset some of that increase. The District believes that nearly all projects will be able to reduce their fees with on-site-measures since local land use agencies currently require some of the measures and many developers incorporate them as standard practice. The District has published an extensive list of control measures that would reduce the applicable fees. The authors' estimate assumes that all homes and industrial and projects will be built with no control features and is not realistic. In addition, the authors apply the worst-case fee to a higher, possibly unsustainable, rate of housing construction. The author then used this inflated fee amount and based the $670 million on a rough assumption of the ratio between housing and commercial/industrial development. The District finds this methodology of fee estimation to be inappropriate and inflated.

The District hired an independent consultant to perform a comprehensive socioeconomic analysis that assesses the economic impact of the proposed rule including any significant impact on housing affordability. This report concluded that rule would have a negligible impact on housing affordability.

35. COMMENT: New Business Developments:

The District's own assessment estimates the level of likely fees on selected properties to be significant. By 2008 it will cost $397,483 in new fees to build a local community shopping center and $131,000 in new fees to build a neighborhood shopping center. These developments are typically home to mom and pop businesses, restaurants and small retail shops and these fees will be directly passed along to these small business owners (and ultimately their consumers and employees). The District also reports that as much as 2/3 of the total fees they plan to collect will come from non-residential projects. Since the District's figures show that the total fees on housing may exceed $225 million, it

is conceivable that the cost to businesses and non-residential developments will exceed $400 million.

RESPONSE: The fees are based on emissions generated by each project. If a commercial development generated emissions that resulted in a fee of $397,483, it would be a very large development or one composed of many small retail establishments. If it were comprised of many small businesses, each one would be responsible for a fair share of the impact and the fee.

The author falsely states that, "the District's figures show …fees on housing may exceed $225 million." The District's figures ***do not*** show that housing fees will be that high. See Response to Comment #34 above, which illustrates how the authors distorted facts to generate an inflated number. In fact, the District's analysis shows that the District may receive up to $103 million from *all* types of development subject to the rule between 2006 and 2008. The 2/3 ratio cited by the author was provided by the District as a rough estimate arrived at by subtracting residential development emissions from all development related emissions. The District used the emission reduction analysis (Appendix B) for fee income analysis since the emissions growth data from the state is well accepted for this purpose. See also Response to Comment #30 and #34.

36. COMMENT: Public Facilities:

The Rules also apply to public and government facilities such as new schools, transit projects, government office buildings, fire houses, police stations and more – driving up the cost of public works projects and ultimately further burdening taxpayers with higher costs. The District's analysis is silent on these costs and their impact on local finances and fees.

RESPONSE: The District has drafted the rule to fairly allocate emissions among all indirect sources. Public uses are a substantial part of the growth in emissions that if not addressed here, would need to be addressed through other means. We agree that the cost of achieving air quality mandates could increase the cost of these facilities; however, we would expect most transit projects, fire houses, and police stations to be exempt since they would produce emissions below the two ton per year level. In addition, schools and government offices are well suited in many cases to incorporate features that enhance walking, bicycling and transit use and use low emission vehicles and equipment that could reduce the fees, possibly to zero.

37. COMMENT: ISSUE #3 – FLAWED SCIENCE

Members of our coalition and others have repeatedly demonstrated that the methodology and modeling that the District staff is using to calculate indirect sources of emissions – and resulting fees and mitigations – are fundamentally

flawed. These flaws result in grossly inflated fees and mitigation requirements. For instance, the URBEMIS model being used by the District (a computer program used to estimated emissions associated with land development projects), overstates vehicle emissions by over 70% (see public comments filed Sierra Research, July 22, 2005). No other air district in the nation uses URBEMIS to determine fees for vehicle emissions because, as the District's modeling consultant said, it's a "sketch planning" tool, not an accurate gauge of the specific emissions resulting from an individual project.

RESPONSE: In context, the term sketch-planning tool did not imply that it is not an accurate gauge of specific emissions resulting from an individual project. In fact, URBEMIS is a proven statewide model used by other air districts, including South Coast and Sacramento Metro Air Districts, in assessing emissions from project-level developments. URBEMIS is commonly used for CEQA analysis, and is also used by other air districts to determine off-site mitigation fees. In addition, the Development Agreements entered into by the District and applicants relied on URBEMIS for emissions estimates. See Staff Report pages 19 through 22 for a detailed discussion on why URBEMIS is the best model for the purposes of the rule. See also Response to Comment #19 above.

The CBIA and its consultant, Sierra Research, have provided comments (See September 1, 2005 Comments #123 through #162 and above comments #18 through #29) about the adequacy or implied lack thereof of the URBEMIS model. However, the District has shown that the 'flaws' stated by the author are not valid.

For example, the authors assert that the model overstates vehicle emissions by over 70%. The comments received by the District compared the URBEMIS model, which counts both ends of trips, to a regional impact model (admittedly inappropriate for project-level analysis- See Comment #19 above) that only accounts for one end of trips. The URBEMIS program does not overstate emissions, as asserted by the author, but accounts for emissions differently than a regional model. It should also be understood how the fee formulas work. Please see Figure 3 and 4 in Appendix B- Emission Reduction Analysis, which clearly show that half of the estimated baseline emissions are not assessed fees.

URBEMIS reflects the state of art in quantifying emissions from development projects. In fact, developers and local land use agencies routinely use URBEMIS to quantify project impacts during the CEQA process. The proposed rule allows for the use of other models that can better quantify emissions from various types of projects. The accuracy of URBEMIS will be further refined through the use of project-specific information in lieu of the otherwise applicable defaults. The authors' claim may have merit if the District rule only allowed for the use of URBEMIS defaults and disallowed the use of project-specific information such as proper traffic counts and vehicle mix. This is not case.

The District is part of a statewide working group that will continually work on refining and enhancing the accuracy of the URBEMIS model.

38. COMMENT: ISSUE #4 – DISTRICT'S OWN DOCUMENTS DEMONSTRATE THAT FEES CANNOT BE AVOIDED THROUGH ON-SITE MITIGATION.

District staff has continually and erroneously stated that if sponsors of new development satisfy the District's list of on-site mitigation measures, they won't have to pay any fees. According to the Air District's own documents and comments by their own staff, this is simply not true.

Even the District's newly revised staff report demonstrates that new homebuilders and businesses likely cannot completely mitigate indirect source emissions on-site (see Draft staff report page 15, 11/17/05). Perhaps this is why, at a recent meeting before the Bakersfield Chamber of Commerce, District Deputy Executive Officer Seyed Sadredin admitted most projects will not be able to mitigate their estimated air impact on site and will likely have to pay all or most of the fees.

Neither the text of the Rules nor the staff report provide useful guidance on how doing one or all of the proposed on-site mitigations will score against the proposed fees and it has provided no detail about the air quality benefits of each of the proposed mitigation measures. Accordingly, applicants have no way of determining how much on-site mitigation will reduce emissions or how it will reduce the fee they're obligated to pay.

Second, the District's proposed on-site mitigation checklist relies heavily on the existence of mass transit and other forms of transportation that don't exist to achieve emission reductions. Further, since there is no plan or realistic prospect of these necessary transportation projects being built in the near future, it is impossible for sponsors of development to comply with these types of on-site mitigations to avoid fees.

RESPONSE: The authors' comments are incorrect. The District has *not* stated that simply enacting the measures on the on-site list would result in no fees. The District has stated, and has conducted internal analysis that verifies, that it is possible to incorporate enough measures to result in no fees. The page referenced to from Staff Report *does not* assert or state that homebuilders and businesses cannot completely mitigate emissions on-site. The Staff Report does demonstrate how a certain percentage of on-site reduction achieves a larger percentage of fee reduction. District staff is unsure how the author misinterpreted the Staff Report, as the text states, "… the "bigger bang for the buck" is achieved with as much on-site mitigation as possible…..See Table 1 for ***examples*** (emphasis added) of on-site emission reductions and the associated off-site fee reduction".

Concerning guidance on how the measures "score" against the fees, and the air quality benefit associated with the measures, the authors should read page 11 of the Staff Report, which states,

> *The measures listed in the checklist have a known quantification methodology in URBEMIS 8.7. The methodologies can be found in the URBEMIS User's Guide, available at South Coast AQMD's website http://www.aqmd.gov/cega/urbemis.html.*

URBEMIS is a free, easy to use program that can be downloaded and used by the public, project applicants, public agency staff, and anyone else. See also September 1, 2005 Response to Comments #7 and #9. Applicants can easily see on their own how incorporation of measures reduces emissions through using the model (most simple projects take less than ½ hour), and can see how that reduces the fees by running the numbers through the fee formulas.

Finally, the checklist does not 'rely' on mass transit and other transportation for emission reductions, but provides a venue to credit emission reductions from those items. Project applicants are not required to 'comply' with the list, but fill in which measures apply to their project, and which measures do not.

The fees can be reduced significantly by employing the reasonable number of measures suggested by the District. We agree that it will be difficult to total eliminate the fees initially with the type of development that has historically occurred in the Valley.

On how to 'score' the emission reduction from the measures suggested by the District, all measures in the on-site lists have a quantification methodology in the URBEMIS model. These methodologies may be read in the URBEMIS User's Guide. The measures do not have a straight "credit" associated with implementation, but a calculated reduction based on various parameters, which may include interaction with other selected measures, amount input, and other parameters. The District will provide a great deal of assistance to the applicants to properly quantify the emissions and the applicable credits for measures employed.

ISSUE 5 – DISTRICT HAS FAILED TO ADDRESS SOME BASIC – BUT IMPORTANT – POLICY QUESTIONS RAISED THROUGHOUT THIS PROCESS

The following represent just a few of the many very important policy concerns that the Air District has failed to address or respond to, despites these questions being raised for many months. Governing Board members should take great pause before voting on Rules without getting answers to these very serious questions and concerns.

39. COMMENT: District has not quantified fees for the full 5-year rule period: The socio-economic and cost/effectiveness analyses provide an incomplete

accounting of fees that the District expects to assess over the 5-year rule period. No information has been provided in either appendix on the cost to public facilities including schools, parks, and roads. No information has been provided in any appendix on the overall economic impact to the Central Valley.

RESPONSE: The fee schedule holds fees past 2008 at the 2008 level. The socioeconomic impact analysis and cost-effectiveness analysis only assess 2006-2008 because those are the amounts being proposed in the rule. If the rule is amended to change the fee amounts by a significant amount, it would result in the preparation of new analyses. If fees are held to the 2008 level, socio impacts would be the same as the 2008 level. For cost effectiveness, the District is confident that targets are feasible through 2008, but past 2008 would be too speculative.

The District disagrees that overall impact on the economy in the Central Valley is not adequately addressed. Since the impact on the development industry was not significant and fees will be recirculated into the regional economy, it is logical to conclude that the rule would not have a significant adverse impact on the regional economy. See also Response to Comment #24 above.

See Response to Comment #36 regarding public facilities.

40. COMMENT: Incomplete Spending Plan: Although Appendix E offers a spending program for the fees collected by Rule 9510, it falls short of what is acceptable. First, it covers only three of the five years of the rule period. Second, the revenue projects cover roughly one-sixth of the Rule's potential revenue: $102 million vs. the potential $670 million in total fees that could be collected.

RESPONSE: As stated above, the first three years have enough information to be adequately assessed.. Second, the $670 million stated by the authors is based on incorrect information and misinterpretations of rule requirements (see above Response to Comments #30 and #34). District analysis, using factual data, shows that the District may receive up to $103 million between 2005 and 2008 based on the availability of the fee deferral option and historic development rates. The cost of reductions is more uncertain farther into the future. The District will reassess the cost of reductions prior to 2009 so that changes in regulations and the availability of new technologies can be taken into account.

The District has proposed a detailed plan in the staff report that will be considered by the Board at the December hearing. Additionally, as a part of the District's annual budget process, the plan will be reviewed and amended as necessary. The District will also provide routine reports on the quantity fees collected, projects funded, and emission reductions achieved per Rule 9510 Section 10.4.

41. COMMENT: Unresolved fee estimation issues: As noted above, the URBEMIS model overstates project emissions by over 70%. The District has not committed to fix URBEMIS prior to Rule adoption and implementation. Unless resolved, Governing Board adoption will result in projects paying fees that are exaggerated by as much or more than 70% due to improper default values that do not reflect actual conditions in the Central Valley.

RESPONSE: As stated previously (Response to Comment #19), the "70%" overestimation is simply not valid. Previous comments have pointed out refinements that should occur to some URBEMIS default values, such as the silt loading factor, and the District has committed to providing guidance prior to implementation and to update URBEMIS as soon as possible with the revised factors (see Response to Comments #19-22, #27-29, #37, and Staff Report pages 21-22). However, the statement that the model grossly overstates vehicle emissions is not valid.

42. COMMENT: Unresolved CEQA conflicts: CEQA already requires mitigation of air quality impacts associated with new development, yet the District states that Rule 9510 is not duplicative and is completely independent of the CEQA process. However, the District's response to EPA concerns is that it is counting on local agency CEQA requirements to make on-site mitigation measures enforceable. The District has not explained how its Rule will interact with local agency CEQA actions to achieve this result.

RESPONSE: Currently, for measures that are required by a local agency, that agency includes them in CEQA documentation and is required to enforce those measures. The District recognizes this enforcement mechanism through CEQA for those measures that are required by the local agency. Therefore, although the project applicant is taking credit for emission reductions from measures required by lead agencies, the District will not have to enforce those measures independently. For measures that are not required by the local agency, the District will be responsible for enforcement. There are no new requirements on local agencies, and no additional 'interaction' is required by the rules.

43. COMMENT: In closing, members of our coalition agree that improving the region's air quality is an important goal and one that demands that everyone in the Central Valley play a role. Accordingly, the District has a duty to convince the public of the value of its new policy and to win their trust in carrying it out. Regrettably, the District has failed to demonstrate the value or benefit of the proposed Rules.

Members of our coalition stand ready to work with the District on an alternative to proposed Rules 9510 and 3180 and towards achieving a more equitable, efficient and cost effective plan to reduce emissions.

In the meantime, we urge you to reject Rules 9510 and 3180 when they're brought before a vote of the Governing Board on December 15, 2005.

RESPONSE: Comment Noted.

SUMMARY OF COMMENTS AND RESPONSES ON THE SEPTEMBER DRAFT RULE SEPTEMBER 1, 2005

EPA:
Date: September 20, 2005

1. **COMMENT:** We are providing comments based on our preliminary review of the draft rule identified above. In general, we are very supportive of the District's effort to reduce emissions from new development projects and we recognize that this effort raises unique challenges. Please direct any questions about our comments to me at (415) 947-4115 or to Lily Wong at (415) 947-4114.

RESPONSE: Comment Noted.

2. **COMMENT:** 1. Program Evaluations and the EIP
This rule relies on market-based strategies to reduce emissions and, as a result, is subject to national guidance entitled, "Improving Air Quality with Economic Incentive Programs" (EIP), EPA-452/R-01-001, January 2001. Specifically, the DESIGN program has elements similar to Clean Air Investment Funds as described in chapter 9 of the guidance. As a result, the District's staff report should demonstrate that the program is consistent with the EIP guidance including, for example, provisions regarding environmental benefit, consistency with attainment/progress plans and automatic suspensions. Generally, we do not believe these demonstrations will be difficult to make. However, we believe the District should expand the scope of the annual program evaluation requirement (rule provision 10.4) to address elements identified in the EIP (sections 5.3(b) and (c)), including evaluation of the overall effects of the program, whether the Air Impact Mitigation Fees are appropriate based on the cost of reductions, and whether the program is achieving the projected emission reductions. The rule should also describe the procedures and criteria for the evaluations. Lastly, since the District will be responsible for obtaining emission reductions for off-site mitigation projects, the SIP submittal should include the District's commitment to rectify in a timely manner any shortfall in emission reductions.

RESPONSE: The District disagrees that the rule is a market based strategy subject to EIP guidance. Indirect sources are not seeking to use incentive funding as a substitute for controlling emissions directly. Although it is not an EIP, the District intends to demonstrate that the program will provide environmental benefit and is consistent with all plans and rules. The appropriate

mechanism to ensure program performance is with annual reporting and corrective action to make up any shortfall. This can be accomplished by focusing funding on more cost-effective projects and would not require any special rule provision to accomplish. In the event that the rule did not achieve a milestone and altering the project mix was not successful, contingency measures are in place in the SIP to make up the shortfall while revisions to the rule are made or new rule(s) are adopted to correct the situation.

3. **COMMENT:** 2. Mitigation
The District should ensure that on-site mitigation of emissions and off-site emission reductions are enforceable.

RESPONSE: The on-site measures are voluntarily chosen by the developer and, when included as a mitigation measure in the local agency environmental document, are enforceable under the California Environmental Quality Act (CEQA). These types of measures have a relatively large amount of uncertainty, but are highly desirable due to their ability to permanently change trip generation and miles traveled. Therefore the District proposes to account for emission reductions accomplished onsite under Voluntary and Emerging Measures guidance. Projects funded with off-site fees will be under contract with the District enforceable under contract law.

4. **COMMENT:** 3. Director's Discretion
The rule (provisions 3.2, 3.5, 5.3) allows the use of an "APCO-approved model" to calculate emissions and emission reductions from development projects. To avoid inappropriate director's discretion, the rule should identify, by name and version, all models that may be used under this rule, or require that the model or model revisions be approved by the District and EPA.

RESPONSE: The rule has been revised to reflect that the District and EPA will approve models and model revisions used under the rule. Since all emission reduction calculations are accomplished using emission factors approved by the ARB and EPA and are consistent with the emission inventory factors, this should allow for quick implementation of model improvements that will be developed over time.

5. **COMMENT:** 4. Surplus
The rule should include provisions and mechanisms to ensure that emission reductions from on-site and off-site mitigation projects will be surplus to the requirements of the plan (e.g., reductions required by Rule 8061), and are not otherwise relied upon in the plan (e.g., part of the planning or growth assumptions in the plan). At a minimum, the rule should define "surplus" to include consideration of rule requirements and planning assumptions, and include provisions to prevent the double counting of emission reductions. We note, for example, that the May 19, 2005 PM-10 Plan (p. 4-45) lists a few specific

activities expected to provide emission reductions for this rule. However, the URBEMIS model allows credit for on-site mitigation measures not included on this list such as fewer wood burning stoves, energy efficiency projects and off-road maintenance equipment. While the Plan may include assumptions regarding these emissions, the District should ensure that the rule achieves the emissions reductions that the Plan predicts for the rule and that mitigation measures do not result in double counting of emission reductions assumed elsewhere in the plan.

RESPONSE: The District will demonstrate that all offsite emission reduction projects submitted for credit are surplus in the documentation for each program developed to utilize the off-site funds. The District's Heavy Duty Engine Incentive Program is the prototype for how it will manage funding received from Rule 9510. This program has stringent criteria for determining if reductions remain surplus for the wide variety of projects. The District works closely with ARB in developing guidelines such as those adopted for the Carl Moyer Program. These guidelines pay particular attention to the issue of surplus reductions. New project types will undergo a similar rigorous process.

ARB: No comment received.

California State Department of Transportation:
Date: September 8, 2005

6. **COMMENT:** The purpose of this letter is to comment on the proposed San Joaquin Valley Unified Air Pollution Control District (District) Rule 9510 (Decreasing Emissions' Significant Impact from Growth and New Development) and the associated fees as stated in proposed rule 3180 (Administrative Fees for Air Impact Assessment Applications). When applied to the California Department of Transportation's (Department) construction sites, these rules attempt to regulate vehicular (mobile) emissions regardless of the District's lack of specific authority to regulate these emissions.

Both statutory and case law clearly establishes that "local and regional authorities have the primary responsibility for control of air pollution other than vehicular sources." (See *California Health and Safety Code* sections 39002, 40000, 43000 and 43013). The responsibility for regulating vehicle emissions belongs to the California Air Resources Board. The proposed District rules attempt to regulate mobile emissions from vehicles without statutory authority and therefore, it is our position that the proposed rules do not apply to vehicular emissions on Caltrans projects.

RESPONSE: Rule 9510 does not attempt to regulate emissions from vehicles. The rule would regulate the emissions resulting from the act of construction and

the emissions resulting from the act of operation. The distinction lies in the following:

- The rule does not set emission reduction requirements for individual engines or pieces of equipment
- The rule does not require retrofits, the use or purchase of certain pieces of equipment or prescribe any specific use of emission reduction technology
- The rule does not limit emissions through hours of operation or prescribe certain activities that reduce emissions
- The rule does not require emission reductions to be achieved through the equipment or engines used.

Simply, an amount of reduction is required by the rule, which can be achieved through any on-site or off-site means that are quantifiable and meet the requirements of the rule. The rule does not set a fleet average, regulate engines or vehicles or otherwise delve into the realm of mobile emissions, which the District does not have authority to regulate. The District does, however, have the authority to regulate indirect sources per Health and Safety Code, Section 40716:

> *"(a) district may adopt and implement regulations to … reduce or mitigate emissions from indirect and areawide sources of air pollution."*

The District has the authority to control indirect sources, defined in the Clean Air Act (CAA §110(a)(5)(C)) as, "… a facility, building, structure, installation, real property, road, or highway which attracts, or may attract, mobile sources of pollution"(emphasis added). This authority comes from the CAA §110(a)(5)(A)(i):

> *Any State may include in a State implementation plan … any indirect source review program.*

The Indirect Source Review Program that the District is proposing would review the emissions from that indirect source (the facility, building , installation, real property, *road*, etc.) that occur from the installation of that source (i.e. construction) and the operation of that source (i.e. area and mobile). For transportation projects, essentially road construction, the District would review only the construction emissions associated with that indirect source.

It is the District's position that the proposed rule is within the authority granted to the District by the federal Clean Air Act and the California Health and Safety Code.

California State Department of Housing and Community Development
Date: September 15, 2005

The Department of Housing and Community Development (Department) has reviewed the Draft Rules as revised September 1, 2005 and continues to have significant concerns about their impact on housing development and costs in the San Joaquin Valley. Many of the concerns expressed in the Department's July 25, 2005 letter have not been addressed by subsequent revisions or by the District's responses to our comments, and are reiterated below.

7. **COMMENT:** 1. The on-site mitigation measures for residential development proposed by the Draft Rule 9510 duplicate the type of mitigation measures already required by the environmental review and mitigation process pursuant to CEQA or the local land-use permitting process. For example, requirements for transit measures, tree canopies, bike trails, etc., are already imposed by local governments during the existing local permitting process. This duplication is of particular concern if the projects cannot receive credit for such measures already incorporated in the project, or if the duplication were to result in most projects being charged fees for off-site mitigation programs. It is not evident that imposing the same type of mitigation requirements as those already imposed by State law (or sometimes federal as well) is necessary for the District to execute its powers as required by Health and Safety Code Section 70727 (b)(5).

Recommendation: Clarify that projects will receive mitigation credits for on-site mitigation measures approved or required by the local government's permitting process.

RESPONSE: It is the District's intent that all quantifiable on-site measures that reduce a project's emissions be given credit in the ISR program. The District does not require the applicant to implement any of the measure listed, but requires the applicant to identify which measures will and won't be implemented. The applicant is required to identify measures that are a requirement of another agency so that the District can identify which selected measures will need District enforcement, and which measures will be enforced by another public agency. The measures listed in Appendix C have a known quantification within the URBEMIS model. Measures selected will be credited to the project. The District will amend the rule language and staff report to reflect this.

8. **COMMENT:** 2. Draft Rule 9510 will lengthen and complicate permit-processing times for new homes in a manner inconsistent with the Permit Streamlining Act, which is applicable to all public agencies (*Chapter 4.5 of the Government Code, commencing with Section 65920)*. Draft Rule 9510 does not meet the consistency standard of Health and Safety Code Section 40727 (b)(4)).

- Section 8.1 of Draft Rule 9510 has been revised to require the District to determine the completeness of Air Impact Assessment (AIA) applications in ten days instead of thirty. It is unclear whether this changes will result in a practical benefit, however, as the Draft Rule does not include a mechanism for facilitating concurrent review between the District and local planning agencies. Sections 5.0 and 8.2 suggest the District is cognizant of the need to coordinate with local agencies, but does not specify the timing and nature of the coordination. Without concurrent review, developers who are required to, or elect to, alter a project may be required to resubmit plans to the local planning agency for additional discretionary review. Such outcomes would have additional and redundant cost implications for permit processing. Further, projects which would otherwise be subject to ministerial permit processing only, should not be subjected to discretionary review because of the Draft Rules.

- Draft rule 9510, Section 8.8, proposes the District should have 90 days to take final action on an AIA application. Consequently, absent a concurrent review, process time could now take an additional 90 days. In some cases, Draft Rule 9510 thus has the potential to double existing processing times.

Recommendation: Revise draft Rule to include a mechanism or process for concurrent review by the District and local planning agencies to avoid impacts on local government. The Rule should not directly, or indirectly, prompt local governments to assess yet additional fees for responsibilities which may fall on them in implementing the District's Rule.

RESPONSE: Draft Rule language will be revised to make application submittal for ISR concurrent with local agency processes. Specifically, applications must not be submitted after application for a final *discretionary* permit in the San Joaquin Valley Air Basin, and may be submitted prior to that time. The rule will not place requirements upon the public agency for review or implementation of the ISR process. The public agency review (§ 8.2) has been revised to a voluntary review. The District will be coordinating review with the public agency through:

1. Making the ISR process concurrent with or prior to the public agency process;
2. Forwarding a copy of the AIA application (upon determination of completeness), a copy of the AIA approval package (upon approval), and a letter of Final Compliance to the public agency for voluntary review and commenting;
3. Communicating with the public agency when necessary during the application review process; and
4. Providing a letter of project status to the public agency upon request.

It should be noted that this rule will not apply to ministerial projects, nor will it prompt ministerial projects into becoming discretionary projects. That determination is made by the local land use authority.

9. **COMMENT:** 3. There is insufficient information or clarity in the Draft Rules regarding not only permit processing coordination, but also quantification and cost of mitigation measures. According to Health and Safety Code Section 40727 (b)(3), a rule or regulation adopted by a District board should be "…easily understood by the persons directly affected by it." Neither the Draft Rules, the Appendices, nor the Draft Staff Report describes the methodology the District will use to determine the number or value of mitigation credits to be associated with the various mitigation measures. Other aspects of the Draft Rules warranting clarification include, but are not limited to: ….*(District - see Comments 10 through 13 below)*

Recommendation: Revise Draft Rule 9510 to include a detailed description and analysis of the methodology the District will use to determine the number or value of mitigation credits to be associated with various mitigation measures. Clarify the items noted above in Draft Rules 9510 and 3180.

RESPONSE: The District will clarify the staff report to address how emission reductions from measures will be assessed. All measures within Appendix C have a quantification methodology in the URBEMIS model. These methodologies may be read in the URBEMIS User's Guide, available at South Coast Air Quality Management District's website http://www.aqmd.gov/ceqa/urbemis.html, and will be made available at the District's website. The measures do not have a straight "credit" associated with implementation, but a calculated reduction based on various parameters, which may include interaction with other selected measures, amount input, and other parameters.

10. **COMMENT:** Draft Rule 9510, Section 5.5 – Mitigation and Monitoring Report Program: The Draft Rule should specify if the applicant or the District is responsible for preparing this document.

RESPONSE: The rule language will be revised to reflect the following: The applicant is responsible for preparing a proposed document. The District will provide the format and recommended keys for the document. The District will then work with the applicant to finalize the document prior to approval. It should be noted that this will only apply to measures selected by the applicant that do not have another enforcement mechanism, such as being a requirement by another public agency.

11. **COMMENT:** Draft Rule 9510, Section 8.5 – Air Impact Mitigation Fee Estimate Acceptance: What amount of time does the developer have to respond to the estimate provided by the District?

RESPONSE: The draft Rule will be revised to reflect the following Unless the applicant has proposed a Fee Deferral Schedule (FDS) prior to AIA approval, the applicant must pay the fee within 60 days, or may propose a FDS within 15 days of receiving the fee invoice. If the applicant proposes a FDS within the allowed timeframe, the District then has up to 15 days to finalize the FDS with the applicant.

12. **COMMENT:** Draft Rule 9510, Section 10.2.3 – Administration of the Mitigation Funds: what, if any, limits are there on the duration of the contract between the developer and the District?

RESPONSE: A distinction must be drawn between the ISR applicant, and an applicant for the funds. Section 10.2.3 discusses the process between the District and the applicant for funds. The duration of the contract will vary depending on the project. Some contracts will be completed upon installation, while others may require reporting for 5 years. For example, a road-paving project would have a contract that is completed upon installation, whereas an engine contract typically contains a 5-year reporting requirement. The staff report will be amended to include this information.

13. **COMMENT:** Draft Rule 3180, Section 4.2 – Application Processing Time Log: How long does the District have to respond to a developer's request for a copy of the Log?

RESPONSE: The District uses an automated Labor Information System (LIS) to track project time by all staff working on a project. This allows the District to easily prepare the time log within a short timeframe. The District standard for this type of request is 10 days. The District will amend Draft Rule 3180, Section 4.2 to state the District has up to 10 days to provide the information.

14. **COMMENT:** 4. The direct and indirect costs imposed by the Draft Rule on the residential development process will result increased housing costs. The rationale for these increased costs as required by the Health and Safety Code Section 40728.5 are not adequately identified nor justified by the complete analysis.

The Department commends the District's decision to reinstate the exemption for housing projects directly assisted by federal, State, or local housing funds. Assisted projects, however, only account for a small percentage of the San Joaquin Valley's workforce housing stock. The majority of new lower- and moderate-income residents will occupy market-rate units. Increases in

construction costs resulting from the Draft Rules will ultimately be passed on to these residents in the form of higher rents and home prices.

Yet, as indicated below, the Executive Summary of the socioeconomic assessment the District prepared pursuant to the Health and Safety Code Section 40728.5 concludes that increases in the construction and housing costs are irrelevant because lower-income residents are already overpaying for housing and are thus dependent on public subsidies:

The analysis demonstrates that, even before the imposition of an air quality fee(s), most low-income (and) households in the Central Valley are priced out of newly constructed multifamily unit market, the rents for which need to be at levels that account for the price of land, development cost, developer fees, and an adequate level of profit, among other things. The analysis discusses how public subsidies can assist in enhancing the financial feasibility of a real estate project in which a certain portion of units are set-aside as below-market rental units (San Joaquin Valley Unified Air Pollution Control District. Socioeconomic Analysis Proposed Indirect Source Rule: Draft Rules 9510 and 3180. 24 August 2005.p.1.)

The demand for assisted housing far exceeds available resources of all levels of government. The District should not assume that higher rents and home prices can be solely addressed by government subsidies. Furthermore, higher housing prices are problematic because the affordability gap widens, forcing more San Joaquin Valley residents to overpay for housing and/or live in overcrowded conditions. Additional regulatory barriers that increase the cost of housing supply must be restructured and their benefit should exceed their cost impacts.

The Department also notes that the socioeconomic assessment does not address the impact of the Draft Rules on small business or analyze the availability or cost-effectiveness of alternatives, as required by Health and Safety Code Section 40728.5(b)(1), (b)(3), and (b)(4). For example, Part 6 (p. 26-32) includes generic information about impacts on single-family and multifamily homebuilders, but does not specify impacts on small homebuilders.

Recommendation: Revise the socioeconomic assessment to include: 1) a more thorough analysis of the impact of the Draft Rules on the economy of the San Joaquin Valley, including the number of consumers who will be overpaying for housing; 2) the impact of the Draft Rules on small residential developers; and 3) alternatives to the Draft Rules.

RESPONSE: The Socioeconomic Analysis will be amended to include analysis on the rule's impact on small businesses. In addition, the analysis does not discuss alternatives because there are no identified alternatives to adoption of the ISR rules.

Although the Socioeconomic Analysis does discuss the role of public subsidies, the District's conclusion is not that low-income housing impacts are irrelevant due to public subsidies. The Socioeconomic Analysis discusses public subsidies to show the options and availability of what subsidies exist. The conclusion of the Socioeconomic Analysis is that the impacts on housing costs (both to the developer and the buyer/renter) are less than significant. The District's conclusion is similar to how some pollutant thresholds of significance are set. For example, the District is in non-attainment for ozone and PM10. It could be argued that because the air is bad already, *any* increase is contributing to non-attainment and therefore is significant. However, the District finds it impractical and unwarranted to force every project that emits *any amount* of the applicable pollutants into the 'significant' category. Therefore, the District determines significance for PM10 and ozone precursors against a threshold that aims to truly differentiate between less-than-significant and significant impacts. Similarly, the Socioeconomic Analysis states on page 37:

For the most part, rents that low-income households should pay are substantially below the rents that the typical new multi-family units construction in the region should command, even before the imposition of the air fee.

That is to say, the market is such that low-income households are already priced out of most new dwelling units. Any increase in housing costs, regardless of origin, will exacerbate this disparity. However, the analysis shows that the potential increase in mortgage is, "*a small fraction of the original household income required to finance a new home in the event no air quality fees were in place*," and the potential increase in rents are, "*similarly small*." (p.1)

15. **COMMENT:** 5. Draft Rule 9510 would impose mitigation fees without adequately establishing a nexus. The Draft Staff Report and Summary of Comments and Responses from the June 30, 2005 public workshop do not adequately support the nexus between the expenditure of mitigation fees and the location of indirect sources. For example, while NOx occurs throughout the District, the impact of other pollutants, such as PM10, is more localized.

Recommendation: Clarify the nexus between PM10 and the expenditure of mitigation fees.

RESPONSE: The District has prepared documentation included in the staff report for the rule that provides the information necessary to demonstrate a nexus between project impacts and the off-site fee. See Response to Comment #125 for the findings of the District's legal counsel's analysis of nexus requirements.

16. **COMMENT:** In summary, the Draft Rules do not appear to comply with the "clarity", "consistency," and "nonduplication" requirements set forth in Health and Safety Code Section 40727(b). Than you for the opportunity to submit additional comments. Given the magnitude of the concerns identified in this letter, the Department recommends that the District not adopt Draft Rules 9510 and 3180 as drafted and continue to work with all interested parties on needed revision.

RESPONSE: The District disagrees that Rule 9510 conflicts with H&S 40727(b). The District prepared a consistency analysis that is provided as Appendix G to the Staff Report. The rule is being revised to improve clarity of the requirements and will provide detailed rule implementation guidance prior to implementation and typically uses compliance assistance bulletins when issues arise after implementation. The rule does not duplicate other requirements on indirect and areawide sources. Emissions estimates used in the rule account for existing controls on vehicles and equipment. The rule requires a reduction of a portion of the remaining emissions after control. Because of the Valley's rapid growth, a substantial portion of benefit of the controls is offset; hence the need for additional emission reductions to reach attainment by deadlines mandated for the District's PM10 and ozone plans.

Local Public Agencies:

City of Hanford
Date: September 23, 2005

17. **COMMENT:** I applaud your efforts to continue to evaluate methods to improve the air quality in the valley. However, I would request that the San Joaquin Valley Unified Air Pollution Control District take the time to further study Draft Rule 9510 and Draft Rule 3180.

RESPONSE: This rule has been under development for more than two years. The District has had three rounds of workshops, focus groups, stakeholder meetings and other outreach. We believe that the rule development process has been adequate.

18. **COMMENT:** On behalf of the City of Hanford, I would ask that you slow down the process and identify specific steps and programs that will be implemented to reduce air pollution; include additional input from representative agencies and clearly identify how the funds collected will actually improve air quality in the valley.

RESPONSE: See the Staff Report for more information on how the rule works to reduce emissions through on and off-site measures and how the District will use funds received as a result of Rule 9510 and Rule 3180. In addition,

Appendix E (Cost Effectiveness Analysis for Rule 9510) for details on the exercise that the District has completed to ensure that:

1. The emission reduction projects exist in a quantity to provide the reductions necessary, and
2. Those projects exist at a cost-effectiveness that can achieve the schedule listed in the rule in Section 7.2.1 and 7.2.2.

19. COMMENT: The incompatibility of the proposed regulations regarding the CEQA requirements poses additional concerns.

RESPONSE: The District believes that Rule 9510 is fully compatible with CEQA requirements. The rule provides a new opportunity to provide consistent air quality analysis and emission reductions on a Valley-wide basis. See Response to Comments #8.

20. COMMENT: Restraint must be used in determining actions that would have a significant impact on our residents, the business community and our local governments. Specifically, there must be a nexus for the fee's charged and the specific identification on how the generated funds would be used to remedy the problem which exists.

RESPONSE: The District has designed the rule to address only a fair share of the impacts caused by new development. We are confident that the rule will mitigate emissions in direct proportion to the impact caused by the project in keeping with nexus standards. The key to meeting the nexus is that impact will be estimated with best available tools and emission reductions obtained to offset the impact will be quantified with best available factors and methods. See also Response to Comment #125.

Council of Fresno County Governments (Fresno COG)
Date: September 9, 2005

At the request of our Transportation Technical Committee (TTC), the Council of Fresno County Government (Fresno COG) is submitting this letter regarding the Air District's DESIGN (Decreasing Emissions' Significant Impact from Growth and New development) program. The most recent draft of the DESIGN program was discussed by Fresno COG staff and TTC members at the September 7, 2005 meeting. Many of our member jurisdictions have significant concerns over the proposed rule and requested that we submit the following comments.

21. COMMENT: Inadequate Notice and Review Time
In some cases, Fresno COG and our member agencies received only a one-day notice for the September 1, 2005 workshop. This late notice prevented several agencies from attending on that day. On several calls with the Air District last month, Fresno COG staff indicated the need for improved communication and

coordination. This continues to be a concern, as the current rule development schedule allows only two weeks to review and comment on the draft rule.

RESPONSE: The District has a list serve for the rule that enables all interested parties to receive immediate notice of workshops and document availability. The District accepts comments up to and including the Governing Board hearing, allowing for more than a month of additional review time should it be needed.

22. COMMENT: Transportation Projects Subject to the Rule
The short review time is especially troubling given the recent addition of transportation projects (with construction emissions greater than 2 tons per year) as subject to the DESIGN rule. Fresno COG and our local agencies are unclear how this will impact the project approval process and need additional time and information to assess the impacts.

RESPONSE: The rule does not impact the project approval process since the District has no discretion over those projects. The rule just provides a mechanism to enable the agencies to reduce the impacts of project construction. See also the Staff report.

23 COMMENT: Demonstrate the Air Quality Benefits
Fresno COG requests that the Air District clarify how this rule will improve air quality. Please provide additional analysis of the air quality improvements and examples of how the revenue will be used.

RESPONSE: The Staff Report contains analysis that quantifies the projected air quality benefits of the rule. Additional details regarding the potential projects funded by the rule are included in the revised Appendix E. See also Response to Comment #18 on the use of off-site funds.

24. COMMENT: Improve Response to Comments
As noted by several commenters at the September 1st workshop and by our member agencies at our committee meeting, Fresno COG also requests that the District develop and adequate process to address comments received. The "Response to Comments" distributed at the workshop was organized by category, rather than submitting agency; this made it time-consuming to locate and review specific Reponses. In several cases, our local jurisdictions indicated that comments were not addressed and needed to be given sufficient consideration by Air District staff.

RESPONSE: The District has modified the Response to Comment format to address this concern. The District feels that the current format will allow commenters to find their specific comments and the associated responses.

25. **COMMENT:** Identify Rule Changes
Please provide a document on the Air District website that identifies and tracks changes made from previous drafts of the rule. This has been the practice with other rule modifications and is essential to reviewing and commenting on this document.

RESPONSE: The changes to the draft from this round of comments will be made in strikeout/underline format.

Fresno County, Department of Public Works and Planning
Date: September 15, 2005

26. **COMMENT:** We are concerned with the language of the rules as it relates to transportation projects. Should 2.2 say "two (2.0) tons" **per year** "of NOx and PM10 combined.", based on similar language in 2.3.4 and 4.2

However, looking more closely, these three are *not* identical in that:
- 2.2 says "NOx and PM10 combined"
- 2.3.3 says "NOx and PM10"
- 4.2 says "NOx and PM10 each"

If there is a specific reason for the differences, can you explain?

RESPONSE: Since construction emissions occur during a specific period, the emissions are based on the total during the construction period. For example, if a project emits 3 tons of combined emissions during a six month construction period, that amount is subject to the 20% NOx and 45% PM10 emission reduction requirement. If a project emits the same 3 tons of emissions over two years, the calculation is also based on the entire construction project.

Section 2.2 refers to construction NOx and PM10, which is based off of 2 tons of NOx and PM10 total tons combined. The District will revise the rule language to clarify that construction pollutants are total tons combined, and operational pollutants are tons per year non-combined. Section 2.3.2 will be revised to state "NOx *or* PM10" and be specific to operational emissions.

27. **COMMENT:** Also, please look at 8.8. Under it you have 8.7.3, but should that actually be 8.8.4?

RESPONSE: The section will be renumbered as noted.

Kern County Planning Department
Date: July 22, 2005

The Kern County Planning Department appreciates the opportunity to comment on Draft Rule 9510 and Rule 3180 which are being implemented to assist the District's attainment goals for State and Federal standards for ozone and PM10. The stated purpose of Rule 9510 is to provide a mechanism for development to mitigate construction, direct and indirect emissions from their projects through design features, on-site and off-site measures. Rule 3180 will provide for payment of the District's staff cost to implement the new rule.

As our comments have consistently stated, the DESIGN Rule, while using the language of CEQA (Significant Impact) avoids all relationship to CEQA and simply defers any questions to a later time after Rule Development is complete. The following is a preliminary list of questions, comments and concerns regarding this matter.

28. **COMMENT:** What is the basis for the exemption of projects that have mitigated baseline below two tons per year for each pollutant from the Rule? Is this basis evidence that 10 projects in the same area producing less then two tons per year each are not cumulatively considerable under CEQA?

RESPONSE: The District has made changes to the project submittal timing in the rule to ensure that the air analysis conducted can also be used to support the CEQA process for the local agencies discretionary approval.

The rule is designed to reduce the impact of the project to the extent needed for the District to reach attainment of ozone and PM10 standards. The District calculated the level of reduction needed on a per-project basis that would achieve the emission reduction committed to in the PM10 and ozone attainment plans. The rule sets levels that are in compliance with state law regarding indirect source regulations and are feasible to achieve. Based on the District's analysis, project's with emissions below two tons per year of operational NOx and PM10 were not required to reduce emissions to achieve the emission reduction required by the District's plans for attainment.

29. **COMMENT:** Why are only NOx and PM10 being addressed when CEQA requires all pollutants to be quantified and mitigated to the extent they exceed thresholds?

RESPONSE: The ISR program's primary purpose is to meet attainment plan requirements *not* as a CEQA compliance method; however, we believe that reducing one precursor, NOx, will reduce the cumulative impact on ozone from new development to less than significant levels.

It is not the District's intent to reduce the impacts of all pollutants in the valley through this rule. The rules are the result of the District's PM10 and Ozone Attainment Plans, as they identified the need to reduce directly emitted PM10 and NOx in order to reach the standards on schedule. Sufficient ROG was obtained from other control measures to enable the District to predict attainment without additional ROG control. Therefore, the rule was able to focus on those two pollutants and can make the case that ROG from predicted growth from new development will not impact the attainment strategy.

30. **COMMENT:** The District has an established threshold in the GAMAQI of 10 tons of ROG yet no provision for mitigation in the DESIGN rule. Why?

RESPONSE: See Response to Comment #29 above. The GAMAQI is the District's Guide for Assessing and Mitigating Air Quality Impacts, specifically written to help lead agencies, as identified in CEQA, address CEQA for air quality impacts and may be revised to reflect changes that are appropriate.

31. **COMMENT:** Section 6.2 requires mitigation of only apportion of the project's emissions (1/3 of the project's first-year area source and operational baseline NOx emissions over a period of ten years) and then states that it "represents cumulative emissions…". The use of the term "cumulative" should be deleted and replaced by another term to explain the Districts intention. An interpretation of the phrase "cumulative emissions" in a CEQA document, under current case law interpretation, does not include such a reduction as proposed by the District. This disconnect will lead to confusion and legal challenges of CEQA documents.

RESPONSE: The District believes that the term "cumulative" best describes the emissions being reduced by the rule. The NOx emissions are declining over time, so a project that reduces emissions to the extent described by the fee formula will be mitigating its cumulative impact. See also Response to Comment #28.

32. **COMMENT:** The District is the authority that provides guidance and direction for local government on air assessments for CEQA and has been recognized as such by the Courts. If the District has sufficient basis for establishment of this Rule with reductions in required emissions to be mitigated on " the concept that annual NOx emission from motor vehicles declines 50% over ten years.", then the District should include in this Rule making, clear direction from the Governing Board to amend the GAMAQI, through a Public Hearing process, to formally adopt this approach in Air Quality Assessment methodology for CEQA documents. This process, which would necessarily include the fact basis for the adoption of this standard, would provide clear direction for the connection of this Rule to CEQA and provide support of the Lead Agency in current challenges to Air Assessment methodology in CEQA documents.

RESPONSE: The primary purpose of the rule is to help the District meet its attainment plan commitments. The rule provides for emission reductions in a framework that provides strong assurance that reductions will be real, surplus, quantifiable, and permanent and therefore should strengthen environmental documents that rely on reductions to reduce significant air impacts. The District's GAMAQI is formally adopted by the Governing Board at a public hearing. Any revisions will also go through a public review process with a workshop and Governing Board hearing. See also Response to Comment #28.

33. COMMENT: The staff report states on Page 11 that "The current concept is that Rule 9510 will mitigate the cumulative impacts of anticipated growth since the reductions attributed to this program was identified in two attainment plans as necessary to achieve the applicable standards." Yet the next sentence weakly states that "The District may (emphasis added) revise the GAMAQI to define the exact role that Rule 9510 will have in the CEQA process, prior to adoption of this program." Please clarify why the District is not committed to amending the GAMAQI to clearly provide relief for local government in CEQA litigation in a matter, air impacts, for which the District is the recognized expert.

RESPONSE: The District is committed to providing guidance through the GAMAQI that accurately reflects the impacts of all adopted District rules and regulations on air quality.See also Response to Comment #28 and #31.

September 1, 2005 Workshop – Verbal Comments

Bakersfield

Dr. Adrian Moore – Reason Foundation

34. COMMENT: There is a lack of a causal link between new uses and an increase in emissions from new trips. If it is automobiles that are causing the pollution that the rule is targeting, then the District should be going after automobiles.

RESPONSE: There are more than twenty years of CEQA documents that have consistently found that new development has a significant impact on air quality. New development is constructed to accommodate growth. Prior to development of green field areas there are no trips and no construction emissions at the project site. The argument that some trips are displaced from another existing use are not valid except in the short term. When people move to a new house, someone can be expected to move into the existing home and replace the trips the old homeowner was making. When commercial uses open in a new growth area, they may temporarily divert trips from existing commercial uses, but in a growing area the most important factor is an expanding market area. When the community adds enough residents to support another like commercial use, the

trips will be drawn from the area farthest from the existing use to the new use, and overall the number of trips is increasing.

35. **COMMENT:** The sources listed in the District's staff report are not published or peer-reviewed. Specifically, Dr. Holtzclaw's study is not published.

RESPONSE: The Holtzclaw study provides analysis of VMT differences in areas with different levels of pedestrian and transit accessibility in California. The study has been available for all who wish to review it. In addition, the study has been referenced by other researches numerous times in peer-reviewed journals.

36. **COMMENT:** Additionally, the benefits from design identified in the staff report are likely the result of self-selection and not an actual shift in modal choices based on design. Therefore the reductions from the increase in the on-site measures implemented will not materialize from implementation of this rule.

RESPONSE: The author's comment is based on a false assumption that there are no people in the San Joaquin Valley that would choose different development designs if they were available. The District maintains that trip making behavior would change if onsite design measures were widely implemented. The causal link between new development and vehicle emissions has been well documented and is generally accepted. The issue of self-selection v. modal shift in development with 'smart growth', 'transit-oriented' or 'pedestrian-oriented' design has not been resolved. It is known that there is a real, verifiable correlation between land use design and vehicle use. Studies show that well-designed development that considers pedestrian, bicycling and transit generates less emissions than totally automobile oriented design.

The District recognizes that there is always uncertainty when predicting individual travel behavior. For this reason, the District proposes to submit reductions claimed for onsite measures as a voluntary and emerging measure that allows for this type of uncertainty in order to promote innovation.

37. **COMMENT:** If it is automobiles that are causing the pollution that the rule is targeting, then the District should be going after automobiles.

RESPONSE: State and federal controls on motor vehicles are not sufficient for the District to attain federal air quality standards within mandated timeframes. The District has authority to seek additional reduction from indirect and areawide sources to close the gap. Stationary sources must provide offsets to further reduce emissions beyond what is feasible onsite. Indirect source rules operate under a similar concept. See also Response to Comment #6.

38. **COMMENT:** Reducing trips doesn't create large reductions relative to increasingly clean vehicles, regardless of increasing VMT

RESPONSE: The heart of the problem is that although vehicles are increasingly clean, increases in travel and VMT are offsetting a substantial portion of the benefit, hence the need for an indirect source review rule.

39. COMMENT: The housing impact is not near accurate because the market could be in a bubble right now. The Socioeconomic Impact Analysis should use quintiles instead of an average; you would find a huge impact on low incomes with that methodology.

RESPONSE: First, the impact on housing stated in the Socioeconomic Analysis was based on the number of housing units used by the District, which were based on the state population forecasts. If the growth rate exceeds the projection, the impacts will be greater and so will the need for emission reductions. Also, a greater number of units subject to the rule would have no added impact on individual development projects. Second, the use of an average is appropriate because the impact of the fee filters out over time, so the effect, such as an increase in rent, isn't immediate. See also Response to Comment #49.

Arthur Unger – Kern-Kaweah Chapter of the Sierra Club

40. COMMENT: The studies in the District's materials regarding differences in trip generation from different types of development are published.

RESPONSE: Comment Noted.

41. COMMENT: Concerning the information provided in the Socioeconomic Impact Report – the prices of housing in the Valley are a result of supply and demand, not necessarily resultant from fees that are assessed.

RESPONSE: The Socioeconomic Analysis supports the author's comment. The report states, "it is apparent that larger market forces are the primary culprit behind the increases in housing prices…"

Carla Waleka – Construction Industry Air Quality Coalition

42. COMMENT: The Construction Industry Air Quality Coalition would like to see the construction calculator and know the assumptions and inputs.

RESPONSE: The calculations used in the rule were done using URBEMIS construction module. The construction calculator used by SMAQMD is proposed as a model for development of a San Joaquin Valley version. We are now proposing to continue using URBEMIS with the option for developers to use a construction calculator if approved by the APCO.

Renee Nelson – Clean Water and Air Matter, Bakersfield

43. **COMMENT:** The process laid out by the District does not comply with CEQA. The process will allow for negotiations with applicants behind closed doors with no option for public input, which is required under CEQA. In addition, CEQA states that mitigation can't be differed until later. The District also put forth a comment that CEQA timelines vary with jurisdiction, which is untrue.

RESPONSE: The ISR program does not involve discretionary approval of development projects, and therefore is not subject to CEQA. We expect local agencies to use the air analysis accomplished for the rule and o-site emission reduction measures agreed to by the applicant *and the local agency* to reduce air impacts in their CEQA process. If a citizen has an issue with the approval of a project due to air quality impacts they will have the same options that are currently available to them to challenge the project and the validity of the analysis used to support the decision made by the local council or board. See also Response to Comments #8 and #28.

44. **COMMENT:** This program must be aligned with CEQA and should not allow changes to a project behind closed doors.

RESPONSE: The rule is being revised to change the application timeframe to be concurrent with the local agency CEQA process. District has no authority to require applicants to include on-site emission reduction measures. We have traditionally worked with applicants to help them identify changes to the project that would reduce air impacts as early in the development process as possible and will continue this effort. The rule requirement is for the applicant to fill out the on-site emission reduction checklist; however, it does not prescribe a minimum or maximum number of measures that should be checked. The responses on the checklist are solely up to the applicant. The land-use decision making authority is with the local land use authority, not the District. The AIA information will be made available to the public. See also Response to Comments #8 and #29.

45. **COMMENT:** Does the ISR program apply to agricultural projects?

RESPONSE: The District believes the applicability section and the definition of a development project effectively exclude agricultural projects.

46. **COMMENT:** Will the ISR apply to waste-hauling projects?

RESPONSE: Hauling projects are not specifically stated as a project in the rule. ISR projects are land-use based, triggered by a discretionary permit in combination with new construction or increased use that generates construction and/or area and mobile emissions that exceed the ISR threshold. If a land use requires a discretionary permit, and meets or exceeds the applicability threshold, then the emissions from hauling would be subject to the rule. However, if the project is hauling operations alone then it would not be subject to the rule.

47. COMMENT: Where will mitigation funds be used in relation to the project assessed the fees?

RESPONSE: The funds will be spent within an area based on the type of pollutant. NOx is a regional pollutant, but every attempt will be made to fund projects in the vicinity of the project site. PM10 is a more localized pollutant, and PM10 funds would be spent closer to the project assessed the fees.

Brian Todd, BIA and Business, Industry and Government (BIG)

48. COMMENT: The District needs to tell the public about how much more fees will be in the Bakersfield area due to the need for additional PM10 reductions.

RESPONSE: The additional PM10 reductions cited by the commenter is the 1-ton per day by 2010 needed in the Bakersfield Metropolitan area. This rule does not address that reduction. ISR program fees are tonnage based and do not adjust by location. The 1-ton needed in Bakersfield is being addressed through a PM10 task force. Voluntary mitigation agreements in the area may be used to the extent that they mitigate beyond the requirements of Rule 9510.

49. COMMENT: The dynamic driving prices for housing in small and medium cities stated in the presentation is due to school fees. The ISR fees will exacerbate this problem. In addition, the housing market may be a bubble. Basing the fee on housing bubble numbers is a flawed methodology because the market is unstable, and the fee revenue depends on the number of houses.

RESPONSE: The District fees were not based on the number of housing units going in. The fees were based on the amount required to offset emissions, and is purely emission based. The expected *fee revenue* and *future impacts* are estimated from the forecasted population data from the state and the emissions from growth in residential and non-residential development.

It is important to note that the District will only be collecting fees to reduce as in there is development creating emissions to reduce. If the number of houses decrease (bubble burst), the District would have fewer emissions to reduce; therefore, the same fee brings the appropriate amount to reduce those emissions (less revenue). If the number of houses increases, the District would

have more emissions to reduce; therefore, the same fee brings the appropriate amount to reduce those emissions (more revenue).

Heather Ellison

50. COMMENT: What is the meaning of 'recreational space' and 'unidentified space' in the rule?

RESPONSE: Rule 9510 §13.7 defines recreational space for recreational uses such as soccer fields. Unidentified is a catchall category to indicate that other land use categories not listed are still subject to the rule if they generate emissions and are not otherwise exempt.

Mike Kelly – Western State Petroleum, Vector Environmental

51. COMMENT: Previous comments to the District were not adequately addressed in the previous response to comments. The law states that the District can regulate the increase in emissions. There is a concern that the Rule will trigger review of those discretionary permits that don't result in an increase in vehicle traffic, such as certain Conditional Use Permits (CUPs).

RESPONSE: The District typically consolidates similar comments and provides a single response. The District will consider providing individualized responses on a case-by-case basis.

The Rule applies to the *increase* in emissions resulting from land-uses changes that require a discretionary permit. Therefore, if project requires a discretionary permit, but does not result in an increase in emissions that meet the applicability threshold, then it would not be subject to the Rule. However, if the CUP allows for an increase in indirect or area source emissions or new construction activity that generates emissions, it would be subject to the rule if not specifically exempt.

Fresno

Bob Keenan – BIA, BIG

52. COMMENT: Fee collection and use is governed by the Health and Safety Code, §6600 subsection G. The rule does not meet those requirements.

RESPONSE: The author cites Government Code Section 66000 (The Mitigation Fee Act) as the impetus for promulgating a nexus document. The legislation clearly states that it is applicable to fees (§66000(b)), "in connection with approval of a development project." Section 66000(a) defines a development project as including, "a project involving the issuance of a permit for construction

or reconstruction, but not a permit to operate." In addition, Section 66001(a) states:

> *In any action establishing, increasing, or imposing a fee* ***as a condition of approval*** *of a development project by a local agency on or after January 1, 1989, the local agency shall do all of the following:*
> (Emphasis added)

Section 66005(a) also ties the legislation with 'condition of approval of a development project'.

1. The District will not approve or disapprove a development project, but will approve or disapprove the project's analysis to determine the quantity of emission reductions required to comply with the rule. The authority to approve or disapprove the development itself is the local land-use agency, not the District.
2. The District will not be issuing a permit, nor will the District give a discretionary approval of the project.
3. The District's ISR action is ministerial, and therefore will not include conditions of approval.

The District stands by its previous assessment. The Mitigation Fee Act does not apply to the ISR rules. However, the District has analyzed the applicability of nexus requirements to this rule. See Response to Comment #125 for the findings of the analysis.

53. **COMMENT:** Fees paid at the permit doubles to the buyer and prices people out of the market.

RESPONSE: Fee prices may price some people out of a particular house, but not necessarily out of the entire market. Currently, market forces are increasing the price of housing to a much greater extent than the fee would. In addition, the difference between paying prior to building permit issuance and at certificate of occupancy can't possibly double the cost unless the loan was at an astronomical interest rate. If the fee were financed in a mortgage at 30 years it may double, but it also doubles the amount they are paying for anything.

54. **COMMENT:** The fees from the program will drive up the costs of existing housing.

RESPONSE: Existing housing is not subject to the rule. Although the District realizes that sellers of existing housing may take advantage of a potential increase in new housing prices by artificially inflating the price of existing housing, the District does not have control over existing housing prices.

Increases in existing housing prices 'attributable' to the rule would be resultant of the seller, not of the District.

55. COMMENT: The impact of the fees resulting from implementation of the ISR program would ruin the Valley's economy.

RESPONSE: The commenter's position that ISR fees would ruin the economy is not supported by factual evidence. The Socioeconomic Analysis found the worst-case scenario of fees to be within the margin that can be absorbed by the economy. This is not to say that there is no impact, but that the impact is less than significant. In addition, the residential scenario in 2008 resulted in a fee of about $1,800 per house. This scenario had no emission reduction measures included; it had a density of 3 unit per acre (increased density decreases emissions), no sidewalks, or any other measure that reduces emissions (and thus fees). See also response to comment #56 and #14. Finally, housing prices have steadily increased in over the last ten years. This increase is far more than $1,800 *every year*. The District does not state this to justify the potential fee, but to illustrate what has occurred in housing prices and that the Valley's economy has not crashed as a result. It is illogical to suggest that a potential $800 per residential unit in 2006 to $1,800 in 2008 would ruin the Valley's economy. As stated in Response to Comment #14, the fee amount listed in the Socioeconomic report is likely much more than will actually occur.

56. COMMENT: The cost of on-site mitigation is not included in the socioeconomic impact report. Therefore, the report does not accurately reflect the impact of the rule.

RESPONSE: The Socioeconomic Analysis does not include the price of on-site emission reduction measures for a specific reason. That is, it is reasonable to expect that an applicant would not choose a more expensive option over a cheaper option. The 'worst-case', no on-site-measure fees are therefore the most that an applicant would pay. It is also important to note that on-site measures are entirely voluntary.

Also of note, many of the on-site measures that count towards reduced emissions are *already* requirements by local land use agencies. For example, most agencies require some amount of sidewalks or bicycle improvements with development that is adjacent to a street. URBEMIS calculates an emission reduction from the amount of sidewalks and bicycle infrastructure built in the project. Therefore, crediting certain on-site measures are of no additional cost to an applicant because they had already incorporated the measures into the project as a result of the public agency requirements.

Mark Stout - Fresno Metro Ministries

57. COMMENT: The proposed rule only mitigates a portion of the emissions. Why does the rule only reduce a portion of the emissions, and why the particular level- for example the 33% for operational NOx.

RESPONSE: The District calculated the level of reduction needed on a per-project basis that would achieve the emission reduction committed to in the PM10 and ozone attainment plans. The rule sets levels that are in compliance with state law regarding indirect source regulations and are feasible to achieve. The 33% is based on the area under the triangle that accounts for declining mobile emissions over time – see the fee formula.

58. COMMENT: A slide of the presentation showed huge NOx emissions increase from 2006 to 2010 from development. The number listed for reduction attributable to the rule seems rather small in comparison.

RESPONSE: The slide incorrectly showed the reductions attributable to construction as cumulative instead of temporary during the construction phase of development.

59. COMMENT: The District would benefit from making the URBEMIS runs available to the community groups. The community groups should be able to review what developers are inputting, and verify the modeling.

RESPONSE: The runs will typically be used in the CEQA process and included with negative declarations and EIRs. The files will be available with a public information request. The District will make this information public. See also Response to Comment #8.

Colby Morrow – Southern California Gas Company

60. COMMENT: Appendix C should be amended. PUC Energy Efficiency programs can be administered by energy companies and municipalities.

RESPONSE: Appendix C, page C-5 will be amended.

Cathy Crosby, Fresno County Public Works, Transportation and Planning

61. COMMENT: The response to comment format from the previous workshop made it difficult to find one's comments and the associated responses. The preferred format would be the EIR format, where the original comment letter is retained.

RESPONSE: The District has revised the response to comment format to address this issue. The format is a hybrid, retaining the original comment but not in the original letterform.

62. COMMENT: Several of the Fresno County July 22nd comments weren't addressed in the response to comments. Specifically:

- Transportation projects should be re-written to include non-vehicle projects, such as pedestrian projects.

RESPONSE: The definition of Transportation projects does not include non-vehicle projects because of the definition of an indirect source. The Clean Air Act (CAA §110(a)(5)(C)) defines and indirect source as, "… a facility, building, structure, installation, real property, road, or highway which attracts, or may attract, mobile sources of pollution". Pedestrian projects do not attract mobile sources of pollution, but pedestrians. It would be inappropriate to include non-indirect sources in with transportation projects to be subject to the requirements of the rule.

63. COMMENT: §7.2.2.2 of their letter describers the dissolution of community service districts.

Previous Comment
7.2.2.2- Community Service Districts (as a means to insure perpetual funding for operational mitigation): The Air District may want to evaluate under what conditions a Community Service District that funds any mitigation activity not directly related to health & safety may, after formation, discontinue assessment or dissolve the Community Service District by vote of property owners making up the District.

RESPONSE: All measures within the on-site checklist have an emission reduction benefit associated with their implementation. The District identified those on-site measures that reduce emissions from development projects, and help reduce the air impact of development projects. The goal of the rule is to reduce emissions from development project to achieve the emission reduction committed to by the PM10 and ozone attainment plans. Although each measure is indirectly associated with an air benefit (reduced emissions and attainment of the PM10 and ozone standards), the District considers the measures to be health-related. Therefore, funding of these measures constitutes a health-related activity.

64. COMMENT: Maintenance concern. Where will the funds for County enforcement of the rule come from?

RESPONSE: The County will not be required to enforce the rule. See Response to Comment #8.

Ray Leon – Latino Issues Forum

65. **COMMENT:** The District should clarify the PM2.5 and toxics issue. Suggests that the District break PM10 down further to strengthen the rule.

RESPONSE: This rule is a result of the PM10 and ozone attainment plan commitments. The rule controls NOx and PM10. Some fraction of PM10 is PM2.5 and will be reduced as a result of the rule. NOx reduces ozone during the warm months and reduces ammonium nitrate, most of which is PM2.5, during the cold months of the year.

The District recognizes the issue of toxic emissions from diesel engines, and the particular hazards of PM2.5. However, toxics are addressed through the District's permitting program, state regulation, and through CEQA commenting. District thresholds of significance for these pollutants are contained in the Guide for Assessing and Mitigating Air Quality Impacts (GAMAQI). In addition, PM2.5 will be addressed in the federal PM2.5 Attainment Plan due in 2005.

Mike Sanchez – City of Fresno

66. **COMMENT:** The city's July 22nd comments need to be addressed; they weren't addressed in the previous response to comments.

Previous Comments (paraphrased)

Nexus and Proportionality

- **A.** What is the Nexus determination for the project
- **B.** ISR rules address emissions from existing development; so, placing requirements on new development to remedy problems from existing development would be inappropriate.

Relationship of SJVAPCD and Rules 9510 and 3180 to CEQA and Planning Law

- **C.** Rule appears to defer or circumvent CEQA analysis because analysis and mitigation would be prepared after CEQA analysis. Also, it appears that the District would be issuing a construction permit, making the District a responsible or trustee agency.
- **D.** There may be differences in interpretation of mitigation measures and the reductions associated with them.
- **E.** Because the District is the appropriate agency to make a detailed determination of air quality impacts and appropriate mitigations, the District should fulfill its CEQA responsibilities by providing analysis and recommendations to the local land use jurisdictions so that the CEQA analysis work can be completed with this information.
- **F.** The District should not determine locations or patterns for development, this is the local jurisdiction's authority.

G. "Analysis and conclusions regarding land use and its vehicular emissions need to be rooted in data… recommend objective criteria"

Applicability of the Rules 9510 and 3180

H. It is not addressed if the rule applies to general, regional, community or specific plan adoptions. At that level, project specific information may not be known, and analysis may not be accurate. Therefore, they should be exempted from the rule**.**

I. Each public agency defines 'discretionary' and there is variability as to what each public agency considers discretionary. Therefore, the ISR rules will be applied inconsistently.

J. Language should be included in the rules to prevent piecemealing.

Timing and Project Tracking

K. Request ISR review to be shortened from 30 to 10 days to , "remain within the statutory CEQA timelines for responding to initial study requests" because URBEMIS runs are quick. The District should send the ISR project information to the public agency for incorporation into CEQA documents.

L. How will timing of construction be controlled for mixed use projects, since commercial often lags behind residential development?

M. How will the District track projects, such as multi-phase tract maps or shell buildings, for review and analysis.

Interagency Cooperation

N. "The ISR Rules propose that cities and counties withhold building permits pending satisfaction of SJVUAPCD requirements." There should be an agreement between the public agencies and the District that includes indemnification of the city.

O. "Local land use jurisdictions should be made a party to any mitigation agreements entered with the developer…(and) it would be ideal if such agreements were recorded as covenants running with the land…for which the … analysis was done."

Use of Mitigation Fees Collected Through ISR Rules

P. It appears that the ISR funds will be used to fund existing programs. New programs that expand mass transit and similar systems should be considered. "… the majority of the funding generated through the ISR rule should address vehicular pollution through measures to reduce traffic volume and relieve traffic congestion in the vicinity of the land use projects paying the ISR Rule-related fee."

RESPONSE:

A. See Response to Comment #125

B. ISR rules address emissions from *growth*, not from existing emissions. See Response to Comment #170. See also, Response to Comments #34 and #39.

C. Rule has been revised to be concurrent with CEQA analysis and Public Agency approval process. See Response to Comments #8 and #44. Also,

the District would not become a Responsible agency as a result of ISR implementation (See Response to Comment #52 and #187)

D. The measures listed in the On-Site Emission Reduction Checklists have a known quantification method associated with them. Applicants will identify the *specific* implementation of each measure, so there will not be interpretation of the amount of reduction. See also Response to Comments #7 and #9.

E. Although the ISR rules were not written to address CEQA, the reductions committed to in the PM10 and ozone attainment plans from this rule and individual project compliance can be used in CEQA documents at the public agency's discretion. See Response C above for timing of ISR implementation. See Response to Comment #8 for information on communications between the District and the land-use authority.

F. The District will not be making land-use decisions, and recognizes that that is the authority of the local land use agency. The land-use design considerations discussed by the District are discussed because they are known to reduce air quality impacts. The District provides these types of measures to encourage applicants to design projects submitted for city/county approval in ways that improve air quality and reduce potential ISR fees. The District has no authority over implementing land-use changes. Please note, the District will not require a minimum selection for the on-site checklist, measures selected are voluntarily identified by the applicant and are likely already part of the project. See also Response to Comment #43 and #44.

G. The measures listed on the on-site checklist have objective criteria, based on extensive research within URBEMIS. Please refer to Appendix D (Recommended Changes to URBEMIS for Rule 9510 and 3180) and the URBEMIS User's Guide (available at URBEMIS User's Guide, available at South Coast Air Quality Management District's website http://www.aqmd.gov/ceqa/urbemis.html). See also Response to Comments #7 and #9.

H. The ISR rules are applied to the last discretionary approval of a development project per Rule 9510 Section 2.1. The adoption of a general plan or specific plan is not usually the last discretionary approval a project will go through. Residential development may be rezoned, and must get a subdivision or tract map. Conditional Use Permits and Site Plan Reviews often apply to commercial and office development. However, the District recognizes that some projects may not require additional discretionary approval after the zoning is approved. Specifically, industrial development may not require additional approval. Therefore, the last discretionary approval will vary depending on the project. The District will provide outreach to developers and the public to ensure awareness of the rule; however, it is the responsibility of the applicant to be aware of the need, or lack thereof, for additional discretionary approval by the local land-use agency, and to apply at

the appropriate time. Additionally, applicants are encouraged to apply *prior* to the application for last discretionary approval with the land-use agency.

I. The District recognizes the variability of the application of 'discretion' in the Valley. As stated in H above, the last discretionary action is the trigger for the rule. This may cause inconsistency early in ISR implementation; however,

J. Language has been included. See Rule 9510 Section 2.3

K. First, the ISR program is not a CEQA compliance program (See Comments above). Analysis of the AIA application involves more than opening and running URBEMIS. The District will be analyzing the documentation for projects, running modeling program, finalizing MRS's, finalizing FDS's, etc. See the Draft Staff Report for additional information. The District will be sending information to the public agency. See Response to Comment #8.

L. The District does not have the authority to control construction timing. See Comments F, G and H above.

M. The District will be tracking projects through a database, and will be tracking project location primarily through APN. Multi-phase projects will be entered as such, with the applicable expected build-out dates. The applicant is responsible for identifying the use and build out of the projects. Should the project change, the applicant is responsible for notifying the District. If the project changes such that there is an increase in air emission and the applicant does not notify the District, they will be in violation of the rule and subject to District enforcement action. The District will share project information with public agencies to coordinate project tracking.

N. The District will not require or request that public agencies withhold building permits for ISR enforcement. However, the District may enter into an agreement with a public agency for information sharing that would facilitate District enforcement of the rules.

O. The District will be sending the public the on-site emission reduction checklist, as well as other information (see Response to Comment #8) during the review process. The District will consider the use of covenants for MRS compliance enforcement.

P. The District will not be using the ISR funds solely for existing emission reduction programs. The District has conducted an analysis of emission reduction projects available, and the cost effectiveness associated with them. This analysis can be found in Appendix E. See Response to Comments #18 for the use of funds, and #47 and #188 on the location of funding projects.

Modesto

Sally Rodeman – CalTrans, District 10

67. COMMENT: District 10 did not receive the notice for the meeting.

RESPONSE: You will be added to the rule mailing list. Other Caltrans staff received notice.

CalTrans District 10 is on the District's mailing list as a street address, to which the District has been mailing notices. District staff looked into the issue, and found that the CalTrans website lists a PO Box for District 10. The District will work to resolve this issue.

68. COMMENT: Is CalTrans a developer as defined by the rule?

RESPONSE: CalTrans would be a developer in those instances where the project meets the applicability of the rule.

69. COMMENT: Can the District put that in writing in the rule?

RESPONSE: The District does not specify or write out *who* a rule applies to, but write *what* a rule applies to. The rule is written so that all entities and individuals conducting activities subject to the rule must comply, so there is no need to list every possible agency or entity subject to the rule.

70. COMMENT: Does the Socioeconomic Impact Report account for impacts on the State of California, considering that the state is broke?

RESPONSE: The socioeconomic analysis provides the overall impact to the economy but does not specifically separate out impact to individual government agencies.

71. COMMENT: Does the District have a list of mitigation measures for construction?

RESPONSE: The Staff Report contains a discussion of measures that reduce emissions from construction activities.

Tom Carlson – Sierra Research

Thanks for addressing Sierra Research's comments from the last draft of the rule. Particularly, for Sierra Research's comments on silt loading, trip links and fleet mix.

72. COMMENT: How will the District be addressing the needed changes to the URBEMIS model?

RESPONSE: Updated default values will be provided as rule guidance. This information may be contained in the next update to the GAMAQI. The next upgrade to URBEMIS, beginning next year will include many of the new defaults and an improved construction module. The upgrade may take as much as a

year to complete, so in the interim, the guidance documents will be provided as needed.

73. **COMMENT:** What is the basis for the targets on PM and NOx reductions from construction?

RESPONSE: The District researched what other air districts had set for reductions, and found that those targets are achieved in practice. The reductions (20% NOx and 45% PM10) are achievable with existing technology with a mix of newer equipment and retrofit devices, and will allow applicants applying moderate effort to pay no fee on construction.

74. **COMMENT:** What is the District's response to the vehicle age distribution by age of project that Sierra Research had provided? Is the information provided by Sierra Research not adequate or substantial enough to change the modeling?

RESPONSE: The District is not currently convinced that the data cited would be valid in all circumstances, but will consider projects that provide evidence supporting a reduction for fleet age. There may be other factors that offset the possible benefit from newer vehicles such as higher rates of vehicle ownership (more vehicles per household).

75. **COMMENT:** URBEMIS is a sketch planning tool. Sierra Research believes the District should use a travel model. Sierra Research believes that a travel model is more accurate than URBEMIS, and found that URBEMIS estimates are 60% higher than the travel model estimates for the same project. In addition, as a sketch tool, URBEMIS is inconsistent with SIP methodology.

RESPONSE: The District believes that URBEMIS has been improved beyond its characterization as a sketch planning tool. Very few of the modules of the program are overly conservative. Most modules rely on statewide averages extracted from the emission inventory which should not be considered conservative estimates. The most important module is the mobile source module that includes the same emission factors used to build the emission inventory. It does a good job of arriving at a composite emission rate needed for a project level analysis. Models can always be made more accurate by individualizing more and more input factors. The District believes that URBEMIS balances data requirements with reasonable output accuracy and ease of use. The travel demand models described by Sierra Research are extremely data intense and would be very costly to run for the approximately 1,000 projects that will be submitted to the District each year. It is uncertain whether the demand models are more accurate for project level analyses than URBEMIS with local information**.**

Jan Ennenga – Manufacturing Council

76. **COMMENT:** There is a concern that the ISR program would apply to CEQA processes and permits for existing facilities that make modifications.

RESPONSE: ISR projects are land-use based, triggered by a discretionary permit in combination with new construction or increased use that generates construction and/or area and mobile emissions that exceed the ISR threshold. If a land use requires a discretionary permit, and meets or exceeds the applicability threshold, then the emissions from hauling would be subject to the rule.

77. **COMMENT:** What exactly does "primary source of emissions" mean for the exemptions section?

RESPONSE: The District had originally include an exemption for "A development project, whose primary source of emissions are from stationary sources…" However, the District is revising exemption to make specific land uses exempt. The District has completed a review of industries permitted by the District. This analysis details the amount of rules that apply to each industry and the amount of pollutants regulated by these rules. The intent is to remove the ambiguity of "primary" emissions and detail which industries will be exempt from the rule. In addition, industries with stationary sources may petition the APCO for ISR exemption.

Bill Zelocci – BIA CC, PSSP, StanCo (Affordable Housing)

78. **COMMENT:** The bill targets housing only. The fees, at least the biggest fees are from housing. The Rule doesn't affect other land uses that produce vehicle trips.

RESPONSE: The rule targets new development that results in area and/or mobile emissions. The rule contains an applicability section and an exemptions section. The rule *does not* target housing exclusively or charge higher fees for residential development. Housing constitutes about 1/3 of the development related emissions and therefore 1/3 of the potential for fees under the rule. Other land uses such as commercial office and retail generate more emissions and potential fees. Housing is used extensively in discussing socio-economic impacts because that is what concerns most people. Fees are emission based, not land-use specific. Fees apply to the broad categories of land uses specified in the rule. Certain land uses are exempted from the rule because their emissions are primarily from stationary sources, and they have been subject to extensive controls and requirements already. The sector targeted by the rule are those land uses without the majority of emissions from controlled stationary sources, which haven't been subject to rules or emission controls.

All fees are tonnage based, and the required reduction formula applies equally to all applicable projects. This means that a particular project only pays the off-site emission reduction fee for the required reductions that are not achieved on-site.

The Socioeconomic Analysis discusses the potential impacts to housing more extensively than the impacts to commercial or industrial, because the impact on housing affordability is of a greater concern to the affected industries and the general public than the impacts on commercial or industrial.

Certain land uses are exempted from the rule because their emissions are primarily from permitted stationary sources (the rule only covers area and mobile emissions), and they are and have been subject to extensive controls and requirements.

79. COMMENT: The rule should also address existing housing.

RESPONSE: The goal of the rule is to achieve an emission reduction from *growth* that was identified in the PM10 and ozone plans. Although VMT is increasing valley wide, the majority of new emissions are attributable to new development. It would be inequitable to assess fees on existing uses with the purpose of mitigating emissions from growth.

80. COMMENT: Part of the presentation used small, unreadable font. Please use a reasonably large font for presentations, so that people may be able to read what is on the screens.

RESPONSE: Comment Noted. The District apologizes for the illegible font-size, and will attempt to make future presentations clear and readable.

Randy Hatch – Planning Director, City of Ceres

81. COMMENT: There is a concern that the ISR program will cause changes to a project after a local agency has granted approval to the project.

RESPONSE: The rule has been changed to make the process concurrent or prior to the approval process by the public agency. The District defers land-use choices to the public agency and the applicant. See Response to Comment #8 for more information.

The District does not place requirements for land-use measures on the project. The on-site emission reduction checklist must be filled out by the applicant, but the District does not have a minimum or maximum requirement for the number or type of measures to be selected. Inclusion of measures is voluntary by the applicant (see Response to Comments #56). The District will not engage in negotiations to include on-site measures (See Response to Comment#44).

Therefore, the District will not be imposing measures that conflict with the local land use agency. It is the applicant's responsibility to make sure that those measures they have voluntarily selected are consistent and approvable by the local land use agency. In the instance that the identified measure is not acceptable by the local land use agency, the applicant is responsible for notifying the District and the on-site emission reduction checklist and emissions modeling will be revised to reflect the project at that time.

In addition, the rule and staff report will be revised to provide more interaction with the public agency and the District. See Response to Comment #8 for more information.

82. COMMENT: How do public agencies determine compliance with the rule, especially if the District's approval can occur after the approval by the public agency?

RESPONSE: The District will revise the ISR process to be concurrent with or prior to the approval process at the public agency. See Response to Comment #8 for more information. Specifically, the District will provide letters notifying the public agency of the Determination of Completeness, AIA Approval and Final Compliance, as well as providing a letter of compliance status to the public agency upon request.

83. COMMENT: What exactly is meant by 'parks' in the applicability section?

RESPONSE: Active recreation parks – parks that attract motor vehicles. It is not the intent of the rule to assess passive recreation parks. Parks will be assessed based on emissions the same as other land uses,

84. COMMENT: The City of Ceres suggests the District alter the application process to make it prior to the final public agency approval, perhaps by tying it to the application to the public agency. In addition, the City suggests the District include a predevelopment process. The City of Ceres has a predevelopment process that aids in the application process.

RESPONSE: The District will amend the rule language and the staff report to make the application to the ISR program concurrent with or prior to the final discretionary approval application to the public agency See Response to Comment #8 for more information. The District does not currently have a plan for formal pre-application consultations. However, the District will be available for consultations any time prior to actual application and encourages applicants to meet with District staff to clarify issues when needed.

Fresno

Kathryn Phillips – Environmental Defense

85. **COMMENT:** Concerning the view that land use does not have an impact on air quality (see comment #34) – that is a minority view. Most have realized that land use does have an impact on air quality.

RESPONSE: Comment Noted.

86. **COMMENT:** Concerning the issue of self-selection (see comment #36), the choice of good design should be available.

RESPONSE: Comment Noted.

87. **COMMENT:** The URBEMIS model is imperfect, but it is appropriate for this rule.

RESPONSE: The District concurs. The District is aware that there is not a 'perfect' model available, nor is there likely to be one in the future. However, the URBEMIS model is best available method for quantifying project emissions and benefits from on-site measures.

88. **COMMENT:** Rule 9510 section 2.1.8 has one threshold for recreation, but the definition includes movies. 'Movie theaters' are more commercial in nature, and should be moved to commercial. In addition, 'parks' should be defined.

RESPONSE: Comment Noted. 'Movie theaters' will be removed from recreation to commercial.

89. **COMMENT:** A 2-ton exclusion level (Rule 9510 section 4.2) is too generous. This level should be reduced.

RESPONSE: See Response to Comment #180.

90. **COMMENT:** Rule 9510 section 2.2 discusses transportation projects that have two tons or more of NOx and PM10 combined. How large of a project would fit this description? How large would a project be to be subject to the rule – a pothole or an interstate exchange?

RESPONSE: Small maintenance projects would not exceed the threshold. Construction of a one-half mile arterial road segment would exceed the threshold. The road project must also be subject to a discretionary approval to be brought into the ISR process.

91. **COMMENT:** Rule 9510 section 3.5 defines 'Baseline Emissions'. This section should be clarified. Where exactly is the baseline?

RESPONSE: The definition will be changed to the following:
Baseline Emissions: the unmitigated estimated NOx and PM10 emissions, output calculated by the APCO-approved model, in the units of tons per year.

In addition, the following will be added to the definition section of the rule to clarify the issue of baseline:

Construction Baseline: the sum of unmitigated NOx or exhaust PM10 for the duration of construction activities for a project or any phase thereof.

Operational Baseline: the entirety of NOx or PM10 emissions, including area source and mobile emissions, calculated by the APCO-approved model, for the first year of buildout for that project, or any phase thereof.

A development would have two construction baselines (one NOx, one PM10) and two operational baselines (one NOx and one PM10), if it does not have phase. For the purposes of this discussion, the four baselines will be referred to as a 'baseline set'. For projects with phases, each phase will have one baseline set. According to the off-site fee formulas, the equations are used for each baseline set.

As and example, one project has three phases. The rule contains four fee formulas: an operational NOx, an operational PM10, a construction NOx, and a construction PM10. Each of the four calculations are performed three times, once for each phase or 'baseline set'.

The operational baseline is calculated at the date of expected buildout, the construction baseline is calculated at the date(s) of expected construction.

92. **COMMENT:** Rule 9510 section 4.1.5 needs clarification of what federal, state and local funds for low income housing are applicable.

RESPONSE: Based on the District's internal analysis of applicability and impacts, the exemption for low-income housing has been removed. It has been determined that the Rule should apply to all new residential development that meets the applicability section of the Rule.

93. **COMMENT:** Rule 9510 section 5.3.2 discusses the application for the AIA. The District should list out what information will be in the application.

RESPONSE: The District will expand that section to include more specific information of what will, at a minimum, be included in the AIA application.

94. **COMMENT:** Environmental Defense recommends including ROG in the rule for emissions reductions.

RESPONSE: See Response to Comment #57 and #65.

95. **COMMENT:** Rule 9510 section 6.1.1.1 and 6.1.1.2 discusses the reductions required from construction emissions. The 45% reduction requirement for PM10 is too low. Applicants can get much higher results with existing technology. The 20% NOx reduction requirement may similarly be too low. In addition, Environmental Defense recommends requiring emission reductions by vehicle and suggests that the District talk to CARB about their in-use construction equipment regulations.

RESPONSE: See Response to Comment #57 and #65.

96. **COMMENT:** Rule 9510 section 10.2 (APCO administration of funds) does not contain the term 'permanent'. The District should aim for permanent reductions.

RESPONSE: Many of the projects funded by the District will meet the strict interpretation of permanent reductions. In some cases, the projects are expected to be permanent but the user of the clean equipment is only obligated to operate it during the contract period. After the contract period ends, it is highly likely that any replacement equipment will be as clean or cleaner than that funded by the District due to lower emission standards and improving technology over time for nearly all source categories.

97. **COMMENT:** The funding of projects with fees received from this rule is implied to be application-based. The rule should state if it is application based.

RESPONSE: Although current District programs are primarily open application based for as long as funding is available, for some source categories it may be more appropriate to have requests for proposals with deadlines and project ranking. Therefore, the rule language should remain the same.

98. **COMMENT:** The economic analysis and other supporting documents don't include health impacts and those costs. This information should be included to keep the purpose and goals of these actions in perspective.

RESPONSE: It is not feasible to assign a dollar amount to the health effects that will be avoided or lessened by the implementation of this rule. However, the District will include health-impacts information from the PM10 and ozone attainment plans in the staff report.

Kristine Foster – Asthma Coalition, Respiratory Therapist, Asthma Educator and CAC member.

99. COMMENT: Land use planning is important and the District needs to include education for the public.

RESPONSE: The District concurs with both of the commenter's points. The District currently believes that Rule 9510 will provide incentives for development that creates fewer impacts and will bring greater awareness of this issue to the public.

Bakersfield

Mike Kelley – Vector Environmental

100. COMMENT: Does the rule apply to the fraction of PM greater than 10 microns?

RESPONSE: No. The rule applies to PM10, the fraction of PM 10 microns or less in diameter.

Chambers of Commerce – Public/Private Organizations

The Greater Merced Chamber of Commerce
Date: September 14, 2005

101. COMMENT: The Greater Merced Chamber of Commerce urges the district to reevaluate the impacts of rules 9510 and 3180 will cause to the Central Valley. The District has no organized plan for the fees that will be charged and when asked, the district indicates grant money for clean air vehicles and other measures to reduce the pollution. Before these rules should be brought to the board for approval, a complete plan should be developed.

RESPONSE: The District has a history of funding more than $100 million in emission reduction projects. These existing programs are underway and the system is in place for processing projects funded by Rule 9510. The District has provided additional information on the types of projects available for the program in Appendix E. The District has identified more than $400 million in projects available at a cost-effectiveness that will allow the District to achieve plan commitments. As technology advances, even more opportunities for retrofit and replacement programs are expected.

102. COMMENT: These rules will make the housing costs rise to a level that will make housing in Merced more unaffordable and will hamper industrial and commercial development in the greater Merced area. A comprehensive study needs to be completed on the effect the rules will have on economic development and jobs in the valley. The valley leads the nation in unemployment figures and the need for jobs through out the Valley is extremely important. These rules ill affect new job creation.

The costs of these new rules will slow down growth that will be coming to the Valley. Without a clear economic study, these rules should not be approved. Growth will happen and proper planning is needed to make sure the growth is well-planned and well-implemented. These rules will create more problems than they will solve.

The Greater Merced Chamber requests more studies and a better economic plan be developed before the rules go forward to the board for approval. Thank you for your consideration of our concerns.

RESPONSE: According the Merced County Association of Realtors, the median home price in Merced County is $330,000. The proposed fee amounts not considering the potential for reductions due to project design are between $800 and $1800 per unit in the first 3 years of program operation. In percentage terms this ranges from .24% to .54% added cost to the median home. The funds

collected from the developers are used for air pollution projects in the area that will benefit the local economy.

Stanislaus Economic Development and Workforce Alliance (Alliance)
Date: September 13, 2005

I am the CEO of the Stanislaus Economic Development and Workforce Alliance. The Alliance is a public private organization comprised of representatives of Stanislaus County, all cities in the county and dozens of private business investors. It is the designated agency for all economic development and workforce activities in the county.

I attended the video conference of an APCD staff presentation at a public \meeting on September 1 in Modesto. I am very concerned about several aspects of that presentation and therefore the consequences of Rule 9510 and Rule 3180 proposed for implementation by the APCD.

My concerns are as follows:

103. **COMMENT:** Regarding the exemption for projects whose primary source of emissions that come from stationary sources, how is **primary** determined?

RESPONSE: The District has completed a review of industries permitted by the District. This analysis details the amount of rules that apply to each industry and the amount of pollutants regulated by these rules. The intent is to remove the ambiguity of "primary" emissions and detail which industries will be exempt from the rule. In addition, industries with stationary sources may petition the APCO for ISR exemption.

104. **COMMENT:** Regarding the submittal of applications no later than 30 days **after** last discretionary approval, what kinds of delays to projects will be experienced while APCD reviews the mitigation plans and does their calculations and assessments. My experience tells me the current workload precludes timely processing or even a return of phone calls regarding ATC requests and other permitting. Staffing is either insufficient or incompetent or both. What steps are contemplated to alleviate the existing gridlock and avoid additional bottlenecks in the future?

RESPONSE: See Response to Comment #8 for the ISR application changes. It should be noted that the ISR process is not a permit, nor is it a discretionary action (See Response to Comment #187). The District is working on producing a streamlined approval process that has clear information requirements and timelines (as listed in the rule). The Planning Department will be responsible for ISR project review and approval. The Planning Department, as well as all affected departments (Compliance, Emission Reduction Incentive Program – ERIP, and Administration), has produced a staffing analysis for implementation

of the ISR program. The Planning Department identified the steps in review and approval, the time associated with those steps, and in this process identified steps that could be merged or simplified. The staffing requests are listed in the Board Memo, and the District will provide a more detailed staffing request before the Board adoption hearing. However, the staffing analysis is for ISR adoption only, and does not address staffing for existing programs.

105. COMMENT: The APCD has not yet created an emissions calculator.

RESPONSE: URBEMIS will be used for Operations, District is working to determine if a modification to URBEMIS or a separate calculator will be needed for construction. However, methodology for construction is known. Take vehicle type, hours of operation and compare to emissions from the state-wide average. URBEMIS can come up with default fleet numbers, we are working about refining them.

106. COMMENT: Developers and business with the same degree of concern on this issue that the APCD exhibits, albeit with a different perspective, have expressed serious reservations about the integrity of URBEMIS. Are these concerns dismissed out of hand with no attempt to verify the soundness beyond your belief that it must be okay because you are using it.

RESPONSE: The Staff Report contains a detailed discussion of why URBEMIS is appropriate for this rule, and why it was chosen over other models. The District has completed extensive research, including hiring a consultant to review existing models to determine the most appropriate, comparisons of models, and detailed model research and has determined that URBEMIS is the most appropriate model for the rule. See Response to Comments # 157.

107. COMMENT: The socioeconomic impact predictions for Rules 9510 and 3180 were calculated using dated methodology (1995) that does not factor in the impact of the meteoric increases in valuations and costs and burden of stagnant incomes regarding affordability.

RESPONSE: The Socioeconomic impact report uses median price data up to 2005. Most data was no older than 2003. The methodology is standard for the air pollution rule development process and is not dated.

108. COMMENT: The financial windfall that will occur if these rules are implemented could total tens of millions of dollars per year in the valley. What accountability is associated with the “mitigation accounts”? Who determines and what is the definition of quantifiable and enforceable mitigation projects?” Is there an audit of these accounts and by whom? How were the fee levels determined? Are they equitable?

RESPONSE:

1. Accountability – The District has successfully managed over $100 million in grant money over the last decade. The District has an outside auditing company to provide assurance to the Governing Board and the public that funds are appropriately managed. The California Air Resources Board has also audited the District.
   Definition of quantifiable – The project to be funded must have emission factors, process rates, and use data, necessary to calculate baseline emissions and emission reductions after the project is implemented.3.
   Enforceable – The project must have a mechanism that ensures that the project will be implemented and that emission reductions will be achieved during the specified timeframe.
2. Fee level determination – The fee levels are based on the average cost of reductions projected for each year for each pollutant. See also Response to Comment #114.
3. The fees are equitable because they are based on emissions generated by the project and each project's emissions are quantified using the same well-accepted models and factors.

109. COMMENT: APCD's goal over the next ten years to reduce the ozone and PM10 emissions targets new development only. If the housing bubble bursts and the corresponding emissions from new growth cease, will the burden shift to commercial, industrial and/or existing housing in order to meet the goals?

RESPONSE: The emission reduction targets for ISR in the PM10 and ozone plan are based on the *predicted* growth in emissions from new development. ISR reduces, through on-site and/or off-site measures, emissions generated by new growth. If that growth does not occur as predicted, for example in a 'bubble burst' scenario, then the emissions from new development will be less than predicted. If the emissions do not occur, they would not have to be reduced through the ISR program. In this situation, ISR does not have to adjust the emission reduction 'burden', or assess additional emission reductions.

110. COMMENT: There seems to be confusion about the degree of compatibility of these rules with the CEQA process, adding additional burden for businesses in meeting timelines and development schedules.

RESPONSE: See Response to Comment #8 and the Staff Report, Section IV.C.

111. COMMENT: Those of us who are tasked with promoting and marketing the valley for business locations and as a quality place to live and work are very concerned about the air quality issues that we fact. Certainly the air quality is a factor in decisions made by individuals and businesses alike when determining the suitability of the valley for their purposes. The major challenge is to address

those issues in a fair and balanced way with techniques and plans that are based on sound logic and a strong scientific basis.

RESPONSE: The District concurs with the author's statement.

Business, Industry & Government Coalition of the South San Joaquin Valley
Date: August 30, 2005

112. COMMENT: Our organization and its members share a deep commitment to improving air quality in the South Valley and applaud all reasonable efforts to attain Federal and State mandates. Draft Rule 9510, as we are coming to understand it, is the program that will be employed by the San Joaquin Valley Unified Air Pollution Control District to involve indirect sources, those land uses that attract or generate motor vehicle trips, in the mitigation of air emissions. The required reviews of the draft rule are delineated, however, the fees associated with the draft rule are not easily understood.

The presentation on Draft Rule 9510 – DESIGN (Decreasing Emissions' Significant Impact from Growth and New Development) gave several members of our organization cause for alarm after the initial public meeting was held. While there were references to fee schedules and proposed costs for building permits, the method describing the establishment of fees was not clearly reviewed. The Building Industry members of our organization are well aware of Public Facility Fees, Govt. Code 66000. Using that base of reference, the description about fee collection and fee usage was not congruent with their experience with Public Facility Fees. Upon further review after the meeting, the fees established through the Health & Safety Codes of California are the references for the Air Board's proposed fees. These fees are "news" to our members and additional information would be very helpful.

RESPONSE: See Response to Comment #6 and the Staff Report Section I(B) for a discussion on District authority for the rule.

113. COMMENT: For the next public meeting, scheduled September 1, 2005, our request is to have staff provide information about the process establishing the fee each year and how the fees are used for programs and projects under the authority of the Air Board. We want to know about the programs and the proposed costs for programs that will be instituted pursuant to Health & Safety Code 42311 (g). Our read of the statute indicates these fees are set annually based on estimated costs of air pollution control programs that will be conducted in the following year. In the event all funds are not expended, the fee revenue will carry over to the next year and will, then, reduce the fees for the subsequent year. What is the reporting mechanism and public process for these fees? While there are specific requirements outlined in the statute, none of our membership

was aware of actual dates for the public hearings and none were aware of what projects are in process for this year or their related cost(s).

RESPONSE: The fee amount is based on the anticipated cost of reductions in each year. Staff performed an analysis of historical project funding costs from our existing grant programs that have successfully contracted over $100 million and examined the potential for projects in the future based on the emission inventory and population of project candidates, the technologies available to reduce emissions from the source, whether the reductions will be surplus in the future based on proposed and adopted regulations on the potential project candidates, and the feasibility the project. Based on these factors, the District made percentage funding estimates for each type of project for each year. This information allows the District to calculate a projected average cost-effectiveness for each year. To further verify these numbers, staff prepared project mix spreadsheets based on available projects and funding for each year to demonstrate that the cost-effectiveness averages are achievable. This information has been added to Appendix E of the staff report.

114. COMMENT: In concert with the fees proposed through H&S Code 42311(g) are the fees outlined in Draft Rule 3180. Those fees are cost recovery based – cost recovery for administering Rule 9510. We ask for clarification on how that rate is developed and how applicants will be billed for the actual hours of staff time to evaluate and review proposed projects. We also ask to be informed if the weighted average labor rate will be reviewed in a public meeting or public hearing prior to annual establishment. The Health and Safety Code reference for the cost recovery fees appears to be in section 40604. The draft report of Staff indicates that section 40604 was codified as a result of legislation SB709, Florez, from the past fiscal year. Section 40604 is devoid of explanation about the fee structure other than to indicate there will be a schedule of fees and the fee schedule "shall be designed to yield a sum not exceeding the estimated cost of the administration of this chapter and mitigation of emissions and the filing of applications". How will this fee be published and through what public process? The project fees allow for annual rollover; how will the administrative fees be managed? If estimated costs are higher than annual costs, how will notification occur and what mechanism will be used to refund overpayment? We are hoping that the public meeting on September 1st will provide answers to this fee.

RESPONSE: The District will use the same average weighted labor rate method that it has used for many years in processing stationary source permits. It is based on labor and overhead rates used to develop the District's budget that is adopted in a public hearing each June. The project review fees are based on the hours predicted for a relatively simple project. Projects proposing standard on-site measures and having air quality impact assessments that use standard factors and default changes that have been agreed to in advance are expected to be covered by the fee amount. Complex projects are expected to require

additional staff analysis and review time that would result in costs that exceed the application fee. The District will be using a project management and billing system to track hours for the project. An applicant can request the status of labor charges at any time. The amounts accumulated to date can be obtained from the database and provided to the applicant. When the District staff completes its review and determines the off-site fee amount, they will generate an invoice that itemizes charges for review and the proposed off-site fee amount.

115. COMMENT: We are concerned that implementation of additional fees (Rules 9510 and 3180) associated with new construction will adversely affect the addition of sorely needed housing stock to the South Valley. Our region of the state is expected to take the brunt of the projected population growth, and we are already woefully under stocked. Our coalition believes that inadequate attention has been placed on studying the socio-economic implications of implementing the proposed fees.

Reducing PM10 and NOX emissions from indirect sources is a commitment thrust upon everyone in the Central Valley. Adding additional reviews and controls during the planning phase of construction is workable as long as all steps in the review process are clearly communicated and upheld. Compounding the issue of added reviews are the added fees for air pollution control and emission reduction projects that are not well known to members of our organization. As requested, providing more information about the type of projects, costs for current year and the process for the annual review of these fees would be most beneficial. Added study and discussion about the factors that influence the socio-economic status of the Central Valley are desired before these draft rules are presented to the Board of Directors for their consideration and vote.

Thank you for your attention to our concerns and we ask that this letter be read into the public record during the meeting on September 1, 2005.

RESPONSE: The District recognizes that the rule may add a relatively small cost to development; however, the rule is structured to maximize benefits for designs and features incorporated into the project that will reduce the fees and add value to the development. It is possible to significantly reduce the fee with measures now commonly included in projects. The District is committed to streamlining the review process wherever possible and strives to minimize costs and delays. The analysis will be accomplished with URBEMIS for most projects. URBEMIS is very easy to use and can be operated using information typically required by local agencies during the CEQA review process.

INDUSTRY

The Construction Industry Air Quality Coalition (CIAQC)

Date: September 15, 2005

The Construction Industry Air Quality Coalition (CIAQC) is composed of the Southern California Contractors Association and the Southern California chapters of the Associated General Contractors Association, Building Industries Association, Engineering Contractors Association and Rock Products Association. Its membership includes 3,500 construction/development companies.

116. **COMMENT:** 2.0 Applicability: The potential emissions from constructing 2,000 square feet of commercial space, 9,000 square feet of educational space and 10,000 square feet of government space appear too small when compared to emissions from constructing 50 residential units, 39,000 square feet of general office space and 25,000 square feet of industrial space.

RESPONSE: The difference is due to different trip rates for different land uses. Commercial space generates many trips per 1000 square feet compared to other land uses.

117. **COMMENT:** While the rules do not have an effective date, the District should consider the economic impact on small contractors with a high percentage of Tier 0 engines of setting relatively small development project baselines in 2006. An annually decreasing baseline from, say, 200 residential units, 10,000 square feet of commercial space, etc., in 2006 would allow small contractors more time to upgrade their fleets and compete in the bidding process.

RESPONSE: The current approach in the rule using the baseline for each year construction occurs and emission based thresholds provides more incentive to purchase or rent the cleanest equipment at the earliest date. Once in use, the cleaner equipment is available for all future projects subject to the rule. Although small contractors may have an older fleet, those are the equipment and vehicles that are in need of upgrade.

118. **COMMENT:** 3.0 Definitions: The use of computer modeling to estimate construction emissions from potential land uses would eliminate many small contractors unless they can seek advice from the District on how to employ these models. Also, CARB should offer assistance in identifying a diesel emission control device that has been verified for typical diesel engines as well as instruction on the use of the construction emission calculator. Ideally, the contractor or developer could submit to the District the number and types of machines he proposes to use on a project and the number of hours he proposes to run them, and the District would estimate his emissions.

RESPONSE: The District will provide assistance on the use of models to calculate construction emissions and staff can run the models for the applicants on a time and materials basis.

119. COMMENT: 4.1.5 Housing projects directly assisted by government housing funds: Why is government assisted housing exempt from mitigation?

RESPONSE: Based on comments received, the District has removed this exemption so that sources are treated based solely on their emissions.

120. COMMENT: 5.0 The draft rule implies in 5.3 that the APCO is willing to produce an AIA from information supplied by the developer. Is that correct?

RESPONSE: The District will prepare air quality impact assessments if the applicant provides the information needed as inputs in the model.

121. COMMENT: 6.0 A developer should be given emission reduction credit for mitigating windblown dust (PM10) as a result of constructing buildings and landscaping an area.

RESPONSE: The developer is already required to mitigate windblown emissions to comply with District Regulation VIII – Fugitive Dust Rules, therefore, the reductions would not be considered surplus.

122. COMMENT: 7.0 Off-site Mitigation Calculations and Fee Schedules for Construction Activities: In order to be reasonably contemporaneous with emission increases, off-site mitigation should be designated and purchased by the District no later than six months after the payment of the funds by the developer.

RESPONSE: The District commits to spend any funds received as quickly as possible. The programs envisioned require an applicant to come to the District to request funds for qualifying projects, so there may be times when funds take longer than six months to expend.

California Building Industry Association (CBIA)
Date: September 15, 2005

California homebuilders, represented by the California Building Industry Association (CBIA) and its five affiliated Building Industry Associations (BIAs) located in the San Joaquin Valley, are respectfully submitting comments on the Draft Rules, 9510 and 3180 ("proposed rules") of the San Joaquin Valley Air Pollution Control District ("the District").

123. COMMENT: CBIA continues to be troubled by what it sees as several fundamental flaws in the District's plan to assess new "air quality mitigation" obligations on new development in the Central Valley:

1) The District has failed to show a nexus between the impacts of new development on air quality in the region and the massive amount of new fees it proposes charging for this purported impact;
2) The District is using flawed scientific modeling to justify charging massive new fees on housing and economic development;
3) The district singles out new development to bear the burden of its new mitigation scheme which contains highly questionable calculations and a woefully deficient cost-benefit analysis.
4) The District has failed to adequately explain what it intends to do with these new fees (taxes) – somewhere between $300 million and $450 million over the next five years – and how charging them will improve the region's air quality; and
5) The District has failed to acknowledge and account for the impacts of these new fees on the region's economy or on housing affordability.

RESPONSE: See Response to Comments #124 through #142 below.

124. COMMENT: For these and other reasons, CBIA remains strongly opposed to the adoption of the proposed rules and urges the District to withdraw them and, working with citizens and other stakeholders in the region, begin the work of developing a more responsible, equitable and scientifically grounded plan for improving air quality in the central valley.

In the pages that follow CBIA will enunciate in detail both its fundamental concerns as well as other defects in the proposed rules.

RESPONSE: Opposition noted. See Response to Comment #17 for additional information on the development of these rules.

125. COMMENT: The District has failed to demonstrate the required legal nexus for imposing its proposed fees. This has been an ongoing concern of CBIA's and thus far the responses to it given by the District have only caused to make that concern grow. Indeed, the sheer weight of the mitigation fees being proposed by the District for new housing, alone – somewhere between $300 million and $450 million over the next five years – demands a clear description as to what the impacts are that justify the District's fee plans and how the level of fees to be charged are supported by anticipated costs.

RESPONSE: Although the District is not subject to the Mitigation Fee Act (See Response to Comment #52), the District's legal counsel has prepared an analysis of nexus requirements. The analysis identifies if a nexus is required, and discusses the following:

The applicability of the 5th amendment of the US Constitution.

- The analysis finds that the fees resultant from the rule are subject to the "reasonable relationship" test established by *San Remo Hotel LP v. City and County of San Francisco*[2].
- Therefore, if the fee is collected from a development because of the expected air pollution from that development, and the fee is used to offset the type and amount of pollution caused by that development – the fee will likely pass under the reasonable relationship test.

California Mitigation Fee Act

- The analysis finds that the Mitigation Fee Act may not apply to the ISR rules, for the reasons cited from the District in the text of Comment # 126, and in the Response to Comment #52.

California Proposition 13

- The analysis finds that Proposition 13 does not apply to the ISR rules.

California Proposition 218

- The analysis finds that Proposition 218 does not apply to the ISR rules.

California Subdivision Map Act

- The analysis finds that the SMA does not preempt the District from assessing fees on a subdivision.

126. COMMENT: Remarkably, however, the District denies there is a problem. To summarize the District's position, the Mitigation Fee Act (AB 1600) does not apply to these types of fees because (1) the District has no approval authority over development projects, is not imposing the fee as a condition of approval of a development project, and the fee is purely regulatory in nature, (2) AB 1600 only applies to fees for "public facilities" and mitigation measures such as diesel retrofit programs are not "facilities," and (3) even if AB 1600 doesn't apply, the district has met the nexus standard under the Act as well as any other legal standard.

This analysis contains multiple flaws. Government Code Section 66000(b) defines a fee as a monetary exaction other than a tax or special assessment, whether established for a broad class of projects by legislation of general applicability or imposed on a specific project on an ad hoc basis, that is charged by a local agency to the applicant in connection with approval of a development project for the purpose of defraying all or a portion of the cost of public facilities related to the development project. The proposed rules are applicable to a broad range of projects. Likewise, the proposed project-level analysis of on-site

[2] *San Remo Hotel, L.P. v. City and County of San Francisco*, (2002) 27 Cal.4th 643, 669-670.

mitigation constitutes an ad hoc, project-specific review. Both types of analyses therefore apply to the proposed rules.

RESPONSE: See Response to Comment #52.

127. COMMENT: Indeed, the District is a local agency subject to the Mitigation Fee Act. Government Code Section 66000 (c) defines "Local agency" as “a county, city, whether general law or chartered, city and county, school district, special district, authority, agency, any other municipal public corporation or district, or other political subdivision of the state.” Certainly the District qualifies as a special district, agency, or other political subdivision of the state.

RESPONSE: The District is considered a local agency, but this distinction is not relevant. The Mitigation Fee Act does not apply to the ISR rules. See Response to Comment #52 for more information.

128. COMMENT: The attempt to limit the application of this statute to public facilities is also incorrect. Government Code Section 66000(d) includes within the definition of "Public Facilities" “public improvements, public services and community amenities.” Cleaning up the air is a service provided by government and, as such, provides a benefit to the community.

Comment 64 states that the District does not have the authority to impose conditions of approval and contemplates that any project review will occur after the local agency has completed its approval of the project. The developer will be “allowed” to either include on site mitigation measures or pay a fee. Regardless of the choice of words, it is impossible to characterize this requirement as anything other than a fee or exaction on new development. If this is not enforceable as an exaction, then it is voluntary and the District cannot take credit for it as a control measure for purposes of demonstrating compliance with the SIP goals and the Federal Clean Air Act requirement to demonstrate reasonable further progress.

RESPONSE: The District does agree that the ISR program may require a fee from new development. However, the District disagrees with this interpretation of air emission reductions as a public service under GC 66000(d). In addition, the Mitigation Fee Act does not apply to the ISR rules. See Response to Comment #52 for more information.

129. COMMENT: The District’s attempt to define itself out of the Constitutional requirement that nexus be demonstrated is highly questionable. As noted in Government Code Section 66005(c): “It is the intent of the Legislature in adding this section to codify existing constitutional and decisional law with respect to the imposition of development fees and monetary exactions on developments by local agencies. This section is declaratory of existing law and shall not be

construed or interpreted as creating new law or as modifying or changing existing law."

RESPONSE: See Response to Comment #125 for the findings of the District's analysis of nexus requirements. See also Response to Comment #52.

130. COMMENT: It is important to examine that larger body of existing law. The constitutional standards for legislatively enacted development fees of general applicability, such as the proposed indirect source fee on new development, are less stringent than are the standards for fees imposed on specific developments on an individual and discretionary basis (see *Ehrlich v. City of Culver City* 12 Cal. 4th 854, 50 Cal. Rptr. 2d 242; 1996). Where a development fee is imposed generally on a broad class of property owners, it need only bear a reasonable relationship to the impacts of the development project (Id. at 875-876, 50 Cal. Rptr. 2d at 256,257). In adopting the fee, the city must make the "nexus" findings set forth in Government Code section 66001.

RESPONSE: Although the Mitigation Fee Act does not apply to the ISR rules (see Response to Comment #52), the rule has been designed to meet this test. The District analysis contained in the staff report for the rule provides supporting information to draw this conclusion.

131. COMMENT: The District uses a flawed analysis to produce huge sums to be collected as fees on new housing and new businesses. According to an analysis conducted by Sierra Research (see attached letter) using the numeric emission reduction goals in the District's approved SIP Measures for NOx and PM-10, as well as the assumptions set forth in Section 7.2 of Draft Rule 9510, including the stated ton-per-year mitigations costs, the District will require a total of $38,844,869 to meet the SIP's emission reduction goals for calendar years 2006 through 2010. Assuming the District's "worst case" fee scenario of $856 per unit in 2006, rising to $2841 per unit in 2010, the District could collect as much as $292,719,600. The disparity between the cost of the service and the fee charged is 754%. Even at a lowered standard of review of "reasonableness," a disparity of that magnitude will not survive judicial scrutiny.

RESPONSE: The District has addressed the analysis that Sierra Research provided in Response to Comments #143 to #162. In these responses, the District details which parts of the analysis provided by Sierra Research are flawed and/or inaccurate.

132. COMMENT: Again, the proposed rules are in direct conflict with California law as they are proposing to collect fees well in excess of what might be justified under a nexus test. State law is clear about what burden is on local agencies which propose to impose new fees on development. Government Code Section 66005(a) says "When a local agency imposes any fee or exaction as a condition

of approval of a proposed development … or development project, those fees or exactions shall not exceed the estimated reasonable cost of providing the service or facility for which the fee or exaction is imposed."

RESPONSE: As stated in Response to Comment #52, the Mitigation Fee Act does not apply to the ISR rules. The author points out a significant reason why. Section 66005(a) clearly states "as a condition of approval". The District cannot place conditions of approval on development projects through the ISR program, as it is a ministerial action. In addition, the fees are designed to mitigate only a fraction of project emissions and there is nearly zero potential for over mitigating. The fees are tonnage based (what is required to buy one ton of reduction for a particular pollutant) and are charged on a tonnage base. For example, if a project is required to mitigate 2 tons of NOx, then the price per ton is multiplied by 2 to obtain the off-site emission reduction fee.

133. COMMENT: Discretionary, site specific fees, the kind that the District proposes to impose on individual development projects after a project-specific analysis of all on-site mitigation measures, are subject to the stricter "essential nexus" and "rough proportionality" requirements of *Nollan v. California Coastal Commission,* 483 U.S. 825, 107 S. Ct. 3141 (1987), and *Dolan v. City of Tigard*, 512 U.S. 374,114 S. Ct. (1994); see discussion in *Ehrlich* at 12 Cal. 4th 876, 50 Cal. Rptr. 2d at 256,257; *City of Monterey v. Del Monte Dunes at Monterey Ltd*., 526 U.S. 687, 119 S. Ct. 1624, 1635, 143 L. Ed. 2d 882 (1999).

RESPONSE: Although the District will not be making discretionary actions, the Rule has been designed to meet this test. The District has prepared an analysis of nexus requirements. See Response to Comment #125 for the findings of the analysis.

134. COMMENT: In spite of repeated requests from various local agencies and members of the public, the District has not made available any calculations of the amount of emissions credits that will be awarded for on-site mitigation measures. For reasons explored in greater detail in Sierra Research's comment letter, the URBEMIS model was not designed to, and is incapable of, accurately calculating the amount of emissions reductions from most of the design or location-based indirect source mitigation measures included in the District's proposed mitigation checklist. The unknown cost of the deferred mitigation (achieved after the fact through a grant program) makes an accurate analysis of proportionality even more difficult. For this reason, any project-specific fee calculation will be suspect, and subject to the higher standard of review.

RESPONSE: The onsite emission reduction measures are calculated using the URBEMIS v8.7 mitigation component. The model is available for free at urbemis.com. The author's statement that URBEMIS is, "was not designed to, and is incapable of, accurately calculating the amount of emissions reductions

from most of the design or location-based indirect source mitigation measures included in the District's proposed mitigation checklist," is inaccurate at best, and misleading at worst.

The URBEMIS model is maintained by a state-wide working group that includes representatives from air districts throughout California, state agency representatives (such as CalTrans). Proposed changes to the model are vetted through peer review. The last model update, sponsored by the District, was changes to the Area Source module, specifically overhauling and quantifying the mitigation section.

The model components and methodologies are available to the public in the URBEMIS User's Guide, available at South Coast Air Quality Management District's website http://www.aqmd.gov/ceqa/urbemis.html, and will be made available at the District's website. In addition, the details of the model and the recent update are available in the Staff Report and as Appendix D-Recommended Changes to URBEMIS.For more information on URBEMIS components, see Response to Comment #9.

The author's second main point is that, "the unknown cost of the deferred mitigation (achieved after the fact through a grant program) makes an accurate analysis of proportionality even more difficult." The cost of 'deferred mitigation' is exactly that of the off-site emission reduction fee. The applicant is assessed a fee based on the calculations provided in the rule. The per-ton fee is also provided in the rule. The applicant is assessed an administrative fee, stated in Rule 3180 as 4% of the off-site fee. The applicant is also assessed time and materials for the AIA review in excess of that covered by the application fee, detailed in Rule 3180. This is the full extent of fees. The 'deferred mitigation' fee is expressly stated in the rules.

135. COMMENT: The District has failed to explain its calculations in determining a massive revenue-raising plan or the cost-benefit of the plan. According to the proposed rules, the District plans to raise between $300 million and $450 million in fees between 2006 and 2010 from housing alone. Similar fees will be collected from new schools, hospitals, government facilities, transportation projects, retail, office, and industrial development. The use of these funds, presumably, is to cut NOx emissions by 4.1 tons per day and PM-10 emissions by 5.2 tons per day. Yet, the District's own estimates show that NOx will cost an estimated $4,650 per ton in 2006, rising to $13,250 per ton in 2010 and that PM-10 reductions will cost $2,907 per ton, climbing to $13,850 per ton in 2010. These totals are far less than the fee revenue the District intends to raise during the same period.

RESPONSE: The rule's emission calculations are designed to identify a level of reductions from new development that will meet the SIP targets at the cost per ton predicted each year for each pollutant. The $300-450 million for residential

development severely overstates the fee potential and is based on an erroneous analysis of the rule requirements and incorrect calculations. For a detailed analysis of the cost effectiveness calculations, please review Appendix E – Cost Effectiveness Analysis for Rule 9510 ISR. For a detailed analysis of the emission reductions, please review Appendix B – Emissions Reductions Analysis for Rule 9510 ISR.

136. COMMENT: The District has failed to lay out a coherent plan for using its mitigation plan to actually clean the air and to account for it. How the District intends to spend the massive amounts of money it is proposing to raise remains unclear. This in light of the recent concerns expressed by the District's Governing board that the District has not expended its existing motor-vehicle surcharge fees – representing over $50 million in taxpayer dollars – on mitigation measures in a timely and effective manner. In addition, in advancing these proposed rules – again, raising hundreds of millions of dollars over the next five years – the District has failed to present a clear and specific program to insure timely expenditures for measures that reduce emissions proportionately in the areas contributing fees.

RESPONSE: The District will provide additional information to clarify the proposed plan for expending any fees collected and has amended Appendix E – Cost Effectiveness Analysis for Rule 9510 ISR accordingly. The District has successfully contracted over $100 million in funds for air quality projects.

137. COMMENT: Finally, the District has failed to adequately recognize or account for the impact of the proposed rules on housing affordability and the region's economy. The Socioeconomic Analysis examines narrowly examines housing impacts in terms of homebuilder profits without any similar analysis of housing cost and affordability impacts. This overlooks some important facts. Fees have a direct impact on homebuyers. According to a national study, every $1,000 added to the price of a home, locks more than 23,000 California families out of the housing market. Further, $1,000 to $4,000 added to the purchase price of a home escalates dramatically when it is financed with a typical 30 year mortgage. What this does to housing affordability in the region is completely ignored. In addition, the Analysis overlooks the impact of higher housing costs on the regional economy. First, more money spent on housing means less money spent on other goods and services. Second, higher housing costs discourage new business development as housing costs are viewed by executives as having the biggest impact on labor costs. Finally, fewer buyers mean fewer homes to be built which means fewer construction jobs and the profound ripple effects on the regional economy. Right now, home construction represents more than $7 billion in annual economic output in the Central Valley and is responsible for creating nearly 70,000 new jobs every year.

RESPONSE: First, the August 24, 2005 Socioeconomic Analysis provided at the September 1st workshop contains an analysis of housing costs and affordability impacts in Section 6.3 – Impacts on Affected Industries. Section 6.3 ¶1 states, "In addition to impacts on homebuilders, the section analyzes how changes in price affect prospective homebuyers and renters," and contains *Affordable Housing for Low-and Moderate Income Households* as a subsection. The analysis found:

> *…that while the residential fee that the typical residential development would pay under Draft Rule 9510 and 3180 can increase the amount of household income required to finance the purchase of a new home, the estimated increase represents a small fraction of the original household income required to finance a new home the event no air quality fees were in place. The affect of the fees on rents is similarly small.* Page 1 Executive Summary

Second, 100 percent of all off-site funds collected will be spent on emission reduction projects in the San Joaquin Valley. This will create economic activity and jobs. Many of these projects involve the construction industry; for example, road paving to control PM10. The District recognizes that all off-site fees have an impact on the cost of development; however, the emission reductions obtained from the rule will benefit all residents of the San Joaquin Valley.

Finally, refer to Response to Comment #53 for additional information.

138. COMMENT: In addition to the impacts on housing, those on businesses and public service activities have not been fully analyzed. Half of the vehicle trips addressed by the proposed rules are assumed to come from non-residential uses, but it remains unclear how much non-residential uses are going to pay their mitigation obligations (fees). The Socioeconomic Analysis fails to mention fees for new schools, medical facilities or public facilities such as government offices, roads and libraries. The Socioeconomic Analysis concludes that the impact on commercial and industrial development will be significant, but fails to identify Valley-wide costs based on the full range of non-residential uses, or the ripple effect on public agencies, business start-ups and expansions, job generation and the cost of goods and services.

RESPONSE: The District is unsure where the author is referencing the assumptions on vehicle trips. The cost to any sector is proportional to the emissions caused by indirect, area, and construction emissions generated by the project. The potential cost to any development can be calculated using the URBEMIS model to calculate emissions and the cost of reductions for the year of development and fee formula from the rule. The fee formula and cost of reductions applies to all development subject to the rule equally.

Valley-wide impacts would be speculative. As stated in the Socioeconomic Analysis (p. 42), "It is not clear how the development will adjust to the additional costs." Although the analysis states that, "a typical commercial or industrial development could absorb air quality fees in 2006 or 2010," developers may choose to pass on the cost to the buyer or renter. This aspect is unknown, and any projected valley-wide impacts as a result would be speculative and non-quantifiable.

139. COMMENT: The proposed rules 9510 lack effectiveness estimates for on-site mitigation that lead to uncertainty and inaccurate fees. Appendix C contains a 12-page checklist of mitigation measures that developers must consider for their project. Project applicants are instructed to justify why they did not apply a particular mitigation measure if they decided not to use it. However, the checklist provides no control efficiencies for the measures, making it impossible for project developers to reach an informed decision about the most cost-effective methods. Of greatest concern, a large number of mitigation measures are not included in URBEMIS, and their effectiveness must be negotiated between the project applicant and the District. These off-model mitigation decisions inject great uncertainty and potential inaccuracy into determining the amount of mitigation provided and fees exacted.

RESPONSE: The effectiveness of on-site measures varies depending on the design of the project and the land uses and transportation systems supporting the project. A single percentage number for each on-site measure is not appropriate. Please see Response to Comments #7 and #9 on URBEMIS quantification of measures. It should be noted that URBEMIS is free, available to the public, and user-friendly.

140. COMMENT: The proposed rules will create an expansive new bureaucracy to perform duties that duplicate and conflict with existing local planning processes. Local jurisdictions already have the ability to address and mitigate construction and operational emissions of new development through environmental reviews – pursuant to the California Environmental Quality Act (CEQA). The most recent draft of the proposed rules actually appears to dismiss this likelihood for greater conflict and overlap with CEQA by eliminating previously published schedules for District staff's performance of project reviews, mitigation analyses and fee calculations. Indeed, at a recent District-sponsored workshop regarding the proposed rules, District staff essentially said that their measures were separate from those identical ones mandated by CEQA. Indeed, the failure of the District to clarify its role as a "responsible agency" within the meaning of CEQA will foster conflicts with local governments, result in conflicting mitigation standards and requirements and fuel legal challenges – with direct and negative implications for job-generating business projects, affordable housing, schools, roads, and medical and public facilities urgently needed in the area.

RESPONSE: The rule will be revised to make the District's timeline more closely match CEQA timelines. An applicant may come to the District prior to or concurrent with the local agency discretionary application. This is similar current District consultation in its role as a commenting agency. Once the applicant has settled on a project design and scope and on-site measures that will be used for reducing air impacts, the District or the applicant can prepare an air quality impact assessment to determine project baseline emissions, mitigated emissions, and a off-site fee, if any is required. There will be no conflict with local agency mitigation standards since all on-site measures will be sent to the agency for voluntary review and the District will not accept conflicting measures. In addition, it is the responsibility of the applicant to ensure that measures selected are approvable by the public agency. If a selected measure is not approvable, the District will remove the selection and re-assess the project's air impacts. Although more projects will be subject to analysis under this rule, air quality is a critical concern in the San Joaquin Valley and should be receiving this additional attention.

141. COMMENT: The proposed rules lack essential information on construction emission reduction requirements. The latest draft rule requires new development to reduce construction emissions, but does not provide any details on how emission reduction requirements will be calculated. At the September 1st rule workshop, District staff was unable to confirm that a construction emissions "calculator" would be available during the public comment period, or indeed prior to Board consideration of the rule. The homebuilding industry will be directly affected by this provision of the rule, but we cannot gauge the impact of the requirement without information on the assumptions and methods for calculating project emissions. It's requested that this information be provided with time for public review period or eliminate construction emission requirements from the proposed rules.

RESPONSE: URBEMIS V 8.7 is available to quantify construction emissions. The District is working on enhancements to the default values in the model and will be considering a spreadsheet based calculator if it is more appropriate. This will be completed at least 30 days prior to program implementation.

142. COMMENT: For these reasons, as well as reasons previously placed on the record, we request that the District withdraw these proposals as inequitable and unworkable and unenforceable. Continuing down this path is a waste of public resources, which could be better put to use in developing alternative control measures well-designed and well-calculated to achieve compliance with the emission reduction goals set forth in the SIP.

RESPONSE:

- The District considers the ISR Rules to be equitable
  Fees and assessment are emissions based and same for all land-uses.

- The District considers the ISR rules to be workable.
  The rules set a clear path of what is required and how to achieve that. The URBEMIS model is used statewide by air districts and public agencies for project-specific air impacts.
- The District considers the ISR rules to be enforceable.
  The District is granted the authority to promulgate and enforce the rules through the following:
  The Clean Air Act Sec. 110 (5)(C) and 110 (5)(D)

Sierra Research
Date: September 15, 2005

On behalf of the California Building Industry Association (CBIA), Sierra Research (Sierra) is pleased to submit the following comments on the revised draft Indirect Source Rules (ISR) 9510 and 3180 released by the San Joaquin Valley Unified Air Pollution Control District (the District) in late August.

Our comments in this letter expand upon those presented before the District at the September 1st workshop. As directed by CBIA, our comments focus on, but are not limited to, technical and modeling issues related to the use of the URBEMIS model under the proposed rules based on our independent review of the model and its underlying assumptions. In this review we were assisted by Dowling Associates, Inc. (Dowling), a transportation planning firm with extensive travel demand modeling experience supporting a number of the San Joaquin Valley Transportation Planning Agencies (TPAs).

Our comments are summarized briefly blow. Detailed explanations of each comment follow in attachment A.

143. COMMENT: Summary
Our overarching concerns with the draft ISR rules stem from their use of the URBEMIS model to calculate pollutant emission impacts from development projects and the fact that URBEMIS broadly overstates vehicular emission impacts from residential projects. Our analysis of typical single-family residential projects indicates that URBEMIS overstates vehicle emissions of both NOx and PM_{10} (the two pollutants targeted by these ISR rules) by over 70%. Since the mitigation fees that developers would pay under the proposed rules are directly related to the emission impacts calculated by URBEMIS, this model also substantially inflates the fees developers should be required to pay by roughly the same percentage. Our key concerns are summarized below.

RESPONSE: Sierra Research's conclusions are based on erroneous information. URBEMIS is designed to estimate all emissions related to a development project and counts all trips going to and coming from the development as is appropriate for a project level analysis. This accounts for the

higher emission numbers. By using trip counts using both ends of the trip, URBEMIS can credit developers who design their projects to generate less trips with reductions for both ends of the trips that were reduced. To avoid charging a fee on emissions that may be attributable to another new or existing indirect source, the fee formula is based on 50% of the baseline emissions after mitigation is applied onsite. The regional transportation model used as a comparison with URBEMIS is flawed when used for a project level analysis. The fees are not inflated compared to the impact. Sierra incorrectly calculated the potential fees.

144. COMMENT: URBEMIS Defaults Are Biased High – Most but not all of our concerns with the URBEMIS model result from its heavy reliance on detailed default assumptions that are not likely to be well understood by project applicants required to use the model under the proposed rules. As our analysis shows, a number of these default assumptions substantially overestimate residential project emissions in the following areas:

- by about 20% for NOx due to over-represented heavy-duty vehicles in the fleet mix;
- by over 20% for NOx, ROG and PM_{10} because of older age distribution assumptions; and
- by roughly 50% for PM_{10} due to incorrect silt loading factors; and
- by 20-30% for all pollutants from overstated average vehicle trip lengths in the San Joaquin Valley.

RESPONSE: The District will provide revised defaults accounting for land use specific fleet mix information, a Valley specific silt loading factor, and updated trip length data prior to rule implementation. The District will consider an age correction factor; however, more evidence of the validity of this approach is needed.

145. COMMENT: URBEMIS Is Inconsistent With SIP Methodology – Region-wide pollutant emissions calculated under State Implementation Plans (SIPs) use a more rigorous set of models to determine motor vehicle travel impacts and resulting emission impacts than represented in URBEMIS. During the ISR rule development, the District has provided no clear evidence that URBEMIS is capable of calculating emissions from development projects in a manner that is consistent with SIP-level emissions and has simply asserted its appropriateness for use under these rules.

To test the District's assertion, Sierra and Dowling performed an equivalent, side-by-side analysis of travel and emissions impacts of a typical hypothetical

"suburban fringe" residential project using both URBEMIS and the Fresno County regional travel demand model (one of several county-level travel demand models used to calculate vehicle travel under the SIP). (As in URBEMIS, emission impacts were calculated using the Air Resources Board's EMFAC2002 vehicle emission factor model.) Our analysis found that URBEMIS estimates over 60% higher vehicle miles traveled (VMT) and over 50% higher emissions for all pollutants than the travel model/SIP-based approach. Moreover, this discrepancy cannot apparently be corrected by using "better" URBEMIS inputs than the default assumptions built into the model. Thus, these findings cast doubt on the validity of broadly applying URBEMIS under the ISR rule as URBEMIS clearly does not produce SIP-consistent emission impacts.

RESPONSE: Prior to implementation, the District will provide updated default values to provide the most accurate emission estimates possible. Regional travel demand models are not practical for project level analysis. The rule requires 50 percent of baseline emissions to be mitigated. The 50 percent more than accounts for emissions due to counting both ends of the trips related to the project. URBEMIS counts two way trips to account for the total impact of the project. When used in analyze a single project, this is appropriate measure of impact. When looking at regional impacts, only half of the trips should be counted since if every project, new and existing were examined at once it would exactly double count the trips. Using URBEMIS will result in consistent analysis from project to project. Emission reductions achieved by the rule from offsite measures will be calculated using emission factors and methods consistent with the SIP. Onsite measures will be credited in accordance with EPA Voluntary and Emerging Emission Measures Policy.

146. COMMENT: Residential Fees Appear Understated in Socioeconomic Report – In addition to the comments summarized above on the URBEMIS model, we also have concerns with the fee estimates for typical residential developments contained in the District's socioeconomic analysis of the ISR rules. Table 16 of the socioeconomic report cites "worst-case" fee estimates ranging from $856 per unit in 2006 to $2,841 per unit in 2010. The supporting text offers no explanation of how these estimates were developed.

Its fundamental flaws notwithstanding, Sierra independently estimated residential fees using URBEMIS, and the fee formulas and cost reduction ratios contained in the August drafts of Rule 9510 and 3180. Our analysis found fees were twice as high ($1,607-$7,971 per unit) over the same period for a single-family residential development, assuming a default housing density of 3 units/acre. When the housing density was doubled (to 6 units/acre), per unit fees were still over 50% higher ($1,295-$5,556 per unit) than those cited (without explanation) In the socioeconomic report. . We also calculated fees assuming a 93% vs. 7% split between single and multi-family units, based on the average number of new single- and multi-family housing units permitted in the San Joaquin Valley in

2002 obtained from the California Department of Finance (http://countingcalifornia.cdlib.org/title/castat.html). Even under these mixed use assumptions, our fee estimates ranged from $1,550-$7,702 per unit, still nearly twice as high as those in the socioeconomic report.

Thus, we question how the estimates in that report were developed. Our analysis suggests that the worst case residential fees are substantially higher than those employed in the socioeconomic analysis. If this is correct, then the impacts quantified in the study are understated and would need to be revised.

RESPONSE: Sierra incorrectly calculated the construction emission reductions. This accounts for the differences between the District's numbers in the socio-economic impact report and Sierra's inflated numbers.

147. COMMENT: Revenue From Residential Fees Will Dramatically Exceed the Cost of Purchasing Mitigation Needed to Meet ISR SIP Commitments – Using information developed by the District for this rulemaking, Sierra prepared estimates of the funds that will be generated from residential fees and spent purchasing mitigation between 2006 and 2010. We found incoming fee revenue exceeded outgoing mitigation expenses by $146 to $728 million depending on the level of the fee assumed (the percent difference ranges from 377% to 1,873%). The magnitude of these differences indicates that the rule is seriously flawed. There are two primary reasons for the discrepancy between fee revenue and mitigation expenses. First, as noted above, URBEMIS default assumptions include biases that lead to significant overestimates of project emissions, which in turn lead to overpayment of mitigation fees. Second, there is a fundamental flaw in the fee formulas developed for the rule that overstates the cost of purchasing mitigation.

The fee formulas are designed to advance to the District a monetary sum necessary to mitigate excess emissions not mitigated onsite for a period of ten years. Assuming no onsite mitigation, the operational NOx formula requires payment for 2.5 times and the operational PM_{10} formula requires payment for 5 times the estimated base year emissions. The important point is that developers would be required to pay mitigation fees that offset several years of project emissions. Mitigation expenses, however, are not denominated in years. Instead they represent a single one-time purchase that continues to provide emission reductions for multiple years. According to the staff report the average project life for NOx mitigation is 7 years and for PM_{10} it is 12 years.

Thus, assuming no onsite mitigation, a project applicant can expect to pay for 17.5 years of mitigation for the base year NOx emissions of the project (i.e., 2.5 × 7) and 60 years of mitigation for the base year PM_{10} emissions of the project (i.e., 5 × 12). This bias is extreme and comes on top of the significant default biases incorporated into URBEMIS. Collectively, they explain the huge absolute

and percentage difference between incoming fees and outgoing mitigation expenses. Since the residential fees in this analysis are used to purchase all of the ISR SIP mitigation commitments, the inclusion of both residential and non-residential (e.g., industrial) development fees would only worsen the already enormous inconsistency between ISR revenue and expenses.

RESPONSE: The fee formula does not include a project life multiplier of 7 or 12 years. Any funds collected will be used on projects with average project lives of 7 for NOx or 12 years for PM10, so the mitigation is effective for that long on average. The fee formula calculates an amount of emissions in tons that must be mitigated at the cost of reductions for each year. For most projects funded, the reductions may be considered permanent since at the end of the project life new engines/devices will be purchased that achieve reductions that are equivalent or better.

148. COMMENT: Conclusions.
The draft ISR rules have serious and fundamental flaws related to their reliance on URBEMIS and its extreme overstatement of residential project emissions. Moreover, our analysis of incoming and outgoing revenue streams indicates that the ISR fee formulas dramatically overstate the amount of revenue needed to buy emission reduction offsets for NOx and PM_{10} at "market" prices estimated by the District.

RESPONSE: The District strongly disagrees with this conclusion. Sierra based its conclusions on erroneous calculations and comparisons.

SIERRA RESEARCH
ATTACHMENT A
DETAILED COMMENTS

Our detailed comments on the ISR rules are presented below. Some of these comments were provided by Sierra to the District in July in response to the preceding versions of the draft rules. For completeness and where relevant as related to the District's response to these earlier comments, they are repeated in this letter. At the end of each of these comments, we have listed the District's response as contained in Appendix A of the August version of the ISR rule packet and provided follow-up comments to these responses.

149. COMMENT: URBEMIS Fleet Mix Overstates Residential Project Emissions – One of the most striking instances of inappropriate default data in URBEMIS is the distribution of vehicle types (e.g., passenger cars, light trucks, heavy trucks, etc.) or "fleet mix" employed in the model. Fleet mix differences can significantly impact calculated vehicle emissions because of the relative stringency imposed on different vehicle types under emission certification standards adopted and implemented by the state Air Resources Board (ARB). Generally speaking,

passenger cars must meet more stringent (i.e., lower) emission standards than larger vehicle types such as heavy-duty trucks.

The default fleet mixes in URBEMIS (which vary slightly by calendar year) are based on statewide average distributions contained in ARB's EMFAC2002 model. Those default distributions assume that roughly 3% of the vehicles are heavy-duty vehicles (trucks and buses). This is reasonable for a statewide or air basin average of a large vehicle fleet, but clearly not representative of the mix of vehicles operating in a new residential project. New residential projects are not likely to contain any heavy-duty vehicles (in the "operating" phase following construction). Thus, the use of the URBEMIS default fleet mixes that contain heavy-duty vehicles is clearly inappropriate for these projects.

Table 1 compares the results of URBEMIS runs with default and "no heavy-duty" adjusted fleet mixes. These URBEMIS runs were performed for hypothetical 100-unit residential development with single family detached housing for calendar year 2005 using default assumptions for the remaining inputs and assume no mitigation.

The upper portion of Table 1 shows the existing default fleet mix and the corrected fleet mix which was adjusted by removing all heavy-duty vehicle categories and renormalizing the remaining percentages. The lower portion compares operating emissions calculated by URBEMIS using each fleet mix. Although the emission impacts for ROG and PM_{10} are minimal, NOx emissions are some 23% lower (2.13 vs. 2.76 tpy) when representative fleet mix is used to model residential project emissions.

Table 1
Emission Impacts of Corrected Vehicle Fleet Mix
(SJV Fleet, Calendar Year 2005)

Vehicle Class	Default Mix (%)	Adjusted Mix (%)
Light Auto	56.1	58.1
Light Truck 1	15.1	15.6
Light Truck 2	15.5	16.1
Med Truck	6.8	7.0
Light-Heavy Truck 1	1.0	-
Light-Heavy Truck 2	0.3	-
Med-Heavy Truck	1.0	-
Heavy-Heavy Truck	0.8	-
Line Haul	0.0	-
Urban Bus	0.1	-
Motorcycle	1.6	1.7
School Bus	0.3	-
Motor Home	1.4	1.5
FLEET TOTALS	100.0	100.0
Heavy-Duty Pct.	3.5	0.0
Operating Emissions (tpy) for 100-Unit Residential Project:		
ROG	2.18	2.16
NOx	**2.76**	**2.13**
PM_{10}	1.99	1.98

This is a clear instance where URBEMIS default inputs are not appropriate and significantly overstate NOx emissions and resulting mitigation fees that would be calculated under the District proposed ISR rules. This finding clearly points out the need for the District to thoroughly review the default assumptions in URBEMIS and carefully consider the technical capabilities of applicants as end users of the model under these rules.

RESPONSE: The District is working to ensure that the fleet mix assumptions in URBEMIS are appropriate for each land use type. The District will provide updated land use specific fleet mix information for residential development and possibly other land uses prior to rule implementation. URBEMIS data files containing the updated fleet mix data will be available for ease of use. We will accept changes to default information such as fleet mix when supported by adequate documentation. While the fleet average may somewhat overstate emissions [from] residential developments there are heavy-duty truck emissions associated with them. These include school buses, refuse collection, package delivery and other service vehicles.

150. COMMENT: Follow-Up – Refuse collection vehicles are contained in the heavy-heavy truck (HHT) category. In 2004, ARB adopted a statewide rule for controlling emissions from solid waste collection vehicles

(http://www.arb.ca.gov/regact/dieselswcv/dieselswcv.htm). Under that effort, a solid waste collection vehicle emissions inventory was prepared which identified the statewide population of both residential and commercial refuse collection vehicles as 11,778 in calendar year 2000. According to EMFAC2002, the statewide population of all HHTs in 2000 was 158,204. Thus, residential and commercial refuse collection vehicles represent only 7% (11,778 ÷ 158,204) of the total HHT population, with residential collection vehicles less than that.

Package delivery and other service vehicles generally span the light-heavy truck (LHT) and medium-heavy truck (MHT) categories, but the vehicle populations and vehicle miles traveled for those vehicles serving residential customers is likely much less than those serving commercial customers. Thus, the EMFAC2002 fleet percentages for the LHT and MHT categories still overstate the fractions of those vehicles serving residential areas.

To address these issues, the analysis presented earlier in Table 1 was revised to include school buses and all LHTs and MHTs at the same proportions of the original EMFAC2002 fleet mix. This addresses the District concern that school buses be included and conservatively overstates the representation of residential package delivery and other service vehicles. Since residential refuse collection vehicles represent a very small fraction of all HHTs (less than 7%), the HHT residential fleet fraction was set to zero. Using this revised residential fleet mix, NOx emissions were calculated to be 2.44 tpy, which are 12% lower (2.44 vs. 2.76 tpy) than those based on URBEMIS defaults.

Thus, we believe NOx emissions for a properly determined residential fleet mix are still 12-20% lower than if URBEMIS defaults are used, depending on what assumptions are made with respect to the package delivery and other service vehicle fractions of LHTs and MHTs.

RESPONSE: EMFAC emission projections are revised periodically to account for changes from adopted motor vehicle emission regulations. The next version of EMFAC is expected to be released in 2006. The District will help fund the next upgrade to URBEMIS to utilize the new EMFAC. The District's methodology for estimating land use specific fleet mixes will be available prior to rule implementation

151. COMMENT: URBEMIS Age Distribution Overstates Residential Project Emissions – Another area where URBEMIS does not accurately reflect particular project conditions relates to the distribution of vehicle ages internally built in to the model. The vehicle age distributions contained in URBEMIS are based on statewide average vehicle registrations for the entire on-road fleet contained in the EMFAC2002 model. These distributions likely reflect a generally older vehicle fleet than exists in a new residential project. Vehicle emissions strongly depend on vehicle age due to ARB's implementation of dramatically tighter

emission standards over the last 30 years. New vehicles today are approximately 10-20 times cleaner than those introduced in the early 1970s. And this trend will continue into the future. Thus, it is necessary to accurately represent the age distribution of a fleet of vehicles when calculating their emissions.

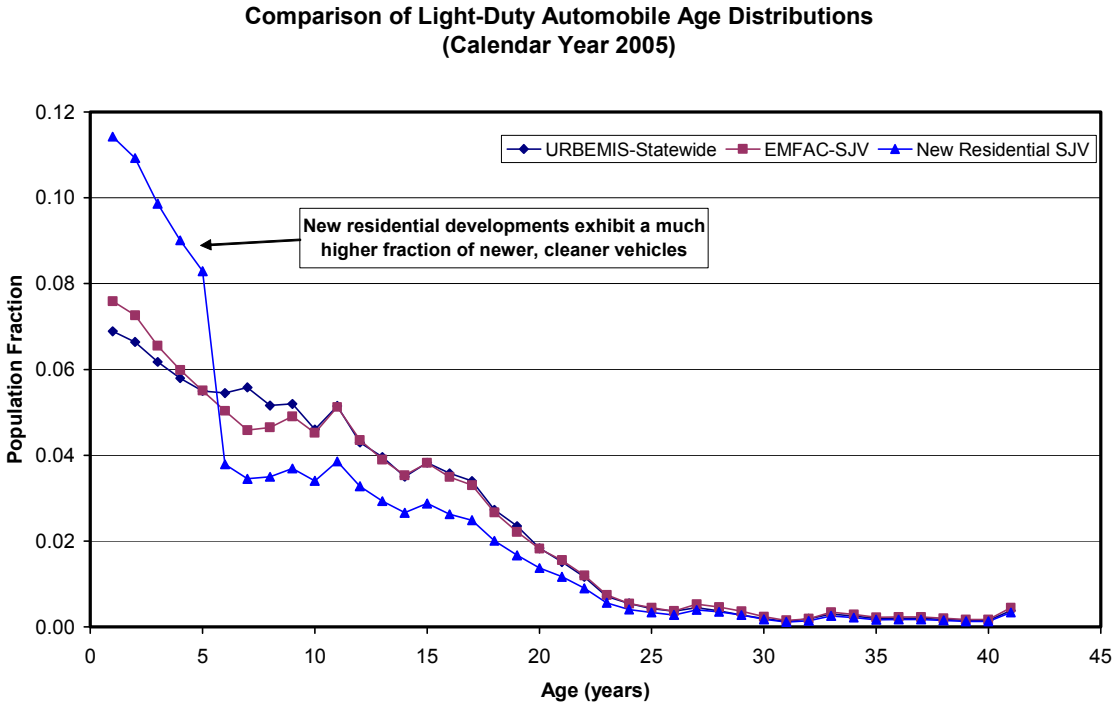
Our subcontractor Dowling has compiled statistics on housing age and vehicle fleet age from two readily available data sources: 1) the 2000 U.S. Census; and 2) the 2001 Caltrans Statewide Household Travel Survey. They compared vehicle age from households in the San Joaquin Valley in two groups:

1. "new" households defined as those that were ≤ 10 years old; and
2. "old" households defined as those older than 10 years.

Dowling found that the "new" housing areas had a 49.5% to 50.5% mix between vehicles ≤ 5 years old and vehicles > 5 years old. In the "old" household areas, the split between ≤ 5 year old vehicles and vehicles > 5 years old was 35.7% to 64.3%, indicating that new households in the San Joaquin Valley reflect a newer vehicle fleet than represented by the URBEMIS model defaults for the entire area.

Figure 1 illustrates the differences in vehicle age distributions between those in the EMFAC2002 model (upon which URBEMIS is based) and those developed for a typical new residential development based on Dowling's findings. As highlighted in Figure 1, new residential developments exhibit a much larger fraction of newer and therefore generally cleaner vehicles.

Figure 1



The emissions impact of using a younger age distribution typically found in new residential developments was determined from a series of spreadsheet calculations by individual model year using age-specific emissions factors extracted from the EMFAC2002 model.

Table 2 presents and compares resulting light-duty automobile exhaust emission factors (in grams per mile) during summer in calendar year 2005. Table 2 also shows the percentage difference in emission factors (and thus calculated project exhaust emissions) using the URBEMIS and New Residential age distributions.

Table 2
Exhaust Emission Impacts of Corrected Vehicle Age Distribution
(SJV Light-Duty Auto Fleet, Calendar Year 2005, Summer)

Quantity/Age Distribution	ROG	NOx	PM_{10}
Emission Factor (grams/mile) - URBEMIS Default	0.177	0.290	0.0082
Emission Factor (grams/mile) - New Residential	0.132	0.222	0.0065
% Difference (New Residential vs. URBEMIS)	**-25.6%**	**-23.3%**	**-20.5%**

As highlighted in Table 2, exhaust emissions of light-duty automobiles were found to be over 20% lower for ROG, NOx and PM_{10} when an age distribution representative of a typical new residential neighborhood is used compared to the

existing fleet-average age distribution contained in URBEMIS. These emission impacts calculated for automobiles are likely to be similar for light-duty trucks as well, which together with automobiles account for about 90% of the vehicles in a residential project fleet.

RESPONSE: The District will consider adding an age correction factor in the fee calculation formula for residential development. The emissions for PM10 in the table appear to be from exhaust and are small compared to the entrained road dust that is not affected by the age of the vehicle.

152. COMMENT: Unlike the previous fleet mix problem which can be addressed by issuing guidance to supply a different fleet mix in one of the URBEMIS input screens, the model cannot be easily revised to properly account for a representative residential vehicle fleet age distribution. The way URBEMIS is currently designed, it internally uses a series of calendar year and season specific emission factor files developed from "upstream" runs of the EMFAC2002 model for a statewide average vehicle fleet. Although it is possible to generate air basin-specific EMFAC2002 files, URBEMIS would need to be re-programmed to utilize these air basin-specific emission factors. More importantly, fleet age distributions for an air basin as a whole are still not likely to reflect those of a typical new residential project. This can clearly be seen from the "EMFAC-SJV" and "New Residential SJV" distribution plotted earlier in Figure 1.

The EMFAC2002 model maintained by ARB is designed to produce several types of outputs under the following three modes: 1) "Burden"; 2) "Emfac"; and 3) "Calimfac". URBEMIS is currently designed to work with "Emfac" mode outputs from EMFAC2002. Although EMFAC2002 can be run with different age distributions, this feature is only available under the "Burden" output mode, not the "Emfac" mode.

Thus, we believe the District will need to completely overhaul the design of URBEMIS and its interaction with ARB's "official" EMFAC2002 emission factor model or consider another analysis method/tool to adequately address this age distribution issue for residential project analyses under the ISR rules.

RESPONSE: The District continues to believe that URBEMIS is the appropriate tool for the job. The District will consider an off model vehicle age correction if well documented. However, the District believes that the fleet average is a reasonable assumption for new development projects. There are a number of factors that impact emissions including age, vehicle class, and fleet turnover. If more specific information is available, the District would consider utilizing project specific numbers.

153. COMMENT: Follow-Up – When asked to clarify this response at the September 1 workshop, District staff indicated that their primary concern with simply using the revised age distributions presented earlier by Sierra/Dowling was that light-duty vehicle class mixes may also be different in new residential areas than represented by URBEMIS defaults. Specifically, the concern was that residential vehicle fleets contain a much higher fraction of sport utility vehicles (SUVs) and pickups than represented in a region-wide fleet.

Our original analysis of the emission impacts of corrected vehicle age distribution was conservatively applied only to passenger cars (which make up less than 60% of the residential fleet), instead of all light-duty vehicles (which comprise roughly 90% of the fleet). We revised our original analysis to include all light-duty vehicles (which include both passenger cars and the light-duty truck categories) because the household survey data upon which the revised age distributions were based included both cars and light-trucks. And to conservatively address the District's concern that a residential fleet would contain a higher fraction of SUVs and pickups than in a region-wide fleet, we doubled the existing fraction of the Light-Duty Truck 2 (LDT2) category (which contains most of the SUVs and large pickups) from roughly 16% to 32%.

Table 3 compares the results of this revised analysis, which applies the newer age distribution to all light-duty vehicles and doubles the LDT2 fleet fraction, to those based on the original URBEMIS defaults. The percentage differences shown in Table 3 are very similar to those presented earlier in Table 2. The reason for this is that although light-duty trucks (specifically LDT2s) have been historically required to meet less stringent in-use emission standards than passenger cars, this gap in stringency has narrowed in recent years and more importantly, their standards have been tightened over time much like passenger car standards. Thus, dramatically increasing the assumed light-duty truck fraction in the residential fleet has much less effect on the relative emission impact compared to URBEMIS defaults and accounting for the younger age distributions of all light-duty vehicles found in newer residential vehicle fleets.

Table 3
Exhaust Emission Impacts of Corrected Vehicle Age Distribution and Doubled LDT2 Fleet Fraction
(SJV Light-Duty Vehicle Fleet, Calendar Year 2005, Summer)

Quantity/Age Distribution	ROG	NOx	PM_{10}
Emission Factor (grams/mile) - URBEMIS Default	0.180	0.345	0.0103
Emission Factor (grams/mile) - New Residential	0.133	0.267	0.0084
% Difference (New Residential vs. URBEMIS)	**-26.1%**	**-22.5%**	**-17.9%**

Therefore, even when accounting for a higher fraction of SUVs and pickups in new residential fleets, we maintain that URBEMIS still overstates NOx and PM_{10} exhaust emissions by approximately 20% due to unrepresentative age distribution assumptions. We believe we have provided the District with ample and readily-available evidence regarding residential fleet age distributions, whose impacts overwhelm those due to what may be higher SUV and pickup fractions in new residential developments. Furthermore, even if fleet data were collected through a survey of new residential developments, the District has not answered the question of how to apply these data since they cannot be accommodated within URBEMIS.

RESPONSE: The District still believes that URBEMIS is the best model for the job and has consistently stated that it would use better data when available. The District will consider applying an age correction factor to the output to address this concern.

154. COMMENT: URBEMIS Silt Loading Factors Inconsistent with ARB Inventory, Overstates Residential Project Emissions – This is another striking example where URBEMIS default assumptions dramatically overstate actual residential project emissions; in this case, by nearly 50% of total operating PM_{10} emissions.

The default silt loading factor supplied to the user by URBEMIS for calculation of entrained (i.e., fugitive dust) PM_{10} emissions is inconsistent with those used by ARB on its emissions inventory and the District's PM_{10} SIP.

In URBEMIS and in ARB's emissions inventory, fugitive dust PM_{10} emissions are calculated for vehicle travel on paved roads using the following equation:

$$EFpaved = k \times (sL/2)^{0.65} \times (W/3)^{1.5}$$

Where:

EFpaved is the emission factor (lb per vehicle mile traveled);
k is the particle size multiplier (0.016 for PM_{10});
sL is the road surface silt loading factor (in grams per square meter);
W is the average weight of vehicle traveling on the road (4,850 lbs is default).

The default road surface silt loading factor in URBEMIS is 0.1 grams per square meter. This value is higher and does not comport with San Joaquin Valley values used by ARB in its statewide inventory for entrained road dust on paved roads, which are different for each roadway type as follows:

- 0.020 g/m^2 for freeways
- 0.035 g/m^2 for major arterials

- 0.035 g/m^2 for collectors
- 0.320 g/m^2 for urban locals
- 1.6 g/m^2 for rural locals.

Using data compiled by the Federal Highway Administration (FHWA) under the Highway Performance Monitoring System (HPMS), the San Joaquin Valley exhibits the following travel percentages by the road types listed above:

- Freeways – 33.25%
- Major Arterials – 38.97%
- Collectors - 27.59%
- Urban Locals – 0.19%
- Rural Locals – 0.01%

The weighted average silt loading factor using these travel fractions and ARB's silt factors by roadway type was calculated to be 0.031 grams per square meter, which is well below the 0.1 default values contained in URBEMIS. Using this ARB and HPMS-based weighted average silt factor for the San Joaquin Valley in the above equation results in a paved road dust emission factor that is 53.6% below that based upon the URBEMIS default silt factor. Use of the ARB-consistent silt factor will also result in a 53.6% reduction in paved road dust PM_{10} emissions computed using URBEMIS defaults.

According to emissions inventory summary data available from ARB on-line at http://www.arb.ca.gov/ei/emsmain/reportform.htm paved road dust PM_{10} emissions make up about 90% of total on-road vehicle PM_{10} emissions in the San Joaquin Valley, excluding unpaved road travel. (We exclude unpaved road dust under the assumption that operating emissions of vehicles in a new residential project exhibit little travel on unpaved roads.) Thus, use of a paved road silt loading factor consistent with ARB's inventory would translate to a 48.2% reduction on total operation PM_{10} emissions of a residential project as described below:

$$\%Reduction = PavedFrac \times (1 - \%SiltReduction) + RemainingFrac$$
$$= 90\% \times (1-53.6\%) + 10\%$$
$$= 48.2\%$$

Where *PavedFrac* is the fraction of project emissions from paved road dust, *%SiltReduction* is the relative reduction in paved road emissions using the ARB-consistent silt factor compared to URBEMIS and *RemainingFrac* is the remaining project emissions of PM_{10} (from exhaust, brake wear and tire wear).

Again, this issue and the alarmingly high overstatement of PM_{10} emissions based on model defaults points out the need to further review and provide detailed guidance for use of URBEMIS in calculating project-specific emissions under the proposed ISR rules.

RESPONSE: The District concurs with Sierra's methodology and will ensure that the correct silt loading factors are utilized in URBEMIS defaults.

155. COMMENT: Follow-Up – We appreciate the District's response to correct the existing silt load factors in URBEMIS. However, when questioned during the September 1 workshop about how and when these silt loading corrections (as well as corrections related to the earlier fleet mix and vehicle age issues) would be addressed, staff indicated that these corrections to URBEMIS defaults would not be completed and released for review prior to the District Board hearing in mid-November for adoption of the ISR rules. Moreover, staff was unclear whether these corrections would be handled by revising the URBEMIS model, or by developing written guidance for users of the model under the ISR rules instructing them how to correct the overstated model defaults when applied to residential development projects.

Given the significance of the impacts of the flawed model defaults on the costs to comply with these proposed rules, we believe these model revisions or guidance documents should be developed and publicly reviewed before ISR rules are adopted if the District intends to pursue the rules despite URBEMIS' deficiencies.

RESPONSE: The District is developing guidance for preparing the air quality impact assessment required by the rule. The guidance will include the default silt-loading factor provided by Sierra Research. The District will provide URBEMIS data files updated with changes that can be used without having to enter the new data. The next upgrade to URBEMIS will contain much of the updated information. The staff report has been updated to describe the impact of these changes on the emissions estimates and economic impacts.

156. COMMENT: URBEMIS Is Inconsistent With SIP Methodology – When a typical residential project was modeled using both URBEMIS and a SIP-based modeling URBEMIS estimates over 60% higher vehicle miles traveled (VMT) and over 50% higher emissions for all pollutants than SIP-based approach.

This is not surprising. The URBEMIS model was originally written as a "sketch-planning" tool, designed to produce intentionally conservative analyses of localized emission impacts from different land uses. For over ten years, the URBEMIS model has been used to assess development project emissions under the California Environmental Quality Act (CEQA) review process. Under CEQA, use of URBEMIS as a conservative (i.e., over-predictive) screening tool is entirely appropriate for comparing project emissions to "significance thresholds"

established under air district guidelines since CEQA requires disclosure of project impacts and significance, but not compliance with regional or state air quality plans or standards. Under this process, URBEMIS-based emission impacts can acceptably err on the side of caution or over-prediction.

RESPONSE: URBEMIS has been continuously updated to provide increased accuracy with each new version. Many of the default values that are based on statewide averages can be changed to use local information when available. The District appreciates the review conducted by Sierra Research to identify additional areas of improvement. The next version of URBEMIS will contain many of these improvements. In the interim, applicants will be instructed to enter local information that is currently available. This information will be provided in a District guidance document. Analyses prepared by the District will also use the local information. URBEMIS remains the best tool for performing project level analyses and provides reasonable estimates of project impacts.

157. COMMENT: Conversely, these ISR rules are being implemented to address specific emission reduction commitments made by the District in Ozone and PM_{10} SIPs for the San Joaquin Valley. Region-wide pollutant emissions calculated under these SIPs use a more rigorous set of models that have been validated with direct measurements to determine motor vehicle travel impacts and resulting emission impacts than represented in URBEMIS. During the ISR rule development, the District has provided no clear evidence that URBEMIS is capable of calculating emissions from development projects in a manner that is consistent with SIP-level emissions. The District has simply asserted the appropriateness of URBEMIS under these proposed ISR rules despite the fact that CEQA guidelines published by other air districts such as the Bay Area and Sacramento clearly characterize URBEMIS as a conservative sketch-planning tool.

RESPONSE: The District believes that URBEMIS has been improved beyond its characterization as a sketch planning tool. Very few of the modules of the program are overly conservative. Most modules rely on statewide averages extracted from the emission inventory which should not be considered conservative estimates. The most important module is the mobile source module that includes the same emission factors used to build the emission inventory. It does a good job of arriving at a composite emission rate needed for a project level analysis. Models can always be made more accurate by individualizing more and more input factors. The District believes that URBEMIS balances data requirements with reasonable output accuracy and ease of use. The travel demand models described by Sierra Research are extremely data intense and would be very costly to run for the approximately 1,000 projects that will be submitted to the District each year. It is uncertain whether the demand models are more accurate for project level analyses than URBEMIS with local information.

158. COMMENT: To test the District's assertion, Sierra and Dowling performed an equivalent, side-by-side analysis of travel and emissions impacts of a typical hypothetical "suburban fringe" residential project using both URBEMIS and the Fresno County regional travel demand model3 (one of several county-level travel demand models used to calculate vehicle travel under the SIP. (As in URBEMIS, emission impacts were calculated using the Air Resources Board's EMFAC2002 vehicle emission factor model.)

For our investigation, we considered a 500-unit single family residential project located within a 160-acre parcel in an undeveloped/lightly-developed area in Clovis northeast of downtown Fresno near the intersection of Minnewawa and Shepherd at the edge of the urban area. This was intended to represent a typical suburban project at the fringe of an urbanized area and roughly matches the default single family residential project density assumed in URBEMIS of three units per acre. We looked at travel activity and emissions during Summer 2010.

Dowling ran the Fresno COG travel demand model in 2010 for a baseline (no project) case and a "with project" case under which the 500-unit project was simulated within the affected traffic analysis zone. The detailed travel model outputs were then fed into ARB's current EMFAC2002/BURDEN model to calculate associated emission impacts with the added project. These results were then compared to an URBEMIS simulation of a 500-unit single-family residential project in the San Joaquin Valley. The URBEMIS run assumed pass-by trips were accounted for and assumed an urban land use type. Since we simulated a single land use (single family residential) in both the travel model and URBEMIS runs, there was no need to apply the "double-counting" correction within URBEMIS.

Our analysis found that URBEMIS estimated daily VMT from this project at 35,817, compared to 21,886 using the SIP-based travel model, an increase of nearly 64%. Emission impacts using URBEMIS were also higher for all pollutants and ranged above 50% compared to the SIP-based approach.

3 Regional travel models such as the Fresno County model mathematically simulate vehicle trip movements over a regional roadway network by dividing the region into demographically similar "traffic analysis zones" (TAZs) similar to census tracts. Demographic and socioeconomic data for each TAZ are used to estimate the number and types of person trips taken between each TAZ. These person trips are then translated into vehicle trips (or non-vehicle trips such as walking or bicycle trips) and loaded onto a series of roadway links that spatially approximate the actual regional roadway network.

From our analysis of the underlying elements of the two approaches, we have preliminarily concluded that the discrepancy in VMT is caused by two related factors:

1. overstated defaults trip lengths for typical suburban residential projects in the San Joaquin Valley; and

2. the inherent underreporting of short trips in household survey data upon which average trip length estimates are based.

The trip generation rates in both models were identically-matched because they both rely on the same source, trip generation rates by land use from the Institute of Transportation Engineers (ITE). The ITE Trip Generation rates are a more accurate representation of vehicle traffic at a particular land use than rates based on household travel surveys. The ITE rates are based on actual driveway traffic counts at many land uses across the United States, and do not rely on self-reporting of trips. Therefore, the use of ITE trip generation rates in URBEMIS would accurately represent total trip-making, if the characteristics of the higher numbers of trips were identical to the characteristics survey-based trips used to determine average trip lengths. However, there is evidence that this is not the case, particularly for trip lengths.

RESPONSE: The District will contact the 8 Valley transportation planning agencies to obtain new recommended trip lengths for each county. This information will be included in the guidance provided by the District for use in URBEMIS. The District is not convinced that using the Transportation Demand Model will provide more accurate results.

159. COMMENT: The 2000-2001 Caltrans travel survey included a parallel study of actual vehicle movements using GPS units. The vehicle movements from the GPS surveys were compared with the self-reported trips from the same households. Overall, the GPS surveys resulted in 29 percent more trips than the self-reported travel survey results.

A related study4 identified the characteristics of underreported trips.5 In particular, the study found that short trips were much more likely to be underreported in travel surveys. Although trips of 10 minutes or less made up 48 percent of the total sample, the short trips accounted for 71 percent of the trips that were missing in self-reported results but identified by the GPS survey. Therefore, the short trips were about 50 percent more likely to be missing from the travel survey results.

4 Joanna Zmud and Jean Wolf, "Identifying the Correlates of Trip Misreporting – Results from the California Statewide Household Travel Survey GPS Study," 10th International Conference on Travel Behaviour Research, August, 2003.

5 Joanna Zmud and Jean Wolf, "Identifying the Correlates of Trip Misreporting – Results from the California Statewide Household Travel Survey GPS Study," 10th International Conference on Travel Behaviour Research, August, 2003.

The URBEMIS model therefore overestimates vehicle-miles of travel by basing the total trip generation on the higher ITE Trip Generation rates, but basing the average trip length characteristics on a smaller survey-based subset of trips that excludes many of the shorter trips. Moreover, it may not be easy or simple to correct this discrepancy because unbiased GPS or instrumented vehicle data may not be available for the San Joaquin Valley.

RESPONSE: It seems that Sierra is attempting to discredit URBEMIS by over complicating the emission calculation process. The differences between the project modeling done by URBEMIS and the regional modeling done by transportation demand models are not a valid comparison. With minor corrections URBEMIS will produce results very close to the SIP inventory model and URBEMIS will continue to be improved with each new version.

160. COMMENT: Although our side-by-side analysis of URBEMIS against a SIP-based approach was limited to a single hypothetical case study of a suburban "fringe" residential development, this case was intentionally selected because in addition to being a common example, it also represented conditions (i.e., urban edge) where it was believed that travel impacts from both approaches would be in closest agreement. Thus, the fact that this case study showed URBEMIS overstated SIP-based travel and emissions impacts by over 60% and 50%, respectively, casts doubt on the validity of broadly applying URBEMIS under the ISR rule as URBEMIS clearly does not produce SIP-consistent emission impacts.

Under both public and private sector work performed throughout California for over twenty years, Sierra has found no precedent at any air pollution control district that employs a fundamentally inconsistent methodology in implementing, monitoring and tracking emission reductions of a district rule from that used to calculate its SIP-based commitments. Given the above findings, we believe District bears the "burden-of-proof" that URBEMIS is consistent with SIP-based methods.

RESPONSE: The District disagrees with the assertion that URBEMIS is fundamentally inconsistent with SIP commitment methodologies. Since the emission inventory is built on a regional basis, the differences in individual projects are not addressed. Benefits of on-site measures and surrounding land uses are not credited in the inventory. URBEMIS is the only tool that can quantify emissions and on-site measures at the project level using readily available emission factors and activity data consistent with other inventory models.

The SIP credit expected from the rule comes from two sources – off-site reductions purchased by the District through its grant programs, and onsite

reductions achieved through project design and infrastructure built into the project. The off-site reductions from projects such as diesel engine replacements and retrofits are quantified using engine specific emission factors and use data and enforced by legally binding contracts. These meet the most stringent SIP monitoring and tracking requirements. The onsite measures are voluntary measures selected by the project developer that are more difficult to quantify and monitor. The District will claim reductions from onsite measures in accordance with EPA's Voluntary and Emerging Measures Program. In this program, EPA recognized that many nonattainment areas will need to implement innovative measures that may not be as quantifiable as traditional SIP measures. Sierra has found no precedent for this at other Districts because the San Joaquin Valley is the first to pursue an indirect source program that will be claimed for SIP credit.

161. COMMENT: Residential Fees Appear Understated in the Socioeconomic Report – In addition to the comments summarized above on the URBEMIS model, we also have concerns with the fee estimates for typical residential developments contained in the District's socioeconomic analysis of the ISR rules. Table 16 of the socioeconomic report cites "worst-case" fee estimates ranging from $856 per unit in 2006 to $2,841 per unit in 2010. The supporting text offers no explanation of how these estimates were developed.

Its fundamental flaws notwithstanding, Sierra independently estimated residential fees using URBEMIS, and the fee formulas and cost reduction ratios contained in the August drafts of Rule 9510 and 3180. For construction emissions, project construction equipment emission factors were assumed to equal those of the statewide inventory. URBEMIS runs were generated for a 100-unit residential project in the urban San Joaquin Valley for calendar years 2006 through 2010 using model defaults except where noted below. A 4% administration fee was assumed and included in our comparisons. Attachment B provides the details of our analysis.

Our analysis found fees were twice as high ($1,607-$7,971 per unit) over the same period for a single-family residential development, assuming a default housing density of 3 units/acre. When the housing density was doubled (to 6 units/acre), per unit fees were still over 50% higher ($1,295-$5,556 per unit) than those cited (without explanation) in the socioeconomic report. We also calculated fees assuming a 93% vs. 7% split between single and multi-family units, based on the average number of new single- and multi-family housing units permitted in the San Joaquin Valley in 2002 obtained from the California Department of Finance (http://countingcalifornia.cdlib.org/title/castat.html). Even under these mixed use assumptions, our fee estimates ranged from $1,550-$7,702 per unit, still nearly twice as high as those in the socioeconomic report.

Thus, we question how the estimates in that report were developed. Our analysis suggests that the worst case residential fees are substantially higher than those employed in the socioeconomic analysis. If this is correct, then the impacts quantified in the study are understated and would need to be revised.

RESPONSE: Sierra calculated the construction emission fee incorrectly. The District-estimated costs will be lower for residential development after the analysis is revised to account for the change to the fleet mix and silt loading factor. If the trip length and vehicle age changes can be verified, they too would lower the impact of the fee.

162. COMMENT: Revenue From Residential Fees Will Dramatically Exceed the Cost of Purchasing Mitigation Needed to Meet ISR SIP Commitments – A spreadsheet was created to prepare an estimate of the revenue that would be generated from residential fees for the 2006-2010 period and the cost of purchasing the mitigation needed to supply the ISR SIP emission reduction commitments during the same time period. Key assumptions used to support the development of these estimates include:

Number of Residential Units Subject to the Rule – According to the Construction Industry Research Board, construction permits were issued for 34,000 residential units in the San Joaquin Valley in 2004. This value represents a mixture of single and multi-family homes and was held constant for the years 2006 – 2010. Since the ISR rule provides an exemption for residential projects that have less than 50 units, this value was discounted by 10% to determine the number of units that would be subject to the rule. Using this approach it was determined that a total of 153,000 units would be subject to ISR fees between 2006 and 2010.

Residential ISR Fees – As noted earlier there is considerable difference between the worst case fees employed in the District's socioeconomic analysis and those that result from the use of default assumptions employed in URBEMIS. Given the discrepancy (i.e., the fees based on default URBEMIS values exceed the District's worse case values), four scenarios were used to cover the potential range in fees:

1. One half district worst-case estimate employed in the socioeconomic analysis was used to represent the low end of potential fees;
2. District worse case fees from the socioeconomic analysis represent the only per unit fee estimate available from the District;
3. URBEMIS default values, which are based on a density of 3 homes per acre represent a true worst case fee; and
4. URBEMIS default values adjusted to represent a higher density of 6 homes per acre represents a lower cost fee.

A summary of the fees that would be required to comply with these scenarios is presented in Table 4. It shows that there are considerable differences between the worst-case District values and those produced using default assumptions from URBEMIS. The URBEMIS based values assume that developers do not supply any on-site mitigation and are required to pay the fee-based expense of mitigation. We do not know what level of on-site mitigation was included in the District's estimate.

Table 4
Per Unit Mitigation Fees ($) For Each of the Scenarios Considered

Calendar Year	One Half District Worst Case	District Worst Case	URBEMIS Default 3du/acre	URBEMIS 6du/acre
2006	468	856	1,545	1,245
2007	705	1,409	3,088	2,385
2008	1,001	2,001	4,847	3,584
2009	1,230	2,459	6,637	4,804
2010	1,421	2,841	7,665	5,343

RESPONSE: The District used 3 units per acre for single family dwelling units in the socioeconomic impact analysis and continues to arrive at the same numbers. Sierra uses a figure of 34,000 units per year for its estimates of overall potential fees. The District used 20,000 units per year based on historical data that included years when construction occurred at a much slower rate and population projections used for the District's attainment plans. We believe that it is inappropriate to base future projections on record years that many expect may be a bubble. If the growth rates do continue, that means that the impact of growth will be much greater than projected and the increased revenue from greater participation in the rule by more units would be needed to offset the additional emissions.

Residential Revenue – This value was computed by multiplying the number of units subject to the Rule times the annual fee (i.e., # of units × $/unit = $).

SIP Emission Reduction Targets – The ton/day pollutant specific reduction targets established in the SIP for NOx and PM_{10}. The same values were employed in the rule making and were documented in Appendix B of the ISR rules packet.

District-Estimated Cost of Reductions – The annual pollutant specific $/ton cost of reductions specified in the residential fee schedule for Rule 9510.

Revenue Demanded – This value was computed by multiplying the pollutant specific incremental ton per day reduction commitment established in the SIP by

the District estimated cost pollutant specific reductions by 365.25 (average days per year) by 1.05 (to account for a combination of the administrative fee of Rule 3180 and an assumed 1% application fee). A key assumption in this calculation is that developers did not provide any onsite mitigation, so the District purchased all of the reductions needed to satisfy the SIP commitment.

Attachment C presents a listing of the spreadsheet values developed for each of the above parameters for each the four mitigation fee scenarios listed above. A summary of the cumulative revenue and mitigation values computed for each scenario for the period from 2006 to 2010 is listed in Table 5. It shows that the revenue varies depending on the ISR fees established by the scenario and that the cost of mitigation is constant. Regardless of the scenario considered, incoming revenue exceeds the mitigation expense by a huge margin. As noted in the summary, we believe that this is a result of biases built into URBEMIS default assumptions and the mitigation fees established for operational emissions from residential units.

Table 5
Analysis of Residential Revenue and Mitigation Expense ($ in millions)

Fee Scenario	Revenue	Mitigation Expense	Unexpended Revenue	Relative Difference (%)
One Half District Worst Case	146.3	38.8	107.5	377%
District Worst Case	292.7	38.8	253.9	754%
URBEMIS Defaults	727.7	38.8	688.9	1,873%
URBEMIS High Density	531.2	38.8	492.4	1,368%

SIERRA RESEARCH
ATTACHMENT B
PER UNIT RESIDENTIAL FEE CALCULATIONS

URBEMIS 8.7 ANNUAL AVERAGE EMISSIONS FOR
100-UNIT SF RESIDENTIAL DEVELOPMENT PROJECT (unmitigated)
USING ALL MODEL DEFAULT VALUES

	Construction		Area Source		Operational (Vehicle)		Area+Operational		Total (C+A+O)	
Calendar	Emissions (tpy)		Emissions (tpy)		Emissions (tpy)		Emissions (tpy)		Emissions (tpy)	
Year	NOx	PM10	NOx	PM10	NOx	PM10	NOx	PM10	NOx	PM10
2006	30.75	2.59	0.30	0.61	2.58	1.99	2.88	2.60	33.63	5.19
2007	29.38	2.48	0.30	0.61	2.42	1.99	2.72	2.60	32.10	5.08
2008	28.01	2.35	0.30	0.61	2.24	1.99	2.54	2.60	30.55	4.95
2009	26.66	2.28	0.30	0.61	2.05	1.98	2.35	2.59	29.01	4.87
2010	25.36	2.18	0.30	0.61	1.87	1.98	2.17	2.59	27.53	4.77

URBEMIS 8.7 ANNUAL AVERAGE EMISSIONS FOR
100-UNIT SF HIGH-DENSITY (6 units/ac) RESIDENTIAL DEVELOPMENT PROJECT (unmitigated)
USING ALL MODEL DEFAULT VALUES (except single family residential density)

	Construction		Area Source		Operational (Vehicle)		Area+Operational		Total (C+A+O)	
Calendar	Emissions (tpy)		Emissions (tpy)		Emissions (tpy)		Emissions (tpy)		Emissions (tpy)	
Year	NOx	PM10	NOx	PM10	NOx	PM10	NOx	PM10	NOx	PM10
2006	26.30	1.79	0.30	0.61	2.29	1.76	2.59	2.37	28.89	4.16
2007	25.14	1.70	0.30	0.61	2.14	1.76	2.44	2.37	27.58	4.07
2008	23.98	1.59	0.30	0.61	1.98	1.76	2.28	2.37	26.26	3.96
2009	22.85	1.53	0.30	0.61	1.82	1.76	2.12	2.37	24.97	3.90
2010	21.75	1.45	0.30	0.61	1.66	1.76	1.96	2.37	23.71	3.82

URBEMIS 8.7 ANNUAL AVERAGE EMISSIONS FOR
100-UNIT SF RESIDENTIAL DEVELOPMENT PROJECT (unmitigated)
USING ALL MODEL DEFAULT VALUES

	Construction		Area Source		Operational (Vehicle)		Area+Operational		Total (C+A+O)	
Calendar	Emissions (tpy)		Emissions (tpy)		Emissions (tpy)		Emissions (tpy)		Emissions (tpy)	
Year	NOx	PM10	NOx	PM10	NOx	PM10	NOx	PM10	NOx	PM10
2006	12.62	0.81	0.21	0.61	1.86	1.43	2.07	2.04	14.69	2.85
2007	*12.07*	*0.77*	*0.21*	*0.61*	*1.73*	*1.43*	1.94	2.04	14.02	2.81
2008	*11.53*	*0.72*	*0.21*	*0.61*	*1.61*	*1.43*	1.82	2.04	13.34	2.76
2009	*10.98*	*0.68*	*0.21*	*0.61*	*1.48*	*1.43*	1.69	2.04	12.67	2.72
2010	10.43	0.63	0.21	0.61	1.35	1.43	1.56	2.04	11.99	2.67

SIERRA RESEARCH
ATTACHMENT B
PER UNIT RESIDENTIAL FEE CALCULATIONS

SJV DRAFT RULE 9510 ISR NOx IMPACT FEE CALCULATIONS

Formula:

$$AIMF_{NOx} = \sum_{i=1}^{n} [(EBE_i \times 7.5/3) - (EBE_i \times 7.5 \times APM_i)] \times CNR_i$$

Calendar Year	Cost of NOx Red ($/ton)
2006	$4,650
2007	$7,100
2008	$9,350
2009	$11,600
2010	$13,250
2011	$13,250
2012	$13,250
2013	$13,250
2014	$13,250
2015	$13,250

where
- AIMF = Air Impact Mitigation Fee (in dollars)
- i = each phase
- n = last phase
- EBE = Estimated Baseline Emissions of NOx as documented in the District approved air impact assessment application (in tons/year)
- APM = Actual Percent Mitigation, as documented in the District approved air impact assessment application (as a fraction of one)
- CNR = Cost of NOx Reductions (in dollars per ton)

$$CN\ AIMF_{NOx} = \sum_{i=1}^{n} [AEE_i - (0.8 \times SEE_i)] \times CNR_i$$

where
- CN AIMF = Construction NOx Air Impact Mitigation Fee (in dollars)
- i = each phase
- n = last phase
- AEE = Actual Estimated Equipment NOx Emissions as documented in District approved air impact assessment application (in total tons)
- SEE = Statewide Average Equipment NOx Emissions as calculated by the District (in total tons)
- CNR = Cost of NOx Reductions (in dollars per ton)

Calculations:

					Area + Operational Sources						Construction Sources			
	Calendar Years			Units per	Estimated Baseline Emissions	Actual Percent Mitigation	Air Impact Mitigation Fee	Area+Ops Fee/Unit	Actual Equipmt Emis AEE	Assumed % AEE	State Avg Equipmt Emis SEE	Constr Air Impact Fee	Constr Fee/Unit	Total Fee/Unit
Scenario	Start	End	Phases	Phase	EBE (tpy)	APM (%)	AIMF ($)	($)	(total tons)	Over SEE	(total tons)	CN AIMF ($)	($)	($)
SF Resid	2006	2006	1	100	2.88	0%	$33,480	$335	102.95	0%	102.95	$95,744	$957	$1,292
SF Resid	2007	2007	1	100	2.72	0%	$48,280	$483	141.85	0%	141.85	$201,422	$2,014	$2,497
SF Resid	2008	2008	1	100	2.54	0%	$59,373	$594	166.30	0%	166.30	$310,985	$3,110	$3,704
SF Resid	2009	2009	1	100	2.35	0%	$69,325	$693	184.82	0%	184.82	$436,176	$4,362	$5,055
SF Resid	2010	2010	1	100	2.17	0%	$71,681	$716	182.29	0%	182.29	$483,071	$4,831	$5,550
HD Resid	2006	2006	1	100	2.59	0%	$38,109	$381	79.19	0%	79.19	$73,643	$736	$1,118
HD Resid	2007	2007	1	100	2.44	0%	$43,310	$433	108.88	0%	108.88	$154,612	$1,546	$1,979
HD Resid	2008	2008	1	100	2.28	0%	$53,295	$533	127.80	0%	127.80	$238,989	$2,390	$2,923
HD Resid	2009	2009	1	100	2.12	0%	$62,540	$625	142.90	0%	142.90	$337,253	$3,373	$3,998
HD Resid	2010	2010	1	100	1.96	0%	$64,925	$649	141.21	0%	141.21	$374,211	$3,742	$4,391
MF Resid	2006	2006	1	100	2.07	0%	$24,064	$241	30.37	0%	30.37	$28,243	$282	$523
MF Resid	2007	2007	1	100	1.94	0%	$34,479	$345	41.63	0%	41.63	$59,168	$591	$936
MF Resid	2008	2008	1	100	1.82	0%	$42,426	$424	48.90	0%	48.90	$91,435	$914	$1,339
MF Resid	2009	2009	1	100	1.69	0%	$49,781	$498	54.65	0%	54.65	$128,968	$1,290	$1,787
MF Resid	2010	2010	1	100	1.56	0%	$51,675	$517	53.90	0%	53.90	$142,827	$1,428	$1,945

SIERRA RESEARCH
ATTACHMENT B
PER UNIT RESIDENTIAL FEE CALCULATIONS

SJV DRAFT RULE 9510 ISR PM10 IMPACT FEE CALCULATIONS

Formula:

$$AIMF_{pm10} = \sum_{i=1}^{n} [(MBE - 0.5\,EBE)_i \times 10\,MCE)_i] / \text{CR}$$

Calendar Year	Cost of PM10 Red ($/ton)
2006	$2,907
2007	$5,594
2008	$9,011
2009	$11,308
2010	$13,850
2011	$13,850
2012	$13,850
2013	$13,850
2014	$13,850
2015	$13,850

where

AIMF = Air Impact Mitigation Fee (in dollars)
i = each phase
n = last phase
EBE = Estimated Baseline Emissions of PM10 as documented in the District approved air impact assessment application (in tons/year)
MBE = Mitigated Baseline Emissions, as documented in the District approved air impact assessment application (in tons/year)
MCE = Mitigated Construction Emissions, as documented in the District approved air impact assessment application (as total tons)
CR = Cost of Reductions (in dollars per ton)

$$AIMF_{pm10} = \sum_{i=1}^{n} [(MBE - 0.5\,EBE)_i \times 10\,MCE)_i] / \text{CR}$$

$$CN\,AIMF_{pm10} = \sum_{i=1}^{n} [(AEE - (0.8 \times SEE)_i] \times CPR$$

where

CN AIMF = Construction PM10 Air Impact Mitigation Fee (in dollars)
i = each phase
n = last phase
AEE = Actual Estimated Equipment PM10 Emissions as documented in District approved air impact assessment application (in total tons)
SEE = Statewide Average Equipment PM10 Emissions as calculated by the District (in total tons)
CBR = Cost of PM10 Reductions (in dollars per ton)

Calculations:

				Area + Operational Sources				Construction Sources				
Scenario	Calendar Years Start	End	Phases	Units per Phase	Estimated Baseline Emissions EBE (tpy)	Actual Percent Mitigation APM (%)	Air Impact Fee AIMF ($)	Area+Op Fee/Unit ($)	Actual Equipmt Emis AEE (total tons)	Assumed % AEE Over SEE	State Avg Equipmt Emis SEE (total tons)	Constr Air Impact Fee CN AIMF ($)	Constr Fee/Unit ($)	Total Fee/Unit ($)
SF Resid	2006	2006	1	100	2.60	0%	$18,896	$189	4.89	0%	4.89	$6,402	$64	$253
SF Resid	2007	2006	1	100	2.60	0%	$36,361	$364	9.02	0%	9.02	$22,700	$227	$591
SF Resid	2008	2006	1	100	2.60	0%	$58,572	$586	13.76	0%	13.76	$55,814	$558	$1,144
SF Resid	2009	2006	1	100	2.59	0%	$73,219	$732	16.69	0%	16.69	$84,949	$849	$1,582
SF Resid	2010	2006	1	100	2.59	0%	$89,679	$897	19.55	0%	19.55	$121,845	$1,218	$2,115
HD Resid	2006	2006	1	100	2.59	0%	$18,823	$188	3.37	0%	3.37	$1,939	$20	$208
HD Resid	2007	2007	1	100	2.44	0%	$34,123	$341	5.80	0%	5.80	$6,499	$65	$406
HD Resid	2008	2008	1	100	2.28	0%	$51,363	$514	8.17	0%	8.17	$14,710	$147	$661
HD Resid	2009	2009	1	100	2.12	0%	$59,932	$599	9.17	0%	9.17	$20,738	$207	$807
HD Resid	2010	2010	1	100	1.96	0%	$67,965	$679	9.84	0%	9.84	$27,258	$273	$951
MF Resid	2006	2006	1	100	2.04	0%	$14,826	$148	1.20	0%	1.20	$1,571	$16	$164
MF Resid	2007	2006	1	100	2.04	0%	$28,529	$285	2.18	0%	2.18	$5,294	$53	$339
MF Resid	2008	2006	1	100	2.04	0%	$45,956	$460	3.31	0%	3.31	$13,417	$134	$594
MF Resid	2009	2006	1	100	2.04	0%	$57,671	$577	3.89	0%	3.89	$19,809	$198	$775
MF Resid	2010	2006	1	100	2.04	0%	$70,635	$706	4.45	0%	4.45	$27,735	$277	$984

SIERRA RESEARCH
ATTACHMENT B
PER UNIT RESIDENTIAL FEE CALCULATIONS

SJV DRAFT ISR RULE FEE CALCULATIONS FOR TYPICAL RESIDENTIAL PROJECTS

Scenario	Calendar Year	Construction Emis %AEE Over SEE NOx	Construction Emis %AEE Over SEE PM10	Rule 3180 Admin Fee (%)	Per Unit NOx Fees Area+Op	Per Unit NOx Fees Constr.	Per Unit PM10 Fees Area+Op	Per Unit PM10 Fees Constr.	Total Fees Per Unit Area+Op	Total Fees Per Unit Constr.	Total Fees Per Unit Admin	Total	Total Less Admin
100-Unit SF Res	2006	0%	0%	4%	$335	$957	$189	$64	$524	$1,021	$62	$1,607	$1,545
100-Unit SF Res	2007	0%	0%	4%	$483	$2,014	$364	$227	$846	$2,241	$124	$3,211	$3,088
100-Unit SF Res	2008	0%	0%	4%	$594	$3,110	$586	$558	$1,179	$3,668	$194	$5,041	$4,847
100-Unit SF Res	2009	0%	0%	4%	$693	$4,362	$732	$849	$1,425	$5,211	$265	$6,902	$6,637
100-Unit SF Res	2010	0%	0%	4%	$719	$4,831	$897	$1,218	$1,616	$6,049	$307	$7,971	$7,665
100-Unit HD SF Res	2006	0%	0%	4%	$301	$736	$188	$20	$489	$756	$50	$1,295	$1,245
100-Unit HD SF Res	2007	0%	0%	4%	$433	$1,546	$341	$65	$774	$1,611	$105	$2,491	$2,395
100-Unit HD SF Res	2008	0%	0%	4%	$533	$2,390	$514	$167	$1,047	$2,557	$143	$3,727	$3,584
100-Unit HD SF Res	2009	0%	0%	4%	$625	$3,373	$599	$207	$1,225	$3,580	$192	$4,997	$4,805
100-Unit HD SF Res	2010	0%	0%	4%	$649	$3,742	$679	$273	$1,328	$4,015	$214	$5,556	$5,343
100-Unit MF Res	2006	0%	0%	4%	$241	$282	$148	$64	$389	$346	$29	$765	$735
100-Unit MF Res	2007	0%	0%	4%	$345	$591	$285	$227	$630	$818	$58	$1,506	$1,448
100-Unit MF Res	2008	0%	0%	4%	$424	$914	$468	$558	$892	$1,472	$94	$2,457	$2,364
100-Unit MF Res	2009	0%	0%	4%	$498	$1,290	$577	$849	$1,075	$2,139	$129	$3,342	$3,214
100-Unit MF Res	2010	0%	0%	4%	$517	$1,429	$706	$1,218	$1,223	$2,647	$155	$4,025	$3,870
Resid Mix - 93% SF, 7% MF	2006	0%	0%	4%	$328	$911	$186	$64	$515	$975	$60	$1,550	$1,490
Resid Mix - 93% SF, 7% MF	2007	0%	0%	4%	$473	$1,917	$358	$227	$832	$2,144	$119	$3,095	$2,976
Resid Mix - 93% SF, 7% MF	2008	0%	0%	4%	$582	$2,960	$577	$558	$1,159	$3,518	$182	$4,864	$4,677
Resid Mix - 93% SF, 7% MF	2009	0%	0%	4%	$680	$4,152	$722	$849	$1,401	$5,001	$256	$6,659	$6,403
Resid Mix - 93% SF, 7% MF	2010	0%	0%	4%	$705	$4,598	$884	$1,218	$1,589	$5,817	$296	$7,702	$7,406

Calendar Year	Worst-Case Socio Report Resid Fees Res Fees ($/Unit)	One-Half Worst-Case Resid Fees Res Fees ($/Unit)
2006	$856	$428
2007	$1,409	$705
2008	$2,001	$1,001
2009	$2,459	$1,230
2010	$2,841	$1,421

SIERRA RESEARCH
ATTACHMENT B
PER UNIT RESIDENTIAL FEE CALCULATIONS

ANALYSIS OF ISR REVENUE SUPPLIED VS. DEMANDED FROM SIP

Assumptions:
34,000 residential units per year in SJV (Source: Construction Industry Research Board, CY2004 Permits)
10% of residential units exempted from ISR rules under the 50-unit project threshold
SocioHalf source of estimated residential fees (SocioWC = SE report/worst-case; SocioHalf = SE report/one half worst-case; URBDft = URBEMIS Defaults; URBHD = URBEMIS High Density)

	SJV ISR Residential Revenue				**SJV ISR Revenue Needed to Achieve SIP Targets**				
Calendar Year	Est. New Residential Units*	Residential ISR Fee ($/Unit)	**Residential Revenue ($/year)**	Calendar Year	SIP Emission Reduction Targets (tons/day) NOx	PM10	District-Estimated Cost of Reductions ($/ton) NOx	PM10	**Revenue** Demanded ($/year)**
2006	30,600	$428	$13,096,800	2006	0.0	1.2	$4,650	$2,907	$1,337,845
2007	30,600	$705	$21,557,700	2007	2.8	2.4	$7,100	$5,594	$10,198,671
2008	30,600	$1,001	$30,615,300	2008	4.0	3.5	$9,350	$9,011	$8,104,425
2009	30,600	$1,230	$37,622,700	2009	5.0	4.6	$11,900	$11,309	$9,295,883
2010	30,600	$1,421	$43,467,300	2010	5.8	5.7	$13,250	$13,950	$9,908,045
Cumulative Totals 2006 to 2010:			**$146,359,800**						$38,844,869
Relative Difference in Revenue: (Supplied vs. Demanded)						377%			

* Discounted to reflect 10% of residential project units exempted under the 50-unit threshold
** Includes 5% "overhead" fee; 4% admin fee per Rule 3180, plus assumed 1% application fee

RESPONSE: The table provided above fails to include the average project life of the emission reduction projects that will be funded by the revenue collected. This results in severely understating the revenue required to purchase emission reductions. NOx projects have an average life of 7 years. PM10 projects have an average life of 12 years. The $/ton number in the fee formula is based on annualized cost divided by annual reductions. This allows for comparison of projects with different project lives. To arrive at the funding needed to achieve the SIP emission reduction commitment, multiply the annual reductions required times the cost per ton of each pollutant.

The District considers it inappropriate to base housing projections on 34,000 units per year. The SIP growth projections are derived from population projections provided by the Valley transportation planning agencies. If these record growth rates continue until 2010, the SIP emission budgets will need to be increased and additional reductions would be needed to achieve attainment on schedule. Rule 9510 would provide some of these additional reductions if growth exceeds predictions.

SIERRA RESEARCH
ATTACHMENT B
PER UNIT RESIDENTIAL FEE CALCULATIONS

ANALYSIS OF ISR REVENUE SUPPLIED VS. DEMANDED FROM SIP

Assumptions:

34,000 residential units per year in SJV (Source: Construction Industry Research Board, CY2004 Permits)
10% of residential units exempted from ISR rules under the 50-unit project threshold
SocioWC source of estimated residential fees (SocioWC = SE report/worst-case, SocioHalf = SE report/one half worst-case, URECdt = URBEMIS Defaults, UREHD = URBEMIS High Density)

	SJV ISR Residential Revenue				**SJV ISR Revenue Needed to Achieve SIP Targets**				
Calendar Year	Est. New Residential Units*	Residential ISR Fee ($/Unit)	**Residential Revenue ($/year)**	Calendar Year	SIP Emission Reduction Targets (tons/day) NOx	PM10	District-Estimated Cost of Reductions ($/ton) NOx	PM10	**Revenue** Demanded ($/year)**
2006	30,600	$856	**$26,193,600**	2005	0.0	1.2	$4,650	$2,907	**$1,317,813**
2007	30,600	$1,409	**$43,115,400**	2007	2.9	2.4	$7,100	$5,594	**$10,198,671**
2008	30,600	$2,001	**$61,230,600**	2008	4.0	3.5	$9,350	$9,011	**$8,104,425**
2009	30,600	$2,459	**$75,245,400**	2009	5.0	4.6	$11,800	$11,308	**$9,295,883**
2010	30,600	$2,841	**$86,934,600**	2010	5.8	5.7	$13,250	$13,850	**$9,908,945**
Cumulative Totals 2006 to 2010:			**$292,719,600**						**$38,844,869**
Relative Difference in Revenue: (Supplied vs. Demanded)						**754%**			

* Discounted to reflect 10% of residential project units exempted under the 50-unit threshold
** Includes 5% "overhead" fee: 4% admin fee per Rule 3190, plus assumed 1% application fee

SIERRA RESEARCH
ATTACHMENT B
PER UNIT RESIDENTIAL FEE CALCULATIONS

ANALYSIS OF ISR REVENUE SUPPLIED VS. DEMANDED FROM SIP

Assumptions:

34,000 residential units per year in SJV (Source: Construction Industry Research Board, CY2004 Permits)

10% of residential units exempted from ISR rules under the 50-unit project threshold

URBDlt source of estimated residential fees (SocioWC = SE report/worst-case, SocioHalf = SE report/one half worst-case, URBDlt = URBEMIS Defaults, URBHD = URBEMIS High Density)

SJV ISR Residential Revenue				SJV ISR Revenue Needed to Achieve SIP Targets					
Calendar Year	Est. New Residential Units*	Residential ISR Fee ($/Unit)	**Residential Revenue ($/year)**	Calendar Year	SIP Emission Reduction Targets (tons/day) NOx	PM10	District-Estimated Cost of Reductions ($/ton) NOx	PM10	**Revenue** Demanded ($/year)**
2006	30,600	$1,545	**$47,283,711**	2006	0.0	1.2	$4,650	$2,907	**$1,337,845**
2007	30,600	$3,088	**$94,481,494**	2007	2.8	2.4	$7,100	$5,594	**$10,198,671**
2008	30,600	$4,847	**$148,331,356**	2008	4.0	3.5	$9,350	$9,011	**$8,104,425**
2009	30,600	$6,637	**$203,082,914**	2009	5.0	4.6	$11,600	$11,309	**$9,295,883**
2010	30,600	$7,665	**$234,541,633**	2010	5.8	5.7	$13,250	$13,850	**$9,908,045**
Cumulative Totals 2006 to 2010:			**$727,721,108**						**$38,844,869**
Relative Difference in Revenue: (Supplied vs. Demanded)						**1873%**			

* Discounted to reflect 10% of residential project units exempted under the 50-unit threshold

** Includes 5% "overhead" fee: 4% admin fee per Rule 3180, plus assumed 1% application fee

SIERRA RESEARCH
ATTACHMENT B
PER UNIT RESIDENTIAL FEE CALCULATIONS

ANALYSIS OF ISR REVENUE SUPPLIED VS. DEMANDED FROM SIP

Assumptions:

34,000 residential units per year in SJV (Source: Construction Industry Research Board, CY2004 Permits)
10% of residential units exempted from ISR rules under the 50-unit project threshold
URBHD source of estimated residential fees (SocioWC = SE report/worst-case, SocioHalf = SE report/one half worst-case, UREDit = URBEMIS Defaults, URBHD = URBEMIS High Density)

	SJV ISR Residential Revenue				**SJV ISR Revenue Needed to Achieve SIP Targets**				
Calendar Year	Est. New Residential Units*	Residential ISR Fee ($/Unit)	**Residential Revenue ($/year)**	Calendar Year	SIP Emission Reduction Targets (tons/day) NOx	PM10	District-Estimated Cost of Reductions ($/ton) NOx	PM10	**Revenue** Demanded ($/year)**
2006	30,600	$1,245	**$38,107,242**	2005	0.0	1.2	$4,650	$2,907	**$1,317,813**
2007	30,600	$2,385	**$72,991,721**	2007	2.9	2.4	$7,100	$5,594	**$10,198,671**
2008	30,600	$3,584	**$109,659,478**	2008	4.0	3.5	$9,350	$9,011	**$8,104,425**
2009	30,600	$4,805	**$147,021,892**	2009	5.0	4.6	$11,800	$11,308	**$9,295,883**
2010	30,600	$5,343	**$163,483,390**	2010	5.8	5.7	$13,250	$13,850	**$9,908,945**
Cumulative Totals 2006 to 2010:			**$531,263,724**						**$38,844,869**
Relative Difference in Revenue: (Supplied vs. Demanded)						**1368%**			

* Discounted to reflect 10% of residential project units exempted under the 50-unit threshold
** Includes 5% "overhead" fee: 4% admin fee per Rule 3180, plus assumed 1% application fee

RESPONSE: The tables provided above are based on erroneous information and so should be disregarded.

PETROtech Environmental Solutions
Date: September 19, 2005

Good morning. It was good to see you at the Chamber of Commerce Meeting on Friday.

163. **COMMENT:** My comment regarding SJVUAPCD Rule 9510 is as follows: I would like to see Exemption Section 4.1.4 changed to read as follows:

"Oil EXPLORATION, Production and Processing"

The way the exemption reads now, only Production and Processing would be covered.

RESPONSE: The Rule will be amended to read "Oil Exploration, Production and Processing.**"**

164. **COMMENT:** I also have a comment regarding Air Quality Guidelines for General Plans. Seyed, until about 5-7 years ago, residential development was ongoing, but it was a fraction of what it is today. I will bet that very few folds from Bakersfield paid attention to them when they were drafted. If PETROtech hadn't started doing Air Quality Impact Assessments, I would have never thought about Rule 9510. But the concern that folds have is based on their fears that sometimes Guidelines, or suggested control measures become part of the requirements.

RESPONSE: Comment Noted.

The California League of Food Processors (CLFP)

Date: September 15, 2005

165. COMMENT: CLFP's primary concern is that it is not entirely clear how some of the provisions of Rule 9510 will apply to a range of manufacturing applications, and the potential compliance costs. Based on a review of the draft CLFP suggests that the District amend the proposed rule as follows:

1. Expand the list of exemptions to include food processing facilities. These facilities should be exempted for the following reasons:
    - A large portion of NOx emissions at most food processing plants can be attributed to stationary sources such as boilers or dryers, and most of this equipment is, or soon will be, subject to new emissions reduction regulations.
    - Forklifts, one of the most common vehicles used at processing facilities, will soon be subject to new emissions control regulations.
    - Unlike many manufacturing and commercial operations, most food processors operate on a seasonal basis, and some only operate for a few months per year. This significantly limits the total amount of employee and product delivery vehicle traffic on the site.
    - A number of the emissions mitigation options suggested by the District are not viable for many food processing facilities. Most processing plants are located in rural areas near where the crops are grown. Charging workers for parking or providing free bus passes to encourage the use of mass transit won't be effective if there is no mass transit available. Cannery workers cannot telecommute or teleconference to conduct their duties, and few may want to ride a bicycle home after working a shift in a factory. Options for creating mixed use facilities may be quite limited. In the case of food processors and many other manufacturers, locating new facilities based on reducing worker travel will imply hauling the raw product further, generating longer trips and additional diesel emissions. The economic viability of investing in some energy savings devices may be limited by the seasonal nature of the business. So, there may be a narrow range of cost effective mitigation measures available to food processors.

RESPONSE: The District will expand the definition to include food manufacturing.

166. COMMENT: 2. The District should clarify how baseline emissions will be calculated for manufacturing and industrial facilities.

RESPONSE: Manufacturing and industrial facilities whose primary function is regulated by the District will be exempt. For those industries subject to the rule such as warehouse distribution centers, only indirect and area source emissions

are used for the baseline calculation. A proposed new facility going through the CEQA process would prepare an air quality impact assessment. The assessment would include an URBEMIS run to quantify area source and mobile source emissions. The facility would concurrently apply to the District for an Authority to Construct for any stationary source equipment/devices subject to permitting. District staff would then estimate stationary emissions.

167. COMMENT: 3. The District should consider the impact of cumulative regulatory costs on industry. Many firms located in the San Joaquin Valley are currently expending substantial funds to comply with an array of new air and water quality environmental regulations. Rule 9510 will place an additional cost burden on industry which will have a direct effect on competitiveness in the global marketplace.

RESPONSE: The District recognizes the cumulative impact of air regulations on industry and the major investments made in stationary source emission controls in compliance with District rules and regulations and has provided exemptions for sources whose primary function is permitted by the District.

Manufacturers Council of the Central Valley
Date: September 15, 2005

On behalf of the Manufacturers Council of the Central Valley, I want to thank you for the opportunity to provide comments on the draft rule 9510 (Decreasing Emissions' Significant Impact from Growth and New Development – DESIGN) and Draft Rule 3180 of the San Joaquin Valley Unified Air Pollution Control District's Rule 4309. The Council represents a number of food processing and related companies in the San Joaquin Valley including several who will be impacted by this rule – some quite significantly and others, quite unexpectedly, unless there are major modifications prior to its adoption by the Governing Board later this year.

These comments are intended to augment those submitted earlier by Rob Neenan of the California League of Food Processors and which we fully support, but will not, in the interest of time, duplicate.

168. COMMENT: As I have communicated to you in a telephone conversation and at the public workshop, the MCCV is particularly concerned with the lack of clarity provided in section 4.1.4 concerning development projects whose primary source of emissions are from stationary sources which are subject to rule 2201 or Rule 2010. At the minimum we would like to see the list of industries expanded to include food processing related companies (including snack foods, candy, milk and cheese), corrugated box manufacturers, can manufacturers, and wineries.

However, even this is insufficient to adequately address the concerns unless a categorical exemption is provided for these industries because the first question

that will be asked is what is the definition of primary? And the subsequent question is how will this be determined? For new developments, this will be somewhat straightforward:

A) If stationary source emissions are projected to be greater than 50 percent of the construction emissions (as calculated by the yet undeveloped emissions calculator) plus the indirect emissions (as calculated by URBEMIS) then project is EXEMPT
B) If less than 50 percent then project is NOT EXEMPT

However, if the development project is an expansion of an existing facility in a jurisdiction which requires discretionary approval, due to its particular ordinance, how will the district review the project and calculate the emissions? What will be the baseline? Will only that portion of the project that is being expanded be subject to the rule? Or will that revert to the policy of the jurisdiction? There are a number of questions that arise and this just touches the surface.

RESPONSE: The rule has been revised to clarify the sources that will be exempt from the rule.

Western States Petroleum Association (WSPA)
Date: September 16, 2005

The Western States Petroleum Association (WSPA[1]) would like to take advantage of the brief opportunity made available by District staff for industry to provide comment on the June 30, 2005 draft of the proposed Rule 9510 (Decreasing Emissions' Significant Impact from Growth and New Development – DESIGN). Our comments on critical development issues related to the rule are attached. We look forward to discussing these issues with the District during future workshop sessions and if necessary providing additional comments should it prove necessary. Preparation of such comments is a crucial aspect of the Rule development process and as such, should be afforded sufficient time for a thorough review of the draft District document and preparation of meaningful comments.

169. COMMENT: I. Indirect Source Review and the SIP
In our July 22, 2005 comments, the Western States Petroleum Association (WSPA) requested that the District designate requirements derived from the proposed regulation as "not federally enforceable". WSPA cited the Federal Clean Air Act at Section 110(a)(5)(A)(i) and the California Health and Safety Code at Section 39602, which we believe support our request.

The Clean Air Act (CAA) at section 110(a)(5)(A)(i) states the following:

1 WSPA is a non-profit trade association representing a full spectrum of companies which explore for, produce, refine, transport, and market petroleum and petroleum products in the Western United States.

"Any state may include in a state implementation plan, but the administrator may not require as a condition of approval of such a plan under this section, any indirect source review program. The administrator may review and enforce as part of an applicable implementation plan an indirect source review program which a state chooses to adopt and submit as part of its plan."

The California Health and Safety Code at Section 39602 states the following:

"…the state implementation plan shall only include those provisions necessary to meet the requirements of the Clean Air Act."

We believe that these sections of the Federal Clean Air Act (CAA) and the California Health and Safety Code when considered together clearly preempt inclusion of indirect source review programs in the California state implementation plan.

The District's response to our comment is contained in Appendix-A of September 1, 2005 draft of the proposed regulation. The District contends that indirect source review programs are required by the CAA, since emission reductions are required to attain ambient air quality standards.

WSPA disagrees. The indirect source review program proposed by the District would be enforceable as a "state only" requirement. Emission reductions from the program would still occur and would reduce ambient concentrations to the same extent. The designation of indirect source review requirements as "federally enforceable" or "non-federally enforceable" has no effect on the attainment of air quality standards.

In California, inclusion of indirect source review programs in state implementation plan is prohibited by H&SC Section 39602 and the CAA section 110(a)(5)(A)(i). Consequently, WSPA requests the proposed regulation include a statement that Rule 9510 is a "state only" regulation.

We believe this to be a critical issue since federal requirements contained in applicable implementation plans must be included in Title V operating permits for major sources. Therefore, under the proposed regulation, mitigation contracts entered into by major stationary sources would require approval (or veto) by the U.S. EPA.

RESPONSE: The District disagrees with the interpretation of CAA sections cited in the comment. The intent of the section was to prohibit EPA from requiring indirect source programs as a Federal Implementation Plan (FIP) measure. Since the District requires the reductions for Rule 9510 to meet commitments in the PM10 Plan, the rule must be enforceable. The enforcement approach we

are proposing is not traditional since this program breaks new ground. The emission reduction projects are enforceable by the District through contract legal actions, but not EPA. If the reductions from the rule and its measures are not achieved, EPA enforcement should require the District to take corrective action to make up for the reductions in accordance with CAA milestone requirements. Since EPA is precluded from requiring the program, they would need to use alternative strategies in the event that a FIP were promulgated.

170. COMMENT: II Rule Applicability

A. Applicability Trigger Date.

In our July 22, 2005 comments WSPA proposed that applications for development projects filed prior to the rule adoption date be reviewed under existing regulations. We continue to believe these development projects should be reviewed under existing regulations. Under existing regulations, projects with significant environmental effects must include all feasible mitigation. The District is provided with notice and an opportunity for commenting on all such projects that are conducted within the San Joaquin Valley. Consequently, the District either has had or will have an opportunity to comment on these projects and to propose mitigation for indirect source and area source emissions. WSPA sees no reason why these projects should have to undergo a second round of regulatory review.

B. Indirect Source Review

As pointed out in our prior comments, Health and Safety Code Section 40717.5 sets forth guidelines and procedures that must be followed by any air district that proposes to adopt or amend a rule or regulation pursuant to Section 40716 or Section 40717.

The requirements contained in Section 40717.5(a) through 40717.5(c) are designed to ensure that emissions from indirect sources are properly allocated to projects that cause an increase in vehicular activity and to ensure that indirect source review requirements are not duplicative of other requirements imposed by the District or other agencies.

The draft version of District Rule does not comply with H&SC Section 40717.5(a)(1) which limits the applicability of indirect source review to those activities that contribute to, "…air pollution by generating vehicle trips that would otherwise not occur".

The District response to WSPA comments (Appendix-A, comment #24, #29) and to similar comments submitted by other was that:

"by their nature new development projects ultimately result in new trips which would not otherwise occur".

The District does not provide any information in support of this generalization and has not made any attempt to determine which types of activities result in an increase in indirect source emissions. In response to other comments the District acknowledges that the proposed rule is intended to control growth induced emissions from indirect sources and new construction (Appendix-A, comment #2, #8, #16). Not all development projects result in growth.

In our July 22, 2005 comments WSPA requested that Rule 9510 be revised to limit rule applicability to indirect source and area source emissions increases. We continue to believe that indirect source review programs established under authority at H&SC Section 40717 and Section 40715.5 are limited to regulation of growth induced indirect source and area source emissions.

WSPA believes that indirect source emissions and area source emissions that are already occurring, or area included in an application for a development project filed before the rule adoption date, should be considered existing emissions and only emissions increase above existing emissions should be subject to Rule 9510 applicability.

RESPONSE: The rule does not target *all* new development, but that development that results in the generation of at least 2 tons per year of NOx or PM10. Certain development, such as an expansion of a manufacturing facility, would be exempt if it does not result in and *increase* of at least 2 tons per year of NOx or PM10 through area and mobile emissions. Therefore, the rule accounts for the *increase* in pollution generation from development projects, and does not place requirements on those developments that do not result in the increase stated above. It is the District's position that projects that result in an increase in pollution emissions are a part of growth. It would be impractical to determine on a case-by-case basis if a project subject to the rule that emits emissions above the applicability threshold is or is not a project resulting from growth in the region.

In regards to projects that have filed for City/County permits *prior* to implementation of the rule, the rule language will be revised to limit the applicability to projects that have applied for a discretionary permit prior to implementation date but have not yet received approval.

171. COMMENT: C Proposed Revision to Applicability
In light of the guidelines specified in the California H&SC at Section 40717.5, and District response to comments, WSPA requests that the following subsection of the Rule Applicability Section 2.0, be revised as follows:

Subsection 2.1

2.1 This rule shall only apply to those elements of a project that require discretionary approval and only if those elements are determined to be part of a development project that meets the following conditions

a. The application for the development project is filed on or after the effective date of this rule.
b. The development project results in an increase in emissions of a pollutant for which the area is designated as nonattainment for either the California, primary ambient air quality standards (CAAQS) or the national, primary ambient air quality standards (NAAQS), for ozone or PM10.
c. The development project results in an increase in indirect source or area source emissions above previously approved existing emissions.

RESPONSE: Comment noted.

172. COMMENT: Subsection 2.1.3

Section 2.1.3 specifies an applicability threshold level of 25,000 square feet for the industrial space category. In our prior comments WSPA requested that the industrial space category be separated into "light Industrial" space and "heavy industrial" space since the vehicle trip ends (VTE) generated by these land use categories differ significantly. For example, according to the institute of Transportation Engineers, "Trip Generation Manual (7^{th} Edition)" the light industrial land use category generates 6.97 VTE per 1,000 square feet. The "heavy industrial" land use category generates 1.5 VTE per 1,000 square feet. The District response to our prior comment was that:

"Most heavy industrial projects would be exempt from this rule, so distinguishing between the different types of industrial would not be productive." (sic)

The District fails to explain why heavy industrial sources would be exempt from the rule's requirements. Furthermore, the District is now proposing to apply the rule to uncategorized discretionary projects involving more than 9,000 square feet. WSPA is again requesting that the "industrial use" category be separated into "light industrial" and "heavy industrial" categories and that the applicability thresholds for these land use categories be established at 25,000ft^2 and 100,000ft^2 respectively.

RESPONSE: Comment noted. The applicability section of the draft rule will be revised to include 25,000 square feet of light industrial, and 100,000 square feet of heavy industrial.

173. COMMENT: Subsection 2.1.9

Delete subsection 2.1.9. The District has not documented why any discretionary project, not otherwise included in a section 2.1 land use category and that is

greater than 9,000 square feet (~1.4 acre) is automatically presumed to have significant indirect source or area source emissions.

RESPONSE: The District prepared emission estimates for all projects listed in the section to determine if they would exceed 2 tons per year of either PM10 or NOx. These projects would be required to prepare an air quality assessment based on their actual design, on-site measures, and characteristics, so in some cases the assessment would determine that no off-site fee is required.

174. COMMENT: Subsection 2.3.2

Delete Subsection 2.3.2. With the exception of the applicability threshold established for "50 residential units", Subsection 2.3.2 supersedes and essentially eliminates the other land use category size thresholds. It can be easily argued that any land use involving nonresidential development, (e.g. commercial, industrial, medial, etc) could accommodate development projects that emit more than 2.0 tons per year of NOx or PM10 (~11ld/day or 0.5 lb/hr).

The District is also proposing that the amount of required mitigation be based on the ability of the property to accommodate future development, whether or not such future development is planned or included as part of the development project responsible for triggering review under this rule.

WSPA believes that developers should not have to provide mitigation for unplanned projects solely because the property has the potential for future development. Future discretionary projects might or might not result in an increase in emissions of air contaminants. Consequently, we request that Subsection 2.3.2 be deleted.

RESPONSE: The rule requires the applicant to come to the District at the last discretionary approval for the project. For industrial and commercial projects this may be a conditional use permit or site plan review. If the use is not known, the general trip rate for the expected use is used to calculate the proposed fee amount. Then, the applicant can use a fee deferral schedule to allow time to identify the actual use. If there were no increase in actual emissions based on the use, the applicant could revise the air assessment and the off-site fee would be not need to be paid.

175. COMMENT: III Definitions

WSPA requests that the following revisions be made to the definitions. We believe the proposed changes will ensure that the definitions are consistent with the stated purpose and applicability of the proposed rule, and will help clarify rule requirements.

Subsection 3.7

In our July 22, 2005 comments WSPA requested that the definition of a development project be revised to exclude projects that require discretionary approval but are required solely to comply with a rule regulation or order of a public agency.

For example, District prohibitory rules frequently require that source operators install control equipment on emission units such as tanks, steam generators, turbines, etc. Installation of the control equipment requires the issuance of an Authority to Construct (ATC) permit which typically involves discretionary approval of an "emission control plan" and control equipment. Depending on the control measure, a source operator could be required to retrofit literally hundreds of individual emission units. The District response to our concerns is summarized below:

> *"The current definition of a development project adequately addresses projects that have ancillary discretionary approvals relating to the project. The applicability of the rule includes not only discretionary approvals but, minimum sizes of projects that must comply with the rule."*

WSPA is confused by the meaning of the first sentence. WSPA requests that the District provide additional explanation of how the current definition of a development project addresses "ancillary discretionary approvals relating to the project".

WSPA assumes that the language contained in the second sentence of the District response means that the District believes that equipment retrofit projects (e.g. steam generators, vapor control systems, etc) are too small to trigger rule applicability. In some cases this may be true. In other cases the size of the control system or facility equipment could easily exceed size threshold specified for industrial sources.

The existing New Source Review Rule (Rule 2201) and many of the prohibitory rules adopted by the District recognize the difference between projects initiated for development and projects undertaken to comply with regulatory requirements. Consequently, WSPA is again requesting that the definition of a development project be revised as follows;

3.7 Development Project: any project, or portion thereof , that is subject to a discretionary approval by a public agency, and will ultimately result in the construction or reconstruction of a building, facility or structure. The Discretionary approval of a project undertaken solely to comply with a rule regulation or order of a public agency shall not be considered a development project.

WSPA also requests that the District staff report clarify the meaning of the word "facility". The use of the word units current context is consistent with the logical meaning of the word and implies that the word "facility" means *"something that is installed or erected to serve a particular purpose".*

RESPONSE: The definition of a development project, in combination with the baseline definition ("area source and operational emissions") effectively eliminates the type of projects the author is commenting about. Permitted equipment emissions are *not* included in the calculations. It is the District's position that all applicable projects that have a baseline above two tons per year of NOx or PM10 from the combination of area and mobile sources should be subject to the emission reduction requirements of the rule, excepting for stated exemptions, regardless of the reason for the project.

176. COMMENT: IV Exemptions

WSPA requests that the exemption section of the rule be revised to include the following changes:

Section 4.1.4

The District has proposed an exemption for a, "development project, whose primary source of emissions are from stationary sources subject to Rule 2201 (New and Modified Stationary Source Review Rule) or Rule 2010 (permits required…". WSPA supports the proposed exemption. However, WSPA requests that the District clarify several items related to the exemption.

First, in response to questions raised by stakeholders during the September 1, 2005 workshop, District staff stated that they though the phrase "primary source of emissions: meant 51% or more of the emissions. Second, in our reading of the proposed exemption we interpret the phrase "stationary sources" to mean air pollutant emitting activities, other than indirect sources and area sources; and not "stationary source" as defined by District Rule 2201.

Assuming our interpretation is correct, then the proposed exemption would be available to development projects where operational emissions from activities other than indirect sources or area sources, comprise 51% or more of the total operating emissions from the development project.

WSPA requests that the District address these issues in their staff report and either confirm our understanding of how the exemption will be applied or provide additional guidance on how subsection 4.1.1 is to be interpreted.

RESPONSE: The District has clarified the exemption section to provide more specifics on the applicable sources that qualify.

177. COMMENT: V Application Requirements

WSPA continues to believe that applications for development projects be submitted to public agencies prior to the effective date of the proposed rule should continue to be processed under the regulations in effect at the time of application submittal. Consequently, we have requested revisions to the applicability section of the rule to be revised accordingly.

Subsection 5.5.5

Delete Subsection 5.5.5. This subsection requires that mitigation, monitoring and reporting programs (MMRP) include provisions for failure to comply, such as stop work authority, permit revocation, civil enforcement, and or administrative appeal. WSPA believes that this subsection should be deleted. The District already has authority to enforce compliance with rules and regulations adopted by the District.

RESPONSE: The District will revise the section to refer to Response to Comment 180, which states the District's authority to enforce provisions of the rule.

178. COMMENT: VI Mitigation

WSPA continues to believe that H&SC Section 477.16 and 47717.5 limit indirect source review programs to control growth induced emissions from indirect sources and area sources. Mitigation should only be required to the extent that a development project causes an increase in indirect emissions or an increase in area source emissions that would not otherwise occur. As we discussed in our prior (July 22, 2005) comments on Rule 9510, WSPA supports the District proposal to allow developers to use a combination of onsite mitigations and offsite mitigation. Developers should also be able to use offsite mitigation resulting from voluntary control of operational emissions from existing development projects upon showing that the emission reductions are surplus and enforceable.

In our July 22, 2005 comments WSPA requested that the District provide a mechanism to enable developers to receive credit for surplus mitigation. We also requested that developers be allowed to provide offsite mitigation by controlling emissions from existing sources through enforceable offsite mitigation programs. Our prior comments are summarized below.

1. For construction emissions, if a developer employs an offsite mitigation strategy, the emission reductions continue to exist after construction is completed. These reductions should be credited to the developer and the developer should be allowed to use the reductions for mitigating construction emissions from future development projects.
2. For operational emissions, developers should receive credit for offsite emission reductions created through voluntary mitigation activities applied ot

previously approved projects. For example, a developer could revegetate or reclaim disturbed surfaces in order to reduce fugitive dust. The developer could then commit these reductions to construction or operational emissions from proposed development projects.

The District response to our comments was:

"The District will consider offsite mitigation proposed by a developer on a case by case basis.".

Based on the District's response, WSPA requests that he District revise Subsection 6.3 as follows:

Subsection 6.3

The requirements listed in Section 6.1 and Section 6.2 above can be met through any combination of onsite or offsite mitigation. Developers may also satisfy the requirements of Section 6.1 and 6.2 by providing mitigation made available by reducing emissions from offsite activities. "the District will consider offsite mitigation proposed by a developer on a case by case basis."

RESPONSE: The District has partially addressed the authors concerns in the September 1, 2005 draft Rule 9510 version in section 7.4.

7.4 The developer shall receive credit for any off-site mitigation measures that have been completed and/or paid for, prior to the adoption of this rule, if the following conditions have been met:

7.4.1 The prior off-site mitigation measures were part of an air quality mitigation agreement with the APCO; or

7.4.2 The developer demonstrates to the satisfaction of the APCO that the off-site emission reduction measures result in real and surplus reduction in emissions**.**

The District will be implementing an off-site emission reduction program that uses fees from the rule to achieve the tonnage reduction required. The District believes that this is the most efficient and effective way to acquire, achieve and track off-site emission reductions. Off-site emission reduction projects that have been coordinated and approved through the District by means of an Air Quality Mitigation Agreement have been thoroughly analyzed and will be administered by the District. Therefore, emission reductions from Air Quality Mitigation Agreements are appropriate to use in the ISR program. However, although a project applicant may be able to find and fund off-site emission reduction projects, it is undesirable to have an applicant administer off-site emission reduction projects to be reviewed by the District on a case-by-case basis. For the purposes of consistency, efficiency, and enforceability, it is most appropriate for off-site emission reduction projects to be administered under the same program.

Applicants and the general public may propose projects for funding through the District's off-site emission reduction program, and the program will have annual review and reporting available to the public.

PUBLIC:

Ann M. Gallon
Date: September 6, 2005

I attended the Sept. 1 Workshop in Bakersfield. This was my first involvement with the Air Pollution Control District. I planned to address you as a private citizen, but all the developers with lengthy statements were a bit intimidating – especially their off screen head nodding and grimacing. They obviously were distressed to have any "controls" of their development projects come under discussion and regulation.

179. COMMENT: What I would have said is that I applaud your plans to contain pollution in our Valley, and I would urge you to stick to your guns – or even tighten up on some rules. As an aside, my stepson once sued the EPA on behalf of the Canadian people for not enforcing their own regulations and causing acid rain which drifted over Canada. The Canadian government prevailed in calling the EPA into action.

RESPONSE: Comment Noted.

180. COMMENT: Applicability to developers of 50-plus residential homes gives them wiggle room to design multiple projects so they could fall under that 50-unit threshold. Another concern of mine is that developers of fewer than 50 units may be less sophisticated in the industry and may create more pollution than you will prevent in the larger developments. I urge you to consider dropping the applicability to 25 units.

RESPONSE: The 50-unit applicability for residential units was specifically chosen for the following reasons:

1. Based on the District's data on the number and units of development occurring in the valley, a threshold of 50 units would capture the majority of the pollution generation from new developments while keeping the number of projects for District assessment at a practical level.
2. Modeling shows with no on-site measures, 50 units may generate approximately 2 tons per year of NOx in 2006
3. This threshold, with the associated 'penetration' of the rule, achieves the emission reductions committed to in the PM10 and ozone plans.

The District will be vigilant to prevent 'piecemealing' of projects to evade compliance with the rule. Rule 9510 §2.3.1 and §2.3.2 specifically address the issue of contiguous or adjacent properties. In addition, District Rule 1110 (Circumvention) states:

A person shall not build, erect, install, or use any source operation, the use of which, without resulting in a reduction in the total release of air

contaminants to the atmosphere, reduces, dilutes or **conceals an emission which would otherwise constitute a violation** of Division 26 of the Health and Safety Code of the State of California or **of these Rules and Regulations**. This rule shall not apply to cases in which the only violation involved is of Section 41700 of the Health and Safety Code of the State of California or of Rule 4102 (Nuisance of these Rules and Regulations. **Violation of this rule is a misdemeanor pursuant to the provisions of Section 42400 of the Health and Safety Code of the State of California**.
(Sections are bolded for emphasis)

181. COMMENT: To give you an example of development traffic, in July we endured seven days of 8am-4pm diesel truck traffic past our home. Trucks were hauling fill dirt to one large residential lot around the corner from us. The whole week we had to remember to close our front windows against the diesel fumes, noise, and dust clouds rising from dirt shoulders.

Mind you, this was a HOT July and we were trying to use just our evaporative cooler (needs open windows to vent) to save money. When the truck traffic continued into the next week I finally called our Supervisor's office to complain and ask if the trucks could travel on the arterial roads instead of on our residential street. I wrote down the following IN and OUT times one morning for 30 minutes:

IN	OUT
	9:35
9:39	9:41
9:44	9:48
9:51	10:01
9:58	10:09
10:05	

By Wednesday, when Supervisor Watson's field rep, Trice Harvey, arrived at our house to look into our complaint, wouldn't you know it – the truck traffic was over. And he said he couldn't tell trucks which roads to take to a construction site. We were going to be pretty much stuck with traffic when there is building going on in our area.

RESPONSE: The author's comments on truck traffic is noted. In addition, the District's Regulation VIII (Fugitive PM10 Prohibitions) contain prohibitions concerning the emissions of dust from construction sites, bulk materials hauling and carryout/trackout. Although these are requirements, certain developments on occasion do not comply with the rule. The District is responsible for enforcing compliance with the rules and employs field inspectors for these issues; however, it is not always possible to catch violations as they occur at the widely disbursed construction sites within the Valley. The District maintains a complaint

hotline for the public to call when they see a violation of the District's rules, including violations of Regulation VIII and Rule 4102 (Nuisance).

County of Residence	**Toll Free Number**
San Joaquin, Stanislaus, Merced	**(800) 281-7003**
Madera, Fresno, Kings	**(800) 870-1037**
Tulare, Valley portion of Kern	**(800) 926-5550**

182. **COMMENT:** So… please stand firm with the building industry – and with Cal Trans who seemed to think they were exempt from air pollution regs – and let's ask everyone to take their share of the responsibility for cleaning up OUR AIR.

RESPONSE: Comment Noted.

183. **COMMENT:** PS That argument of one man about mitigation fees of $2000 pricing thousands of people out of homes in California was statistical but not logical. If they can *only* qualify for a $300,000 home and the $2,000 fee is going to put them "out of the market," then they can just drop their expectations and builder options and by a home for $295,000. Also, it is bad financial planning to try to buy the most expensive house you can qualify for.

RESPONSE: Comment Noted.

ENVIRONMENTAL

Clean Water & Air Matter (CWAM)
Date: September 15, 2005

Thank you for the opportunity to comment on the above mentioned draft rules as proposed for the District. In addition to my verbal comments made during the September 1, 2005 workshop, I wanted to touch on the following topics.

184. COMMENT: No net gain does not equal a loss. When we begin to mitigate more pollution than we create while adding new pollutants, we will finally begin to achieve reductions in total pollutant levels. Until this happens, we are still adding to the pollutant total without ever actually subtracting anything.

RESPONSE: The author's comment does not hold when applied to mobile emissions. Emissions from mobile sources are reducing over time due to regulations on new vehicles. For example, no net increase in the number of vehicles would result in lower future emissions from vehicle turnover to cleaner fleets. The District takes this and other factors into account in the PM10 and Ozone attainment plans. The plans identify growth and reductions in source categories. The plans quantify the reduction from current District rules and proposed rules as well as state and federal regulations, and then model future emissions to determine if the District may reach attainment for applicable pollutants. For development projects, the 'subtracting' occurs through on-site and off-site emission reductions *and* mobile emission reductions over time. The PM10 and Ozone plans have determined that the ISR rule, in addition to existing and future rules and conditions, will help the Valley clean the air and reach attainment.

185. COMMENT: The Californian Environmental Quality Act (CEQA) is very clear when it comes to mitigation measures and how they must be available for public review before the decision makers (who also must have them for review) vote on the project. In reference to Section 5.0 Application Requirements it is imperative that the mitigation measures not be deferred until after project approval.

In Sundstrom v. County of Mendocino (1st Dist. 1988) 202 Cal. App. 3d 296 [248 Cal Rptr. 352] the court ruled that the deferral of an environmental assessment (in this case a hydrological study) until after the project approval violated CEQA's policy that impacts must be identified before project momentum reduces or eliminates the agency's flexibility to subsequently change it course of action. In addition, because the permit authorized the applicant himself, subject to planning staff approval, to conduct the required analysis, the county had violated CEQA's requirement that an agency's decisionmaking body must ultimately review and vouch for all environmental analysis mandated by CEQA. (202 Cal.App.3d at 306-308]

RESPONSE: Rule 9510 §5.0 has been revised to make application and review of ISR projects concurrent with or prior to the CEQA process a project would undertake with the local land use agency. It should be noted that the ISR program does not involve discretionary approval and therefore not itself a CEQA process. Additionally, compliance with District Rules is a *requirement,* not mitigation.

186. COMMENT: Furthermore, local agencies are instructed to integrate the CEQA review process into the other planning and environmental review procedures they are legally or otherwise obligated to conduct. To the maximum extent feasible, CEQA procedures and other procedures should run concurrently, rather than consecutively. (Pubic Resources Code Section 21003 subd. (a).) Regarding Comment #50- CEQA is a state law and does not vary by jurisdiction. This comment should be changed.

RESPONSE: Concerning timing of application to the ISR program, see the response to comment above. Although CEQA itself does not vary by jurisdiction, the implementation of the time requirements does. CEQA provides the master timeline in the framework of minimum and maximum times for various activities. Each jurisdiction has the authority to implement CEQA with procedures that reduce a particular activity's time to far below the maximum time allowed under CEQA. Therefore, each jurisdiction may have a different timeline for project review and approval based on individual procedures that comply with CEQA. The District will not change response to comment #49 from the June 30, 2005 workshop.

187. COMMENT: While there are exceptions, contextually, the agency is creating a broad, sweeping plan to cover many projects, including but not limited to, commercial, industrial and residential. Consideration of public involvement in the process would facilitate information regarding mitigation at the beginning of the process, rather than after the project has been approved.

This issue, when addressed early in the application process can carry over to all levels of approval, rather than have the public or decision makers continually have to request effective, enforceable mitigation as part of the project not only with the lead agency, but the responsible agency as well.

RESPONSE: While the District concurs that public involvement is important, and will amend the rule and staff report to include mechanisms for public involvement, the ISR program is *not* a CEQA process. ISR is a ministerial action not subject to CEQA, per PRC §21080 *Division Application to Discretionary*

Projects; Nonapplication; Negative Declarations; Environmental Impact Report Preparation (b)(1):

(b) This division does not apply to any of the following activities:
(1) Ministerial projects proposed to be carried out or approved by public agencies.

188. COMMENT: There should be some method for the dispersal of funds to account for project area pollutants and either the on-site or near-by mitigation funded by said project. Money going into the big pot in Fresno and ending up who knows where, by some group that has asked, will not address source point pollution.

RESPONSE: The District will track the location, by City and County, of the projects funded through the off-site emission reduction fund. The District will also complete annual reporting of how much, where and what tons of reductions occurred, which will be made available to the public. The District is unsure of the author's intent with the comment on point source pollution. This rule does not attempt to address emissions from source points. However, if an off-site emission reduction project is a point source, that information will be available in the District's annual reporting, and upon request.

189. COMMENT: Regarding the pollution prevention proposals, it would a be beneficial to have some long-term pollution reduction by means of phyto-remediation. Trees are known, quantifiable and effective pollution reduction technique. The use of trees should be encouraged to help cleanse the valley air. This mitigation could be achieved with tree farms using mitigation banking credits for a controlled system of distribution.

RESPONSE: The District is aware of the air quality benefits of trees. Specifically, trees reduce ambient temperature (reducing formation of ozone), cool housing and AC units (reduce energy consumption), cool cars and paving in parking lots (reduced evaporation of volatiles[6]). It is also known that some of these benefits are quantifiable. The District would entertain a tree program as an off-site project if it meets the requirements set forth in the rule, including cost effectiveness.

190. COMMENT: Enforcement of air quality mitigation measures is the responsibility of the District. I mention again in these comments a critical issue: Currently the district is notified of a project's start when there is a complaint filed by a member of the public. While this is not always the case, this type of complaint based enforcement system is inefficient as best and at worst, a heavy burden on the public to be responsible to see that the approved mitigation measures are actually followed or the best possible attempt to prevent more air pollution

6 McPherson, E. Gregory. Sacramento's parking lot shading ordinance: environmental and economic costs of compliance. Landscape and Urban Planning 57 (2001) 105-123

RESPONSE: The District is notified of the start of a project through several means. The CEQA process allows an opportunity for the District to review and comment on development projects within the Valley. The District also receives Dust Control Plans (DCP) and Notifications from project developers as a *requirement* of Regulation VIII (Fugitive PM10 Prohibitions). It should be noted that District rules are *requirements* and not mitigation, and the District has the authority to take enforcement action for non-compliant projects. The District is notified of Regulation VIII non-compliance through mandatory self-reporting (DCPs, etc.)

191. COMMENT: Additionally, it would be beneficial to both the public and all decision makers reviewing environmental air quality assessment to have the inputs for the baseline for the modeling runs at the beginning of the reports and if the report is quoted in the document, in the text of the document as well.

RESPONSE: The preparation of environmental CEQA documents is the responsibility of the lead agency. The District will make project specific information available to the lead agency and the public (See Response to Comments #8 and #59), but the District cannot prescribe a format that lead agencies must follow.

Kern-Kaweah Chapter of the Sierra Club
Date: September 15, 2005

Here are the comments of the Kern-Kaweah Chapter of the Sierra Club. Our chapter has 1,600 members and there are a few thousand other Sierra Club members in the San Joaquin Valley.

My copy of the September 1 draft is post marked August 26. Does the Air District Staff believe in summer vacation and Labor Day Weekend?

Instead of including our July 15, 2005 letter by reference, we put chunks of it in this letter and put the rest at the end of this letter.

GENERAL REMARKS ON THE RULE

192. **COMMENT:** At the September 1 workshop I learned that air quality regulations forbid the development industry from sheltering those of us with low or even moderate incomes. At previous workshops I learned that air quality regulations prevent farmers from feeding us and prevent various industries from affording to employ us. Perhaps the best plan is for residents to continue to suffer asthma and for those who die prematurely of heart or lung disease to be eulogized as "heroes of the economy".

RESPONSE: Comment Noted.

193. **COMMENT:** Our previous comments applauded 6.1 "The developer shall mitigate 100% of the construction emissions associated with its development project." Construction emissions do not last as long as operational emissions, but exposure to pollution is the same whether the pollution is from construction or from operation; thus, mitigation for construction emissions should be briefer and equally vigorous as construction from operation.

RESPONSE: The draft rule does not require 100% mitigation from construction. Rule 9510 Section 6.1.1 states that exhaust emissions must be reduced from the statewide average by 20% for NOx and by 45% for PM10.

194. **COMMENT:** We object to having developers choose consultants to prepare an Air Impact Assessment; we think consultants will not be chosen by developers unless they make findings as favorable to the developer as possible. The air impact assessment must be produced by the District or by a consultant of the District's choosing. Developers shall pay for the air impact assessment.

RESPONSE: The District will require all inputs and assumptions for the Air Impact Assessment, per the requirements of the rule. This information is contained in the application. The District will review the inputs, assumptions and modeling for accuracy, and will require additional information and/or revision for items that are inaccurate, inconsistent or unjustified. The modeling must be replicable and reasonable, and the emission reduction measures selected must be incorporated into the project and enforced through either other public agency requirements or by a District Monitoring and Reporting Schedule.

195. **COMMENT:** I did not find anything about mitigation by replacing inefficient equipment. Our July 18, 2005 letter said: "If existing equipment is replaced because it is worn out, no mitigation credits must be given unless the new equipment is better than other equipment that could be used. The mitigation credit must be limited to the difference in cost between the cheapest equipment that could have been obtained and the lower emitting equipment that was obtained."

RESPONSE: It is unclear if this comment pertains to on-site emission reduction or off-site emission reductions. For on-site emission reductions from construction, no justification is necessary to achieve credit for cleaner engines. For off-site emission reductions, the reductions will be achieved through the ISR off-site funding program, which will follow criteria and established emission reduction calculations. For programs that replace existing engines with new engines, the old engine must be operational and have a remaining useful life that is the basis of the emission reductions. How those emission reductions are calculated depends on the type of project and the specific components of the project. See the Staff Report and Appendix E – Cost Effectiveness Analysis for additional information on off-site emission reduction projects.

GENERAL REMARKS ON THE NOx REDUCTION OF THE RULE

196. COMMENT: Rule 9510 sets the goal of reducing emissions from projects that produce more than two tons per year of NOx by half. There is no justification for mitigating only 50% of emissions. Reducing NOx by half, rather than complete reduction, would be acceptable if all trips to or from the regulated development projects were to other projects that also reduced their NOx emissions by half. For the most part, rule 9510 regulates new development projects on the edge of town; most of the trips associated with those projects will be to or from long established business, recreational or work sites that have never paid any air quality mitigation fee and have no on site mitigation. If the trip to those sites had been made from an older development nearer the established sites, air emissions would be less. That is why the goal should be complete mitigation for all polluting emissions from all sources including Area Sources.

RESPONSE: The goal of the rule is to achieve an emission reduction from growth that was identified in the PM10 and ozone plans. The District calculated the level of reduction needed on a per-project basis that would achieve the emission reduction committed to in the PM10 and ozone attainment plans. The rule sets levels that are in compliance with state law regarding indirect source regulations and are feasible to achieve. Charging a fee for trips that are the responsibility of another new source or an existing indirect source would not equitably distribute responsibility for existing and new vehicle trips as required by H&S 40717.5. The 33% accounts for declining mobile emissions over a ten year period – see the fee formula.

197. COMMENT: How much NOx will future vehicles make? When will increased gasoline prices cause us to use fewer light trucks and more efficient sedans? The staff report, bottom of page 3, says cars are predicted to decrease pollution between 1994 and 2003. Has this occurred?

RESPONSE: NOx emissions were reduced substantially between 1994 and 2003; however, certain heavy-duty diesel vehicles showed an increase during that period due to use of computer controls that enabled the vehicles to meet emission tests but emit at higher levels during actual operation. This problem has now been corrected. The amount of future NOx is identified in Attachment 2 of Appendix B – Emissions Reduction Analysis for Rule 9510 (ISR). Studies of the effects of gasoline prices indicate that very large price increases would be needed to significantly change travel behavior.

198. **COMMENT:** Here are examples where rule 9510 may cause someone to pay more than their share to mitigate air quality. Someone might move to a newly built home in order to take a job near that home; they would create emissions only when they drove to established business, recreational sites not I their new neighborhood or visited persons living a distance from their new home. A retired person who moved to a newly built home in order to be near the people they most often visit would generate fewer emissions than most of those who move to a newly built home. These exceptional cases do not seem to justify making this rule weaker or more complex.

RESPONSE: The District recognizes that there are a variety of factors that affect emissions from new projects. It is infeasible to model or account for all this variation at the development stage. In addition, there is no guarantee that those cases of less-emissions, same-house would occur over the ten years assessed by the rule, let alone the life of the project. The District considers the URBEMIS model to be the most accurate model available that meets the needs of the ISR rules. More information on URBEMIS may be found in the Staff Report and in Appendix D – Recommended Changes to URBEMIS.

APPENDIX A: RESPONSE TO COMMENTS

Industry and Public:

199. **COMMENT:** Comment 1 Each individual development must be held responsible for all the travel it generates. When persons move to the edge of town from a site closer to the center of town, their old home is occupied; the emissions of their old home do not change. The emissions of their new home must all be mitigated. Consider a mitigation fee for those who move into an existing home that is further from the center of the City than their previous home.

RESPONSE: The District agrees that each individual development should be responsible for the trips it generates, but also must consider that the reductions required must be fair and feasible. The District may consider a future rule revision or other program to address existing indirect sources.

200. **COMMENT:** Comment 7 If the emissions of a structure continue beyond ten years, so should the mitigations. Can the air district prove that cleaner cars will allow us to attain PM 10 and ozone standards in ten years and prevent increased emissions thereafter? What if attainment in does not permanently occur?

RESPONSE: The mobile source regulations currently in place and scheduled to go into effect in the next few years provide for a cleaner car and truck fleet well into the future even when accounting for projected growth in trips and vehicle miles traveled. Continued diligence will be required to ensure maintenance of the standards. This is accomplished through a maintenance plan that will provide the reductions needed to keep emissions from increasing due to growth.

201. **COMMENT:** Comments 11 and 18 Response 11 correctly anticipates new standards. Response 18 implies that PM 2.5 is not likely to be one of those new standards because attaining PM 10 standards will control PM 2.5. So far it looks like a lot of PM 10 is geologic particulates that are not as harmful as the smaller particles included in PM 10. The smaller particles, PM 2.5, are products of combustion or are a combination of ammonia and NOx. If so, decreasing PM 10 will not decrease PM 2.5.

RESPONSE: The rule is designed to reduce both fugitive dust PM10 and combustion PM10. Most engine replacement and retrofit projects provide NOx and PM10 benefits. Most of the combustion PM10 is comprised of the fine fraction less than 2.5 micrometers in diameter. The PM10 standard cannot be achieved without fugitive PM10 reductions and so must be part of this rule.

202. **COMMENT:** Comment 25 Some recreational space reduces motor vehicle use, such as a park that many persons can easily access on foot or by bicycle. Some recreational space increases motor vehicle use, such as a motocross facility or any facility that attracts visitors from a distance.

RESPONSE: Recreational uses that attract vehicle trips and exceed the operational threshold of 2 tons/year of NOx or PM10 will be subject to the rule. Uses that attract pedestrians or bicyclists would not trigger the rule.

203. **COMMENT:** Comments 67 and 70 The Socioeconomic impact of these rules must include the decrease in the cost of illness and death that this rule will cause. The cost of illness includes pain, suffering, premature loss of income, absence from school, absence from work and loss of companionship. To estimate the incidence of these events, please consult physicians who have reported such figures to CARB; for example, there are 106,695 workdays lost in Kern County due to PM10.

RESPONSE: See Response to Comment #98.

204. **COMMENT:** Comment 87 I do not bicycle on very hot days and most folks stay indoors those days. When I do bicycle on days of elevated ozone levels, I expose myself to ozone rather than use my car to raise ozone levels for everyone else. There are, or would be if bike paths are constructed, many persons as virtuous as I.

RESPONSE: Comment Noted.

205. **COMMENT:** Comment 96 Mitigating air pollution as close as reasonably possible to the source of the pollution may be more acceptable to the public than distant mitigation; however, insistence on mitigating in the immediate area can be used as a way to make mitigation more difficult.

RESPONSE: See Response to Comment #188.

206. **COMMENT:** Comment 98 Limiting mitigations to those that match the source of the mitigations can be used as a way to make mitigation more difficult. A ton of NOx generated by Valley traffic is the same as a ton of NOx mitigated by reducing Valley generation of electricity from fossil fuel.

RESPONSE: See Response to Comments #188.

207. **COMMENT:** Comment 102 As inflation and the completion of the most cost effective measures occur, how will mitigation fees be increased?

RESPONSE: Off-site fees are dictated by the amount it would take to offset a ton of the applicable pollutant. The District has included the fee schedules for 2006 through 2008. If an adjustment is required, for example, if during implementation the District finds that there aren't enough off-site projects achieve the set cost-effectiveness, the District can amend the cost-effectiveness schedule in the rule through a rule amendment. Rule amendment procedures are standard, and must be adopted by the Board.

EPA

208. **COMMENT:** Comment 7 p. A 25 Is EPA completely satisfied with this response to their thoughtful comment?

RESPONSE: See Response to Comment #5 for additional comments to the issue of surplus mitigation.

209. **COMMENT:** Comment 18 p. A 28 A high density residential project far from jobs, shopping, schools and other services does not decrease emissions except for trips between residents. A high density project that enables residents to

access jobs, shopping, schools and other services on foot, bus or bicycle decreases emissions and should get credit for on site mitigation.

RESPONSE: See Response to Comments #7 and #9 for discussion on URBEMIS on-site measure quantifications.

210. COMMENT: Comment 36 p. A 30 We are pleased that low-income housing is not exempt from the rule. Low-income housing often has elderly residents whose diseased lungs and hearts are especially susceptible to air pollution. Government can help pay the small cost of clean air for poor people if the voters wish.

RESPONSE: Comment noted.

Remarks On The Wording Of The Rule

211. COMMENT: 1.1
Does the reference to "particulate matter" include PM 2.5 and the smaller particles such as PM 0.1 that can be inhaled from ambient air into the blood stream? Comments 11 and 18 apply: Response 11 correctly anticipates new standards. Response 18 implies that PM 2.5 is not likely to be one of those new standards because attaining PM 10 standards will control PM 2.5. So far it looks like a lot of PM 10 is geologic particulates that are not as harmful as the smaller particles included in PM 10. The smaller particles, PM 2.5, are products of combustion or are a combination of ammonia and NOx. If so, decreasing PM 10 will not decrease PM 2.5.

RESPONSE: See Response to Comments #57 and #65 for the Districts response to which pollutants, and how much reduction was chosen.

212. COMMENT:2.1.8
Comment 25 applies: Some recreational space reduces motor vehicle use, such as a park that many persons can easily access on foot or by bicycle. Some recreational space increases motor vehicle use, such as a motocross facility or any facility that attracts visitors from a distance.

RESPONSE: The Air Quality Impact Assessment uses URBEMIS to calculate mobile source emissions from each project. URBEMIS uses trip generation rates for each type of use and allows for different trip rates to be used for different types of recreational facilities. This will allow for an accurate differentiation between the uses mentioned in the comment.

213. COMMENT: 2.3.1 & 2.3.2
We wish to thank whoever brought to your attention that the draft of 9510 dated June 30, 2005 did not address cumulative impact of adjacent development.

These paragraphs at least call our attention to this failing. As I understand 2.3.1 & 2.3.2, if I had one piece of land big enough to build 147 units, I could build 49 residential units that rule 9510 would not apply to. Then, in lieu of inheritance I could give each of my two children land so that they each build 49 residential units. We would thus build 147 residential units without having to comply with rule 9510. No one would ever know if I benefited financially from my children's property.

RESPONSE: See Response to Comment #214.

214. COMMENT: The only way I can write rule 9510 to avoid this problem and avoid high administrative cost is to say that even one house will be subject to this rule but that small tracts can pay a mitigation fee, rather than have their emissions determined and mitigated.

Our comments of July 18, 2005 on 2.2 and 4.2 of rule 9510 are included here:

The rule should apply to even the smallest projects so that developers do not piece meal. Building many little developments can have a major cumulative effect; CEQA has cumulative impact concerns. Among the 6 30 05 comments that supported not omitting projects that make only two tons of NOx and only two tons of PM 10 per year was one by a City of Clovis employee who forecast developments of 49 houses. Dr. Nipp has commented on over a dozen housing developments that somehow had just under ten tons per year of NOx and just under ten tons per year of ROG. Several years ago several natural gas 48 or 49 MW cogeneration power plants were built in Kern County; 50 MW plants had to be reviewed by the California Energy Commission.

These exemptions could also increase administrative costs and give some developers an advantage over others. What happens if soon after a new 20,000 square feet store is occupied, it fails or for some other reason becomes general office space? The store has paid a fee that it would not have paid if it had been built as general office space.

Please disregard our next paragraph of July 18, 2005; it is in error. It read: The rule could say that if a project is small, and no developer has enough land at the site to develop any other source of emissions small projects could be exempted.

RESPONSE: The District added rule language that prohibits piecemealing of projects to evade the applicability threshold. In addition, the District will implement procedures for identifying non-compliant projects and will have staff assigned to ensure compliance with the rule.

215. COMMENT: 3.22 & 3.23
In view of the decrease in emissions that will result from replacing some of our private auto travel with public transit, we might need to mitigate emissions form public transit construction less stringently than emissions from other construction. Since building new roads leads to more car and truck use, and therefore more pollution, road building emissions must be strictly mitigated.

RESPONSE: The District has determined that transit projects involving construction in excess of 2 tons total of NOx and PM10 combined should remain subject to the rule.

216. COMMENT: 4.1.4
Agriculture should be among these exemptions provided it is regulated under other rules as provided in the SB 700 series of bills.

RESPONSE: See Response to Comment #45.

217. COMMENT: 4.3
Transportation Projects should not be exempt from the requirements of the rule. If more roads, as opposed to mass transit, are made available, more people will use the roads rather than mass transit. This is called induced traffic. If bicycle paths and mass transit become available, some of us will choose to use them.

RESPONSE: The District specifically exempted transportation projects from the 'operational emission reduction requirements of the rule. Transportation projects are subject to the construction emission reduction requirements of the rule. Although not part of this rule, the District may consider including operational and area requirements in a future rule or rule amendment.

218. COMMENT: 5.0
CEQA provides that information such as provided by an AIA be available to the public and to decision makers before any discretionary action is approved. Please change the first sentence of 5.0 so that if complies with the CEQA.

RESPONSE: The District intends to submit air quality impact assessments to local agencies so that they may use them in their CEQA documents prepared for the land use approval. Although the rule provides analysis and emission reductions that will be useful in the CEQA process, the main focus of the rule is attainment of PM10 and ozone standards. (See Response to Comments #8 and #59). Also keep in mind, the ISR program is not discretionary approval and therefore *not* a CEQA process (See Response to Comment #187).

219. COMMENT: 5.1
Any consultant involved by any developer must be identified.

RESPONSE: The District will amend the rule language to include the above.

220. COMMENT: 5.4.1.1
Does this say that any mitigation required by laws existing before a development occurs can not be counted as an indirect source mitigation under rule 9510? We hope the answer to this question is "yes". The Air District intends to obtain agreed upon mitigations, as 5.5.6 shows.

RESPONSE: Any on-site measure that is quantifiable through the APCO approved model shall be counted towards on-site emission reduction. Only measures that do not have an enforcement mechanism through city/county or other requirements will be required to complete a monitoring and reporting schedule with the District.

221. COMMENT: 6.1.1
Are a 20% reduction in NOx emissions and a 45% reduction in PM10 emissions all developers are reasonably capable of, or is it just enough to attain a CAA standard deadline? Why does the Federal Clean Air Act allow areas like Bakersfield, that fail to attain daily 8 hour ozone standards on more days than any other place in the USA, to employ RACM, not BACM?

Does the Air District intend to wait for 2007 to complete a plan to attain federal 8-hour ozone standards? If so, how do you justify this to children who can not play outdoors when there is too much ozone in the air?

RESPONSE: The emission reduction requirements were based on the availability of new technology that can achieve the results allowing for a reasonable period of time for equipment owners to phase in the cleaner equipment considering the high cost of large construction equipment and its long useful life.

The District is working as rapidly as it can on 8-hour ozone planning. We are currently working with a Northern California 8-hour State Implementation Plan Working Group to coordinate the modeling and other efforts to get the plans out on time. The atmospheric modeling now beginning is needed to identify the reductions required. The District continually works to identify control measures that can be adopted to achieve reductions as early as possible. The District's goal is to complete the 8-hr plan in the spring of 2007.

Appendix C: On-Site Mitigation Checklist

222. **COMMENT:** Except for push mowers, this is identical to our July 18, 2005 letter. Local office holders must be tested on various parts of appendix C and recalled if they fail.

RESPONSE: Comment Noted.

223. **COMMENT:** 1 Bicycle Infrastructure:
Class II bike lanes on arterial/collector streets are more dangerous than class I.

RESPONSE: Comment noted. The corresponding URBEMIS mitigation component states "Percent of Arterials/Collectors with Bike Lanes: Or Where Suitable, Direct Parallel Routes Exist." 'Bike Lane' is the Class II category. 'Bike Path' is the more desirable Class I category. In addition, the District believes appropriate "complete street" planning adequately addresses the issue of safety.

224. **COMMENT:** 7 Pedestrian Oriented Infrastructure:
Place store entrances just off the sidewalk. Folks dislike walking across busy, un-shaded parking lots.

RESPONSE: The District will add the above to the items listed under "Pedestrian Oriented Infrastructure"

225. **COMMENT:** 16 Parking
Some employers offer employees about $40/month in lieu of free parking; employees who accept are left to choose among transit, bicycle, car pool, walking etc.

RESPONSE: This type of measure is appropriate for projects where the building tenant is known at the time the project review is accomplished. It could be included as an employer Transportation Demand Management Program. The emission reductions will depend on individual measures that the employer will implement and the pedestrian, bicycle, and transit service at the project site.

226. **COMMENT:** 25 Energy Efficiency
Provide space for outdoor passive solar clothes dryers, once known as wash lines and space for portable indoor drying racks.
Shaded, reflective or white roofs are not as good as the items you mention, but they are better than dark, unshaded roofs. Roof overhangs that shade windows in summer decrease heating costs.
Water heater should be located in most sinks so that a central hot water heater does not need to be turned on just to get hot water in one sink.
Provide fluorescent lighting, including compact bulbs.

If air conditioners, rather than swamp coolers, are insisted upon, they should be placed on the ground, north of the building, in the shade.

RESPONSE: The items listed above relate to the individual components that may increase energy efficiency. The On-Site Emission Reduction List contains the following measure:

> *Increase the building energy efficiency rating above what is required by Title 24 requirements. This can be accomplished by any combination of the following (this list should not be considered comprehensive):*

The list mentioned is an 'idea list' to inform the applicant of the variety of components that are available. The District will amend the list as additional energy-saving components are identified.

227. COMMENT: 47 Landscaping
At least let folks know push mowers are available at stores and they lower body weight.

RESPONSE: The District has a Public Information Department that has an excellent track record in getting the word out on the many options available for individuals to reduce their air impacts.

Appendix F: Socioeconomic Analysis

228. COMMENT: We agree that the affect of rule 9510 on home prices and rents will be small if the assumptions of the study by "Applied Development Economics" are made. We think that in general and in the Valley's housing market, supply and demand have a much greater effect on price than costs do; therefore we think the rule will have negligible effect on prices.

Our remarks on comments 67 and 70 above apply.

RESPONSE: Comment Noted.

229. COMMENT: If rule 9510 results in increased use of public transit, it will decreases the amount of money spent on gasoline. Sixty per cent of America's crude oil is imported. If residents divert money from partly imported gasoline to local products and to paying the wages of those employed by public transit, it will increase the gross domestic product of the Valley except for a decrease in money going to local oil drilling and refining. Would the net of this have a significant effect on Valley incomes? What if we decrease crude imports without decreasing local crude oil production?

RESPONSE: The District believes that although the implementation of Rule 9510 will have some economic impacts, it also will have a potentially significant beneficial economic effect on the San Joaquin Valley's economy through funding

off-site emission reduction projects. For example, a PM10 project may be paving unpaved roadways. This could result in an increase in jobs. However, the District does not speculate on the rule's potential secondary impact on the petroleum industry due to increase or decrease in fuel use.

230. COMMENT: If society desires a certain rate of home ownership among those with lower income, or otherwise wishes to increase the standard of living for those with lower income society can subsidize their mortgage payments, pay more for their work or tax them less and tax others more.

RESPONSE: Comment Noted.

Environmental Defense
Association of Irritated Residents
Steven and Michele Kirsch Foundation
Union of Concerned Scientists
Latino Issues Forum
Relational Culture Institute
Center for Energy Efficiency and Renewable Technologies
Fresno Metro Ministry
Natural Resources Defense Council
Merced/Mariposa County Asthma Coalition
Earthjustice
Date: September 14, 2005

We represent national, regional and local environmental, public health, and community organizations that are actively engaged in finding solutions to the San Joaquin Valley's air pollution. We have been closely following the district's development of DESIGN (Rule 9510) and the accompanying air impact assessment application fee (Rule 3180). We believe that together these rules have great potential for reducing and mitigating air pollution that accompanies growth in the Valley.

As noted in the comment letter many of us signed regarding the June 30 version of the draft rules, we believe the two rules have great potential for improving the quality of life for everyone in the Valley, and not just through the direct benefit of cleaner air. The two rules can increase opportunities and incentives for affordable housing located near jobs; reduce the climb in daily vehicle miles traveled; reduce traffic congestion and encourage viable transportation choices; protect agricultural lands from encroachment; and be the first words in a regional conversation about how to best accommodate growth without increasing pollution.

We believe that the September 1 version of the draft rule is an improvement over the June 30 draft. We are pleased that the latest draft has more detail. We also appreciate the district's effort to prevent gaming of the rule by ensuring that projects on contiguous

or adjacent property under common ownership of a single entity will be treated as one project. However, we believe that overall, the current version still falls short of ensuring that the DESIGN program meets its full potential to reduce air pollution.

We urge the district to consider the following comments and make appropriate changes to the September 1 draft rule before submitting it to the board for approval.

231. COMMENT: Section 2.0 Applicability. The thresholds for the size of developments covered by the rule are too high. The thresholds appear to be set to cover developments that would be expected to produce two or more tons per year of pollution. Neither the staff report nor the draft rule provides any strong logic for ignoring developments that produce less than 2 tons but at least 1 ton per year. Leaving tons on the table unnecessarily reduces the rule's effectiveness and eliminates cost-effective opportunities to protect public health. The thresholds should be set to cover developments that produce 1 ton or more per year.

RESPONSE: See Response to Comments #57 and #180 for the District's determination of the applicability level.

232. COMMENT: Section 3.5 Definition of Baseline Emissions. The wording for this definition needs to be clearer. The current wording leaves it unclear whether the first year of the project or any phase of the project is included in the baseline emissions. Additionally, as we discuss below, the emissions covered should include reactive organic gases.

RESPONSE: See Response to Comment #91.

233. COMMENT: Section 3.14.7 Definition of Recreational. The definition is too inclusive. It should be refined to ensure that facilities within this category generate similar levels of pollution. A community park, for instance, does not generate the same amount of pollution as a movie theater. Movie theaters and fitness clubs are probably more appropriately included in commercial categories.

RESPONSE: See Response to Comment #88.

234. COMMENT: Section 4.1.5 Housing Projects Exemption. This definition needs to be clearer. It appears that the district is interested in exempting housing that would qualify as affordable housing and that is receiving public funding to ensure its status as affordable housing. However, the definition as it now stands could be interpreted as offering a much broader exemption, and including any housing that receives federal- or state-backed loans. The definition should be more clearly and narrowly stated to reflect the district's intent.

RESPONSE: The District has eliminated this exemption in the proposed rule.

235. COMMENT: Section 5.3 Air Impact Assessment (AIA), Section 5.4 On-site Mitigation Checklist, Section 5.5 Mitigation Monitoring and Reporting Program (MMRP), and Section 5.6 Air Impact Mitigation Fee Deferral Schedule (FDS). The rule should overtly guarantee public access to documents and information required by these sections. While state law would allow public access, to ensure that access is available in a timely fashion, and not subject to delays resulting from the need to file public records act requests, the rule should specifically note that the district will make available to the public the application and information described in sections 5.3, 5.4, 5.5 and 5.6 within two weeks of the district's receipt and review of these documents.

RESPONSE: The ISR program will not be a discretionary program, and thus is not subject to the public review requirements of CEQA (See Response to Comment #187). The District will be including mechanisms for public agency and public review of certain ISR documents. See Response to Comment #8 for Public Agency access. See Response to Comment #59 for public access. See Response to Comments #178 and #188 for public access to the Off-Site Program.

236. COMMENT: Section 6.1 Construction Equipment Emissions. Construction equipment emissions reduction goals should be set as a minimum standard for individual vehicles, not as a fleet average. We applaud the district's inclusion in this draft of a section specifically requiring reductions in construction vehicle tailpipe pollution. Uncontrolled construction equipment represents some of the dirtiest and most health-threatening mobile emissions. However, the fleet average approach suggested in the draft rule fails to protect those working and living closest to, and therefore at most risk from, the emissions from individual pieces of the dirtiest uncontrolled equipment. We recommend requiring a minimum level of control for all construction equipment that limits emissions to those achieved by Tier 1 controlled construction equipment, in combination with a fleet average as described in the rule.

RESPONSE: The District does not have the authority to set emission standards for mobile sources. Please see Response to Comment # 6 for additional information.

237. COMMENT: Section 6.2 Operational and Area Source Emissions. The rule should fully mitigate the most health-threatening indirect source pollutants. We are pleased that the district has clarified that PM 2.5 will be included in the emissions controlled. However, we continue to believe that, like the June 30th version, the September 1 draft rule does not provide the level of health protection warranted. The rule addresses only oxides of nitrogen (NOx) and coarse and fine particulate matter (PM 10 and PM 2.5). It should also require mitigation of reactive organic gases (ROG), a precursor that leads to the

formation of ground-level ozone. Mobile sources account for almost 40% of ROG emissions in the San Joaquin Valley.

Additionally, the draft rule continues to call for reducing just a third of the NOx emissions and half of the operational PM 10 emissions over a ten-year period. This approach leaves the majority of pollutants produced by a new development unmitigated. The district staff has arrived at these discounts short of 100 percent mitigation to avoid double counting. It has thus assumed that every vehicle traveling to or from a new development is starting or ending the trip at another new development also covered by the rule. This is an unreasonable expectation.

At the very least, if the district believes it must discount mitigation levels to avoid double counting, it should arrive at the proposed discount in a logical, defensible fashion. The district should engage the URBEMIS update advisory group, composed of professional air regulators familiar with the model and the literature on land use and transportation, to define a reasonable and defensible default number for discounting trips to avoid double counting.

RESPONSE: See Response to Comments #57 and #65 for the District's response on the amount, pollutant type, and calculations for emission reductions. By ensuring that the program does not mitigate more than half the trips generated by the project, the District is ensuring compliance with the H&S Code that requires indirect source programs to differentiate between new and existing trips. URBEMIS accounts for all trips related to a development but does not differentiate between new and existing trips. When analyzing a project in an area that is planned but not built out, some of the trips will be going to new development that will also be subject to the rule in the future and other trips will be going to existing development not subject to the rule. Both types of trips should not be charged to the project being analyzed so that impacts are fairly allocated among all uses

238. COMMENT: Additionally, the mitigation requirement should extend beyond ten years. One need not look very far in California to see that most buildings continue to attract pollution-emitting traffic for much longer than ten years. The DESIGN rule should more faithfully reflect the real life of—and real life of emissions from—the development project. We suggest a minimum of 30 years, which assumes a development will last at least as long as a standard mortgage.

The rule should also recognize that developments have variations in emissions over their lives. This change reflects the changing demographics in housing developments over time, and the changing uses of buildings, including commercial and industrial buildings. The rule should include that variation in emissions modeling and the district should require a review of actual emissions from projects at least once every five years to ensure that the match between emissions and required mitigation is strong.

RESPONSE: See Response to Comment #198 for the District's response on variations.

239. COMMENT: Section 10.2 Administration of Mitigation Funds. Mitigation measures should be permanent. The district, in Section 10.2, the draft rule indicates that it will use mitigation fees to fund quantifiable, enforceable and surplus NOx and PM10 emissions from off-site mitigation projects. All mitigation, whether on-site or off-site, should be permanent as well.

Some mitigation measures, such as the incremental improvement from retrofitting a diesel truck engine, are not permanent. The incremental improvements last only as long as that retrofitted or replaced engine is in operation and go away once a newer, cleaner engine replaces that older engine. Yet the pollution those measures intend to mitigate do not change. Therefore, short-term mitigation measures should be sequenced with other mitigation measures, to ensure that mitigation lasts as long as the mitigated pollution does.

RESPONSE: The District disagrees with this commenter's characterization of permanent reductions. The key is that all equipment and vehicles wear out and must be replaced over time. If the old equipment is replaced at the end of its useful life with new equipment that is as clean or cleaner than the old equipment then the emissions continue at the same or lower rate and the reductions should be considered permanent. If the equipment were replaced with dirtier equipment at the end of its useful life, the reduction would not be permanent. The District uses project life estimates from the Carl Moyer program that are very conservative. For example, ag IC engines are allowed a project life of 7 years, but our experience in the grant program has shown that many engines are operated for 20 to 30 years.

240. COMMENT: The District Should Develop Long-Term Measures with Mitigation Funds, and Invite the Public to Participate.

The September 1 draft, like the earlier drafts, is vague and uncertain about how monies will be spent and leaves critical decision-making about spending the funds up to the air district. The district should use the Carl Moyer program as a model. Broad areas for expenditure are outlined in the statute establishing the Moyer program, and then the lead regulatory agency, after public workshops and hearings, adopts guidelines about the specifics of how the Moyer funds will be spent.

Mitigation funds collected from developers for off-site mitigation should help create and fund long-term air pollution mitigation measures. Improving transportation choices by investing in vanpool systems and providing incentives for affordable housing located near existing job sites are examples of just two

long-term measures. The district needs to engage the public, local government and other agencies to identify the best uses of mitigation funds to get these long-term emissions reductions. The rule should establish development of a public process and guidelines for determining the best uses of the mitigation funds.

RESPONSE: Long-term measures as described in the comment may be funded if they can meet the reductions are quantifiable and enforceable. There will be opportunities to add programs once the rule is adopted.

241. COMMENT: Include Discussion of Health Costs of Air Pollution**.**
In the staff draft report, in the draft rules, and in the socioeconomic analysis, there is no indication that air pollution costs money. There is no indication that the main purpose for this and every other rule adopted by the air district is to make the air healthier to breath. The air district staff, and by extension the air district board, does itself and the cause of clean air a disservice by continually ignoring this critical issue. Dirty air is costly. It impairs health and costs residents in time lost at work, in lost productivity, in lost days at school, in direct health care costs. It also costs crop damage and materials damage. More than a decade ago, researchers established that not meeting federal ambient air quality standards in the Los Angeles air basin costs that region at least $9 billion a year.

We continue to be disappointed by the district staff's refusal to note in its rule reports and socioeconomic analyses that air pollution has costs, especially health costs. We urge the district to use this rulemaking opportunity to bring to the public's attention the very real health costs associated with air pollution. Ample information is available from the California Air Resources Board and other state and national environmental agencies to help district staff provide sound information about the costs of air pollution.

RESPONSE: See Response to Comment #98.

242. COMMENT: Finally, we applaud the district for its decision to develop rules 9510 and 3180, and we appreciate the district staff's hard work on this rule. We hope to see another draft that incorporates the changes we have recommended. We also look forward to further discussions with the district about the rule as it moves forward.

RESPONSE: Comment Noted.

Yokuts Group, Sierra Club
Date: September 1, 2005

243. COMMENT: While I think several of the commentators today made the point, I, as a long-time low-income person, would like to tell your socioeconomic that, yes, a $100 increase in rent or mortgage, DOES make a difference. Obviously

he has never been in the position of not having enough money to pay all of his bills.

I'm not qualified to comment on the rest of the presentation, but that I do know about.

RESPONSE: The author's comment on the impacts of pricing on low income persons is well taken. It is important to point out that the rule exempts housing of less than 50 units; and it applies to only *new* housing developments. In addition, the impacts discussed in the Socioeconomic Analysis are the unlikely 'worst-case' scenario where all developments contain no sidewalks, all residential is built at 3-units per acre, there are no transit services, bike racks or any other measure that reduces emissions. The District believes that the exemptions and applicability stated above as well as the more likely, less-fee scenario reduce the impacts on housing affordability beyond that stated in the Socioeconomic Analysis.

244. COMMENT: And I would agree with Kathryn that the cost of *not* doing anything about pollution has to be spelled out. All too often only the costs of rectifying our past neglect are all we look at. That, actually is only relevant when comparing the benefits of several alternatives for cleaning our air.

RESPONSE: The District believes that rule by rule analysis of the health benefits of individual rules is not appropriate; however, the cumulative benefit of the District's attainment strategy on health is extremely important. The District will be revising the Staff Report to include discussion on health impacts as addressed in the PM10 and Ozone plans.

Late Comments

City of Manteca
October 7, 2005

245. COMMENT: The Manteca City Council recently adopted the attached Resolution opposing the adoption of Draft Rules 9510 and 3180. We are aware that we live in a non-attainment area. We are also in favor of lowering the amount of PM-10 and NOx emissions. However, before the assessment of additional fees occurs, a program needs to be presented that will show how the funds collected will be used to lower the emissions.

We will be happy to reconsider our actions when a positive plan has been presented.

RESPONSE: The District has provided a clear and positive plan for use of fees in Appendix E – Cost Effectiveness Analysis for Rule 9510. Detailed program guidance for new programs will be developed once the rule is adopted.

Resolution No R2005-446
A RESOLUTION OF THE CITY COUNCIL OF THE CITY OF MANTECA OPPOSITION THE SAN JOAQUIN AIR POLLUTION CONTROL DISTRICT DRAFT RULES 9510 AND 3180

246. COMMENT: WHEREAS, the San Joaquin Valley Air Pollution Control District has proposed two potentially costly draft rules (9510 and 3180) that will impose new taxes and fees on every new office building, home, retail store, restaurant and other private development in the counties of Fresno, Madera, Merced, Kern, Kings, San Joaquin, Stanislaus and Tulare; and

RESPONSE: The Draft Rules 9510 and 3180 do not apply to all new development, nor does it place fees on all development. Please refer to Response to Comment #170. See also Response to Comments #46, #51, and #78, and #175.

247. COMMENT: WHEREAS, every Central Valley Resident will pay for these new air district taxes and fees, as business pass along their new costs through increased prices on goods and services; and

RESPONSE: Please refer to Response to Comments #89, #138, and #180.

248. COMMENT: WHEREAS, adding tens of millions in new taxes and fees every year will hamper the Valley's economic development and job-growth in a region that has among the highest unemployment rates in California; and

RESPONSE: Please refer to Response to Comment #137. See also Response to Comment #55 and #102.

249. COMMENT: WHEREAS, the air district taxes and fees will exacerbate the housing affordability problem in the Central Valley by adding more than $50 million in new costs each year to the construction of homes and apartments, driving up the cost of mortgages and rents and pricing thousands of families out of homes they can no longer afford; and

RESPONSE: Please refer to Response to Comment #137.

250. COMMENT: WHEREAS, the air district taxes and fees would fund the expansion of a bureaucracy that lacks accountability or any specific plan to improve air quality. The air district has failed to present a plan of what improvements to the region's air quality it will make with its new taxes and fees; and

RESPONSE: Please refer to Response to Comments #101, #104, #108, #113, #114, #115 and #137, and #188. Also refer to Rule 9510 Section 10.

251. COMMENT: WHEREAS, the air district has failed to provide scientific evidence to support the new taxes and fees it is proposing; and

RESPONSE: Please refer to Response to Comments #135. In addition, considerable study and analysis went into the District's PM10 and ozone attainment plans, which identified reductions from Indirect Sources as a requirement for attainment of the PM10 and ozone standards.

252. COMMENT: WHEREAS, the air district taxes and fees will interfere and conflict with local government land use authority by creating a new and competing review process, that will erode local control over land-use decision making; and

RESPONSE: Please refer to Response to Comments #8, #81, #133, and #140. . In addition, please refer to the Staff Report Section (B) *District Authority and Limitations*, and Section (D) *State Environmental Review – CEQA*

253. COMMENT: WHEREAS, the air district land-use power is redundant and conflicts with existing environmental rules and safeguards, such as the California Environmental Quality Act and existing air quality and environmental reviews.

RESPONSE: The District does not have land-use power, nor does it desire to usurp the local land-use authorities discretion on land use power. Please refer to Response to Comments #8, #81, #133 and #140. In addition, please refer to the Staff Report Section (B) *District Authority and Limitations*, and Section (D) *State Environmental Review – CEQA*

254. COMMENT: ***NOW, THEREFORE, BE IT RESOLVED*** that the City Council of the City of Manteca opposes the San Joaquin Valley Air Pollution Control District Draft Rules 9510 and 3180

RESPONSE: Opposition noted. The District notes that the substance of the letter is unsupported - see Response to Comments #245 to #253.

STOP the AIR BOARD TAX – We'll All Pay! (Coalition)

A.L. Gilbert Company.
African American Chamber of Commerce of San Joaquin County
Building Industry Association of Central California
Building Industry Association of the Delta
Building Industry Association of Kern County
Building Industry Association of San Joaquin Valley
Building Industry Association of Tulare and Kings Counties
Business, Industry & Government (BIG) Coalition of the South San Joaquin Valley
Cal Bennett's
California Black Chamber of Commerce
California Building Industry Association
California Business Properties Association
California Manufacturers & Technology Association
California Mexican American Chamber of Commerce
California Restaurant Association
California Retailers Association
California Senior Advocates League
California Taxpayers' Association
Central California Hispanic Chamber of Commerce
Constructing Industry Air Quality Coalition
Consulting Engineers and Land Surveyors of California
Consumers First, Inc
City of Avenal
City of Clovis
City of Escalon
City of Lodi
Coalinga Area Chamber of Commerce
Greater Bakersfield Chamber of Commerce

Greater Merced Chamber of Commerce
Howard Jarvis Taxpayers Association
J.F. Shea Co., Inc
KRC Safety
Kern County Farm Bureau
Kern County Hispanic Chamber of Commerce
Kern County Taxpayers Association
International Council of Shopping Centers
Lemke Construction
Lodi Association of REALTORS, Inc
Lodi Chamber of Commerce
Madera Hispanic Chamber of Commerce
Matthews Homes
National Association of Industrial and Office Properties – California Chapters
National Coalition of Hispanic Organizations
National Tax Limitation Committee
Orange Belt Board Realtors
Raymus Homes
Rainscape
Reason Foundation
San Joaquin Valley Black Chamber of Commerce
San Joaquin Chamber of Commerce
Scolari Tile & Co., Inc
Self-Help Enterprises
Sharp Insurance & Bonding
Small business Action Committee
The Hispanic Chamber of Commerce of Stanislaus County
Tulare and Kings Counties Builders Exchange
The Tulare/Kings Hispanic Chamber of Commerce
Tulare Chamber of Commerce
Tulare County Association of REALTORS
Tulare County Farm Bureau
Valley Taxpayer's Coalition
Valley Outdoor Advertising
Visalia Chamber of Commerce

255. **COMMENT:** On behalf of small business, labor, taxpayer, local government, community and other diverse organizations, we strongly oppose draft Rules 9510 and 3180. These measures will impose new taxes and fees on Central Valley residents, hurting our economic development and job-growth but offering no accountability and no guarantees of cleaner air.

RESPONSE: New Taxes: The Draft Rules 9510 and 3180 do not apply to all new development, nor does it place fees on all development. Please refer to

Response to Comment #170. See also Response to Comments #46, #51, and #78, and #175.

Hurt Economy: Thee is no factual evidence that implementation of the rules will hurt the economy. Please See the Staff Report and Appendix F – Socio Economic Impact Analysis for more information. Please refer to Response to Comment #137. See also Response to Comment #55 and #102.

Accountability: The authors' statement is untrue. Accountability is built into the rule. Refer to Rule 9510 Section 10. See also Response to Comments #101, #104, #108, #113, #114, #115 and #137, and #188.

256. COMMENT: The proposed rules will impose a slew of new taxes and fees that will apply to every newly constructed property – offices, homes, retail stores, restaurants and small or large businesses. Combined, these taxes and fees are expected to cost hundreds of millions of dollars over the next five years. This fee will price tens of thousands of families out of housing they can afford and worsen the housing crisis in the Central Valley.

RESPONSE: New Taxes: The Draft Rules 9510 and 3180 do not apply to all new development, nor does it place fees on all development. Please refer to Response to Comment #170. See also Response to Comments #46, #51, and #78, and #175.

Costs of Rule: The District analyzed the calculations that the BIA provided via Sierra Research, and concluded that the analysis was flawed and inaccurate. Please see Response to Comments #161 and #162.

Housing Impact: The Socioeconomic Impact Analysis did not find a significant impact to housing builders or housing buyers/renters. See the Staff Report and Appendix F for more information. In addition, please see Response to Comments #137, #41, and #53.

257. COMMENT: By imposing similar costs on new businesses, these measures will hamper the Valley's economic development and job-growth which will be particularly disastrous in a region that has among the highest unemployment rates in California.

Ultimately, these additional costs will be passed along to consumers, meaning we all pay.

RESPONSE: The District disagrees that the rule will hamper economic development in the Valley. Please see Response to Comment #55.

258. COMMENT: Most troubling is the fact that there are no accountability mechanisms built into the draft Rules and no guarantees that the funds will actually improve the air quality. The Air Board has failed to present a detailed list of the specific air-quality-improvement activities it intends to pursue and has failed to provide credible scientific support for the proposed rules.

RESPONSE: Accountability: The authors' statement is incorrect. Accountability is built into the rule. Refer to Rule 9510 Section 10. See also Response to Comments #101, #104, #108, #113, #114, #115 and #137, and #188.

Credible Scientific Support: Again, the authors' statement is not valid. The District has been developing the rule over several years, involving extensive research and documentation. Please refer to Response to Comments #135, the Staff Report, and associated Appendixes. In addition, considerable study and analysis went into the District's PM10 and ozone attainment plans, which identified reductions from Indirect Sources as a requirement for attainment of the PM10 and ozone standards.

259. COMMENT: Lastly, the new bureaucracy will interfere with local government land use decision-making by creating a new and unworkable process that erodes local control over land-use planning. This will stall much-needed new housing, businesses and other economic growth in our communities. For example, the draft Rules are redundant and even conflict with existing environmental rules and safeguards, such as the California Environmental quality Act and Existing air quality and environmental reviews

RESPONSE: First, 100% of off-site fees will be used for off-site emission reduction programs only. None of the off-site fees will be used for District administration or other uses. Second, the rules are not redundant, conflicting, unworkable, or otherwise interfere with the environmental review process, existing laws, or the land-use agencies' discretionary land use authority.

The District does not have land-use power, nor does it desire to usurp the local land-use authorities discretion on land use power. Please refer to Response to Comments #8, #81, #133 and #140. In addition, please refer to the Staff Report Section (B) *District Authority and Limitations*, and Section (D) *State Environmental Review – CEQA*

260. COMMENT: Draft Rules 9510 and 3180 are misguided solutions that will hurt every Central Valley Resident, potential new homeowners and renters and the

economic climate in the Central Valley. For these reasons we the undersigned oppose draft Rules 9510 and 3180 and urge your opposition as well.

RESPONSE: Opposition Noted. The District notes that the substance of the letter is unsupported – See Response to Comments #255 to #259 above.

Merced County Economic Development Corporation (MCEDCO)
Dated September 13, 2005
Received September 19, 2005

261. COMMENT: On behalf of the Merced County Economic Development Corporation (MCEDCO) we urge members of the San Joaquin Valley Air Pollution Control District (Air Board) to oppose draft Rules 9510 and 3180. The draft Rules will impose hundreds of millions in new fees on residential, commercial and business developments, discourage investments and job growth throughout the Central Valley and hinder affordable housing without any guarantee that they will directly improve the situation

RESPONSE: The factual evidence supports the District's position that the Draft Rules will have a less-than-significant effect on the housing market in the Valley, and a minimal effect on other land use projects. In addition, there is no supporting evidence that the rules would 'discourage investments and job growth'. Finally, there is solid scientific evidence that the rules will benefit the air quality of the valley. The District has been developing the rule over several years, involving extensive research and documentation. Please refer to Response to Comments #135, the Staff Report, and associated Appendixes. Accountability is built into the rule as draft Rule 9510 Section 10. In addition, considerable study and analysis went into the District's PM10 and ozone attainment plans, which identified reductions from Indirect Sources as a requirement for attainment of the PM10 and ozone standards. See also Response to Comment #55.

262. COMMENT: MCEDCO is a private/public nonprofit 501c4 organization that offers economic development expertise to the incorporated cities and unincorporated communities within Merced County. MCEDCO's primary mission is to promote and facilitate net, new employment growth, encourage increased corporate investment and assist in the diversification of the Merced County economy. MCEDCO focuses on retention and expansion of existing businesses, small business start-up, and recruitment of new enterprises

MCEDCO's efforts serve the entire community by encouraging new jobs opportunities for residents, increased sales and improved productivity for local business and new tax and fee revenues to support programs and services

offered by the cities and county. Without new business investment, employment growth is not realized and subsequently residential growth falters.

California is already recognized as a costly business location. Businesses frequently cite high fees and development expenses as a disincentive to new investment. The rising cost of property in tandem with additional fees and high operating costs jeopardizes potential wealth generation opportunities.

Environmental issues, in particular clean air for the Valley, are important matters to prospective business investors. However, MCEDCO is concerned that the draft Rules may not directly improve the situation and may deter residential and other construction that is often considered a primary trigger to economic development.

RESPONSE: The District recognizes the author's concerns. However, the District has provided detailed calculations of the emission reductions predicted by the rule as well as potential off-site emission reduction projects available, Appendix B and E respectively. In addition, considerable study and analysis went into the District's PM10 and ozone attainment plans, which identified reductions from Indirect Sources as a requirement for attainment of the PM10 and ozone standards. See also Response to Comment #55.

263. COMMENT: The draft Rules may also thwart affordable housing, a top priority in the Merced area given our ranking as the least affordable community in the nation. Balancing environmental concerns with affordable housing and new employment is a daunting challenge, not likely to be furthered by the draft Rules. Efforts to improve air quality are supported by the MCEDCO provided that said activities reflect a balanced approach with a clear plan for improvements.

RESPONSE: The District feels that it has met the criteria stated by the author. The draft ISR rules are part of a larger plan, the PM10 and ozone attainment plans, that identified emissions inventories for various activities and land uses, looked at the predicted growth, identified controls, modeled future air quality and determined a mix of actions that would reduce air pollutant emissions to bring the valley into attainment for PM10 and ozone. Part of this plan (also mandated by state law – SB 709) is to reduce emissions from indirect and area sources. As stated in Response to Comment # 17, the ISR development process has taken several years, multiple workshops, as well as working with the state-wide URBEMIS working group, careful analysis of existing regulations and programs. For more information, please see the Staff Report and associated Appendixes.

SUMMARY OF COMMENTS AND RESPONSES FROM THE PUBLIC WORKSHOP HELD ON JUNE 30, 2005

EPA: No comment received.

ARB: No comment received.

Industry and Public:

General Comments

1. **COMMENT:** The rule does not address the increase in trip length or vehicle trips resulting within the region from existing development.

RESPONSE: The purpose of the rule is to mitigate the emissions that result directly from new development. While the growth in the footprint of the region can result in increased travel, it is not practical to assign that growth to an individual development.

2. **COMMENT:** With new housing growing the housing inventory by at most 3% a year, we are therefore ignoring 97% of the homes and cars that create pollution. Our legislators have a responsibility to address the issue head on and not hide behind the pretense that burdening 3% of the households can mitigate the pollution of the other 97%.

RESPONSE: The District agrees that Rule 9510 does not address the emissions associated with existing residential, commercial, and industrial development. Given the requirements of the Health and Safety Code Section 40717.5, the District is precluded from regulating emissions resulting from existing trips associated with existing development. The purpose of the rule is to mitigate growth which is occurring at a rate of about 3% per year. In 10 years, the cumulative growth will constitute 30 percent of emissions. In other words, without growth at the projected rate, emissions would be 30 percent lower in 10 years.

3. **COMMENT:** Stakeholders are gravely concerned about the District's ability to take on these complex new tasks accordant workload.

RESPONSE: The District has a long history of analyzing the impact from new developments and suggesting appropriate mitigation. Additionally, the District has extensive experience operating incentive program to purchase off-site emissions reductions. In conjunction with the rule adoption the District will provide an assessment of workload and an appropriate staffing recommendation.

4. **COMMENT:** There needs to be protections built into the program for speedy processing of air quality assessments.

RESPONSE: The draft rule contains timelines for the District process applications. The District received a number of comments concerning how those timelines relate to the land-use approval process. The District will make every effort to ensure that the timelines in the rule do not unduly delay the land-use approval process. The rule allows developers to submit applications prior to beginning the CEQA process. For projects where the project description is not expected to change, all analysis and preliminary emissions estimates can be accomplished prior to the CEQA document being released for public review.

5. **COMMENT:** Why are only NOx and PM10 being addressed when CEQA requires all pollutants to be quantified and mitigated to the extent that they exceed thresholds?

RESPONSE: Rule 9510 is being developed to meet commitments that the District has made in the PM10 and Ozone attainment demonstration plans. The District has not committed to reductions of other pollutants in this rule. While the mitigation contained in the rule will help applicants comply with CEQA that is not the primary purpose of the rule. The revision to the GAMAQI document will outline how this rule will work under CEQA.

6. **COMMENT:** Not all of the classes of development projects identified in Section 2.2 are defined in Section 3.11.

RESPONSE: The District will make the appropriate changes ensure that there are no internal discrepancies in the rule.

7. **COMMENT:** Most buildings in the SJVAB last longer than ten years. The ten-year period should be expanded to at least thirty years, since that is the term of the standard mortgage.

RESPONSE: The District selected ten years based upon a number of factors. First, since the rule has been committed to attain the federal ozone and PM10 standards in 2010 the ten-year time frame is sufficient to get past the attainment deadlines and ensure that they last into the maintenance period. Also, utilizing a thirty-year time period would have a significant financial impact on the region.

8. **COMMENT:** What would happen if a change of use occurs and the previous use required fees that were already paid, and the actual use did not?

RESPONSE: The District is not proposing to re-assess a project at change of use. The program will only deal with new construction.

9. **COMMENT:** Better clarification of the definition of "baseline emissions" is needed.

RESPONSE: The District will ensure that the definition is clear.

10. **COMMENT:** Consultants should either be chosen by the District or the District itself should performed the Air Impact Assessment, so that consultants will be less likely to manipulate numbers.

RESPONSE: The District can ensure that air impact assessments are properly performed. This can be achieved with the District performing the analysis or with private consultants performing an analysis that is reviewed by the District.

11. **COMMENT:** Projected NOx emissions reductions exceed the 2010 SIP commitment. The reductions should stay in line with SIP commitments.

RESPONSE: The District has utilized the plan commitment as a guideline for rule development but the final emissions reductions will be governed by developing an effective rule. Final reductions from the rule will be within range of the SIP commitment. It is also important to achieve as many reductions as feasibly possible, since there are numerous new standards that the District will need to meet.

12. **COMMENT:** The inclusion of the proposed rule in the SIP is prohibited by the Health and Safety Code since this is voluntary compliance with the Clean Air Act and not required.

RESPONSE: The emissions reductions associated with the rule are required to achieve attainment of the federal ozone and PM10 standards and are therefore federally required and are commitments in two federally enforceable plans.

13. **COMMENT:** All requirements pertaining to indirect source review or derived there from should be designated as "not federally enforceable."

RESPONSE: See previous response.

14. **COMMENT:** The inclusion of the proposed rule in the SIP is prohibited by the Health and Safety Code since the authority for this rule is to attain a state, not federal, ambient air quality standard.

RESPONSE: The District is not aware of any such prohibitions since the emissions reductions associated with the rule are needed to attain the applicable National Ambient Air Quality Standards.

15. **COMMENT:** The definition of a development project should include the following additional language: The issuance of a permit for construction or reconstruction, where such permit is required solely to comply with a rule, regulation or order of a local agency shall not be considered to be a development project. The issuance of an operating permit shall not be considered a development project.

RESPONSE: The current definition of a development project adequately addresses projects that have ancillary discretionary approvals relating to the project. The applicability of the rule includes not only discretionary approvals, but also minimum sizes of projects that must comply with the rule.

16. **COMMENT:** It appears that the mitigation measure resulting from this rule are to be used to comply with mandates of attainment plans for ameliorating existing air pollution problems in the Valley. That is, the rule is not primarily intended to prevent new pollution from occurring, they are intended to address pollution that has occurred/is occurring from existing development. Case law in this area would indicate that new development should not be expected to remedy impacts created by previously approved and existing development.

RESPONSE: The purpose of the rule is to reduce the emissions impact from projected development in the San Joaquin Valley not existing development. The emissions inventory in the relevant PM10 and ozone plans contain estimates of emissions totals that include the growth in emissions. The emissions reductions commitment for this rule does not exceed the emissions projected for growth, and therefore only addresses the impact of new development.

17. **COMMENT:** It is unclear how the District will track the various developments and the various iterations of each approval.

RESPONSE: The District will work with local government agencies to ensure that appropriate tracking mechanisms are in place.

18. **COMMENT:** PM2.5 should be included as well.

RESPONSE: The definition for PM10 includes particulates less than 10 microns in size. By definition this would include PM2.5 emissions.

19. **COMMENT:** The rule should require that all NOx and PM emissions be mitigated.

RESPONSE: There are specific previsions of the Health and Safety Code that make it difficult to mitigate 100 percent of projects emissions without violating state law. Additionally, the District has committed to specific emissions reduction levels in the applicable ozone and PM10 plans. The District can achieve these reductions without requiring 100 percent mitigation from projects.

20. **COMMENT:** Discounting the trips at 50% is not defensible. The District should engage the URBEMIS group, composed of professional air regulators to define a reasonable and defensible default number for discounting trips.

RESPONSE: The purpose of discounting the trips by 50% is to ensure that the district does not charge fees on both ends of a trip. If the District did not discount the trips by 50% there is a very real possibility of charging both residential and commercial projects for the same trips, which could result in double counting.

21. **COMMENT:** The rule should recognize the variation in emissions over the life of the development. Therefore, the rule should include a review of actual emissions every five years to ensure that the match between the emissions and the required mitigation is strong.

RESPONSE: The URBEMIS model contains average assumptions for types of development projects. While there is some variation from project to project, and over the life of a project, the assumptions in the model are adequate when applied over a large number of projects.

Applicability

22. **COMMENT:** What was the basis for establishing the project build-out thresholds?

RESPONSE: The project build-out thresholds are based upon the emissions associated with those types of projects. The thresholds reflect 2 tons per year. By setting project build-out thresholds, the District can address the maximum amount of the emissions associated with new development while minimizing the administrative burden on small projects.

23. **COMMENT:** The rule should be set to cover developments that upon build-out create 1 ton or more per year of any pollutant. The size associated with each development project listed in section 2.2 would then be cut in half.

RESPONSE: See previous response.

24. **COMMENT:** The applicability section should include the following language: The increase in emissions from the development project result from an increase in vehicular activity that would not otherwise occur, or the increase in emissions from the development project results from new area sources, not previously authorized.

RESPONSE: By their nature new development projects ultimately result in new trips that would not otherwise occur.

25. **COMMENT:** Other land use categories should be added, such as recreational space and military bases, since these activities generate a significant number of vehicular trip ends.

RESPONSE: The District will add these categories.

26. **COMMENT:** The industrial space threshold should be replaced with light industrial space at 25,000 square feet and heavy industrial space at 100,000 square feet, since trip generation from these types of land use differ significantly.

RESPONSE: Most heavy industrial projects would be exempt from this rule, so distinguishing between the different types of industrial would not be productive.

29. **COMMENT:** The proposed rule does not comply with H&SC Section 40717.5(a)(1) which limits the applicability to activities that contribute to "…air pollution by generating vehicle trips that would not otherwise occur."

RESPONSE: By their nature new developments ultimately result in new trips that would not have otherwise occurred.

30. **COMMENT:** Under the proposed rule, the installation of equipment, wherein such installation requires a public agency "exercise judgment" in approving the permit, would make the project discretionary and subject to Rule 9510 even though the project might not result in vehicular activity.

RESPONSE: These projects would not be subject to the rule since the size of the equipment would be lower than the applicability thresholds of the rule.

31. **COMMENT:** 55,000 square feet of general office space is excessive.

RESPONSE: Comment noted.

32. **COMMENT:** The rule should not retroactively apply to permit applications filed prior to the effective date of the rule. This appears to defer or circumvent CEQA

analysis. The seriousness of the pollution problem in the SJVAB makes all information on air pollution and its mitigation extremely pertinent and necessary to consideration of development projects prior to project approval.

RESPONSE: The rule is not intended to replace the CEQA review for projects. The mitigation developed for a project through the CEQA process can be credited to the requirements of the rule.

33. COMMENT: The applicable square footage thresholds in section 2.2 are discriminatory in that "government space" thresholds are considerably less than non-government identified spaces.

RESPONSE: The applicable square footage thresholds are based upon emissions estimates for different land-use types. These estimates are influenced by a number of factors including trip generation rates that are specific to each land-use type. Government spaces tend to have higher trip rates, so a lower threshold for those spaces are warranted.

34. COMMENT: Will the rule as it relates to urban residential development be applicable to development proposed in the unincorporated areas of the county?

RESPONSE: The rule will apply to new development projects in the entire San Joaquin Valley Air Basin.

35. COMMENT: The definition of "discretionary" projects would be applied inconsistently throughout the SJVAB since different jurisdictions handle them differently. By defaulting to the jurisdictions' interpretation of the term, the District is allowing for the rule to be applied inconsistently.

RESPONSE: The District does not have the authority to change the local government process. Therefore the District is defaulting to the jurisdictions' interpretation, so as not to interfere with the local jurisdictions' land use authority.

36. COMMENT: A simplified and flexible approach should apply to all projects smaller than the exemption thresholds. Smaller projects should be exempt from the detailed analysis, but should still be required to implement all feasible onsite mitigation strategies and make a contribution to offsite mitigation.

RESPONSE: Projects that go through CEQA and have a significant impact are required to implement all feasible mitigation.

Exemptions

37. **COMMENT:** There should be a new exemption section added, section 4.3, which should include the following: Any project subject to federal Section 7 or Section 10 consultations with the United States Fish and Wildlife Services (USFWS) or a 2081 consultation with California Department of Fish and Game (CDFG), since these projects will require life of project mitigation.

RESPONSE: It is not understood how a project that is required to mitigate the life of the project for Fish and Wildlife, would mitigate their air impact. Therefore, this exemption will not be added.

38. **COMMENT:** Section 4.1.4 should read as follows: A development project where the emissions primarily result from direct sources or from emissions units as defined by Rule 2201 (New and Modified Stationary Source Review Rule); or projects subject to Rule 2010 (Permits Required). Examples of exempt sources can be expanded to include: Oil Production and Natural Gas Production, Refineries and Natural Gas Processing Plants, Waste Disposal and Waste Management Facilities, Mineral Extraction and Processing Plants.

RESPONSE: Comment noted, with the exception of waste facilities and mineral facilities. These types of facilities may include a significant traffic component, therefore they should be subject to the rule. The stationary source emissions associated with all facilities will not be included.

39. **COMMENT:** Section 4.1.4 needs to be modified to include gas plants, bulk loading terminals, and gas liquid processing plants.

RESPONSE: See previous response.

40. **COMMENT:** The 50 unit exemption is bound to result in “gaming” or several tract maps coming in at 49 units.

RESPONSE: The District will modify the rule to minimize the potential for circumventing the requirements of the rule.

41. **COMMENT:** The exemption for the applicability should be extended to the reconstruction of owner occupied low-income housing.

RESPONSE: Reconstruction of a single unit would be below the thresholds for rule applicability.

42. **COMMENT:** What is the rationale for exempting transit and transportation projects?

RESPONSE: The exemptions for transit and transportation projects were intended to be from the operational emissions portion of the rule. Since these

projects do not generate or attract trips it would not be appropriate to include these projects operational emission. There are significant emissions from the construction of these projects. The rule will be modified so that the construction requirements apply to transportation projects. Transit projects will continue to be exempt, since they are ultimately considered mitigation.

43. **COMMENT:** This rule is akin to the local conformity rule, Rule 9110 and overlaps with US EPA's General Conformity requirements of 40 CFR 51. In fact, the conformity rules are more stringent that this proposed rule. Sources subject to general conformity should be exempt from the rule.

RESPONSE: In some cases the general conformity rule is more stringent than the DESIGN rule. In those cases federal sources will be given credit for the efforts to meets conformity requirements. In other cases, federal sources are not required to mitigate their emissions if they are already included in the SIP. In those cases the DESIGN rule would be more stringent than the general conformity provisions.

44. **COMMENT:** The definition of projects subject to the rule does not address whether general, regional, community, or specific plan adoption would be considered "discretionary" projects subject to the rule. These plans and subsequent information for URBEMIS inputs are too general to furnish precise estimates of pollution as a result of those plans. Therefore, the consideration and adoption of specific plans should be exempt from the rule, unless the adopting land jurisdiction does, in fact, intend to issue development/construction permits pursuant to a specific plan without subsequent environmental analysis.

RESPONSE: As long as the general, regional, community, or specific plan are not the last discretionary approval of a project or portion of that project, the rule would not be applied to these approvals, but rather to the later more specific discretionary action for the project. If these plans were the last discretionary approval, perhaps the plan or CEQA document could contain a condition of approval or mitigation measure requiring the developer to provide an analysis to the District once the project design is finalized and prior to final ministerial site plan review or subdivision map or issuance of the building permit.

CEQA

45. **COMMENT:** The proposed rule does nothing to protect against CEQA lawsuits with respect to air quality mitigation.

RESPONSE: Due to limitations in state law, the District is unable to develop a rule that provides the same level of mitigation that some communities are seeking through the CEQA process. The District has established a program

through which project proponents can work with the District to fully mitigate their projects through CEQA.

46. **COMMENT:** There is a disconnect between the levels of significance in the Guidelines for Assessing and Mitigating Air Quality Impacts (GAMAQI) and the proposed rule.

RESPONSE: The purpose of the rule is to assist the District in attaining clean air standards. The rule is not intended to satisfy the requirements of CEQA. However, the GAMAQI will be revised to describe how compliance with this rule would affect CEQA.

47. **COMMENT:** What is the basis for the exemption of projects that have a mitigated baseline below two tons per year? Is this basis evidence that 10 projects in the same area producing less than two tons per year each are not cumulatively considerable under CEQA?

RESPONSE: The threshold was in part determined by selecting a level where reductions achieved would meet the commitments outlined in the PM10 and ozone plans. The revisions to the GAMAQI will outline the issue of cumulative impacts, in relation to this rule.

48. **COMMENT:** The District should include in this rulemaking, clear direction from the Governing Board to amend the GAMAQI, through a public hearing process, to formally adopt the concept of NOx mitigation over ten years in Air Quality Assessment methodology for CEQA documents. This would provide clear direction for the connection of this rule to CEQA and provide support for the Lead Agency in the current challenges to Air Assessment methodology in CEQA documents.

RESPONSE: The District will continue to improve its CEQA process to insure that appropriate analysis and mitigation are included for projects. Pending Governing Board adoption of this rule, the GAMAQI will be revised through a public process.

49. **COMMENT:** Please clarify why the District is not committed to amending the GAMAQI to define the exact role that this rule will have in the CEQA process, which would clearly provide relief for local government in CEQA litigation in a matter, air impacts, for which the District is the recognized expert.

RESPONSE: As was mentioned previously, the purpose of the rule is to achieve the emissions reductions necessary to attain the federal PM10 and ozone standards. The primary purpose of the rule is not CEQA compliance. However, the GAMAQI will be revised, and will provide clarification on how this rule works under CEQA.

50. **COMMENT:** The appropriate time for District analysis of projects under the rule would be during the early consultation process, before the overall environmental analysis of a project is completed and before the mitigation measures are approved for the project.

RESPONSE: Since the timelines for land use approval and CEQA vary greatly from jurisdiction to jurisdiction, the District cannot prescribe a timeline that will fit all jurisdictions. To that end, it is up to the developer to determine when would be the best time to approach the District. It is the District's preference that it is as early in the process as practicable so that the analysis and impact assessement could be completed prior to circulation of the CEQA document.

Regulatory Process

51. **COMMENT:** The best time to analyze and mitigate environmental impacts is at the comprehensive higher plan level. However, this rule discourages master planning in favor of piecemeal, small projects due to the liabilities stated for changes in design.

RESPONSE: The applicability of the rule at the last discretionary approval stage does not provide a disincentive to planning at a higher plan level. In fact, the opposite is true. Building in mitigation at the comprehensive plan level will assist in complying with the requirements of the rule.

52. **COMMENT:** The proposed rule creates a major burden for project applicants by imposing new requirements for preparation of detailed air quality studies.

RESPONSE: Many projects are already doing comprehensive analysis during the CEQA process. It is intended that the analyses and work for this rule provide a foundation for and/or complement the analyses required under CEQA. The District will work to provide tools and training to streamline the analysis process.

53. **COMMENT:** The mitigation agreement is wholly duplicative of the mitigation procedures set forth in CEQA, and will create chaos and confusion.

RESPONSE: Given that mitigation is consistent with the CEQA process it should not create chaos or confusion. The mitigation should in most cases be included as a mitigation measure in the CEQA document. Measures provided by the developer after the CEQA process is complete will require an agreement to ensure compliance.

54. **COMMENT:** The requirement for a new assessment based on changes to the construction schedule approaches absurdity with a master-planned community. How can one accurately predetermine market forces over a 20-year period?

RESPONSE: The fact that the rule is applied at the last discretionary approval of a project will mitigate the need to reanalyze projects. If a project is phased over an extremely long period of time it is appropriate to re-analyze the project if the schedule is significantly altered.

55. COMMENT: There is a conflict when the review of the Air Impact Assessment Application is to be done and when the review and assessment of the EIR must be accomplished.

RESPONSE: The District will not prescribe when the application is required. Therefore, it is likely that the same analysis could be used for both purposes.

56. COMMENT: The developer, who might be expected to pay for the mitigation fees in order to get land entitlements, may not be the same entity that purchases the project to eventually build the development. So if the latter decides to terminate the project and not build, there would be an administrative headache in terms of refunds.

RESPONSE: The District has offered the option for a fee deferral agreement that could defer the fees for projects that have an uncertain future.

57. COMMENT: The 30 day review process, plus the time necessary to process an application will significantly add to the development review time for a project's approval.

RESPONSE: The District has altered the timeframes in the rule to ensure that the rule will not result in unnecessary delays in the development process.

58. COMMENT: How would the rule apply to Master Plan Communities/Developments? Would each project in that plan need to be evaluated or just the plan? The difference in administration of the two options would be enormous.

RESPONSE: The rule requires the review at the last discretionary approval for a project.

59. COMMENT: The approval of the Air Impact Assessment should be done prior to CEQA hearings, and the details of the calculations should be made available to the public prior to those hearings.

RESPONSE: It is the District's intent to have the Air Impact Assessment available prior to the adoption of the project.

60. **COMMENT:** We request that the 30 day review period for determining an application complete be shortened to 10 days, since that is more in line with the 10 day review period for Initial Study consultation comments, and since URBEMIS analyses can be done within a matter of minutes, with the exception of EIRs since those can have a 30 day response time.

RESPONSE: Comment noted.

61. **COMMENT:** We request that the District forward a copy of the URBEMIS findings to the local jurisdictions for incorporation in their CEQA documentation prepared for projects.

RESPONSE: The District is willing to share information with local jurisdictions and in fact regularly comments on CEQA documents.

62. **COMMENT:** The rule proposes that cities and counties withhold building permits pending satisfaction of the District requirements.

RESPONSE: The rule does not include this provision.

63. **COMMENT:** The District should ensure timely public access to information used to calculate emissions. This would include publishing the information.

RESPONSE: The District will make all appropriate information available to the public.

Mitigation Fee Act

64. **COMMENT:** The draft rule fails to comply with the nexus test required by AB1600.

RESPONSE: The District has determined that this rule is not subject to AB 1600 (the Mitigation Fee Act) for two reasons. First, the District has no approval authority over development projects and, therefore, is not imposing a fee as a "condition of approval of a development project." Any fee will be assessed as a separate regulatory fee after the project has been approved by the local land use agency. Second, the Mitigation Fee Act applies only to fees assessed for the purpose of defraying the cost of "public facilities." The District does not believe that air pollution mitigation projects such as diesel engine retrofits are public facilities. However, notwithstanding the above, the District has met the "nexus" test under the Mitigation Fee Act or any other legal standard. New developments subject to the rule attract pollution caused by construction activities and vehicle traffic. The rule seeks to mitigate such pollution by allowing the developer to (1) include on-site mitigation measures in the design of the development that mitigate the types of air pollution caused; and/or (2) pay a fee

that will be used to fund emissions reduction projects, such as engine retrofits, that will mitigate the types of air pollution caused. Thus, the purpose of the fee and its uses are clear. In addition, there is clearly a reasonable relationship between new development and a fee imposed to mitigate the air pollution it causes. Finally, the fees will be reasonable in amount in that they will be directly tied to the cost of reducing the emissions caused by the development. The fee is established on a site-specific basis through URBEMIS modeling designed to determine the amounts and types of excess emissions caused by the development and then calculating the cost of reducing those emissions. URBEMIS is currently the best tool in existence for quantifying such emissions and has been used in similar contexts in the past. Thus, the fee meets all nexus requirements outlined in AB 1600.

65. **COMMENT:** The draft rule does not distinguish between the two-prong analytical paths in AB1600.

RESPONSE: See previous response.

66. **COMMENT:** The District has not circulated any documentation reflecting a nexus study.

RESPONSE: See previous response.

Socioeconomic Impact Analysis

67. **COMMENT:** The District has not released a socioeconomic impact analysis as required by the Health and Safety Code.

RESPONSE: The District will be distributing the socioeconomic impact analysis in conjunction with this draft of the rule.

68. **COMMENT:** The socioeconomic Impact analysis should demonstrate the impacts on the following: housing costs, rents, low-income families.

RESPONSE: Comment noted.

69. **COMMENT:** The socioeconomic Impact analysis should demonstrate the impacts of the processing, fee and mitigation proposals on new businesses.

RESPONSE: Comment noted.

70. **COMMENT:** The socioeconomic analysis should make a note of the overall costs to the public of air pollution.

RESPONSE: The District will include a general discussion of the impacts of air pollution on public health in the socioeconomic analysis.

URBEMIS

71. **COMMENT:** URBEMIS is a useful tool for calculating emissions only at the "sketch planning" level. It is not capable of evaluating specific design elements and operational measures, and accordingly, there is no way to do an accurate project-specific analysis of mitigation.

RESPONSE: The District does not agree. In fact, URBEMIS has been utilized to analyze the impact from projects through the CEQA process for years. The model has recently been updated based upon an extensive review of travel behavior studies to ensure that it provides proper credit for design features that are built into a project.

72. **COMMENT:** Please clarify how URBEMIS will be used in the process. Is the operating assumption that all discretionary development, regardless of its consistency with the general plan, is "new" for the purposes of modeling (i.e. additional development, and not replacing land uses/emissions already assumed within the model), or will the assessment be based on its placeholder land use?

RESPONSE: The analysis will be conducted at the last discretionary approval for a project regardless of whether the project is consistent with the existing general plan. If the general plan is the last discretionary approval for that particular land-use the district will analyze the land-use based upon the highest emitting use that could be built under that land-use category. The modeling would be based on approved land uses or those proposed in the case of a large plan area that contains the project being analyzed. This will enable credit to be taken for innovative community design and layout.

73. **COMMENT:** The URBEMIS fleet mix overstates residential emissions by roughly 50%. It is based on the statewide mix of vehicle types, which is comprises 3% of heavy-duty trucks.

RESPONSE: The District is working to ensure that the fleet mix assumptions in URBEMIS are appropriate for each land-use type. While the fleet average may somewhat overestimate emissions residential developments there are heavy duty truck emissions associated with them. These include school buses, refuse collection, package delivery, and other service vehicles.

74. **COMMENT:** The URBEMIS age distribution overstates residential project emissions. The defaults are based on the statewide mix of vehicle types, which are generally older than a new residential fleet. Vehicles, in new housing units that were 10 years or younger, had a 50/50% split on vehicles 5 years or

younger, and older than five years. Housing units older than 10 years had a 36/64% split. This problem cannot be easily revised within the current framework of URBEMIS.

RESPONSE: The District believes that the fleet average is a reasonable assumption for new development projects. There are a number of factors that impact emissions including age, vehicle class, and fleet turnover. If more specific information is available, the District would consider utilizing project specific numbers.

75. **COMMENT:** URBEMIS silt loading factors for entrained PM10 emissions overstate residential project emissions by nearly 50%.

RESPONSE: The District will ensure that the correct silt loading factors are utilized.

76. **COMMENT:** URBEMIS trip lengths are inconsistent with TPA model data and recent statewide travel surveys.

RESPONSE: The District will continue to update trip lengths with local data as the model is updated. Project proponents can utilize project specific information in lieu of the URBEMIS defaults.

77. **COMMENT:** URBEMIS default vehicle speed and estimated vehicle speeds vary by as much as 50-100% of survey data.

RESPONSE: The defaults for vehicle speeds may be modified if project specific information is available.

78. **COMMENT:** URBEMIS is not based on the most recent version of EMFAC in the Ozone SIP.

RESPONSE: As the URBEMIS model is updated it will be updated with the most recent version of EMFAC that is available. The District will ensure that emissions are credited to the Ozone SIP in the proper SIP currency.

79. **COMMENT:** Many commercial and industrial buildings are permitted and built, not knowing who the tenant will be in advance. How will URBEMIS estimate emissions for these types of development?

RESPONSE: In this case the analysis will assume the highest emitting use that would be allowed under the land-use designation.

Construction

80. COMMENT: Construction activities are not considered to be indirect sources.

RESPONSE: The purpose of the rule is to mitigate the emissions associated with new developments, not just indirect source emissions.

81. COMMENT: The rule overlaps and conflicts with existing District and ARB regulations that control emissions from construction activities and equipment, specifically Regulation VIII and the Dust Control Plan requirement.

RESPONSE: The District is proposing modifications to the rule that do not target dust emissions, but rather target mitigating emissions associated with the construction fleet.

82. COMMENT: There is no precedent in District or state regulations that require 100% mitigation of a particular source. 100% mitigation is not reasonable or feasible, as required by CEQA.

RESPONSE: Comment noted.

83. COMMENT: Regulation VIII should address more stringent controls on fugitive PM10 from construction activities and not an indirect source rule.

RESPONSE: Comment Noted.

84. COMMENT: The Regulation VIII list serve and mailing list should be notified of the rule.

RESPONSE: Comment noted.

On-site Mitigation

85. COMMENT: Reductions from many of the individual measures on the Mitigation Checklist are “off-model.”

RESPONSE: The rule includes the provisions that the APCO can approve alternative modeling methodologies. This would include approving appropriate “off-model” adjustments for mitigation that cannot be analyzed in URBEMIS. Many of the mitigation measures that are currently not included in URBEMIS have been removed from the checklist.

86. COMMENT: The Mitigation Checklist needs to be reviewed and modified with input from the development community.

RESPONSE: The District is happy to discuss the checklist with stakeholders.

87. **COMMENT:** Reduction measures such as requiring motorists to abandon vehicles in lieu of intermittent bus scheduling or biking on a 100 degree not appear capable of substantially reducing the amount of smog forming pollutants in our air.

RESPONSE: Any reduction in vehicle use would reduce emissions. URBEMIS accounts for differences in transit service and the quality of the road system to accommodate bicycling. The District is not requiring any on-site mitigation measures, but allowing them to be used. It is the discretion of the developer and the local jurisdiction to require those types of measures.

88. **COMMENT:** Most local jurisdictions are concerned about the mitigation measures being land use and urban design strategies, since these matters are not the District's province. By intending to consider and apply mitigation measures after all other analysis is done, it would appear that the rules would be positioning the District as the ultimate authority on land use and urban design.

RESPONSE: The mitigation measures in the checklist are voluntary. A developer can choose many measures, some measures, or no measures from the checklist. It is up to the local jurisdiction to approve of those measures, in regards to their land use authority. The District expects any design and infrastructure measures must comply with all local development standards and would be included in city/county approved plans and maps. The District has no authority to require that particular measures be included in the project.

89. **COMMENT:** If mixed uses or conjunctive residential and non-residential uses are considered to be a mitigation measure, how will the timing of construction be controlled, since commercial uses tend to postpone construction until the demographics can be analyzed?

RESPONSE: The project will be credited based upon the uses that are planned to be constructed. If the planned uses were changed that would be considered in a subsequent analysis.

90. **COMMENT:** Local land use jurisdictions should be made a party to any mitigation agreements entered with the developer.

RESPONSE: Comment noted.

Off-site Mitigation

91. **COMMENT:** The District has calculated that fees will escalate rapidly and allows for APCO adjustment based on actual costs. This fails the nexus test.

RESPONSE: The District has eliminated the option for APCO discretion to change the fee amount.

92. COMMENT: The District fails to state how the fees will be used.

RESPONSE: The fees will be utilized to purchase emissions reductions through the District's incentive programs.

93. COMMENT: The sequencing of payments does not fit the reality of permitting, financing, and constructing homes.

RESPONSE: The district has provided the option of paying the fees based upon the schedule in the rule, or through a fee deferral agreement with the District. The fee deferral agreement allows the flexibility to collect the fees based upon the project's unique financing situation.

94. COMMENT: The Mitigation Fee Act states that local agencies shall not require the payment of fees until the date of final inspection or the date of certificate of occupancy.

RESPONSE: See response to #64 above.

95. COMMENT: The fee formula needs to be simplified so that there is predictability and a lack of opportunity for controversy.

RESPONSE: The District will develop templates and/or calculators that will allow applicants to easily assess their projects and have predictable outcomes.

96. COMMENT: The impact revenue should be used, first and foremost, within the immediate area of the project that the fees are collected from.

RESPONSE: Fees collected from a project will be spent to mitigate the impacts associated with the particular development project.

97. COMMENT: The district should indicate whether increased district enforcement of existing regulations would be an eligible expenditure of mitigation fees. Air quality improvement would be expected given the responses from the District that its enforcement staff is very limited when apparent violations have been reported.

RESPONSE: The District is not proposing to utilize fees to increase enforcement staff other than staff to enforce the provisions of this rule.

98. **COMMENT:** The fees collected should be used on "traceable" mitigation measures (mitigation must be traced to the activity which the agency approves) as specified in CEQA. Since the proposed rule mainly targets vehicle traffic, traffic synchronization appears to be a logical solution.

RESPONSE: The District proposes to utilize funds for cost-effective emissions reduction projects. The District will track the emissions reductions achieved through the expenditure of fees generated by the rule. If an application for grant funds for traffic synchronization were submitted, the District would assess whether or not it could be funded based on cost-effectiveness and other criteria such as whether the reductions can be verified over time.

99. **COMMENT:** The APCD should develop a Regional Intelligent Transportation Authority (RITA) responsible for regional traffic synchronization, regional transit and intermodal planning, assisting cities with TCM implementation, and integrated collaboration with Caltrans. RITA should be funded by the rule and Section 40605(b) surcharge fees.

RESPONSE: The District will continue to assess opportunities, such as this suggestion, to utilize fees to achieve cost-effective emissions reductions.

100. **COMMENT:** The emissions reduction calculations for off-site mitigation need to calculate the benefit from a new piece of equipment to a less-emitting new piece of equipment.

RESPONSE: There are a variety of incentive programs that the fees can be utilized for. In some cases it is appropriate to compare a base new piece of equipment to less-emitting new piece of equipment. In other cases, where there is useful life left in a piece of equipment, and the equipment is taken out of service, it is appropriate to provide credit for emissions that are eliminated by retiring the old equipment.

101. **COMMENT:** Developers should receive credit for offsite emission reductions created through voluntary implementation of additional mitigation measures applied to previously approved projects. For example, a developer could revegetate or reclaim disturbed surfaces in order to reduce fugitive dust. The developer could then commit these reductions to construction or operational emissions from proposed development projects.

RESPONSE: The District will consider off-site mitigation proposed by a developer on a case-by-case basis. Any mitigation must be surplus and quantifiable.

102. **COMMENT:** We opposed the unilateral authorization to adjust the cost of controls. The APCO should be allowed to adjust the cost of reductions after

providing notice and an opportunity for public comment. We strongly believe that any increase in the mitigation fees should be subject to a cost effectiveness analysis and the approval of any fee increase should be subject to approval by the Governing Board.

RESPONSE: The District has eliminated the APCO discretion to modify fees.

103. COMMENT: It is a concern that the District intends to use these revenues primarily to fund existing programs and activities such as scrapping old vehicles and replacing lawnmowers, rather than to partner more closely with cities and counties to make alternative transportation more accessible and useful. The best use of the money would be to expand/create mass transit systems and alternative transportation routes in the Valley, and to fund measures that reduce traffic volume and relieve traffic congestion.

RESPONSE: The District will consider programs that achieve cost-effective emissions reductions.

104. COMMENT: The District should ensure that the off-site mitigation measures are permanent, as opposed to the short-term benefit of replacing engines. Examples include vanpool systems, incentives for locating affordable housing close to existing job sites.

RESPONSE: While the benefits from the District's incentive programs are credited for a short period of time, the actual reductions from the projects will continue. Additionally, the District has committed a specific tonnage requirement in the short-term to attain the ozone and PM10 attainment deadline of 2010. If the reductions were stretched over an extended period of time the District would not meet its plan goals, or attain the standards. It should also be noted that vanpool systems are currently eligible projects under the REMOVE II incentive program, and would be eligible for funds collected under this rule.

105. COMMENT: The District needs to engage the public, local government, and other agencies to identify the best uses of the funds, and establish a public process and guidelines for determining those best uses.

RESPONSE: Any new incentive program is subject to Governing Board approval, and thus it will be subject to public review.

106. COMMENT: Long-term reductions strategies may appear costly at first, but they can have the largest cumulative emissions avoidance benefits, making them cost effective in the long run. Not only will initial reductions occur, but they will have a self-perpetuating ripple effect of infill and/or redevelopment.

RESPONSE: Cost-effectiveness calculations used by the Moyer Program and the District account for the project life, so long lived projects with low annual reductions may have good cost-effectiveness compared to short lived projects with higher annual reductions. The proposed rule is primarily focused on existing incentive program projects, since they are already established and can demonstrate cost-effective reductions. Upon adoption of the rule, the District will take a closer look at other types of emission reduction projects, and develop incentive program and procedures for viable and cost-effective project types.

107. COMMENT: Similar to an investment portfolio, the District needs to identify a variety of short-, mid- and long-term off-site mitigation strategies.

RESPONSE: See previous response.

Rule 3180

108. COMMENT: If the air impact Assessment Application is done at the same time as the SJVAPCD review of the air impact in a CEQA document, the rule could be a source of funding for the SJVAPCD review of EIR documents.

RESPONSE: It may be possible that some projects that would have been reviewed under CEQA, would now be subject to this rule which requires a more comprehensive look at it. To that end, the District needs to recover any time and materials spent related to this rule.

109. COMMENT: The administrative fee should be reduced initially, and there should be a sunset clause on it once the basic fund is built up to the point that the interest revenue from the funds is sufficient to cover the cost of the program.

RESPONSE: The District will amend the portions of the rule, which is subject to a public review and adoption, if the need arises.

COMMENTS FROM FOCUSED WORKSHOPS HELD ON MARCH 11, 15, 24, 31, 2004

EPA:

1. **COMMENT:** The District should ensure that a "District approved model" is identified by name in the rule and that their use is appropriate based on consultation with EPA and other federal agencies.

   RESPONSE: The rule specifies the District approved model and allows additional models to be approved by the District.

2. **COMMENT:** Section 5.3.2.3 allows the use of the Institute of Transportation Engineers Trip Generation Manual. It is unclear whether this is the same manual that was developed by the Department of Transportation (DOT). We consider the trip generation rates in the DOT manual to be appropriate.

   RESPONSE: The Institute of Transportation Engineers Trip Generation Manual is used by the California Department of Transportation (DOT).

3. **COMMENT:** More specificity is needed for sections: 5.1, 5.3.1.1, 5.3.2.2-4, 5.3.3.6, 5.4.2-3, 5.5, and 5.7.2.2-3, 5.7.3.2

   RESPONSE: Comment noted.

4. **COMMENT:** Section 3.27 defines a "vested project," however; the rule does not specify the process by which a project will be designated as "vested." The rule should indicate what minimum components are required to become a "vested project."

   RESPONSE: "Vested projects" is a relatively standard development procedure in which the developer requests the applicable agency to vest his/her project. If a project is vested, it cannot be liable for future changes in regulations for that agency. In exchange for that status, the applicable agency may require other items or actions of the developer. The procedure for vesting status varies by jurisdiction. The current version of the rule should eliminate the need to specify that process, since vested projects will be treated the same as non vested projects.

5. **COMMENT:** Section 3.25 excludes developments where streets are a portion of the project from the definition of "transportation projects." Rule 9510 should not allow sources to receive credit for road paving associated with new developments, which it appears to allow by this definition and the exemption contained in Section 4.3. The rule should also define those developments where streets are a portion of the project.

RESPONSE: The definition of transportation projects has been modified to exclude projects where the traffic surfaces are a portion of the project. It would be virtually impossible to define developments where the traffic surfaces are a portion of the project, since most developments are designed to accommodate transportation. The emissions from constructing internal roads in a project are included in the construction emissions for the land use and are not considered a transportation project.

6. **COMMENT:** Section 5.5 would be clearer if it stated that the developer shall provide the project information "Upon final local agency discretionary approval."

RESPONSE: Comment noted.

7. **COMMENT:** The District needs to ensure that the level of mitigation that is required under Section 5.1 exceeds the level of mitigation already required under other rules and programs in place, specifically Regulation VIII.

RESPONSE: URBEMIS contains district-specific emission factors, and therefore only the portion of non-regulated emissions will be counted in the estimated project baseline total. The emissions totals contained in Appendix B already have Regulation VIII control subtracted from them.

8. **COMMENT:** In order to ensure consistency between the implementation of this rule and the transportation conformity activities of the MPOs, the District may want to work with these agencies on implementation procedures or additional rule language.

RESPONSE: The District will coordinate with the MPOs.

9. **COMMENT:** Rule 9510 should distinguish the various types of agencies and the various types of permits that would be subject to the rule.

RESPONSE: Many jurisdictions handle permits and projects differently. However, writing a prescriptive rule that identified every kind of project at varying stages of planning would be extremely difficult. To that end, the wording of the current rule meets our needs. If an individual agency had a question regarding their coverage by the rule, the District could make a determination.

10. **COMMENT:** Monitoring programs in Section 5.3.3.6 should be further described for clarity.

RESPONSE: Comment noted.

ARB: No comments.

INDUSTRY/PUBLIC:

Trips

1. **COMMENT:** The proposed program should only regulate new trips and not redirected trips.

RESPONSE: The proposed program has been designed to regulate new sources of emissions.

2. **COMMENT:** Double-counting trips will lead to overestimating and overcharging.

RESPONSE: The proposed program will not be double-counting trips and appropriate modifications have been made to prevent that.

3. **COMMENT:** Trip lengths in URBEMIS are not accurate.

RESPONSE: The trip lengths in URBEMIS are based on data submitted by the local transportation planning agencies. If project specific trip lengths are available, they should be used instead of URBEMIS defaults.

4. **COMMENT:** URBEMIS double-counts reductions from existing rules.

RESPONSE: URBEMIS contains district-specific emission factors, and therefore only the portion of non-regulated emissions will be counted in the estimated project baseline total.

5. **COMMENT:** There are emissions impact from mitigation measures, such as lighting, and increased energy use.

RESPONSE: Any emissions impact from this rule will be considered under CEQA. Emissions from power generation is small in comparison to emissions reduced from vehicles and combustion equipment used at the project site due to emission controls at the power plant and higher efficiency of electrical equipment such as electric lawnmowers.

6. **COMMENT:** There should be a de minimis level of new trips.

   RESPONSE: The rule sets an applicability threshold based upon the emissions from a project.

URBEMIS/Analysis

7. **COMMENT:** URBEMIS is not reliable for establishing a fee schedule.

   RESPONSE: The district maintains that URBEMIS is the right tool for this program. URBEMIS contains district and state specific emissions factors, and is the most widely-used air emissions model in the State of California, and many courts have made decisions based on its output. URBEMIS has also been updated to reflect the state-of-the-science on air mitigation measures.

8. **COMMENT:** Future changes to URBEMIS should be a public process.

   RESPONSE: URBEMIS is owned by all the air districts in the state of California, as well as ARB. The district does not have direct control over whether or not changes to URBEMIS should be public.

9. **COMMENT:** The option of another model should be given.

   RESPONSE: Comment noted.

10. **COMMENT:** Consultants should not be conducting an analysis of the development. There is opportunity for “tweaking” the numbers. It would be more efficient and consistent if the District were to do it.

    RESPONSE: There are adequate safeguards in place to ensure that the District can verify the work of applicant or the applicant’s consultant. Each URBEMIS run creates a document that specifies any changes that were made to default values. The District can then verify any changes with the applicant or the applicant’s consultant.

11. **COMMENT:** The District should use a checklist approach instead of an analysis approach, so that the process is streamlined and there is no fee.

    RESPONSE: Emissions reductions associated with each mitigation measure is dependant upon project specific variables, and therefore cannot be streamlined to a checklist approach.

12. **COMMENT:** There needs to be clear time limits on analyses conducted by the District.

RESPONSE: Comment noted.

13. **COMMENT:** The Expedited Review option sends a mixed message, almost a pay-to-pollute message.

RESPONSE: Comment noted.

14. **COMMENT:** Construction emissions should be addressed, since some projects can take up to 10 years to fully construct.

RESPONSE: Comment noted.

15. **COMMENT:** There should be an appeals section for all analyses.

RESPONSE: Comment noted.

On-Site Mitigation

16. **COMMENT:** The proposed rule would allow the District to indirectly regulate land use at the local level through its required on-site mitigation measures.

RESPONSE: The current draft of rule 9510 gives the developer the option of how to comply with the rule. If certain on-site mitigation measures, such as mixed use development, are not allowed in a jurisdiction, then the developer cannot use that measure. On-site mitigation measures are designed to give the developer the option to reduce the emissions on-site. The developer can choose from a broad range of on-site mitigation measures. Any on-site measures that reduce emissions will reduce the amount emissions that need to be mitigated through fees. This rule does not impinge upon local agency land use authority.

17. **COMMENT:** Some mitigation measures, such as traffic signals or sidewalks, are not put in place for 5-20 years.

RESPONSE: Traffic flow improvements, such as traffic signals, will not be used as a mitigation measure under this program. Sidewalks, if used as a mitigation measure, should be constructed prior to operation of the project.

18. **COMMENT:** Credit should be given for high-density residential projects.

RESPONSE: Comment noted.

19. **COMMENT:** Some of the on-site mitigation measures lack enforceability or may not work.

RESPONSE: The mitigation measures in URBEMIS have been revised to help alleviate that problem. Also, the current version of the rule requires developer and the district will enter into a mitigation agreement that will include provisions for enforcement, in the event that the local jurisdiction does not have enforcement mechanisms in place.

20. **COMMENT:** The fees from this program will overlap with traffic mitigation fees.

RESPONSE: Fees collected for traffic mitigation are primarily aimed alleviating congestion and/or fixing roads. While those items may have an incidental, temporary air benefit, this program intends to directly mitigate emissions from projects. If an activity is conducted or developed, or a mitigation measure is included for traffic mitigation, and it benefits air quality, the assessment/URBEMIS will quantify the air quality benefits.

21. **COMMENT:** There should be a list of mitigation measures so that developers can fast track the process.

RESPONSE: Comment noted. Please see Appendix C.

22. **COMMENT:** The effectiveness of the mitigation measures is unlikely given the climate of the SJVAB.

RESPONSE: The mitigation measures included in the new mitigation component of are based on the most recent research available.

23. **COMMENT:** The district should provide the control efficiencies of the proposed mitigation measures.

RESPONSE: The control efficiencies are contained in Appendix D of this staff report.

24. **COMMENT:** The list of mitigation measures should be open-ended, to allow for new and innovative measures.

RESPONSE: While the District would like to encourage new and innovative mitigation measures, each measure needs to have substantial evidence demonstrating the emissions are in fact reduce because of that measure. The District will consider giving credit to additional mitigation measures as they are proposed.

25. **COMMENT:** The 30-day review time period is excessive given the timelines required by CEQA. It should be 10 days.

RESPONSE: The District will streamline the process where possible**.**

26. **COMMENT:** Title 24 is already being implemented.

RESPONSE: The mitigation measure seeks to take credit for emissions reductions achieved by going above and beyond Title 24.

General

27. **COMMENT:** The program should regulate existing as well as new homebuyers.

RESPONSE: The District is precluded by the Health and Safety Code from charging fees to mitigate existing trips.

28. **COMMENT:** The District should consider an annual fee approach for residential sources.

RESPONSE: Due to provisions of the Health and Safety Code, this approach would be an excessive administrative and enforcement burden.

29. **COMMENT:** Indirect regulations are not the way to go.

RESPONSE: The concept of mitigating the indirect emissions from new development has a long history of being implemented through the California Environmental Quality Act. Likewise, the purpose of this program is to mitigate the impacts of new development.

30. **COMMENT:** Area sources do not generate new vehicle trips.

RESPONSE: The applicability has been changed to reflect new emissions.

31. **COMMENT:** Why is the District focusing on the cleanest developments in the air basin?

RESPONSE: New development is not necessarily the cleanest developments. Depending upon location of the new development, it could be responsible for more vehicle miles traveled and/or trips.

32. **COMMENT:** The District should form a technical advisory committee.

RESPONSE: Comment Noted.

Applicability

33. **COMMENT:** This program should include schools, regional parks, and churches.

RESPONSE: This program will include any new development that is estimated to emit equal to or more than the threshold where indirect sources are the primary source of emissions from the project.

34. **COMMENT:** The current wording of Section 2.0 would include projects that come to the District for an Authority to Construct. Is it the District's intent to include those projects?

RESPONSE: It was not the original intent. The exemptions have been expanded to exempt projects where stationary sources of emissions from a development are the primary source of emissions.

35. **COMMENT:** The current wording of Section 2.0 would exclude State projects, because they do not have to apply for or obtain development permits.

RESPONSE: The new wording should include state projects.

Exemptions

36. **COMMENT:** Low-income housing should not be exempt because 1) residents tend to drive older, more polluting vehicles, 2) there are higher concentrations of people, and 3) those residents can benefit from alternate forms of transportation.

RESPONSE: Comment noted. There is no exemption for low-income housing in the current version of the rule.

37. **COMMENT:** If there is not an exemption for low-income housing with a broader scope, many contractors will go out of business.

RESPONSE: Comment noted.

38. **COMMENT:** Structures that are required to obtain a Permit to Operate (PTO) should be exempt from the rule.

RESPONSE: See response to comment #34.

39. **COMMENT:** Infill projects, schools, public parks, and other public facilities should be exempt.

RESPONSE: See response to comment #33.

40. **COMMENT:** General plans, specific plans, and community plans should be exempt from the rule.

RESPONSE: The rule applies to the last discretionary approval for a project.

Nexus

41. **COMMENT:** The Nexus should identify the benefits of the program.

RESPONSE: As with all District rule, an analysis of the emissions reduction associated with the rule has been developed.

Misc.

42. **COMMENT:** The rule should not distinguish between ministerial and discretionary projects.

RESPONSE: Many jurisdictions handle discretionary and ministerial differently. However, writing a prescriptive rule that identified every kind of project at varying stages of planning would extremely difficult.

43. **COMMENT:** Local agencies may use the Mitigation Agreement as a tool to hinder mitigation for projects.

RESPONSE: Local agencies may disapprove of measures in a Mitigation Agreement due to health, safety, and welfare reasons. For example, if a bus bulb was desired, but the bulb interferes with a pedestrian element, it might be a legitimate cause for disapproval.

44. **COMMENT:** How will the Bakersfield Metropolitan Project be addressed?

RESPONSE: That project will be handled separately through a “task force.”

45. **COMMENT:** How will overlap with CEQA be handled?

RESPONSE: This rule may meet many of the air-related CEQA issues for development in this air basin. The Guidelines for Assessing and Mitigating the Air Quality Impacts (GAMAQI) document will be revised and adopted prior to implementation of the program, and will explicitly define how the district interprets this program in relation to CEQA.

46. **COMMENT:** The socioeconomic analysis should look at the per unit cost differential between a home built in a large residential development and a home built on a smaller development.

RESPONSE: Comment noted.

47. **COMMENT:** The socioeconomic analysis should consider the costs of health if the program was not implemented.

RESPONSE: The socioeconomic analysis is an analysis that is mandated by the Health and Safety Code. That portion of the cost does not require a health benefit analysis. That type of analysis is better handled at the plan stage when demonstrating attainment of a health based standard.

48. **COMMENT:** There should be a clause in the rule that protects developers from later changes of the rule, similar to the Safe Harbor clause in habitat regulations.

RESPONSE: Any potential changes to District rules go through a public process. Any discussion of exemptions to rules or changes to rules should be handled through that process.

49. **COMMENT:** There should not be an administrative fee as well.

RESPONSE: An administrative fee is imperative to recover the districts costs associated with administering this program.

50. **COMMENT:** There should be a broader spectrum of stakeholders involved.

RESPONSE: Notices are distributed via newspapers in all eight counties and published on the district's website. Whether or not portions of the public choose to become involved is up to them.

51. **COMMENT:** The draft rule is silent on enforcement mechanisms. How will this be enforced?

RESPONSE: Any on-site mitigation measures included in the design of the project will be identified in a mitigation checklist. Those measures that do not have an enforcement mechanism through the local agency will be subject to a mitigation agreement between the district and the developer. That agreement will identify those measures and their enforcement.

52. **COMMENT:** The proposed certified mitigation program to be administered by local agencies is impractical.

RESPONSE: Comment noted.

Off-Site Mitigation

53. **COMMENT:** Section 5.8 should allow local jurisdictions to use the fees collected because they may know of local opportunities.

RESPONSE: The District will consider local projects when allocating any fees collected through this program.

54. **COMMENT:** Section 5.8 needs to be more specific.

RESPONSE: Comment noted.

55. **COMMENT:** There should be an appeals section for the expenditure of fees.

RESPONSE: See response to comment #15.

56. **COMMENT:** A process for fee reimbursement should be provided if emissions reductions are not achieved.

RESPONSE: Comment noted.

57. **COMMENT:** There needs to be a mechanism in place to expand off-site projects.

RESPONSE: Comment noted.

58. **COMMENT:** Fee expenditures should be located in the jurisdiction of origination.

RESPONSE: Fee expenditures will be located in a manner that will mitigate the emissions impact from the project.

59. **COMMENT:** All fleets should have the opportunity to obtain grants.

RESPONSE: The district is currently drafting a fleet grant program. Any fleet that submits a cost-effect project consistent with the District's guidelines will be eligible to receive funds.

60. **COMMENT:** There should be an appeals section for all project types, not just the Complete Analysis.

RESPONSE: See response to comment #15.

61. **COMMENT:** The grant programs should focus on diesel and smoking vehicles.

RESPONSE: The grant programs will focus on getting the most cost effective emissions reduction.

62. **COMMENT:** There should not be a limitation on spending the fees on research.

RESPONSE: The district needs to obtain immediate and quantifiable emissions reduction. Research does not meet the district objectives for this program.

63. **COMMENT:** The fees should go towards traffic congestion mitigation.

RESPONSE: The purpose of the program is to mitigate the impacts of development on air quality. While traffic congestion may be a part of the air quality problem, there are already traffic congestion fees in some jurisdictions. Also, traffic congestion mitigation is a temporary fix to the air quality problem. Studies have shown that increasing traffic flow increases capacity, and more capacity attracts more traffic.

COMMENTS FROM SCOPING MEETINGS HELD ON OCTOBER 7 - 9, 2003

EPA: None received.

ARB: None received.

INDUSTRY:

1. COMMENT: Public input and oversight should be built into the process.

RESPONSE: The District intends to provide periodic reports to the District Governing Board that will be available to the public that will enable public oversight. The development of the indirect source rules will be conducted in an open public process that allows for public input at every stage.

2. COMMENT: The fee structure implemented should be a Mello-Roos based fee requiring an annual payment by the owner of record.

RESPONSE: The DESIGN program is designed to reduce the impact that new development has on the growth in emissions. The program gives credit to projects based upon design features that are incorporated into a project to reduce emissions. Any fees charged are utilized to make up the gap between mitigation measures incorporated in the project and a 50% reduction in emissions. This type of program would not be appropriate for a Mello-Roos based program.

3. COMMENT: This program should be handled similarly to that of the school district fees.

RESPONSE: The calculation and collection of school fees is relatively simple compared to calculating air quality impacts of the project. The proposed program gives the opportunity for a project applicant to incorporate design measures that could potentially reduce emissions over the life of that project. This means that each project may need its own determination of emissions after on-site mitigation have been accounted for to calculate the appropriate fee amount.

4. COMMENT: How will the indirect source fee's impact on air pollution be measured and monitored?

RESPONSE: Projects funded with indirect source fees will have annual reporting requirements that will demonstrate that the emissions claimed are being achieved. The District will physically inspect all projects to ensure that the project is accomplished as claimed by the applicant for the funds and will credit those reductions in the appropriate attainment plans and progress reports.

5. **COMMENT:** What provisions will be made for repealing the fee if it is enacted but is not effective at reducing air pollution from automobiles?

RESPONSE: The emission reductions achieved from any fee collected will be subject to reporting and monitoring requirements. All projects that are based on retrofit or replacement of old technology with new technology must use equipment/devices that are emission certified or verified by the California Air Resource Board (ARB) and so are proven effective. The District will consider a periodic review of the entire program to ensure that the anticipated emissions reductions have in fact occurred. District staff would then present the results of the review and a recommendation to the governing board.

6. **COMMENT:** An indirect source fee will act as a disincentive for homebuyers to help clean the air by purchasing a new home.

RESPONSE: The decision to purchase a new home is influenced by a number of factors. If a subdivision incorporates on-site mitigation measures that reduce trips and area source emissions, which would lessen the fee amount and add value to the development, there may be more of an incentive to purchase a new home.

7. **COMMENT:** If fees are to be charged based on automobile usage, all development, not just new development, should be charged.

RESPONSE: The purpose of the program is to reduce the emissions associated with new development. The District prefers a preventative approach. One of the key features of the DESIGN program is to incorporate mitigation measures on-site, which will reduce emissions over the life of the development. This is possible during the design of new projects. It would not be feasible to "retrofit" existing homes and development; accordingly, they would probably pay 100% of the fee amount.

8. **COMMENT:** Infill developments with special measures incorporated into their design should receive a credit from this program.

RESPONSE: The reductions achieved by the DESIGN program are a combination of on-site design elements and off-site emissions reductions that are achieved by buying emissions reductions with fees to make up any shortfall

in on-site mitigation. In-fill projects that incorporate design features that reduce the emissions associated with the project will be given credit for those reductions and will reduce their potential fee amount.

9. **COMMENT:** Fees should be roughly proportional to the number of trips generated by that land use, as directed by the U.S. Supreme Court in the case of Nollan v. California Coastal Commission (1987) and Dolan v. City of Tigard (1994).

RESPONSE: The District expects any fee collected under this rule to meet this condition. The fee formula is based upon the emissions associated with the project.

10. **COMMENT:** The District needs to demonstrate how assessing a fee on land development will mitigate air pollution from automobiles.

RESPONSE: The purpose of the program is to mitigate the emissions associated with new development through on-site mitigations and potential fees. The District will outline the Nexus between any potential fees charged and the projects that they are mitigating.

11. **COMMENT:** Fees should be collected no earlier than at the final inspection or certificate of occupancy and paid at close of escrow, when the calculated emissions would actually begin.

RESPONSE: The fees need to be collected early enough to achieve emissions reductions prior to occupancy. Collecting the fee at occupancy would not provide adequate time to achieve the necessary emissions reductions prior to occupancy. Additionally, not all local agencies within the SJVAB have a Certificate of Occupancy permit for all uses, which would make enforcement of proposed requirements difficult. The proposed Rule 3180 may include the option for a Fee Deferral Agreement, which will operate under the capabilities of the local agency involved.

12. **COMMENT:** Fees should be collected at close of escrow, so <u>all</u> homebuyers are charged. This will lower the fee and generate funding at a much quicker rate.

RESPONSE: Please see Response #7.

13. **COMMENT:** Funds generated should be restricted for use in the jurisdiction where they were generated and should be restricted to uses that relate directly to whichever land use is paying the fee.

RESPONSE: The District will utilize any fees collected to mitigation the impact of the emissions associated with the projects that paid the fees.

14. **COMMENT:** Funds should be collected by the local agency at the building permit stage, and that local agency should utilize the funds for emission reduction activities. The local agency would then provide periodic reports to the District.

RESPONSE: The District has over 10 years of experience managing projects that reduce emissions. Providing training and oversight to all jurisdictions within the SJVAB, to ensure proper use of the funds and track emissions reductions would be time-consuming. Also, the District wants to ensure that existing local agency funds are not replaced with indirect source funds to pay for a project that would have occurred anyways. In order to utilize the funds generated in the most efficient and consistent manner, the District has proposed to manage the funds collected.

15. **COMMENT:** Consideration should be given to projects with low-cost housing or in economically depressed areas.

RESPONSE: The District will consider potential exemptions during the rule development process. On-site measures that enable people to use alternatives to the automobile for their personal transportation needs are very important in low-income areas.

16. **COMMENT:** Several jurisdictions already have fees for the purpose of reducing traffic congestion and automobile emissions that it creates. There should not be another fee that accomplishes the same purpose.

RESPONSE: The District will calculate the benefit of mitigation that is included in the project. If existing fees result in real, quantifiable, surplus emissions reductions the District will credit those reductions to the project.

17. **COMMENT:** There may be some overlap with conformity analyses. This needs to be addressed.

RESPONSE: Emission reductions from the indirect source program are reflected in the motor vehicle conformity budgets in the PM10 Plan. When budgets are set for the next ozone plan, they will also reflect emission reduction estimates. Conformity analysis done for individual transportation projects could take into account changes in trip generation rates and VMT resulting from mitigation incorporated by new development when determining if the transportation project will result in a decrease or increase in emissions. However, the transportation models may not provide the level of detail that would enable the user to provide input for individual development projects.

18. **COMMENT:** How will final build out versus phasing be addressed?

RESPONSE: That issue will be discussed at length during the Administrative Procedures focused workshop.

19. COMMENT: The applicant should assume the responsibility of interacting with the District.

RESPONSE: The District has incorporated this suggestion into the rule language.

20. COMMENT: Fees collected through this program should not fund projects that would have otherwise occurred.

RESPONSE: The District agrees that these projects not be funded. The District will take suggestions on how to prevent that.

21. COMMENT: The computed fee should be increased by 25% or more to fund projects that would improve our air, instead of just offsetting emissions.

RESPONSE: The DESIGN Program is being developed to ensure that any fees will meet the nexus standard. Thus, the fee cannot be set "above" the anticipated emissions.

22. COMMENT: Double counting should be addressed.

RESPONSE: The District is limiting the mitigation associated with the project to 50% of the projects base year emissions. This eliminates any potential double counting.

23. COMMENT: Funds should not be spent on public education processes or research type activities, but on projects where emissions reductions are quantifiable.

RESPONSE: It is mandatory that all projects funded will result in real and quantifiable emissions reductions. The specific policies on how the funds will be spent will be included in the draft staff report at the final workshop.

24. COMMENT: A grant-like program could potentially result in large amounts of fees collected with no projects being implemented. An expenditure program managed by the District and/or the Councils of Governments (COGs) should be developed.

RESPONSE: The District is currently formulating how the funds will be spent.

25. **COMMENT:** The District should clearly explain the relationship between the reductions from this program to the CEQA threshold discussions in the District's Guide to Assessing and Mitigating Air Quality Impacts (GAMAQI). The GAMAQI should be used as an implementation tool for this rulemaking project and it should be updated to provide consistent direction on the preparation of environmental documents.

RESPONSE: The District will calculate emissions for each project based on mitigation measures included in the project. If a project has agreed to mitigation measures as part of CEQA, then those measures will be reflected in the emission calculation. It is anticipated that the GAMAQI will be revised after the rules are adopted to show the relationship between the rules and CEQA.

26. **COMMENT:** Construction emissions should be included in the emissions total, and hence, subject to a fee.

RESPONSE: The District intends to include mitigation for construction emissions in the formula.

27. **COMMENT:** It is likely that mitigation fees will be used to fund the most cost-effective projects first. Thus, as time goes on, costs associated with pollution reduction projects will probably rise. The schedule of fees should be subject to upwards revisions based on this contingency.

RESPONSE: The types of projects available for funding are not static. The District has analyzed the types of projects that it anticipates will be available in the near future and has adjusted the cost-effective factor appropriately for future years.

APPENDIX B

Emissions Reduction Analysis for Proposed Rule 9510 (Indirect Source Review) and Rule 3180 (Administrative Fees for Indirect Source Review)

December 15, 2005

EMISSION REDUCTION ANALYSIS FOR RULE 9510 (Indirect Source Review)

I. INTRODUCTION

Both the 2003 PM10 Plan and the Extreme Ozone Attainment Demonstration Plan, contain emissions reduction commitments for proposed Rule 9510 of 4.1 tons per day of NOx and 5.2 tons per day of PM10 to be achieved by 2010. Those estimates were based on assumptions at the time and are commitments that are necessary to assist the district in meeting the federal and state PM10 and ozone standards. This appendix contains emissions and emissions reduction estimates that update those original estimates.

II. BASELINE EMISSIONS

A. Sources of Emissions from New Development

It is generally accepted in both air quality and transportation planning, as well as in case law that new emissions occur from new development. The construction of new structures is undertaken in order to accommodate the growth in population of a particular area. With the projected growth and development in the San Joaquin Valley Air Basin (SJVAB), there will also be a corresponding growth in emissions from energy usage, landscape maintenance equipment, wood combustion, motor vehicles, and entrained dust from paved and unpaved roads.

Energy Usage

Emissions associated with energy usage from new development primarily occur from two different sources, electricity generation and fuel combustion. NOx and PM10 emissions result from using space heating, water heating, cooking, and from other miscellaneous electrical appliances/equipment. ARB estimates fuel combustion emissions from natural gas, distillate oil or LPG, using EPA emission factors, and gas sales.[1] Emissions attributed to use of electricity generated at power plants are not easily quantified due to the variety of sources that supply electricity, which are located in and out of the basin and the state. Therefore, electrical generation emissions associated with new development will not be quantified or addressed for this program.

1 Air Resources Board, Emissions Inventory Procedural Manual, Vol. III, Methods for Assessing Area Source Emissions, October 1997 with revisions through November 1998, section 7.2-7.3.

Landscape maintenance equipment

Landscape maintenance equipment generates NOx and PM10 emissions from fuel combustion (gasoline, diesel, or LPG or CNG) and from evaporation of unused fuel. Equipment in this category can include leaf blowers, lawn mowers, trimmers, edgers, chainsaws, chippers, etc. ARB uses the OFF-ROAD model to estimate PM10 and NOx emissions using population, activity duration, and emission factors.[2] URBEMIS uses OFF-ROAD results and quantifies emissions by the number of homes and business units.[3] Based on District analysis, the growth in NOx and PM10 emissions from residential landscape maintenance equipment is relatively small, 15 tons per year, despite a projected increase of nearly 1.8 million pieces of residential landscape equipment in the SJVAB. The primary reason for the small emissions increase is that the new equipment is significantly cleaner than the older equipment.

Wood Combustion

Residential wood combustion emissions of PM10 and NOx come from burning wood or similar materials inside fireplaces, wood stoves and inserts. ARB estimates emissions totals using the following factors: tons of wood used per house, BTU rating per cord, number of houses, fraction of active wood combustion devices, average number of days burned per house, and other representative factors.[4] The recent amendment to Rule 4901 (Wood Burning Fireplaces and Wood Burning Heaters) will reduce a significant portion of emissions from those devices. Rule 4901 contains limits on wood combustion devices in new development, however, it still allows new devices in a development of a certain size or larger. Therefore, reductions from this category can still occur if the development can still install those devices and chooses not to.

Motor Vehicle Emissions

Motor vehicle emissions is the largest category of emissions attributed to new development. The inventory includes estimates of exhaust and evaporative VOCs, NOx, and PM10 associated with exhaust, tire wear and brake wear. On-road motor vehicles account for approximately 43% of the entire NOx inventory for 2002.[5] ARB estimates emissions from on-road vehicles using the EMFAC2002 model, which uses emission factors, vehicle numbers and vehicle activity. Emission rates are derived primarily from direct testing by the state or EPA. Vehicle population and vehicle age data are obtained from the Department of Motor Vehicles (DMV). Travel activity, which includes vehicle miles traveled (VMT), distribution of VMT by speed, the number of trips taken per vehicle each day, are provided by the California Department of Transportation

2 Staff report for Public Meeting to Consider Approval of the California Small Off-road engine emissions inventory, http://www.arb.ca.gov/msei/off-road/pubs/sore_final.doc

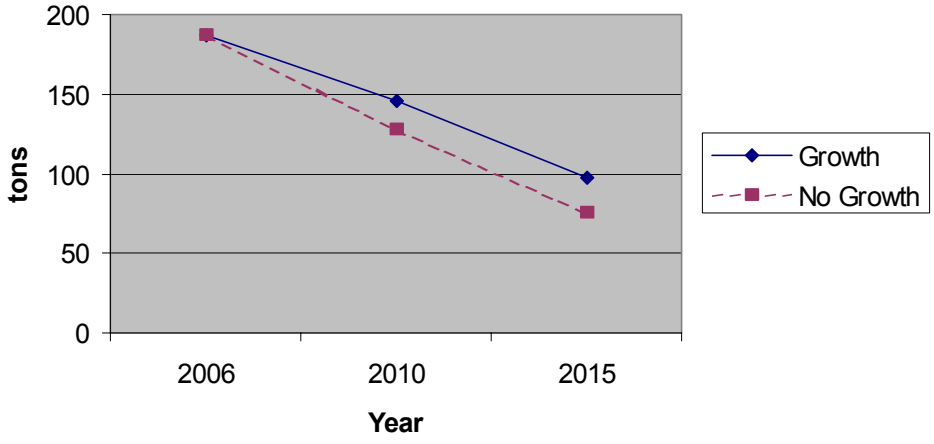
3 URBEMIS2002 Users' Guide, Version 7.4, May 2003, Appendix B.

4 Air Resources Board, Emissions Inventory Procedural Manual, Vol. III, Methods for Assessing Area Source Emissions, October 1997 with revisions through November 1998, section 7.1.

5 2003 PM10 Plan, Chapter 3, NOx Emissions Inventory

(Caltrans), local Metropolitan Planning Organizations (MPOs), local Councils of Governments (COGs), and fleet monitoring.[6] URBEMIS quantifies vehicle emissions attributed to a particular development based on the emission factors and vehicle activity found in EMFAC2002, in combination with project specific data. While the motor vehicle emissions inventory in both the PM10 and ozone plans show that vehicle emissions are declining, emissions would have declined even more if growth were not to occur, thus hampering the ability of the region to reach attainment of the PM10 and ozone standards. The following chart shows the emissions from all motor vehicles for the current population if it would have remained constant (No-Growth), and the emissions from vehicles for the projected population as reported in the 2003 PM10 Plan emissions inventory (Growth). Based on an analysis performed by ARB using EMFAC2002, which can be found in Attachment 1, the difference is an estimated 17.3 tons per day of NOx attributed to projected increase in growth in the SJVAB between 2006 and 2010.

Figure 1
Difference in NOx Emissions for All Vehicle Types



Re-entrained Road Dust

PM10 emissions from road dust occur by vehicles driving on unpaved roads, or by vehicles entraining or re-entraining dust on paved roads. ARB estimates PM10 emissions by using the following factors for different road types: silt loading on roads, vehicle weight, and VMT traveled. The majority of new development occurs on or creates new paved roads, however, some development in rural areas still use unpaved roads. Unpaved road emissions are estimated by using an emission factor and total VMT traveled.[7]

6 Overview of the On-Road Emissions Inventory, http://www.arb.ca.gov/msei/on-road/briefs/emfac6.pdf

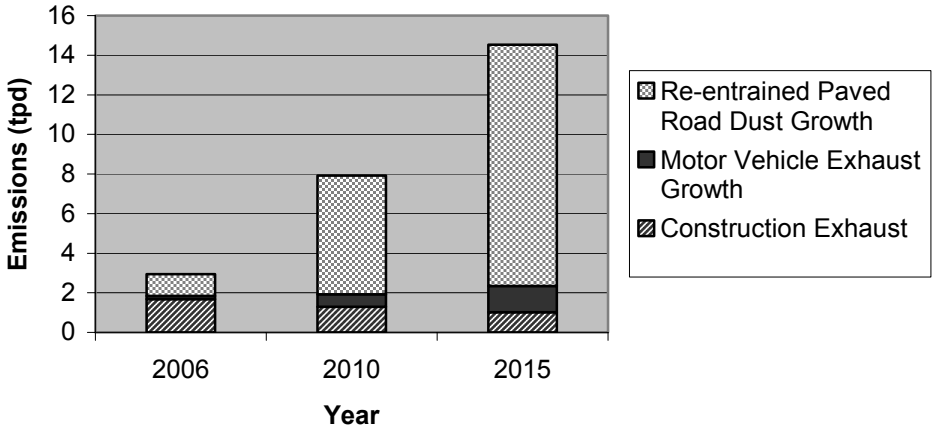
7 Air Resources Board, Emissions Inventory Procedural Manual, Vol. III, Methods for Assessing Area Source Emissions, October 1997 with revisions through November 1998, section 7.9-7.10.

Construction

This category of emissions differ slightly from the others, since all emissions from construction are due to new development, regardless of growth in the category. Emissions associated with construction activities occur for the purpose of building residential, commercial, industrial, institutional, or governmental structures. Emissions result predominantly from equipment associated with site preparation work, which may include scraping, grading, loading, digging, compacting, and other operations. ARB estimates construction emissions by utilizing a computer model called OFF-ROAD. The construction emissions in the OFF-ROAD model are estimated using the population, activity, and fuel usage of the varied types of construction equipment.

The following figure demonstrates PM10 emissions and emissions growth from construction equipment, re-entrained paved road dust, and vehicle exhaust associated with new development.

Figure 2
PM10 Emissions from Development



B. Projected Emissions from New Development

The following table illustrates the projected growth in emissions, as can be discerned from the emissions inventory:

Total Emissions Attributed to Land Use Growth in the SJVAB in 2010

NOx

Emissions Category	Emissions from Growth In 2010 (tpd)	Emissions from Growth during 2006-2010 (tpd)
On-road Vehicles[A]	2.2	17.3
Construction Equipment[C]	21.3	21.3
Total NOx	**23.5**	**137.8**

PM10

Construction Equipment[C]	1.4	1.4
On-road Vehicles[A]	0.2	0.6
Paved Road Dust[B]	1.1	5.2
Total PM10	**2.7**	**13.4**

A. Emissions Growth between 2006 and 2010 was estimated based on an ARB EMFAC 2002 version 2.2 run, dated June 10, 2005 (Attachment 1). This will be revised to obtain a total for 2006.

B. 2003 PM10 Plan emissions inventory

C. ARB Emission Inventory for 2010

It should be noted that some sources of emissions from new development are not included in the above table for several reasons. While there may be difficulties in assessing what portions of the emissions inventory are resulting from new growth, there are new emissions from growth occurring. Therefore, the above table represents a conservative estimate of what will occur, and does not overestimate. Therefore, any reductions applied to the emissions outlined in the above table will represent a conservative estimate of actual reductions resulting from this program.

III. EMISSIONS REDUCTION OPTIONS FOR NEW DEVELOPMENT

A. On-site Project-Specific Emissions Reductions

On-site mitigation measures and their corresponding emission reduction methodologies were developed by Nelson/Nygaard and put into URBEMIS. The following discussion lists measures/conditions, if implemented that would result in emissions reductions from a development project. The maximum percent reduction is in general terms. The actual reduction relies on project specific information and factors, and how the mitigation measure is used in combination with other measures.

Increase Energy Efficiency Beyond Title 24

This measure would reduce emissions by decreasing the amount of natural gas that is needed and in turn combusted for a particular development. Examples of how this could be achieved include: using insulation in the attic and walls, insulating ductwork, using whole house fans, double-paned and/or high performance glazed windows, maximizing the use of natural lighting, installing EnergyStar appliances, orienting the

building north or south to utilize passive heating and cooling, designing the building to maximize natural ventilation, or any number of other items that would decrease the use of natural gas, and therefore decrease emissions. The emissions reductions associated with this mitigation measure in URBEMIS would require a quantification of the % reduction beyond what is already required by Title 24 as determined by a computer model developed for Title 24 purposes.

Electrical landscape maintenance equipment

This measure would reduce emissions by eliminating some or all of the combustion of gasoline or diesel in standard landscape equipment by replacing it with equipment that relies on batteries, an electrical outlet, or manually-powered equipment. Emissions reductions are quantified by using the % of the development that would use non-combustion powered equipment.

Hearth

This measure would reduce emissions by eliminating construction of a wood combustion device that would have otherwise been allowed under Rule 4901.

Net Residential Density

Emissions reductions from this measure would occur when an individual from a particular residential use forgoes the use of the automobile and uses an alternate form of transportation. A considerable volume of research has investigated the links between density and travel behavior and has determined that there is a significant and quantifiable relationship between residential density and automobile use. Three key studies of travel behavior and density itself have identified elasticities, which has been used to develop a formula to determine the reduction in vehicle trips and vehicle miles traveled, and the corresponding emissions reductions. The maximum reduction in trips/VMT and resulting emissions that may occur from this measure is calculated to be 55%.

Mix of Uses

Emissions reductions from this measure would occur when an individual forgoes the use of the automobile and uses other forms of transportation. Research has shown that there is an impact of diversity or mix of uses on travel behavior, which can occur at the macro-scale, such as jobs-housing balance. Numerous studies of travel behavior and mix of uses have identified elasticities, which has been used to develop a formula to determine the reduction in vehicle trips and vehicle miles traveled, and the corresponding emissions reductions. The maximum reduction in trips/VMT and resulting emissions that may occur from this measure is calculated to be 9%.

Local Serving Retail

Emissions reductions from this measure occur when an individual forgoes the use of the automobile, since the proximity of the retail encourages other forms of transportation. The maximum reduction in trips/VMT and resulting emissions that may occur from this measure is calculated to be 2%.

Transit Service

Emissions reductions from this measure would occur when an individual forgoes the use of the automobile and uses transit. Transit choices could include buses, light rail, dedicated shuttles, and trolleys. Since emissions from transit services already exist, the elimination of trip(s) from the automobile would result in emissions reductions. URBEMIS determines emissions reductions from transit use based on a Transit Service Index, which is based on the latest California-specific research on transit use. The maximum reduction in trips/VMT and resulting emissions that may occur from this measure is calculated to be 15%.

Bicycle and Pedestrian Facilities

Emissions reductions from this measure would when an individual forgoes the use of the automobile and uses a bicycle or walks. Since the use of a bicycle or the action of walking does not emit emissions, the elimination of trip(s) from the automobile would result in emissions reductions. URBEMIS determines emissions reductions from bicycle use and pedestrian activities based on quantitative values of network density, sidewalk completeness and bike lane completeness. The maximum reduction in trips/VMT and resulting emissions that may occur from this measure is calculated to be 9%.

Affordable Housing/Senior Housing/ Assisted Living

This measure would reduce emissions by designating residential units as deed-restricted below-market-rate (BMR) housing. Research has shown that lower-income households and senior citizens own fewer vehicles and drive less. By designating residential units as deed-restricted BMR, only lower-income individuals that use the automobile less would occupy those units, which would result in lower emissions due to less automobile use. The maximum reduction in trips/VMT and resulting emissions and resulting emissions that may occur from this measure is calculated to be 4%.

Transportation Demand Management Programs

TDM Programs can include free transit passes, parking restrictions and telecommuting. Emissions reductions from this measure would occur when a landlord provides an incentive, such as transit passes, to individual(s), who then forgoes the use of the automobile and uses transit. These programs provide an incentive for the individual(s) to use the transit, and studies have show that these programs both increase transit ridership and reduce vehicle trips. The maximum reduction in trips/VMT and resulting emissions and resulting emissions that can be achieved under this measure is 25%.

Fleet Modifications

Reductions from this measure occur when a fleet owner makes vehicle specific modifications or agrees to purchase and/or use only vehicles with controls, such as a particulate filters or catalysts. There are numerous options available. The maximum reduction in emissions that can be achieved under this measure varies by control option.

It is important to note that many of the mitigation listed above requires a change in travel behavior of an individual in order for the emissions reductions to occur. It is not guaranteed that the mitigation measures will be successful at changing travel behavior to the exact amount as calculated, however, it represents the best estimate/projection of what will occur based on the most recent research conducted on existing travel behavior to date.

B. Off-site Emissions Reductions

In the event that the emissions impact of a particular project is not fully mitigated on site a proportional fee will be assessed and collected for the NOx and PM10 emissions not mitigated. The fees collected would be placed into a mitigation fund for each pollutant and county, and expended on projects that reduce emissions of that pollutant in that county, utilizing a grant-like program. The district has over eleven years experience with grant programs designed to reduce primarily NOx, and some VOC. Each grant program has had strict guidelines on emissions reductions, qualifying equipment, and the related administration of the program. Based on that experience, the District has decided that a grant program would provide the most cost-effective emissions reductions for the money that will be collected.

The District has employed the California Air Resources Board (ARB) and the California Department of Transportation document "*Methods to Find the Cost Effectiveness of Funding Air Quality Projects"* for finding the cost effectiveness and emission reduction benefits for a wide variety of emission reduction projects. This document can also be accessed through an associated on-line database. The methods described are generally accepted and include: a list of information needed to calculate cost effectiveness, emission factors, project life, defaults that may be used when project-specific data is not available (assumptions) and formulas to calculate vehicle emission reductions for three major pollutants, NOx, PM10, and VOC's. Many of those methods were used to develop the grant programs that could be funded under this program.

The most successful District grant program has been the Heavy-Duty Engine Incentive Program. This program replaces older model high polluting engines with newer and cleaner burning engines. Eligible project types funded under the heavy-duty program include, but are not limited to: on-road and off road vehicles and equipment, agricultural pump engines, marine vessels, forklifts, truck stop electrification technology, and school bus projects.

The Voluntary Accelerated Vehicle Retirement (Scrap) Program is designed to accelerate the voluntary retirement of older, higher polluting passenger vehicles. Monetary incentives are provided to individuals who agree to scrap their high polluting passenger vehicles. Ideally, this incentive money will help them purchase newer vehicles with cleaner burning engines.

The Light and Medium Duty Vehicle Incentive Program is designed to encourage the purchase and use of cleaner engine technology for passenger vehicles. To be eligible under the program, the light and medium duty vehicles must be powered by natural gas, electricity, fuel cells, or gasoline-electric hybrid technology.

The Carl Moyer Program provides incentive funds for significant near-term reductions in NOx. Eligible project types under the Carl Moyer Program include: new alternative fuel vehicle projects, on and off-road vehicle engine replacement projects, agricultural pump engine replacements, locomotive engine replacements, marine vessels, forklifts, and airport ground support equipment engine replacements. Projects are funded based on cost effectiveness, utilizing criteria developed by the state in coordination with the air districts and the statewide Incentive Program Implementation Team (IPI).

In addition to the sources listed above, the District receives grant funds from other state and federal funding sources including: the State's Lower Emission School Bus Program, Peaker Plant Offset funds, and the State's NOx and PM Program funds.

IV. EMISSIONS REDUCTION OPTIONS FOR CONSTRUCTION

Construction PM10 emissions can be mitigated in numerous ways. The following discussion lists measures/conditions, if implemented that would result in emissions reductions from construction activities. The percent reduction identified was based on the URBEMIS2002 Users' Guide.

A. On-site Reduction Options

There are several on-site construction emissions reductions available. The following lists the current mitigation measures that reduce PM10 and NOx. There is a statewide effort to update the construction portion of URBEMIS, so there may be more mitigation measures identified that are not included in this appendix.

Equipment Exhaust Control

There are several options available for controlling NOx and PM10 emissions from equipment used for construction. Options can include, purchasing newer equipment, altering fuel usage, modifying an engine, using exhaust after-treatments, or renting equipment that help meet the rule requirements. New equipment can provide a high percentage of emissions reductions, depending on the horsepower and the year of the equipment. Reductions that can occur from using newer equipment reductions range from 8-62% for PM10, and 20-38% for NOx. Different fuels are available for use that would reduce emissions from construction equipment. Ultra-low sulfur diesel can achieve a 5-9% reduction in PM10. Alternative diesel fuels can achieve 5-16% reduction in NOx and a 40-63% reduction in PM10. Diesel oxidation catalysts can reduce PM10 by 25-50%. Diesel particulate filters can reduce PM10 by 85%. Selective Catalytic Reduction can reduce NOx by 80% and PM10 by 25%.

Worker Commute Trip Reductions

This measure would entail using a shuttle to take construction workers to a retail establishment for lunch. This would eliminate numerous trips, which would reduce vehicle exhaust, and entrained and/or re-entrained road dust. The maximum PM10 reduction from this measure is 1.3%.

B. Off-site Reduction Options

Since any fees collected will reduce construction emissions off-site, the same emissions reduction options listed in section III above apply.

V. PROJECT-SPECIFIC EMISSIONS REDUCTIONS

Each development project, subject to Rule 9510, will have an assessment of the project performed. The assessment will include an APCO-approved model run that identifies the project or project phase baseline emissions and the emissions reduction resulting from on-site mitigation measures. The remaining emissions will be quantified and will fund emissions reduction project(s), using the fee formulas identified below.

Area and Operational NOx Fee Formula

The NOx fee formula must identify the total tonnage of mitigation required, subtract the tonnage mitigated on-site, and multiply the remaining tonnage by the cost of reductions in order to determine the cost to reduce emissions off-site.

Figure 3

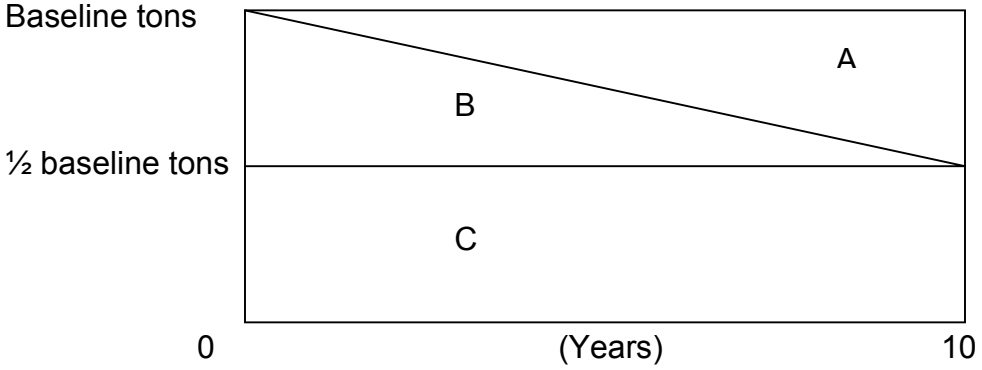


Figure 3 represents a development project's NOx emissions over a period of ten years. Section A represents the emissions reductions projected to be achieved from ARB's tailpipe control, which is 25% of the total project's 10 years emissions. The remaining 75% is the project's estimated NOx emissions for ten years. The mitigation required by Rule 9510 is represented by the triangle B, which equal to a third of the non-A section. Thus, the total tonnage of mitigation required can be identified as follows:

$$\frac{\text{Estimated Baseline Emissions (tons) x 10 years x 75\%}}{3}$$

which is equal to:

EBE (tons) x 2.5

The next step is to subtract the percent reduction achieved from on-site mitigation measures. This is determined by using the estimated baseline emissions over ten years and applying the percent mitigation, as follows:

Estimated Baseline Emissions (tons) x 10 years x 75% x Actual % Mitigation
=EBE x 7.5 x APM

Thus,

(EBE x 2.5) **-** (EBE x 7.5 x APM)

determines the total emissions remaining to mitigate off-site. That number then needs to multiplied by dollars per ton, in order to determine total dollars required to mitigation emissions off-site. The resulting NOx Air Impact Mitigation Fee is as follows:

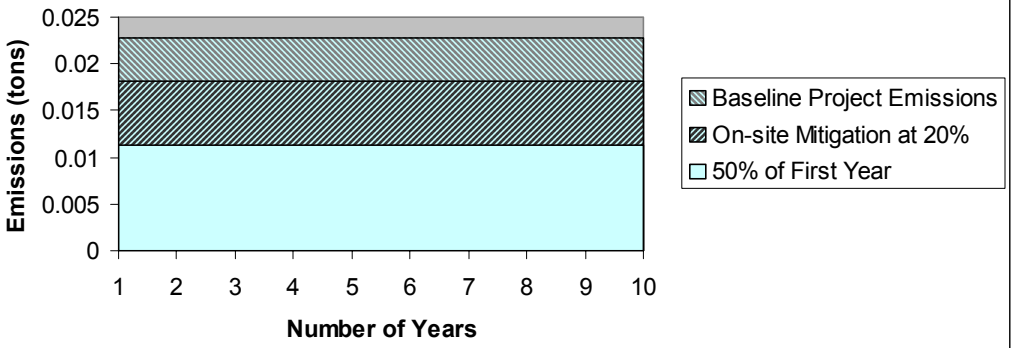
[EBE x 2.5] **-** [EBE x 7.5 x APM] **x** [Cost of NOx Reductions/ton]

It is important to note that the percent reduction achieved onsite, results in a greater reduction of the NOx fee. While on-site mitigation is not required, the "bigger bang for the buck" is achieved with as much on-site mitigation as possible.

Area and Operational PM10 Fee Formula

The Air Impact Mitigation Fee for PM10 is more straightforward since a project's PM10 emissions remain relatively constant over the life of the project. For ease of understanding, Figure 4 below demonstrates the relationship between baseline emissions, mitigated emissions and half of the baseline emissions.

Figure 4
PM10 Project Emissions and Reductions Compared to 50% of the First Year Emissions



The required PM10 mitigation is half of the baseline emissions for ten years. In order to determine the emissions that are subject to a fee, half of the baseline emissions need to be subtracted from the Mitigated Emissions and multiplied by cost of reductions in dollars per ton. Thus the resulting PM10 Air Impact Mitigation Fee is calculated as follows:

(Mitigated PM10 emissions – ½ Baseline PM10 emissions) (Cost of PM10 Reductions)

Construction Formulas

The Air Impact Mitigation Fees for construction are based on the project's estimated construction equipment emissions, and compared to the statewide fleet average emissions. The required information is as follows: 1)a list of construction equipment used, 2)the model year, and 3)the hours estimated to be used is compiled, which can be determined from the National Construction Estimator or using project-specific information if known. Then the model specific emission factors are used to determine the actual estimated emissions (designated as AEE). The same hours are multiplied by a statewide average fleet emission factor for a particular year, to determine the statewide average estimated emissions (designated as SEE). Since the requirement is to reduce construction NOx emissions by 20% beyond the statewide average, this is determined as follows:

NOx Construction = (AEE) – [(1.00 x SEE) – (SEE x 0.20)]
(AEE) – [1.00SEE – 0.20SEE]
(AEE – 0.8SEE)

PM10 is almost identical, except that the requirement is to reduce construction PM10 emissions by 45% beyond the statewide average.

PM10 Construction = (AEE) – [(1.00 x SEE) – (SEE x 0.45)]
(AEE) – [1.00SEE – 0.45SEE]
(AEE – 0.55SEE)

VI. EMISSIONS REDUCTIONS FROM RULE 9510

Both the 2003 PM10 Plan and the Extreme Ozone Attainment Demonstration Plan, contain emissions reduction commitments for proposed Rule 9510 of 4.1 tons per day of NOx and 5.2 tons per day of PM10 to be achieved by 2010. Those estimates were based on assumptions at the time and are commitments that are necessary to assist the district in meeting the federal and state PM10 and NOx standards. The methodology contained in this section and related attachments demonstrate the draft emission reductions for the program.

As part of determining the emissions reductions, sources that are exempt from the rule need to be subtracted out. The District has numerous years of experience in commenting on projects subject to CEQA. Based on that experience and the thresholds contained in Rule 9510, it is estimated that 15% of all development project emissions will be exempt from the provisions that rule. Attachment 2 and Attachment 3 identify the growth in emissions for each pollutant for each year, and subtract the emissions that will be exempt from the program. Once the emissions subject to the program are identified, the required mitigation is applied, which is 33.3% of baseline NOx emissions over ten years, 50% of baseline operational PM10 emissions over ten years, 20% of construction NOx emissions and 45% of construction PM10 emissions. The reductions achieved on-site were calculated by multiplying the estimated percent of sources opting to use on-site measures, the percent reduction achieved on-site, by the baseline emissions. Off-site reductions were estimated differently. Since grant programs typically rely on project life to determine cost effectiveness and emissions reductions, the reduction was divided by the average project life for that pollutant's cost-effectiveness, which is 7 years for NOx and 12 years for PM10, and spread out over that number of years. Attachment 2 and 3 contain the detailed emission reductions calculations. The results of those calculations reveal that the program, as currently defined, will result in reductions of 5.4 tons per day of NOx in 2010 and 5.8 tons per day of PM10 in 2010.

Attachment 1 - Emissions and Growth in Emissions from Motor Vehicles

Passenger Cars						
Total - Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	46,763,000	1,186,080	27.53	25.64	1.69	282.88
CY 2007	48,037,000	1,215,840	25.06	23.34	1.73	260.25
CY2008	49,324,000	1,246,060	22.80	21.26	1.77	239.16
CY2009	50,625,000	1,276,970	20.74	19.32	1.81	219.49
CY2010	51,952,000	1,308,670	18.80	17.52	1.85	200.89
CY2011	53,253,000	1,340,690	17.11	15.87	1.90	184.01
CY2012	54,544,000	1,373,190	15.61	14.39	1.94	168.64
CY2013	55,835,000	1,406,290	14.28	13.07	1.99	154.78
CY2014	57,127,000	1,440,000	13.12	11.89	2.04	142.42
CY2015	58,427,000	1,474,400	12.12	10.85	2.08	131.38
Total - No Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	46,763,000	1,186,080	27.53	25.64	1.69	282.88
CY 2007	46,817,000	1,184,970	23.52	21.39	1.68	242.70
CY2008	46,857,000	1,183,740	20.86	18.97	1.68	217.58
CY2009	46,878,000	1,182,430	18.52	16.81	1.67	194.91
CY2010	46,885,000	1,181,030	16.38	14.86	1.67	174.13
CY2011	46,849,000	1,179,460	14.55	13.13	1.67	155.73
CY2012	46,784,000	1,177,840	12.96	11.61	1.67	139.41
CY2013	46,702,000	1,176,250	11.58	10.29	1.66	125.00
CY2014	46,601,000	1,174,680	10.39	9.13	1.66	112.39
CY2015	46,487,000	1,173,100	9.37	8.14	1.66	101.32
Total - Difference						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2007	1,220,000	30,870	1.54	1.95	0.05	17.55
CY2008	2,467,000	62,320	1.94	2.29	0.09	21.58
CY2009	3,747,000	94,540	2.22	2.51	0.14	24.58
CY2010	5,067,000	127,640	2.42	2.66	0.18	26.76
CY2011	6,404,000	161,230	2.56	2.74	0.23	28.28
CY2012	7,760,000	195,350	2.65	2.78	0.27	29.23
CY2013	9,133,000	230,040	2.70	2.78	0.33	29.78
CY2014	10,526,000	265,320	2.73	2.76	0.38	30.03
CY2015	11,940,000	301,300	2.75	2.71	0.42	30.06

Light-Duty Truck (GVWR < 3,751 lbs)						
Total - Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	19,277,000	504,871	16.65	16.97	0.75	191.39
CY 2007	19,879,000	518,651	15.59	15.63	0.77	177.66

CY2008	20,503,000	532,766	14.54	14.39	0.78	164.45
CY2009	21,148,000	547,300	13.50	13.21	0.80	151.41
CY2010	21,810,000	562,308	12.50	12.10	0.82	138.99
CY2011	22,456,000	577,812	11.70	11.10	0.84	128.18
CY2012	23,103,000	593,638	10.97	10.22	0.86	118.33
CY2013	23,754,000	609,742	10.27	9.41	0.88	109.08
CY2014	24,410,000	626,177	9.61	8.68	0.90	100.56
CY2015	25,072,000	642,987	9.02	8.01	0.93	92.73
Total - No Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	19,277,000	504,871	16.65	16.97	0.75	191.39
CY 2007	19,374,000	505,480	14.54	14.03	0.75	163.40
CY2008	19,478,000	506,121	13.21	12.57	0.74	147.26
CY2009	19,582,000	506,782	11.96	11.22	0.74	132.09
CY2010	19,683,000	507,465	10.80	10.01	0.74	118.19
CY2011	19,756,000	508,326	9.87	8.96	0.74	106.40
CY2012	19,816,000	509,186	9.04	8.04	0.74	95.88
CY2013	19,869,000	510,001	8.26	7.22	0.74	86.35
CY2014	19,912,000	510,803	7.55	6.49	0.74	77.79
CY2015	19,949,000	511,590	6.93	5.86	0.74	70.11
Total - Difference						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2007	505,000	13,171	1.05	1.60	0.02	14.26
CY2008	1,025,000	26,645	1.33	1.82	0.04	17.19
CY2009	1,566,000	40,518	1.54	1.99	0.06	19.32
CY2010	2,127,000	54,843	1.70	2.09	0.08	20.80
CY2011	2,700,000	69,486	1.83	2.14	0.10	21.78
CY2012	3,287,000	84,452	1.93	2.18	0.12	22.45
CY2013	3,885,000	99,741	2.01	2.19	0.14	22.73
CY2014	4,498,000	115,374	2.06	2.19	0.16	22.77
CY2015	5,123,000	131,397	2.09	2.15	0.19	22.62

Light-Duty Truck (GVWR 3,751 to 5,750 lbs)						
Total - Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	14,206,000	363,542	11.60	15.81	0.74	133.05
CY 2007	14,550,000	373,494	11.03	14.80	0.76	125.36
CY2008	14,919,000	383,713	10.48	13.85	0.78	117.89
CY2009	15,308,000	394,213	9.95	12.93	0.80	110.66
CY2010	15,718,000	405,048	9.44	12.05	0.83	103.67
CY2011	16,150,000	416,094	8.90	11.17	0.85	96.52
CY2012	16,591,000	427,382	8.39	10.34	0.87	89.90
CY2013	17,045,000	438,884	7.89	9.56	0.90	83.57
CY2014	17,507,000	450,596	7.40	8.83	0.92	77.55
CY2015	17,972,000	462,557	6.97	8.16	0.95	72.09

Total - No Growth						
	VMT	Pop	ROG	NOx	PM10	CO
CY 2006	14,206,000	363,542	11.60	15.81	0.74	133.05
CY 2007	14,180,000	364,010	10.37	13.49	0.74	116.90
CY2008	14,173,000	364,523	9.61	12.29	0.74	107.14
CY2009	14,175,000	365,028	8.90	11.17	0.74	98.08
CY2010	14,185,000	365,543	8.25	10.14	0.74	89.63
CY2011	14,208,000	366,056	7.59	9.16	0.75	81.45
CY2012	14,230,000	366,582	6.99	8.27	0.75	74.06
CY2013	14,257,000	367,092	6.42	7.46	0.75	67.24
CY2014	14,281,000	367,573	5.87	6.72	0.75	60.96
CY2015	14,300,000	368,032	5.41	6.06	0.75	55.36
Total - Difference						
	VMT	Pop	ROG	NOx	PM10	CO
CY 2007	370,000	9,484	0.66	1.31	0.02	8.46
CY2008	746,000	19,190	0.87	1.56	0.04	10.75
CY2009	1,133,000	29,185	1.05	1.76	0.06	12.58
CY2010	1,533,000	39,505	1.19	1.91	0.09	14.04
CY2011	1,942,000	50,038	1.31	2.01	0.10	15.07
CY2012	2,361,000	60,800	1.40	2.07	0.12	15.84
CY2013	2,788,000	71,792	1.47	2.10	0.15	16.33
CY2014	3,226,000	83,023	1.53	2.11	0.17	16.59
CY2015	3,672,000	94,525	1.56	2.10	0.20	16.73

Medium-Duty Truck (GVWR 5,751 to 8,500 lbs)						
Total - Growth						
	VMT	Pop	ROG	NOx	PM10	CO
CY 2006	5,521,000	141,790	5.01	7.94	0.29	57.52
CY 2007	5,679,000	146,113	4.79	7.46	0.30	54.45
CY2008	5,844,000	150,494	4.57	7.00	0.31	51.57
CY2009	6,017,000	155,025	4.36	6.56	0.32	48.81
CY2010	6,196,000	159,717	4.16	6.15	0.33	46.11
CY2011	6,369,000	164,373	3.96	5.74	0.33	43.46
CY2012	6,547,000	169,143	3.77	5.35	0.34	40.99
CY2013	6,728,000	174,015	3.60	4.99	0.36	38.71
CY2014	6,914,000	178,995	3.44	4.65	0.37	36.65
CY2015	7,105,000	184,102	3.29	4.34	0.38	34.70
Total - No Growth						
	VMT	Pop	ROG	NOx	PM10	CO
CY 2006	5,521,000	141,790	5.01	7.94	0.29	57.52
CY 2007	5,535,000	142,403	4.47	6.84	0.29	50.71
CY2008	5,552,000	142,967	4.16	6.25	0.29	46.84
CY2009	5,571,000	143,548	3.87	5.71	0.29	43.19
CY2010	5,591,000	144,140	3.60	5.20	0.29	39.82
CY2011	5,603,000	144,606	3.35	4.73	0.29	36.65
CY2012	5,615,000	145,080	3.12	4.30	0.30	33.75

CY2013	5,628,000	145,550	2.91	3.91	0.30	31.12
CY2014	5,640,000	146,015	2.72	3.55	0.30	28.80
CY2015	5,653,000	146,480	2.54	3.24	0.30	26.65
Total - Difference						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2007	144,000	3,710	0.32	0.62	0.01	3.74
CY2008	292,000	7,527	0.41	0.75	0.02	4.73
CY2009	446,000	11,477	0.49	0.85	0.03	5.62
CY2010	605,000	15,577	0.56	0.95	0.04	6.29
CY2011	766,000	19,767	0.61	1.01	0.04	6.81
CY2012	932,000	24,063	0.65	1.05	0.04	7.24
CY2013	1,100,000	28,465	0.69	1.08	0.06	7.59
CY2014	1,274,000	32,980	0.72	1.10	0.07	7.85
CY2015	1,452,000	37,622	0.75	1.10	0.08	8.05

Light Heavy-Duty Truck (GVWR 8,501 to 10,000 lbs)						
Total - Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	2,281,000	34,879	2.13	5.00	0.12	12.85
CY 2007	2,304,000	35,651	1.96	4.95	0.12	11.55
CY2008	2,321,000	36,449	1.84	4.89	0.13	10.52
CY2009	2,334,000	37,270	1.74	4.84	0.13	9.70
CY2010	2,344,000	38,123	1.68	4.71	0.13	9.01
CY2011	2,351,000	38,998	1.65	4.58	0.13	8.49
CY2012	2,356,000	39,887	1.63	4.46	0.13	8.06
CY2013	2,362,000	40,784	1.63	4.34	0.13	7.67
CY2014	2,371,000	41,696	1.63	4.23	0.13	7.34
CY2015	2,384,000	42,634	1.64	4.13	0.13	7.04
Total - No Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	2,281,000	34,879	2.13	5.00	0.12	12.85
CY 2007	2,246,000	34,746	1.91	4.82	0.12	11.24
CY2008	2,205,000	34,626	1.74	4.64	0.12	9.99
CY2009	2,161,000	34,511	1.61	4.48	0.12	8.97
CY2010	2,115,000	34,405	1.51	4.24	0.12	8.13
CY2011	2,068,000	34,309	1.45	4.02	0.11	7.46
CY2012	2,021,000	34,213	1.40	3.82	0.11	6.91
CY2013	1,976,000	34,113	1.36	3.63	0.11	6.42
CY2014	1,934,000	34,014	1.33	3.45	0.11	5.98
CY2015	1,897,000	33,921	1.31	3.28	0.10	5.60

Total - Difference						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2007	58,000	905	0.05	0.13	0.00	0.31
CY2008	116,000	1,823	0.10	0.25	0.01	0.53
CY2009	173,000	2,759	0.13	0.36	0.01	0.73

CY2010	229,000	3,718	0.17	0.47	0.01	0.88
CY2011	283,000	4,689	0.20	0.56	0.02	1.03
CY2012	335,000	5,674	0.23	0.64	0.02	1.15
CY2013	386,000	6,671	0.27	0.71	0.02	1.25
CY2014	437,000	7,682	0.30	0.78	0.02	1.36
CY2015	487,000	8,713	0.33	0.85	0.03	1.44

Light Heavy-Duty Truck (GVWR 10,001 to 14,000 lbs)						
Total - Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	624,000	10,645	0.76	2.78	0.06	4.45
CY 2007	626,000	10,885	0.75	2.67	0.05	4.18
CY2008	630,000	11,133	0.74	2.57	0.05	3.93
CY2009	637,000	11,387	0.72	2.47	0.05	3.67
CY2010	645,000	11,651	0.70	2.33	0.05	3.42
CY2011	653,000	11,922	0.68	2.19	0.05	3.18
CY2012	664,000	12,200	0.66	2.06	0.05	2.98
CY2013	674,000	12,484	0.64	1.93	0.05	2.79
CY2014	686,000	12,773	0.62	1.81	0.05	2.63
CY2015	699,000	13,071	0.60	1.70	0.05	2.46
Total - No Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	624,000	10,645	0.76	2.78	0.06	4.45
CY 2007	611,000	10,609	0.73	2.60	0.05	4.07
CY2008	599,000	10,576	0.70	2.43	0.05	3.73
CY2009	590,000	10,544	0.67	2.29	0.05	3.40
CY2010	582,000	10,514	0.63	2.10	0.05	3.09
CY2011	575,000	10,489	0.60	1.92	0.04	2.80
CY2012	569,000	10,465	0.56	1.76	0.04	2.56
CY2013	564,000	10,442	0.53	1.61	0.04	2.34
CY2014	560,000	10,420	0.50	1.48	0.04	2.15
CY2015	556,000	10,400	0.47	1.35	0.04	1.96
Total - Difference						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2007	15,000	276	0.02	0.07	0.00	0.11
CY2008	31,000	557	0.04	0.14	0.00	0.20
CY2009	47,000	843	0.05	0.18	0.00	0.27
CY2010	63,000	1,137	0.07	0.23	0.00	0.33
CY2011	78,000	1,433	0.08	0.27	0.01	0.38
CY2012	95,000	1,735	0.10	0.30	0.01	0.42
CY2013	110,000	2,042	0.11	0.32	0.01	0.45
CY2014	126,000	2,353	0.12	0.33	0.01	0.48
CY2015	143,000	2,671	0.13	0.35	0.01	0.50

Medium Heavy-Duty Truck (GVWR 14,001 to 33,000 lbs)						
Total - Growth						
	VMT	Pop	ROG	NOx	PM10	CO
CY 2006	1,844,000	32,324	4.23	20.26	0.61	31.38
CY 2007	1,897,000	33,004	3.94	19.34	0.58	29.10
CY2008	1,951,000	33,694	3.69	18.42	0.57	27.07
CY2009	2,005,000	34,411	3.45	17.53	0.56	25.24
CY2010	2,058,000	35,155	3.22	16.29	0.54	23.47
CY2011	2,113,000	35,925	3.00	15.10	0.52	21.80
CY2012	2,168,000	36,711	2.79	13.96	0.50	20.22
CY2013	2,223,000	37,512	2.60	12.87	0.49	18.77
CY2014	2,279,000	38,329	2.40	11.85	0.48	17.36
CY2015	2,334,000	39,167	2.23	10.88	0.46	16.05
Total - No Growth						
	VMT	Pop	ROG	NOx	PM10	CO
CY 2006	1,844,000	32,324	4.23	20.26	0.61	31.38
CY 2007	1,849,000	32,166	3.83	18.83	0.56	28.33
CY2008	1,853,000	32,009	3.49	17.48	0.54	25.68
CY2009	1,856,000	31,864	3.19	16.21	0.52	23.34
CY2010	1,857,000	31,726	2.90	14.68	0.49	21.15
CY2011	1,859,000	31,605	2.64	13.27	0.46	19.15
CY2012	1,860,000	31,488	2.39	11.96	0.43	17.32
CY2013	1,859,000	31,376	2.17	10.76	0.41	15.68
CY2014	1,859,000	31,267	1.96	9.65	0.39	14.15
CY2015	1,857,000	31,163	1.77	8.65	0.37	12.76
Total - Difference						
	VMT	Pop	ROG	NOx	PM10	CO
CY 2007	48,000	838	0.11	0.51	0.02	0.77
CY2008	98,000	1,685	0.20	0.94	0.03	1.39
CY2009	149,000	2,547	0.26	1.32	0.04	1.90
CY2010	201,000	3,429	0.32	1.61	0.05	2.32
CY2011	254,000	4,320	0.36	1.83	0.06	2.65
CY2012	308,000	5,223	0.40	2.00	0.07	2.90
CY2013	364,000	6,136	0.43	2.11	0.08	3.09
CY2014	420,000	7,062	0.44	2.20	0.09	3.21
CY2015	477,000	8,004	0.46	2.23	0.09	3.29

Heavy Heavy-Duty Truck (GVWR 33,001 to 60,000 lbs)						
Total - Growth						
	VMT	Pop	ROG	NOx	PM10	CO
CY 2006	4,845,000	31,643	6.00	82.30	1.85	44.21
CY 2007	4,978,000	32,260	5.70	78.05	1.72	41.00
CY2008	5,123,000	32,896	5.44	73.87	1.65	38.44
CY2009	5,281,000	33,555	5.18	69.88	1.60	36.18
CY2010	5,449,000	34,235	4.90	64.43	1.52	33.93
CY2011	5,628,000	34,939	4.64	59.06	1.44	31.99

CY2012	5,817,000	35,648	4.39	53.91	1.37	30.10
CY2013	6,019,000	36,370	4.13	49.01	1.31	28.31
CY2014	6,235,000	37,118	3.91	44.50	1.26	26.84
CY2015	6,451,000	37,891	3.68	40.44	1.22	25.19
Total - No Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	4,845,000	31,643	6.00	82.30	1.85	44.21
CY 2007	4,852,000	31,440	5.49	75.87	1.67	39.47
CY2008	4,866,000	31,251	5.10	69.98	1.57	36.07
CY2009	4,890,000	31,071	4.73	64.51	1.48	33.09
CY2010	4,918,000	30,896	4.37	57.97	1.37	30.23
CY2011	4,951,000	30,738	4.03	51.80	1.27	27.78
CY2012	4,989,000	30,577	3.71	46.09	1.18	25.48
CY2013	5,034,000	30,420	3.41	40.86	1.10	23.37
CY2014	5,086,000	30,279	3.15	36.19	1.03	21.61
CY2015	5,133,000	30,148	2.90	32.08	0.97	19.78
Total - Difference						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2007	126,000	820	0.21	2.18	0.05	1.53
CY2008	257,000	1,645	0.34	3.89	0.08	2.37
CY2009	391,000	2,484	0.45	5.37	0.12	3.09
CY2010	531,000	3,339	0.53	6.46	0.15	3.70
CY2011	677,000	4,201	0.61	7.26	0.17	4.21
CY2012	828,000	5,071	0.68	7.82	0.19	4.62
CY2013	985,000	5,950	0.72	8.15	0.21	4.94
CY2014	1,149,000	6,839	0.76	8.31	0.23	5.23
CY2015	1,318,000	7,743	0.78	8.36	0.25	5.41

School Bus						
Total - Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	186,000	3,982	0.32	2.54	0.10	3.59
CY 2007	190,000	4,082	0.31	2.57	0.10	3.39
CY2008	195,000	4,185	0.31	2.60	0.10	3.35
CY2009	200,000	4,290	0.31	2.63	0.10	3.26
CY2010	205,000	4,398	0.31	2.65	0.10	3.22
CY2011	210,000	4,512	0.31	2.67	0.10	3.19
CY2012	216,000	4,627	0.32	2.66	0.10	3.15
CY2013	221,000	4,743	0.31	2.64	0.10	3.03
CY2014	227,000	4,861	0.31	2.62	0.10	2.93
CY2015	232,000	4,981	0.31	2.60	0.10	2.81
Total - No Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	186,000	3,982	0.32	2.54	0.10	3.59
CY 2007	185,000	3,978	0.30	2.50	0.10	3.30
CY2008	185,000	3,975	0.29	2.47	0.10	3.17

CY2009	185,000	3,972	0.29	2.43	0.09	3.01
CY2010	185,000	3,969	0.28	2.39	0.09	2.90
CY2011	185,000	3,969	0.28	2.34	0.09	2.80
CY2012	185,000	3,968	0.27	2.27	0.09	2.69
CY2013	185,000	3,967	0.26	2.20	0.09	2.53
CY2014	185,000	3,966	0.25	2.13	0.08	2.39
CY2015	185,000	3,963	0.24	2.06	0.08	2.23
Total - Difference						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2007	5,000	104	0.01	0.07	0.00	0.09
CY2008	10,000	210	0.02	0.13	0.00	0.18
CY2009	15,000	318	0.02	0.20	0.01	0.25
CY2010	20,000	429	0.03	0.26	0.01	0.32
CY2011	25,000	543	0.03	0.33	0.01	0.39
CY2012	31,000	659	0.05	0.39	0.01	0.46
CY2013	36,000	776	0.05	0.44	0.01	0.50
CY2014	42,000	895	0.06	0.49	0.02	0.54
CY2015	47,000	1,018	0.07	0.54	0.02	0.58

Urban Bus						
Total - Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	330,000	2,407	1.30	4.70	0.08	11.25
CY 2007	338,000	2,468	1.29	4.69	0.08	11.08
CY2008	347,000	2,531	1.28	4.68	0.08	10.88
CY2009	356,000	2,595	1.28	4.67	0.08	10.78
CY2010	365,000	2,661	1.27	4.66	0.08	10.55
CY2011	374,000	2,730	1.27	4.64	0.08	10.29
CY2012	384,000	2,800	1.26	4.56	0.08	9.87
CY2013	393,000	2,870	1.26	4.54	0.08	9.41
CY2014	403,000	2,942	1.26	4.44	0.08	9.05
CY2015	413,000	3,014	1.25	4.40	0.08	8.47
Total - No Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	330,000	2,407	1.30	4.70	0.08	11.25
CY 2007	330,000	2,406	1.25	4.56	0.07	10.78
CY2008	329,000	2,404	1.21	4.44	0.07	10.32
CY2009	329,000	2,403	1.17	4.31	0.07	9.97
CY2010	329,000	2,402	1.14	4.19	0.07	9.51
CY2011	329,000	2,402	1.11	4.07	0.07	9.04
CY2012	329,000	2,401	1.07	3.90	0.07	8.45
CY2013	329,000	2,401	1.04	3.79	0.06	7.86
CY2014	329,000	2,400	1.02	3.61	0.06	7.37
CY2015	329,000	2,398	0.98	3.49	0.06	6.72

Total - Difference						
	VMT	Pop	ROG	NOx	PM10	CO
CY 2007	8,000	62	0.04	0.13	0.01	0.30
CY2008	18,000	127	0.07	0.24	0.01	0.56
CY2009	27,000	192	0.11	0.36	0.01	0.81
CY2010	36,000	259	0.13	0.47	0.01	1.04
CY2011	45,000	328	0.16	0.57	0.01	1.25
CY2012	55,000	399	0.19	0.66	0.01	1.42
CY2013	64,000	469	0.22	0.75	0.02	1.55
CY2014	74,000	542	0.24	0.83	0.02	1.68
CY2015	84,000	616	0.27	0.91	0.02	1.75

Motorhome

Total - Growth						
	VMT	Pop	ROG	NOx	PM10	CO
CY 2006	531,000	34,851	0.84	2.04	0.03	21.00
CY 2007	552,000	36,150	0.80	2.01	0.03	19.78
CY2008	574,000	37,508	0.75	1.97	0.03	18.26
CY2009	598,000	38,927	0.70	1.93	0.03	16.91
CY2010	624,000	40,417	0.66	1.86	0.03	15.57
CY2011	651,000	42,003	0.60	1.79	0.03	14.09
CY2012	679,000	43,650	0.56	1.72	0.03	12.73
CY2013	709,000	45,360	0.50	1.63	0.04	11.26
CY2014	741,000	47,134	0.45	1.54	0.04	9.86
CY2015	772,000	48,973	0.40	1.46	0.04	8.67
Total - No Growth						
	VMT	Pop	ROG	NOx	PM10	CO
CY 2006	531,000	34,851	0.84	2.04	0.03	21.00
CY 2007	538,000	35,232	0.78	1.95	0.03	19.27
CY2008	546,000	35,632	0.71	1.87	0.03	17.33
CY2009	554,000	36,045	0.65	1.78	0.03	15.65
CY2010	563,000	36,475	0.59	1.68	0.03	14.04
CY2011	573,000	36,951	0.53	1.57	0.03	12.39
CY2012	583,000	37,440	0.48	1.47	0.03	10.92
CY2013	593,000	37,940	0.42	1.36	0.03	9.41
CY2014	604,000	38,449	0.37	1.25	0.03	8.04
CY2015	615,000	38,965	0.32	1.15	0.03	6.89

Total - Difference						
	VMT	Pop	ROG	NOx	PM10	CO
CY 2007	14,000	918	0.02	0.06	0.00	0.51
CY2008	28,000	1,876	0.04	0.10	0.00	0.93
CY2009	44,000	2,882	0.05	0.15	0.00	1.26
CY2010	61,000	3,942	0.07	0.18	0.00	1.53
CY2011	78,000	5,052	0.07	0.22	0.00	1.70
CY2012	96,000	6,210	0.08	0.25	0.00	1.81
CY2013	116,000	7,420	0.08	0.27	0.01	1.85

CY2014	137,000	8,685	0.08	0.29	0.01	1.82
CY2015	157,000	10,008	0.08	0.31	0.01	1.78

Motorcycle						
Total - Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	342,000	38,680	2.17	0.55	0.02	20.14
CY 2007	352,000	39,251	2.14	0.57	0.03	20.42
CY2008	361,000	39,854	2.06	0.57	0.02	19.23
CY2009	369,000	40,483	1.99	0.56	0.02	18.12
CY2010	376,000	41,132	1.93	0.56	0.02	17.19
CY2011	383,000	41,807	1.88	0.56	0.02	16.31
CY2012	389,000	42,499	1.85	0.56	0.02	15.62
CY2013	395,000	43,204	1.83	0.56	0.02	15.05
CY2014	401,000	43,920	1.81	0.57	0.02	14.58
CY2015	408,000	44,655	1.80	0.57	0.02	14.21
Total - No Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	342,000	38,680	2.17	0.55	0.02	20.14
CY 2007	343,000	38,255	2.08	0.55	0.02	19.89
CY2008	343,000	37,861	1.95	0.54	0.02	18.27
CY2009	342,000	37,486	1.84	0.52	0.02	16.79
CY2010	339,000	37,121	1.74	0.51	0.02	15.52
CY2011	337,000	36,780	1.66	0.49	0.02	14.37
CY2012	333,000	36,453	1.59	0.48	0.02	13.42
CY2013	330,000	36,136	1.53	0.47	0.02	12.61
CY2014	327,000	35,827	1.48	0.46	0.02	11.91
CY2015	324,000	35,529	1.43	0.45	0.02	11.32
Total - Difference						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2007	9,000	996	0.06	0.02	0.01	0.53
CY2008	18,000	1,993	0.11	0.03	0.00	0.96
CY2009	27,000	2,997	0.15	0.04	0.00	1.33
CY2010	37,000	4,011	0.19	0.05	0.00	1.67
CY2011	46,000	5,027	0.22	0.07	0.00	1.94
CY2012	56,000	6,046	0.26	0.08	0.00	2.20
CY2013	65,000	7,068	0.30	0.09	0.00	2.44
CY2014	74,000	8,093	0.33	0.11	0.00	2.67
CY2015	84,000	9,126	0.37	0.12	0.00	2.89

San Joaquin Valley - Total						
Total - Growth						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	96,748,000	2,385,690	78.53	186.52	6.33	813.73
CY 2007	99,384,000	2,447,850	73.37	176.07	6.25	758.21
CY2008	102,094,000	2,511,290	68.48	166.08	6.27	704.76
CY2009	104,878,000	2,576,430	63.91	156.53	6.30	654.24
CY2010	107,741,000	2,643,520	59.57	145.29	6.30	606.01
CY2011	110,590,000	2,711,800	55.70	134.46	6.30	561.51
CY2012	113,456,000	2,781,370	52.19	124.18	6.32	520.59
CY2013	116,360,000	2,852,260	48.93	114.56	6.34	482.43
CY2014	119,300,000	2,924,540	45.95	105.61	6.38	447.77
CY2015	122,271,000	2,998,430	43.32	97.54	6.43	415.80
Total - No Growth						
	VMT	**Pop***	**ROG**	**NOx**	**PM10**	**CO**
CY 2006	96,748,000	2,385,690	78.53	186.52	6.33	813.73
CY 2007	96,860,000	2,385,690	69.25	167.42	6.09	710.08
CY2008	96,988,000	2,385,690	63.03	153.93	5.95	643.40
CY2009	97,114,000	2,385,690	57.40	141.45	5.83	582.49
CY2010	97,233,000	2,385,690	52.20	127.97	5.68	526.32
CY2011	97,291,000	2,385,690	47.65	115.47	5.54	476.01
CY2012	97,315,000	2,385,690	43.59	103.99	5.42	430.85
CY2013	97,326,000	2,385,690	39.89	93.55	5.30	389.92
CY2014	97,319,000	2,385,690	36.58	84.13	5.20	353.53
CY2015	97,284,000	2,385,690	33.68	75.81	5.12	320.71
Total - Difference						
	VMT	**Pop**	**ROG**	**NOx**	**PM10**	**CO**
CY 2007	2,524,000	62,160	4.12	8.65	0.16	48.13
CY2008	5,106,000	125,600	5.45	12.15	0.32	61.36
CY2009	7,764,000	190,740	6.51	15.08	0.47	71.75
CY2010	10,508,000	257,830	7.37	17.32	0.62	79.69
CY2011	13,299,000	326,110	8.05	18.99	0.76	85.50
CY2012	16,141,000	395,680	8.60	20.19	0.90	89.74
CY2013	19,034,000	466,570	9.04	21.01	1.04	92.51
CY2014	21,981,000	538,850	9.37	21.48	1.18	94.24
CY2015	24,987,000	612,740	9.64	21.73	1.31	95.09

* Note: The EMFAC model slightly redistributed vehicle populations within vehicle classes; however, the total vehicle population are all CY2006 numbers. See below:

CY2007 with CY2006 Veh Pop: 2,385,695 Compared to: 2,385,690
% Difference: 0.00021%

Attachment 2
NOx Emissions and Emissions Reductions

	NOx Emissions (tons per day)								
Emission Inventory Category	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Total Growth in Motor Vehicle Emissions[A]	0.0	8.3	11.6	14.3	16.4	17.9	19.0	19.8	20.2
Total Annual Growth in Motor Vehicles Emissions[A]	0.0	8.3	3.2	2.7	2.1	1.5	1.1	0.7	0.5
Rule Penetration (tpd)[B]	0.0	7.1	2.7	2.3	1.8	1.3	1.0	0.6	0.4
On-Site Reductions									
Estimated Sources to perform on-site reductions[C]	40%	45%	50%	55%	60%	65%	70%	70%	70%
Average Mitigation achieved on-site (%)[C]	7%	9%	11%	13%	14%	15%	15%	15%	15%
Reductions from 2006 Development	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reductions from 2007 Development		0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2
Reductions from 2008 Development			0.2	0.1	0.1	0.1	0.1	0.1	0.1
Reductions from 2009 Development				0.2	0.2	0.1	0.1	0.1	0.1
Reductions from 2010 Development					0.1	0.1	0.1	0.1	0.1
Reductions from 2011 Development						0.1	0.1	0.1	0.1
Reductions from 2012 Development							0.1	0.1	0.1
Reductions from 2013 Development								0.1	0.1
Reductions from 2014 Development									0.0
Total On-site Reductions[D]	**0.0**	**0.3**	**0.4**	**0.6**	**0.7**	**0.8**	**0.8**	**0.8**	**0.8**
Off-site Reductions									
Remaining Subject Emissions[E]	0.0	6.8	2.6	2.2	1.6	1.2	0.9	0.5	0.4
Reductions from 2006 Development	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
Reductions from 2007 Development		2.4	2.4	2.4	2.4	2.4	2.4	2.4	
Reductions from 2008 Development			0.9	0.9	0.9	0.9	0.9	0.9	0.9
Reductions from 2009 Development				0.8	0.8	0.8	0.8	0.8	0.8
Reductions from 2010 Development					0.6	0.6	0.6	0.6	0.6
Reductions from 2011 Development						0.4	0.4	0.4	0.4
Reductions from 2012 Development							0.3	0.3	0.3
Reductions from 2013 Development								0.2	0.2
Reductions from 2014 Development									0.1
Total Off-site Reductions[F]	**0.0**	**2.4**	**3.4**	**4.1**	**4.7**	**5.1**	**5.4**	**5.6**	**3.3**
Total Reductions	**0.0**	**2.7**	**3.8**	**4.7**	**5.4**	**5.9**	**6.3**	**6.5**	**4.2**

A. ARB performed an EMFAC2002 model run that estimated the growth between 2006 and 2015 (Attachment 1). Since this analysis needs growth per year, the current year's missions are subtracted by the previous year's emissions to obtain the annual growth.

Medium-Heavy and Heavy-Heavy Duty emissions have been reduced by 12% to account for through-valley traffic

B. Rule penetration is estimated to be 85% based on District experience with CEQA projects.

C. Staff estimate

D. Determined by multiplying rule penetration of operational emissions, estimated sources to perform on-site reductions, average mitigation achieved on-site, and adding the reductions for each year

E. Determined by subtracting a particular years on-site reduction from the Rule Penetration of Operational Emissions for that year.

F. Determined by multiplying Remaining Subject Emissions with 250%, and dividing by 7 to account for the average project life of the estimated emission reduction projects.

G. The rule requires mitigation of 250% of the first years emissions. That total was then divided by 7 to account for the average project life of the estimated emission reduction projects.

On-Site reductions are reduced over time to account for the reduction in mobile emissions

Attachment 3
PM10 Emissions and Emissions Reductions

EMISSIONS INVENTORY CATEGORY	ANNUAL GROWTH IN PM10 EMISSIONS (tons per day)[A] 2006	2007	2008	2009	2010	2011	2012	2013	2014
Operational PM10 Emissions									
Re-entrained Paved Road Dust[B]:									
Freeway	0.4	0.4	0.4	0.3	0.3	*0.3*	*0.3*	*0.3*	*0.3*
Collector Streets	0.1	0.1	0.1	0.1	0.1	*0.1*	*0.1*	*0.1*	*0.1*
Major Streets	0.4	0.4	0.4	0.4	0.4	*0.5*	*0.5*	*0.5*	*0.5*
Local Streets	0.2	0.2	0.1	0.2	0.2	*0.2*	*0.2*	*0.2*	*0.2*
Rural Streets	0.4	0.4	0.4	0.4	0.4	*0.5*	*0.5*	*0.5*	*0.5*
On-road vehicles[C]	0.0	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1
Total Annual Growth in Operational PM10 Emissions	**1.1**	**1.2**	**1.1**	**1.3**	**1.3**	**1.5**	**1.5**	**1.5**	**1.5**
Cumulative Growth in Operational PM10 Emissions[D]	1.1	2.3	3.4	4.7	6.0	7.5	9.1	10.6	12.2
Rule Penetration of Operational Emissions (tpd)[E]	0.9	1.0	1.0	1.1	1.1	1.3	1.3	1.3	1.3
On-site Reductions									
Estimated Sources to perform on-site reductions[F]	40%	45%	50%	55%	60%	65%	70%	70%	70%
Average Mitigation achieved on-site (%)[F]	7%	9%	11%	13%	14%	15%	15%	15%	15%
Reductions from 2006 Development	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Reductions from 2007 Development		0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Reductions from 2008 Development			0.05	0.05	0.05	0.05	0.05	0.05	0.05
Reductions from 2009 Development				0.08	0.08	0.08	0.08	0.08	0.08
Reductions from 2010 Development					0.09	0.09	0.09	0.09	0.09
Reductions from 2011 Development						0.13	0.13	0.13	0.13
Reductions from 2012 Development							0.14	0.14	0.14
Reductions from 2013 Development								0.14	0.14
Reductions from 2014 Development									0.14
Total On-site Reductions (tpd)[G]	**0.0**	**0.1**	**0.1**	**0.2**	**0.3**	**0.4**	**0.6**	**0.7**	**0.8**
Off-site Reductions									
Remaining Subject Emissions[H]	0.9	1.0	0.9	1.0	1.0	1.2	1.2	1.2	1.2
Reductions from 2006 Development	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Reductions from 2007 Development		0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Reductions from 2008 Development			0.4	0.4	0.4	0.4	0.4	0.4	0.4
Reductions from 2009 Development				0.4	0.4	0.4	0.4	0.4	0.4
Reductions from 2010 Development					0.4	0.4	0.4	0.4	0.4
Reductions from 2011 Development						0.5	0.5	0.5	0.5
Reductions from 2012 Development							0.5	0.5	0.5
Reductions from 2013 Development								0.5	0.5
Reductions from 2014 Development									0.5
Total Off-site Reductions[I]	**0.4**	**0.8**	**1.2**	**1.6**	**2.0**	**2.5**	**3.0**	**3.5**	**4.0**
Total Operational PM10 Reductions[J]	**0.4**	**0.9**	**1.3**	**1.8**	**2.3**	**2.9**	**3.5**	**4.2**	**4.8**

A-P

See footnotes on following pages.

EMISSIONS INVENTORY CATEGORY	ANNUAL EMISSIONS (tons per day)[K] 2006	2007	2008	2009	2010	2011	2012	2013	2014
Construction Equipment Emissions									
Total Construction Equipment NOx Emissions[L]	26.9	25.5	24.1	22.7	21.3	20.1	18.9	17.6	16.4
Construction Equipment PM10 Equivalent[M]	17.9	17.0	16.1	15.1	14.2	13.4	12.6	11.7	10.9
Rule Penetration of Construction Equipment Emissions (tpd)[E]	15.2	14.4	13.7	12.9	12.1	11.4	10.7	10.0	9.3
On-site Reductions									
Estimated Sources to perform fleet reductions (%)[F]	10%	20%	30%	40%	50%	50%	50%	50%	50%
Average Fleet Reductions (%)[N]	20%	20%	20%	20%	20%	20%	20%	20%	20%
Construction Fleet Reductions[G]	**0.3**	**0.6**	**0.8**	**1.0**	**1.2**	**1.1**	**1.1**	**1.0**	**0.9**
Off-site Reductions									
Remaining Emissions (tpd)[4]	14.9	13.9	12.8	11.8	10.9	10.3	9.6	9.0	8.4
Reductions from 2006 Development	0.4	0.4	0.4	0.4	0.4	0.4	0.4		
Reductions from 2007 Development		0.4	0.4	0.4	0.4	0.4	0.4	0.4	
Reductions from 2008 Development			0.4	0.4	0.4	0.4	0.4	0.4	0.4
Reductions from 2009 Development				0.3	0.3	0.3	0.3	0.3	0.3
Reductions from 2010 Development					0.3	0.3	0.3	0.3	0.3
Reductions from 2011 Development						0.3	0.3	0.3	0.3
Reductions from 2012 Development							0.3	0.3	0.3
Reductions from 2013 Development								0.3	0.3
Reductions from 2014 Development									0.2
Total Off-site Reductions[O]	**0.4**	**0.8**	**1.2**	**1.5**	**1.8**	**2.1**	**2.4**	**2.2**	**2.1**
Construction Equipment Reductions[J]	**0.7**	**1.4**	**2.0**	**2.5**	**3.0**	**3.2**	**3.4**	**3.2**	**3.0**

A. Annual Growth in emisions were determined by subtracting one years emissions from the previous year's emissions.
Emissions' growth in 2011-2014 were determined by taking the difference between 2015 and 2010 and dividing that by 5 years.

B. The growth in these emissions were taken directly from the emissions inventory, and were reported by road type. Control for Regulation VIII is accounted for.

C. These totals were obtained from ARB. Current year's emissions are subtracted by the previous year's emissions to obtain the annual growth.

D. Cumulative growth was determined by creating a running total of emissions from each year

E. Rule penetration is estimated to be 85% based on District experience with CEQA projects.

F. District staff estimate

G. Determined by multiplying rule penetration of operational emissions, estimated sources to perform on-site reductions, average mitigation achieved on-site, and adding the reductions for each year.

H. Determined by subtracting a particular years on-site reduction from the Rule Penetration of Operational Emissions for that year.

I. Equals 5 x Remaining Subject Emissions That total was then divided by 12 to account for the average project life of the estimated emission reduction projects.

J. Determined by adding On-site Reductions and Off-site Reductions

K. Total emissions were used for each year, since all construction activity each year is for new development

L. These emissions were taken from ARB and interpolated based on 2005, 2010, and 2015.

M. Modeling in the 2003 PM10 indicated that 1.5 tons of NOx are equivalent to 1.0 tons of PM10.

N. This is a rule requirement

O. Determined by multiplying Remaining Subject Emissions with 20%, and dividing by 7 to account for the average project life of the estimated emission reduction projects.

P. Determined by multiplying Remaining Subject Emissions with 45%, and dividing by 12 to account for the average project life of the estimated emission reduction projects.

ANNUAL PM10 EMISSIONS (tons per day)[K]

EMISSIONS INVENTORY CATEGORY	2006	2007	2008	2009	2010	2011	2012	2013	2014
Construction PM10 Exhaust Emissions									
PM10 Exhaust from Construction Equipment[L]	1.7	1.6	1.5	1.4	1.4	1.3	1.2	1.2	1.1
Rule Penetration of Construction PM10 & PM10 Equiv. Emissions (tpd)[E]	1.4	1.4	1.3	1.2	1.2	1.1	1.0	1.0	0.9
On-site Reductions									
Estimated Sources to perform on-site reductions (%)[F]	10%	20%	30%	40%	50%	50%	50%	50%	50%
Average Mitigation achieved on-site (%)[N]	45%	45%	45%	45%	45%	45%	45%	45%	45%
Onsite Reductions (tpd)[G]	**0.1**	**0.1**	**0.2**	**0.2**	**0.3**	**0.2**	**0.2**	**0.2**	**0.2**
Off-site Reductions									
Remaining Emissions (tpd)[H]	1.4	1.2	1.1	1.0	0.9	0.8	0.8	0.8	0.7
Reductions from 2006 Development	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Reductions from 2007 Development		0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Reductions from 2008 Development			0.04	0.04	0.04	0.04	0.04	0.04	0.04
Reductions from 2009 Development				0.04	0.04	0.04	0.04	0.04	0.04
Reductions from 2010 Development					0.03	0.03	0.03	0.03	0.03
Reductions from 2011 Development						0.03	0.03	0.03	0.03
Reductions from 2012 Development							0.03	0.03	0.03
Reductions from 2013 Development								0.03	0.03
Reductions from 2014 Development									0.03
Reductions from 2015 Development									
Total Off-site Reductions[P]	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**	**0.3**
Total Construction PM10 Reductions (tpd)[J]	**0.1**	**0.2**	**0.3**	**0.4**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**
TOTAL ESTIMATED PM10 REDUCTIONS (tpd)	**1.2**	**2.4**	**3.6**	**4.7**	**5.8**	**6.6**	**7.5**	**7.9**	**8.3**

A. Annual Growth in emisions were determined by subtracting one years emissions from the previous year's emissions. Emissions' growth in 2011-2014 were determined by taking the difference between 2015 and 2010 and dividing that by 5 years.

B. The growth in these emissions were taken directly from the emissions inventory, and were reported by road type. Control for Regulation VIII is accounted for.

C. These totals were obtained from ARB. Current year's emissions are subtracted by the previous year's emissions to obtain the annual growth.

D. Cumulative growth was determined by creating a running total of emissions from each year

E. Rule penetration is estimated to be 85% based on District experience with CEQA projects.

F. District staff estimate

G. Determined by multiplying rule penetration of operational emissions, estimated sources to perform on-site reductions, average mitigation achieved on-site, and adding the reductions for each year.

H. Determined by subtracting a particular years on-site reduction from the Rule Penetration of Operational Emissions for that year.

I. Equals 5 x Remaining Subject Emissions That total was then divided by 12 to account for the average project life of the estimated emission reduction projects.

J. Determined by adding On-site Reductions and Off-site Reductions

K. Total emissions were used for each year, since all construction activity each year is for new development

L. These emissions were taken from ARB and interpolated based on 2005, 2010, and 2015.

M. Modeling in the 2003 PM10 indicated that 1.5 tons of NOx are equivalent to 1.0 tons of PM10.

N. This is a rule requirement

O. Determined by multiplying Remaining Subject Emissions with 20%, and dividing by 7 to account for the average project life of the estimated emission reduction projects.

P. Determined by multiplying Remaining Subject Emissions with 45%, and dividing by 12 to account for the average project life of the estimated emission reduction projects.

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APPENDIX C

On-Site Emission Reduction Checklist for Proposed Rule 9510 (Indirect Source Review) and Rule 3180 (Administrative Fees for Air Impact Assessment Applications) and On-Site Enhancing Measures List

November 17, 2005

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MIXED USE OR NON-RESIDENTIAL ON-SITE EMISSION REDUCTION LIST

No.	Measure – Objective
	LOCATION
Bicycle Infrastructure	
M-1	Project is located within 1/2 mile of existing or planned Class I or II bike lanes on arterial/collector streets, or where a suitable parallel route exists. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Bicycle and Pedestrian Node)*
Mass Transit Infrastructure	
M-2	Project is located within 1/4-1/2 mile of a transit stop. *(URBEMIS Location: Operation Emissions: Mitigation Measures: Transit Service Node)*
	* Office floor area ratio is 0.75 greater within 1/4 mile of existing transit stop.
Mixed Use/Density	
M-3	Include high density residential, mixed, or retail/commercial uses on site or locate near (within a 1/2 mile of project center). *(URBEMIS Location: Operational Emissions: Mitigation Measures: Mix of Uses Node and/or Operational Emissions: Mitigation Measures: Local Serving Retail)*
	* Day care facilities
	* Restaurant or cafeteria
	* Bank or ATM
	* Dry cleaners
	* Post office / services
	* Entertainment (movie / video)
	* Recreation facility / fitness center
	* Public Park
	* Residential development / On-site employee living spaces
M-4	Average Residential density is 7 Dwelling Units (DU) per acre or greater. *(URBEMIS Location: Land Use Selection - Acreage)*
	▪ Project contains ancillary residential units - "Granny Flats"
M-5	Designate a portion of residential units as deed-restricted below-market-rate (BMR) housing. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Affordable Housing Node)*
	▪ Include Affordable Housing/Senior Housing/ Assisted Living
	BICYCLE/PEDESTRIAN
Bicycle Storage	
M-6	Provide Class I and Class II bicycle parking facilities on-site. Bicycle parking facilities should be near destination points and easy to find. At least one bicycle parking space for every 20 vehicle parking spaces. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
	* One bicycle parking space for every 10 car parking spaces is considered appropriate.
	* Provide secure bicycle storage at public parking facilities.

⊗ These operational, program-oriented measures must be implemented for at least 10years from build-out to qualify as an emission reduction measure

No.	Measure - Objective
M-7	Provide shower and locker facilities to encourage employees to bike and/or walk to work, typically one shower and three lockers for every 25 employees. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
M-8	Provide Class I bicycle parking at apartment complexes or condos without garages. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*

Pedestrian- Bicycle Oriented Infrastructure

M-9	Install Class I or II bike lanes on arterial/collector streets, or where a suitable route exists. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Bicycle and Pedestrian Node)*
M-10	Install complete, separate, safe, and convenient pedestrian sidewalks/paths that connect multiple uses. This can be implemented through the following project designs: *(URBEMIS Location: Operational Emissions: Mitigation Measures: Bicycle and Pedestrian Node)*
	* Provide direct pedestrian connections
	* Provide paths and building access which are physically separated from street parking lot traffic and that eliminates physical \barriers such as walls, berms, landscaping and slopes that impede the use of pedestrians, bicycle facilities, or public transportation vehicles
	* Place store entrances close to adjacent sidewalks.
	* Provide pedestrian signalization and signage to improve pedestrian safety
	* Provide continuous sidewalks separated from the roadway by landscaping and on-street parking.
	* Provide clearly delineated crosswalks at intersections.
	* Provide on and off-site pedestrian facility improvements such as overpasses and wider sidewalks
	* Provide on and off-site pedestrian facility improvements such as trails linking them to designated pedestrian commuting routes and/or on-site overpasses and wider sidewalks.
	* Provide street lighting
	* Provide shaded pathways (e.g. provide street trees or building overhangs)
	* Link cul-de-sacs and dead-end streets to encourage pedestrian and bicycle travel
	* Provide traffic calming modifications to project roads, such as narrower streets, speed platforms, bulb-outs and intersection modifications designed to reduce vehicle speeds, to encourage pedestrian and bicycle travel.
	* Provide a parking lot design that-includes clearly marked and shaded pedestrian pathways between transit facilities and building entrances
	* Provide pedestrian access between bus service and major transportation points and destination points within the project.
	* Minimize building setback to adjacent existing or planned pedestrian infrastructure
	* Setback distance is minimized between development and transit, bicycle, or pedestrian corridor
	* Setback distance is minimized between development and neighboring properties

TRANSPORTATION DESIGN

Signage

M-11	Provide a display case or kiosk displaying transportation information in a prominent area accessible to employees, residents, or visitors. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
	* Display Bike Route Maps
	* Display Bus Schedules
	* Display other transportation information such as carpooling, carsharing, etc.

⊗ These operational, program-oriented measures must be implemented for at least 10years from build-out to qualify as an emission reduction measure

No.	Measure - Objective
Streets	
M-12	Project design uses models by the Local Government Commission (LGC) in the "Smart Growth Guidebook," such as: street block patterns that form an interconnected grid, short block faces, numerous alleys and narrow streets. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Bicycle and Pedestrian Node)*
PARKING	
Strategies: Pricing and Preferential Parking	
M-13	Develop and implement parking pricing strategies, such as charging parking lot fees to low occupancy (single occupant vehicles) vehicles. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
M-14	Provide preferential parking spaces near the entrance of buildings for those who carpool/vanpool/rideshare and provide signage. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
Parking Amount	
M-15	Provide parking reduction. The following are guidelines: *(URBEMIS Location: Operational Emissions: Mitigation Measures: Parking Supply)*
	* Office 25%
	* Medical office 8%
	* Commercial 5%
	* Industrial 10%
	* Additional 10-20% if located along transit station
BUILDING/SITE DESIGN	
Energy Efficiency	
M-16	Increase the building energy efficiency rating above what is required by Title 24 requirements. This can be accomplished by any combination of measures. The following is an idea list of measures that may be implemented to achieve this measure (this list should not be considered comprehensive): *(URBEMIS Location: Area Emissions: Mitigation Measures Node)*
	General
	* Participate in and implement available PUC energy-efficient rebate programs including air conditioning, gas heating, refrigeration, and lighting programs.
	* Install efficient heating and other appliances, such as water heaters, cooking equipment, refrigerators, furnaces and boiler units beyond Title 24 requirements (see Title 24, Part 6, Energy Efficiency Standards for Residential and Nonresidential Buildings: http://www.energy.ca.gov/title24/standard)
	* Capture waste heat and re-employ it in nonresidential buildings.
	* Trees should be carefully selected and located to protect the building(s) from energy consuming environmental conditions and to shade paved areas
	* Improve the thermal integrity/efficiency of buildings, and reduce the thermal load with automated and timed temperature controls or occupant sensors.
	Roof
	* Install "Green Roof" System
	* Install EPA/DOE Energy Star labeled roof materials
	* Install roof photovoltaic energy systems as a standard feature (on new homes)

⊗ These operational, program-oriented measures must be implemented for at least 10years from build-out to qualify as an emission reduction measure

No.	Measure - Objective
M-16	*Solar Design*
Cont	* Design buildings with proper orientation, fenestration, and other design components that maximize the potential of passive cooling and heating, include shading master plan
	Components
	* Use devices that minimize the combustion of fossil fuels.
	* Install low nitrogen oxide (NOx) hot water heaters.
	* Install high efficiency Energy Star heating or ground source heat pumps
	* Install energy efficient interior lighting.
	* Install built-in energy efficient appliances.
	* Install door sweeps and weather stripping if more efficient doors and windows are not available.
	* Install energy-efficient and automated controls for air conditioning
	* Install of energy-efficient lighting (includes controls) and process systems such as water heaters, furnaces and boiler units.
	* Install electrical outlets on the exterior walls of both the front and back of residences or all commercial buildings to promote the use of electric landscape maintenance equipment.
	* Install electric vehicle recharging station with both conductive and inductive charging capabilities in residential garages / parking lots.
	* Install a gas outlet for use with outdoor cooking appliances, and in any proposed fireplaces, including outdoor recreational fireplaces or pits.
	* Use low energy street lights (i.e. sodium).
	* Use low energy traffic signals (i.e. light emitting diode).
	* Install Medium Efficiency Filters
	* Install High Efficiency Filters
	* Install HEPA (High Efficiency Particle Arrestance) Filters
	* Install "whole-house" or "fresh-air" ventilation system

Building Maintenance/Indoor Air Quality

M-17	Reduce VOC emissions from Architectural Coatings⊗ *(URBEMIS Location: Area Emissions: Architectural Coatings - Nonresidential)*
	* Use Low-VOC Coatings
	* Use surfaces that do not require coatings, such as stone or brick
	* Use No-VOC Coatings

Fuel Combustion

M-18	Provide Electrical outlets at front and rear of residences for the use of electrically powered landscape equipment (See Measure 47 below) *(URBEMIS Location: Area Emissions: Mitigation Measures Node)*
M-19	Provide electrical outlets at non-residential units for the use of electrically powered landscape equipment. In combination with Measure M-31 below. *(URBEMIS Location: Area Emissions: Mitigation Measures Node)*
M-20	Reduce Wood Fireplaces and/or Woodstove above that required by District Rule 4901. *(URBEMIS Location: Area Emissions: Hearth Fuel Combustion Node)*

OPERATIONAL MEASURES

Telecommunication

M-23	Implement an employee telecommuting policy *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
	* Install videoconferencing system
	* Include teleconferencing capabilities, such as web cams or satellite linkage, which will allow employees to attend meetings remotely without requiring them to travel out of the area.

⊗ These operational, program-oriented measures must be implemented for at least 10years from build-out to qualify as an emission reduction measure

No.	Measure - Objective
M-23	* Offer low cost financing to employees for the purchase of telecommuting equipment, or lend company-owned equipment.
Cont	* Provide satellite work offices when appropriate. Applicable to office/industrial and educational institutions.

Alternative Transit

M-24	Provide guaranteed ride home⊗ *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
M-25	Provide carpool matching assistance⊗ *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
M-26	Provide Car-Sharing Services⊗ *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
M-27	Employ or appoint an Employee Transportation Coordinator to work with the TMA and the District⊗ *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
	* Implement a rideshare program
	* Provide incentives to employees to carpool/vanpool, take public transportation, telecommute, walk, bike, etc.
	* Participate in an employee "flash-pass" program, which provides free travel on transit buses.
	* Provide transit pass subsidy (100%) and/or commute alternative allowance
	* Participate in alternative transportation programs such as CalTrans rideshare where deemed appropriate by local transportation planning agencies and/or APCD
	* Provide transit-use incentives, as approved by applicable transportation planning agencies such as subsidized transit passes and accommodation of unusual work schedules to encourage transit use
	* Provide funds for on line computer rideshare matching.
	* Provide an employer subsidized shuttle service to connect to existing transit sites.
	* Provide an employer subsidized free or reduced transit fares for midday central business district trips.
	* Provide financial incentives to carpoolers for vehicle tune-up or maintenance
	* Implement a lunchtime shuttle to reduce single occupant vehicle trips.
	* Provide Flextime for non-SOV (single occupancy vehicle) commuters
	* Maintain a fleet of bicycles for employee and business use
M-28	Provide transit pass subsidy (100%) and/or commute alternative allowance⊗ *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
M-29	Provide a display case or kiosk displaying transportation information in a prominent area accessible to employees or residents. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
	* Provide ridesharing information in a homeowner's association package.

Work Schedules

M-30	Implement alternative work schedules such as compressed workweek schedules where weekly work hours are compressed into fewer than five days.⊗ Examples of these options are: 9/80, 4/40, 3/36 *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*

Landscaping

M-31	Project provides and/or requires use of electric maintenance equipment; including, but not limited to electric lawn mowers, electric leaf blowers. In combination with measure M-19. *(URBEMIS Location: Area Emission: Mitigation Measures Node)*
	* Prohibit gas powered landscape maintenance equipment within developments.

⊗ These operational, program-oriented measures must be implemented for at least 10years from build-out to qualify as an emission reduction measure

No.	Measure - Objective
M-31 *Cont*	* Contract only with commercial landscapers who operate with equipment that complies with the most recent California Air Resources Board certification standards, or standards adopted no more than three years prior to date of use.
	* Provide battery powered or electric landscape maintenance equipment for new residences, commercial and industrial land uses.

Fleet / Engines

M-32	Implement clean air business practices such as using low-emission delivery vehicles, contract with alternative-fuel waste hauling companies, contracting with carrier, delivery, security, or other services utilizing electric, low-emission, alternative fuel, convert fleet to cleaner vehicles or utilizing heavy-duty vehicles that are CARB certified to optional low-emission standards for NOx.⊗ *(URBEMIS Location: Operational Emissions: Mitigation Measures: On-Road Trucks)*
	Medium Trucks - 5,751 to 8,500 lbs
	* ESW Particulate Reactor
	* PuriNOx Emulsified Diesel fuel
	* CCRT Particulate Filter
	* CRT Particulate Filter
	* Cleaire Longview (ultra low diesel)
	Light Heavy - 8,501 to 10,000 lbs
	* DCM DOC Muffler w/series 6000 or 6100 catalyst
	* ESW Particulate Reactor
	* PuriNOx Emulsified Diesel fuel
	* CCRT Particulate Filter
	* CRT Particulate Filter
	* Cleaire Longview (ultra low diesel)
	Light Heavy - 10,001 to 14,000 lbs
	* DCM DOC Muffler w/series 6000 or 6100 catalyst
	* ESW Particulate Reactor
	* PuriNOx Emulsified Diesel fuel
	* CCRT Particulate Filter
	* CRT Particulate Filter
	* Cleaire Longview (ultra low diesel)
	Medium Heavy - 14,001 to 33,000 lbs
	* AZ Purifier & AZ Purimuffler (Cummins & Navistart: 1991-03)
	* DCM DOC Muffler w/series 6000 or 6100 catalyst
	* ESW Particulate Reactor
	* PuriNOx Emulsified Diesel fuel
	* DPM DPF muffler with/Series 6300 catalyst formulation
	* CCRT Particulate Filter
	* CRT Particulate Filter
	* Lubrizol Engine Control Systems Purifilter
	* Cleaire Longview (ultra low diesel)

⊗ These operational, program-oriented measures must be implemented for at least 10years from build-out to qualify as an emission reduction measure

No.	Measure - Objective
M-32 Cont	*Heavy Heavy - 33,001 to 60,000 lbs*
	* DCM DOC Muffler w/series 6000 or 6100 catalyst
	* Cleaire Flash and Match oxidation catalyst
	* ESW Particulate Reactor
	* PuriNOx Emulsified Diesel Fuel
	* DPM DPF muffler w/series 6300 catalyst formulation
	* CCRT Particulate Filter
	* CRT Particulate Filter
	* Lubrizol Engine Control Systems Purifilter
	* Cleaire Flash Match system (Cummins M11 engines only)
	* Cleaire Longview (ultra low diesel)
	Line Haul Vehicles >60,000 lbs
	* DCM DOC Muffler w/series 6000 or 6100 catalyst
	* Cleaire Flash and Match oxidation catalyst
	* ESW Particulate Reactor
	* PuriNOx Emulsified Diesel Fuel
	* DPM DPF muffler w/series 6300 catalyst formulation
	* CCRT Particulate Filter
	* CRT Particulate Filter
	* Lubrizol Engine Control Systems Purifilter
	* Cleaire Flash Match system (Cummins M11 engines only)
	* Cleaire Longview (ultra low diesel)
	Urban Bus
	* ESW Particulate Reactor
	* PuriNOx Emulsified Diesel Fuel
	* CCRT Particulate Filter
	* CRT Particulate Filter
	* Cleaire Longview (ultra low diesel)
	School Bus
	* ESW Particulate Reactor
	* PuriNOx Emulsified Diesel Fuel
	* CCRT Particulate Filter
	* CRT Particulate Filter
	* Cleaire Longview (ultra low diesel)
	General
	* Utilize electric fleet vehicles
	* Utilize Ultra Low-Emission fleet vehicles
	* Utilize methanol fleet vehicles
	* Utilize liquid propane gas fleet vehicles

⊗ These operational, program-oriented measures must be implemented for at least 10years from build-out to qualify as an emission reduction measure

No.	Measure - Objective
M-32	* Utilize compressed natural gas fleet vehicles
Cont	* Replace diesel fleet with alternative fuel engine technology and infrastructure
	* Retrofit existing equipment to reduce emissions using methods such as particulate filters, oxidation catalysts, or other approved technologies.
	* Fleet vehicles that use clean-burning fuels as may be practicable
	* Adopt a Vehicle Idling Policy requiring all vehicles under company control to adhere to a 5 minute idling policy.
	* Conversion to cleaner engines
	* Use of cleaner (reduced sulfur) fuel
	* Regular maintenance – keep equipment well tuned
	* Add-on control devices, e.g., particulate traps, catalytic oxidizers
	* Repower/Retrofit heavy-duty diesel fleet with cleaner diesel engine technology and/or diesel particulate filter after-treatment technology
	* Replace diesel fleet with alternative fuel engine technology and infrastructure
	* Replace auxiliary power units with cleaner engine technology, alternative fuels, or require electric connection while at loading dock
	* Replace diesel fleet vehicles with cleaner fueled low emission vehicles (i.e. school buses, buses, on- and off- road heavy duty vehicles, lighter duty trucks and passenger vehicles)

⊗ These operational, program-oriented measures must be implemented for at least 10years from build-out to qualify as an emission reduction measure

RESIDENTIAL ON-SITE EMISSION REDUCTION LIST

No.	Measure - Objective
	LOCATION
Bicycle Infrastructure	
R-1	Project is located within 1/2 mile of existing or planned Class I or II bike lanes on arterial/collector streets, or where a suitable parallel route exists. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Bicycle and Pedestrian Node)*
Mass Transit Infrastructure	
R-2	Project is located within 1/4-1/2 mile of a transit stop. *(URBEMIS Location: Operation Emissions: Mitigation Measures: Transit Service Node)*
Mixed Use/Density	
R-3	Include high density residential, mixed, or retail/commercial uses on site or locate near (within a 1/2 mile of project center) these uses to minimize the need for trips. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Mix of Uses Node and/or Operational Emissions: Mitigation Measures: Local Serving Retail)*
	* Day care facilities
	* Restaurant or cafeteria
	* Bank or ATM
	* Dry cleaners
	* Post office/services
	* Entertainment (movie/video)
	* Recreation facility/fitness center
	* Public Park
	* Residential development/On-site employee living spaces
R-4	Average Residential density is 7 Dwelling Units (DU) per acre or greater. *(URBEMIS Location: Land Use Selection- Acreage)*
	* Project contains ancillary residential units - "Granny Flats"
R-5	Designate a portion of residential units as deed-restricted below-market-rate (BMR) housing. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Affordable Housing Node)*
	* Include Affordable Housing/Senior Housing/ Assisted Living
	BICYCLE/PEDESTRIAN
Bicycle Storage	
R-6	Provide Class I bicycle parking at apartment complexes or condos without garages *(URBEMIS Location: Operational Emissions: Mitigation Measure: Transportation Demand Management Node)*
Pedestrian- Bicycle Oriented Infrastructure	
R-7	Install Class I or II bike lanes on arterial/collector streets, or where a suitable route exists. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Bicycle and Pedestrian Node)*
R-8	Install complete, separate, safe, and convenient pedestrian sidewalks/paths that connect multiple uses. This can be implemented through the following project designs: *(URBEMIS Location: Operational Emissions: Mitigation Measures: Bicycle and Pedestrian Node)*
	* Provide direct pedestrian connections

⊗ These operational, program-oriented measures must be implemented for at least 10years from build-out to qualify as an emission reduction measure

No.	Measure - Objective
R-18	* Provide paths and building access which are physically separated from street parking lot traffic and that eliminates physical \barriers such as walls, berms, landscaping and slopes that impede the use of pedestrians, bicycle facilities, or public transportation vehicles.
Cont	* Place store entrances close to adjacent sidewalks.
	* Provide pedestrian signalization and signage to improve pedestrian safety
	* Provide continuous sidewalks separated from the roadway by landscaping and on-street parking.
	* Provide clearly delineated crosswalks at intersections.
	* Provide on and off-site pedestrian facility improvements such as overpasses and wider sidewalks
	* Provide on and off-site pedestrian facility improvements such as trails linking them to designated pedestrian commuting routes and/or on-site overpasses and wider sidewalks.
	* Provide street lighting
	* Provide shaded pathways (e.g. provide street trees or building overhangs)
	* Link cul-de-sacs and dead-end streets to encourage pedestrian and bicycle travel
	* Provide traffic calming modifications to project roads, such as narrower streets, speed platforms, bulb-outs and intersection modifications designed to reduce vehicle speeds, to encourage pedestrian and bicycle travel.
	* Provide pedestrian access between bus service and major transportation points and destination points within the project.

Transportation Design

Signage

R-9	Provide a display case or kiosk displaying transportation information in a prominent area accessible to residents, or visitors. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
	* Display Bike Route Maps
	* Display Bus Schedules
	* Display other transportation information such as carpooling, carsharing, etc.

Streets

R-10	Project design uses models by the Local Government Commission (LGC) in the "Smart Growth Guidebook," such as: street block patterns that form an interconnected grid, short block faces, numerous alleys and narrow streets. *(URBEMIS Location: Operational Emissions: Mitigation Measures: Bicycle and Pedestrian Node)*

Building/Site Design

Energy Efficiency

R-12	Increase the building energy efficiency rating above what is required by Title 24 requirements. This can be accomplished by any combination of measures. The following is an idea list of measures that may be implemented to achieve this measure (this list should not be considered comprehensive): *(URBEMIS Location: Area Emissions: Mitigation Measures Node)* *General*
	* Participate in and implement available PUC energy-efficient rebate programs including air conditioning, gas heating, refrigeration, and lighting programs.

⊗ These operational, program-oriented measures must be implemented for at least 10years from build-out to qualify as an emission reduction measure

No.	Measure - Objective
R-12	* Install efficient heating and other appliances, such as water heaters, cooking equipment, refrigerators, furnaces and boiler units beyond Title 24 requirements (see Title 24, Part 6, Energy Efficiency Standards for Residential and Nonresidential Building
Cont	* Trees should be carefully selected and located to protect the building(s) from energy consuming environmental conditions and to shade paved areas
	* Improve the thermal integrity/efficiency of buildings, and reduce the thermal load with automated and timed temperature controls or occupant sensors.
	Roof
	* Install "Green Roof" Technology
	* Install EPA/DOE Energy Star labeled roof materials
	* Install roof photovoltaic energy systems as a standard feature (on new homes)
	Solar Design
	* Design buildings with proper orientation, fenestration, and other design components that maximize the potential of passive cooling and heating, include shading master plan
	Components
	* Use devices that minimize the combustion of fossil fuels.
	* Install low nitrogen oxide (NOx) hot water heaters.
	* Install high efficiency Energy Star heating or ground source heat pumps
	* Install energy efficient interior lighting.
	* Install built-in energy efficient appliances.
	* Install door sweeps and weather stripping if more efficient doors and windows are not available.
	* Install energy-efficient and automated controls for air conditioning
	* Install of energy-efficient lighting (includes controls) and process systems such as water heaters, furnaces and boiler units.
	* Install electrical outlets on the exterior walls of both the front and back of residences to promote the use of electric landscape maintenance equipment.
	* Install electric vehicle recharging station with both conductive and inductive charging capabilities in residential garages / parking lots.
	* Install a gas outlet for use with outdoor cooking appliances, and in any proposed fireplaces, including outdoor recreational fireplaces or pits.
	* Use low energy street lights (i.e. sodium).
	* Use low energy traffic signals (i.e. light emitting diode).
	* Install Medium Efficiency Filters
	* Install High Efficiency Filters
	* Install HEPA (High Efficiency Particle Arrestance) Filters
	* Install "whole-house" or "fresh-air" ventilation system

Fuel Combustion

R-13	Provide Electrical outlets at front and rear of residences for the use of electrically powered landscape equipment (See Measure R-18 below). *(URBEMIS Location: Area Emissions: Mitigation Measures Node)*
R-14	Reduce Wood Fireplaces and/or Woodstove above that required by District Rule 4901. *(URBEMIS Location: Area Emissions: Hearth Fuel Combustion Node)*

⊗ These operational, program-oriented measures must be implemented for at least 10years from build-out to qualify as an emission reduction measure

No.	Measure - Objective
	OPERATIONAL MEASURES
Alternative Transit	
R-15	Provide Car-Sharing Services⊗ *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
R-16	Transit pass subsidy (100%) and/or commute alternative allowance⊗ *(URBEMIS Location: Operational Emissions: Mitigation Measures: Transportation Demand Management Node)*
R-17	Provide a display case or kiosk displaying transportation information in a prominent area accessible to residents. *(URBEMIS Location: Operational Emissions: Mitigation Measure: Transportation Demand Management Node)* * Provide ridesharing information in a homeowner's association package. * Provide an opportunity to receive either a complimentary bicycle or electric bicycle retrofit kit to each residential buyer * Provide electric shuttle or minibus service to transit stops * Provide free transfers between all shuttles and transit. * Operation of a shuttle bus to shopping, health care, public services sites and other nearby trip attractors to reduce automobile use.
Landscaping	
R-18	Project provides and/or requires use of electric maintenance equipment; including, but not limited to electric lawn mowers, electric leaf blowers, etc (In combination with measure R-13 above).⊗ *(URBEMIS Location: Area Emissions: Mitigation Measures Node)* * Prohibit gas powered landscape maintenance equipment within developments. * Contract only with commercial landscapers who operate with equipment that complies with the most recent California Air Resources Board certification standards, or standards adopted no more than three years prior to date of use. * Provide battery powered or electric landscape maintenance equipment for new residences.

⊗ These operational, program-oriented measures must be implemented for at least 10years from build-out to qualify as an emission reduction measure

ON-SITE ENHANCING MEASURES

No.	Measure - Objective
	LOCATION
Mass Transit Infrastructure	
A	* Project is located within one mile of a park and ride lot operated by a transportation agency.
	TRANSPORTATION DESIGN
Transit Support	
B	Include transit support features in the project where deemed appropriate by the local agency with jurisdiction over the project as demand and service routes warrant subject to review and approval by local transportation planning agencies, including (but not limited to):
	* On-site/off-site turnouts
	* Route signs and displays
	* Bus turnouts/bulbs
	* Street lighting
	* Passenger benches
	* Shelters at transit access points
C	Develop park-and-ride lots
Streets	
D	Make street design/speeds consistent with requirements for neighborhood electric vehicles
	PARKING
Parking Amount	
E	Use of any excess parking over zone code requirements as on-site parking-n-ride lots.
Parking Construction	
F	Provide a parking lot design that includes clearly marked and shaded pedestrian pathways between transit facilities and building entrances
G	Loading and unloading facilities for transit and carpool/vanpool users. (Provide Signage)
H	Provide grass paving or reflective surface paving for unshaded parking lot areas, driveways, or fire lanes that reduce standard paving by 10% or more.
	* Portland concrete is the preferred paving material
	* Other reflective surfaces to be determined in consultation with SJVAPCD.
	* "Chip Seal" methodology
	* Green Pavement http://www.invisiblestructures.com/GP2/grasspave.htm
I	Structural soil should be used under paved areas to improve tree growth.
J	Provide electric vehicle charging facilities with preferential parking

ON-SITE ENHANCING MEASURES

No.	Measure - Objective
	BUILDING/SITE DESIGN
Telecommuting Infrastructure	
K	Provide necessary infrastructure for telecommuting
	* Provide fiber optic wiring and connections
	* Provide T1 wiring and connections
	* Install a teleconferencing facility
	* Install a on-site telecommunications center
	* Build new homes with internal wiring/cabling that allows telecommuting, teleconferencing, and telelearning
Landscaping	
L	Plant trees sufficient to shade 1/2 the paved area within 15 years after development is constructed.
M	Landscape with low-emission native drought-resistant species (plants, trees and bushes) to reduce the demand for gas powered landscape maintenance equipment. Contact the District for a list of low-emission trees and shrubs.
	OPERATIONAL MEASURES
Telecommunication	
N	Provide free-access telework terminals in multi-family projects
O	Provide a community videoconferencing system coordinated with TMA.
P	Design and implement "Shop by Telephone" or "Shop-by-Computer" services. Applicable to shopping centers and retail facilities.
Goods Movement	
Q	Establish delivery services. Applicable to retail facilities (frequent use), shopping centers, and restaurants.
R	If the development is a grocery store or large retail facility, provide home delivery service for customers.
S	Schedule goods movement for off-peak traffic hours.

APPENDIX D

Recommended Changes to URBEMIS for Proposed Rule 9510 (Indirect Source Review) and Rule 3180 (Administrative Fees for Air Impact Assessment Applications)

Area and On-road: Jones & Stokes Memo
Operational: Nelson/Nygaard Memo

November 17, 2005

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Jones & Stokes

Revised Memorandum

Date: October 20, 2004

To: Jennifer Barba, San Joaquin Valley Unified Air Pollution Control District

From: Tim Rimpo

Subject: **Recommendations for URBEMIS2002 On-Road and Area Source Mitigation Measures**

Introduction

This memorandum describes Jones & Stokes' proposed approach for updating URBEMIS2002's on-road and area source emission calculations and mitigation measures. The information included in the memo combines and modifies information in two previous memos based on comments received from the District and the URBEMIS Working Group during several conference calls held during the summer of 2004.

ON-ROAD MITIGATION MEASURES

The current version of URBEMIS2002 (version 7.5.0) includes operational mitigation measures that focus on travel behavior. They include measures designed to encourage individuals to walk, bike, or use transit in lieu of driving. A separate memo prepared by Nelson\Nygaard Consulting Associates (September 9, 2004) describes proposed changes to URBEMIS2002's operational mitigation measures.

In its current format, URBEMIS does not allow the user to enter mitigation measures to reduce on-road emissions associated with medium- and heavy-duty vehicles. This memorandum describes Jones & Stokes' proposed approach for incorporating operational on-road mitigation measures into URBEMIS2002.

The proposed addition of on-road mitigation to URBEMIS would focus on those measures that can be used to reduce emissions from diesel powered medium and heavy-duty engines (over 14,000 lbs). Although these on-road mitigation measures could be used to reduce emissions for any land use designation, they are most useful for land uses with a high percentage of on-road truck use, such as warehouses, manufacturing firms, and industrial uses. Other land uses that have a large number of on-road truck trips, such as large retail stores, may also reduce emissions using this new mitigation option.

Jones & Stokes' original proposal was to group on-road mitigation measures into the following four categories:

- Repower existing engines,
- Retrofit existing engines,
- Purchase new engines, and/or
- Use alternative fuels.

However, after discussing this topic with the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD) during the May 13th, 2004 conference call, it became clear that this approach had too many uncertainties and could not be accurately estimated by URBEMIS.

Instead, for project applicants wishing to provide on-road mitigation for medium- or heavy-duty trucks, the applicant would be required to work with the SJVUAPCD to estimate the pounds per day and tons per year emission reductions associated with the project. URBEMIS would be modified so that the user has the option of entering the pounds per day and tons per year emission reductions as calculated by the SJVUAPCD.

This approach would work much the same way in other air districts. The project applicant would need to work with the air district to determine the emission reduction associated with a project. That emission reduction would then be entered directly into URBEMIS.

AREA SOURCE MITIGATION MEASURES

URBEMIS2002 currently can be used to estimate emissions from five categories:

- Natural gas fuel combustion,
- Woodstove fuel combustion,
- Fireplace wood combustion,
- Landscape fuel combustion, and
- Consumer products.

We propose adding one additional area source category, architectural coatings, to the area source emissions module. Each of these six area source emission categories is discussed separately below.

Natural Gas Combustion

Emission Factors

URBEMIS2002 can be used to estimate natural gas fuel combustion emissions from cooking and water and space heating using an approach first described in Tables A9-12, A9-12-A, and A9-12-B in the South Coast Air Quality Management District CEQA handbook (South Coast Air Quality Management District 1993). The equation used to estimate CO, ROG, NOx, and PM10 emissions from natural gas combustion is described in the URBEMIS2002 User's Manual. No changes are proposed to those emission factors.

Mitigation Measures – Natural Gas Combustion

URBEMIS currently includes three categories of area source mitigation measures: residential, commercial, and industrial. The residential and commercial categories include several mitigation measure check boxes that apply to space and water heating. They include:

- Solar water heaters;
- Central water heaters;
- Orient buildings north/south; and
- Increase insulation beyond Title 24.

One additional mitigation measure - all electric landscape maintenance equipment – is included in URBEMIS for residential and commercial land uses. That mitigation measure is described separately below under the landscape fuel combustion heading. Orienting buildings north/south is currently the only industrial mitigation measure included within URBEMIS.

Jones & Stokes proposes modifying the natural gas combustion mitigation measures so that only three measures are included, one each for residential, commercial, and industrial land uses. Each measure would be based on building energy efficiency relative to Title 24, California's energy efficiency regulation for residential and nonresidential buildings. The three URBEMIS measures are as follows:

- ❑ Residential Land Uses: Increase energy efficiency ___% beyond Title 24.
- ❑ Commercial Land Uses: Increase energy efficiency ____% beyond Title 24.
- ❑ Industrial Land Uses: Increase energy efficiency ____% beyond Title 24.

The user would be required to turn on the appropriate measure and enter the percentage increase in energy efficiency. Emission reductions would be proportional to the increase in building energy efficiency beyond Title 24. For example, the developer of a

commercial land use that proposes an increase in energy efficiency 10% beyond the Title 24 requirements would receive a 10% reduction in natural gas combustion emissions compared to uncontrolled emissions.

Title 24 requires that compliance (with Title 24) be demonstrated before a building permit can be issued. This requirement applies to any heated building in California. Consequently, the percentage increase in energy efficiency beyond Title 24 would be based on the required compliance documentation.

Residential natural gas combustion primarily includes space heating, water heating, and cooking. One comment raised during the May 13th conference call was whether natural gas used for cooking is properly accounted for in the above mitigation. Data published by the California Air Resources Board (Emission Inventory Source Category 7.2 Residential Natural Gas Combustion, Revised November 1998) lists the percentage of residential natural gas use by category. That evaluation shows that approximately six percent of natural gas used in California residences is for cooking. Title 24 includes specific measures for natural gas cooking equipment. Since Title 24 covers natural gas cooking and because the cooking category is relatively small compared to total gas use, the mitigation measures listed above for total natural gas are sufficient to account for natural gas used for cooking.

Wood Stoves, Natural Gas Fireplaces, and Wood Fireplaces

Currently, URBEMIS includes wood stoves and wood fireplaces as separate area source emission categories. We propose modifying how these two emission source categories appear within URBEMIS and adding a third category, natural gas fireplaces.

The user, upon selecting this category, would be shown a screen with four tabs, which represent four separate screens that can be selected. As illustrated in the following table, the first screen would list the percentage of woodstoves, natural gas stoves, and fireplaces associated with the selected residential land uses. The remaining three screens would show the values that could be modified by the user for woodstoves, natural gas fireplaces, and wood fireplaces, respectively.

In the San Joaquin Valley, the percentage of homes with each of the three hearth options would vary based on housing density allowed by the SJVUAPCD's Rule 4901. For example, if the residential land uses entered by the user had a housing density of three per acre, then URBEMIS would, on the first "hearth" screen, show the percentages in the second column of Table 1.

The following table illustrates the percentages for the three situations allowed by Rule 4901. Where the housing density is 3 per acre, 2 homes or 67% could use woodstoves and 33% of the homes would be allowed to have wood stoves. For housing densities

exceeding three per acre, the percentage of woodstoves would decrease and the percentage of natural gas stoves would increase. Where the density of homes is between 2 and 3, 100% of homes are assumed to have wood stoves. Finally, when the density of homes is 2 per acre, half are assumed to have a fireplace and half are assumed to have woodstoves.

Table 1. Wood Stove, Natural Gas Fireplace, and Wood Fireplace Percentages

	PERCENTAGE OF HOMES WITH THIS OPTION		
	3 or more homes per acre	More than 2, less than 3 homes per acre	2 or fewer homes per acre
Wood Stoves	67%	100%	50%
Natural Gas Stoves	33%	0%	0%
Fireplaces	0%	0%	50%
None of the Above	0%	0%	0%
Total	100%	100%	100%
Assumption	Assumes 3 per acre	Assumes 2.5 per acre	Assumes 2 per acre
Based on SJVUAPCD Rule 4901.			

For areas outside of the San Joaquin Valley, URBEMIS will assume the following percentages:

- Wood Stoves: 35%
- Natural Gas Stoves: 55%
- Fireplaces: 10%
- None of the above: 0%.

These percentages represent the existing percentages within URBEMIS for wood stoves and fireplaces while also assuming that the remaining homes will have natural gas stoves.

Each air district would have the option to modify these default percentages.

Wood Stove Emission Factors

The emission factors currently used by URBEMIS to calculate wood stove emissions are the most recently available, based on a review of the wood stove emission factors at the U.S. EPA's emission factor web site (http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s10.pdf). Consequently, no changes are proposed to URBEMIS' wood stove emission rates. The emission rate equations are listed in the URBEMIS2002 User's Manual.

Natural Gas Stove Emission Factors

Jones & Stokes will incorporate natural gas stove emission factors into URBEMIS using the AP-42 emission factors for natural gas combustion (U.S. EPA, 1998). Emissions will be estimated using the following equations:

Pounds per day = A * B * C * D

Tons per year = Pounds per day * (E / 2000)

Where: A = fireplace emission rate for each pollutant,

- 94 pounds NOx / standard cubic foot (scf),
- 40 pounds CO/scf,
- 5.5 pounds ROG/scf,
- 7.6 pounds PM10/scf, and
- 0.6 pounds SO_2/scf.

B = amount of natural gas burned per day (scf),
C = number of residential units,
D = percentage of units with natural gas fireplaces, and
E = days per year (for tons per year emission calculations).

The emission equation will assume that the average stove is 30,000 Btu's, that there is 1,020 Btu's per standard cubic foot of gas, that the stove is used for an average of 2 hours per day during the winter months, and 100 days per year (200 hours per year).

Wood Fireplace Emission Factors

The emission factors currently used by URBEMIS to calculate fireplace emissions are the most recently available, based on a review of the fireplace emission factors at the U.S. EPA's emission factor web site http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s09.pdf Consequently, no changes are proposed to URBEMIS' fireplace emission rates.

Wood Stoves, Natural Gas Fireplaces, and Wood Fireplaces Mitigation Measures

Currently, URBEMIS2002 has no mitigation measures for woodstoves or wood fireplaces (Natural gas fireplaces are not currently part of URBEMIS2002.). Mitigation measures will be included in URBEMIS2002. The proposed change will allow the user to make changes to the percentages of wood stoves, natural gas fireplaces, and wood fireplaces that will be installed in new residences.

Landscape Fuel Combustion

Emission Factors

Landscape maintenance equipment generates emissions from fuel combustion, from evaporation of unburned fuel, and from fugitive dust generated by equipment such as leaf blowers. Emissions include NOx, ROG, CO, and PM10. The emission factors used to estimate equipment emissions include exhaust and evaporation. Emission factors have not yet been developed for the fugitive dust generated by certain types of equipment generate.

Equipment in the landscape category includes lawn mowers, roto tillers, shredders/grinders, blowers, trimmers, chain saws, and hedge trimmers used in residential and commercial applications. Engines in this category are 25 horsepower or less. This category also includes air compressors, generators, and pumps used primarily in commercial applications (California Air Resources Board 2004).

The California Air Resources Board has enacted regulations to limit emissions from landscape maintenance equipment. Beginning in 1994 these regulations imposed emission limits on all landscape maintenance equipment sold. Those regulations became more stringent for equipment sold in 1999 and later. Consequently, the emissions from this source category are similar to automobile emissions in that the turnover in the equipment fleet plays an important part in how quickly emission reductions are achieved.

URBEMIS2002 estimates emissions from this source category based on the year in which the user is attempting to estimate emissions. The California Air Resources Board has prepared estimates of emissions in 2000 and 2010. The proposed equations for this source category are divided into residential and commercial categories. The residential equation applies only to SFHU. The commercial equation is based on emissions per business unit and includes multifamily residential land uses.

The equations shown below are similar to those currently used by URBEMIS except that the pounds of pollutant per single-family residential unit and commercial business have been updated to reflect recent data developed by the California Air Resources Board (Cordero, M. and W. Wong, 2003).

2000 Emissions - Residential
ROG (pounds/day) = 0.0077 pounds ROG / SFHU/day * SFHU
CO (pounds/day) = 0.0449 pounds CO / SFHU/day * SFHU
NOx (pounds/day) = 0.0003 pounds NOx / SFHU/day * SFHU
PM10 (pounds/day) = 0.0002 pounds PM10 / SFHU/day * SFHU

2000 Emissions - Commercial
ROG (pounds/day) = 0.1593 pounds ROG / Business Unit * Number Business Units
CO (pounds/day) = 0.9298 pounds CO / Business Unit * Number Business Units
NOx (pounds/day) = 0.0061 pounds NOx / Business Unit * Number Business Units
PM10 (pounds/day) = 0.0041 pounds / PM10 Business Unit * Number Business Units

2010 Emissions - Residential
ROG (pounds/day) = 0.0038 pounds ROG / SFHU/day * SFHU
CO (pounds/day) = 0.0305 pounds CO / SFHU/day * SFHU
NOx (pounds/day) = 0.0005 pounds NOx / SFHU/day * SFHU
PM10 (pounds/day)= 0.0001 pounds PM10 / SFHU/day * SFHU

2010 Emissions - Commercial
ROG (pounds/day) = 0.0899 pounds ROG / Business Unit *Number Business Units
CO (pounds/day) = 0.6310 pounds CO / Business Unit * Number Business Units
NOx (pounds/day) = 0.0094 pounds NOx / Business Unit * Number Business Units
PM10 (pounds/day)= 0.0013 pounds PM10 / Business Unit * Number Business Units

The residential emission factors shown in the 2000 emission equations are based on total California single family residential emissions divided by the total number of California SFHU in 2000. Similarly, the commercial emission factors for 2000 are based on total California non-farm business emissions divided by the California's total 2000 business units (U.S. Department of Commerce 2003). For the commercial equations, URBEMIS2002 bases the number of business units on the number of non single-family housing land uses specified by the user.

The 2010 emission rates are based on ARB's estimates of emissions for this source category, broken into residential and commercial categories.

URBEMIS2002 will use the emission rates shown for 2000 for 2000 emissions. For 2001 through 2009, URBEMIS2002 will use interpolated emission factors by assuming a uniform decrease in the emission rate each year between 2000 and 2010. In 2010 and succeeding years, the 2010 emission rates will be used.

Average annual emissions assume that daily emissions would occur only during the summer period of 180 days. The end user will be able to modify the length of the summer period.

Mitigation Measures – Landscape Fuel Combustion

URBEMIS2002 currently allows the user to specify a mitigation measure in which electric powered equipment can be used to replace gas-powered equipment. However, this is currently an all or none mitigation measure. The following measure will allow the user to enter a percentage representing the proportion of residential and non-residential equipment that will be replaced by electrically powered equipment as follows:

- Replace ____% of residential landscape equipment with electrically powered equipment and provide electrical outlets at the front and rear of residences.

- Replace ____% of non-residential landscape equipment with electrically powered equipment and provide electrical outlets for the use of such equipment.

Consumer Products

Emission Factors

Consumer products comprise one of the largest solvent-use categories of reactive organic gases in California. Consumer product emissions are any chemically formulated product used by household and institutional consumers. They include a wide range of product categories, including air fresheners, automotive products, household cleaners, and personal care products (California Air Resources Board, 2000).

Emissions associated with these products primarily depend on the increased population associated with residential development. URBEMIS estimates consumer products when one or more residential land uses have been selected by the user. ROG emissions associated with consumer product use are currently estimated with the following equation:

ROG (pounds/day) = 0.0171 daily pounds of ROG per person * number of residential units * 2.861 persons per residence

The revised consumer products emission factor equation includes modifications of the pounds ROG per person and persons per residence variables:

ROG (pounds/day) = 0.013 daily pounds of ROG per person * number of residential units * 2.93 persons per residence (will vary by county).

The ROG emission factor is based on an average of the total estimated ROG emissions from consumer products divided by the total California population (California Air Resources Board, 2004; California Department of Finance, 2004). The ROG pounds per person emission factor ranges from 0.1927 in 2003 to 0.2182 in 2020. An average of these emission factors – 0.2055 pounds ROG per person – will be incorporated into URBEMIS as the default emission factor.

The persons-per-residence shown in the equation above is a California average. Within URBEMIS, separate estimates of persons per residence will be included for each county.

Mitigation Measures – Consumer Products

No feasible mitigation measures have been identified to reduce consumer product emissions.

Architectural Coatings

Emission Factors

Currently, URBEMIS estimates architectural coatings emissions as part of the construction module but not as part of area sources. However, a percentage of buildings are repainted each year and the ROG emissions associated with those buildings will be incorporated as an area source emission category.

Architectural coating emissions will be calculated using the same approach as in the construction module except that two additional variables will be added, one for residential coatings and one for non-residential. Those variables, which can be edited by the user, will show the percentage of a project's total square footage that will be repainted each year. We currently propose using 10% for both residential and non-residential buildings. However, this value may change as we continue to research this issue. Also, the individual air districts will have the option of modifying this percentage.

Mitigation Measures – Architectural Coatings

There are few feasible mitigation measures available to reduce evaporative emissions associated with architectural coatings. The best approaches involve using materials that require no architectural coatings during building construction or using coatings with lower ROG content than are currently required by regulation.

Instead of being considered a mitigation measure, we will assume that the use of "no-coatings" building materials is part of the project. Consequently, the use of coatings free building materials would have to be accounted for within the unmitigated portion of URBEMIS. This could be accounted for be reducing the coating thickness or the conversion factors (2.7 for residential, 2.0 for non-residential) that is used to convert building square footage to the amount of surfact area to be painted.

Although the use of low ROG content coatings is a feasible mitigation measure, it is considered unenforceable, especially during the operational phase of a project. Consequently, no mitigation measures will be incorporated into the architectural coatings category of the URBEMIS area source mitigation measures.

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nelson\nygaard consulting associates

833 Market Street, Suite 900
San Francisco, CA 94103-1814
(415) 284-1544 FAX: (415) 284-1554

M E M O R A N D U M

To: Tim Rimpo

From: Patrick Siegman

Date: October 10, 2004

Subject: **Final Recommendations for URBEMIS 2002 Mitigation Measures**

Introduction

This memorandum sets out recommendations to revise the operational mitigation component of URBEMIS 2002. These have been developed with three main aims in mind:

- **Simplify** the existing mitigation component, which while extremely detailed, is daunting to new users and has extensive data requirements. In particularly, the division between "environment factors" and "mitigation measures" can be confusing.
- **Improve consistency.** Many of the inputs to the mitigation component are extremely subjective (e.g. whether some, few or no bike routes provide wide paved shoulders and have few curb cuts). We propose making these more quantitative, and/or providing additional guidance in the users' manual or within the program itself.
- **Improve accuracy and transparency.** While many of the inputs to the current mitigation component have been proven to have an impact of travel behavior, research is still at an early stage of assessing quantitative impacts, and how these interrelate with other mitigation strategies. The recommendations here update the current mitigation component in the light of new research.

An extensive body of research has been compiled as to the impacts of particular mitigation strategies on travel behavior. However, in general, this has either had an academic focus, or been undertaken for the purposes of developing citywide or regional travel models. For example, many agencies have sophisticated procedures for assessing non-single occupancy auto travel at the level of TAZ or above, but not at the development level. There is extremely little guidance on how to use this data in the type of application needed for URBEMIS 2002 – namely, to provide quantitative estimates of the impact on trip generation and vehicle miles traveled (VMT) at the development level.

Many agencies do provide credits for individual developments that implement mitigation measures, for example when assessing impact fees or conducting traffic studies. Some California examples include C/CAG in San Mateo County and VTA in Santa Clara County. A brief, national review was also conducted for purposes of this memorandum.1 In general, however, these credit programs are only loosely based on the latest travel research, and it could be argued that they function more at a policy level, in providing incentives for developers to incorporate elements such as demand management programs that the agency considers desirable.

The recommendations here therefore attempt to bridge the gap between academic studies and complex regional or area-wide models on the one hand, and more site-specific traffic assessments on the other hand. The emphasis is on providing the best possible estimate while minimizing data requirements. The overall effect, compared to the existing mitigation component, is to reduce the number of inputs required, but make them more quantitative.

It cannot be too highly stressed that the trip reductions recommended here are valid at a sketch-planning level only, and are subject to considerable uncertainty. While they should ideally be expressed as a range, in order to expressly account for this uncertainty, a single value is needed for purposes of the Indirect Source Review in order to allow the appropriate fee to be calculated. The same limitations noted in the documentation for the existing mitigation component still apply, and are worth repeating here:

> The URBEMIS 2002 mitigation component is a significant advance over past attempts to quantify the benefits of air quality mitigation measures, however, users should recognize that travel behavior is very complex and difficult to predict. The component relies on the user to determine factors critical to travel behavior that are somewhat subjective. As GIS and electronic traffic monitoring and data collection become a reality in many cities, the ability to identify factors critical to walking, bicycling, and transit use will be enhanced. The URBEMIS 2002 mitigation component provides a starting point for using currently available data to demonstrate the benefits of urban design and traditional mitigation measures in reducing air quality impacts.

1 Agencies contacted included: New York Metropolitan Transportation Council; Atlanta Regional Commission; Alameda County, CA; and San Luis Obispo County, CA.

The mitigation component results, however, should still be interpreted as the mid-point of a range. Recent research has pointed towards the dangers inherent in reporting precise values, when the results are the subject of considerable uncertainty (Shoup, 2003). However, although the methodological dangers are obvious, there is generally no question about the *direction* of the relationship, only its size and the appropriate variable. Some adjustment is better than none at all – which is what most conventional trip generation methodologies provide (Ewing & Cervero, 2001). In addition, existing project-level trip generation methodologies, even though well-accepted within the transportation planning and engineering profession, are themselves subject to considerable uncertainty, and results are reported with unwarranted precision (Shoup, 2003).

Other considerations that should be noted include:

- The key output that is sought here is reduction in *vehicle trips.* Research results, however, often report results in terms of VMT. Where no alternative is available, we assume that VMT is proportional to vehicle trips.
- Elasticities are generally used to make the calculations, since when used with care, they provide a satisfactory, means of preparing first-cut aggregate response estimates for various types of transportation system changes (Pratt *et. al.,* 2000). They also provide a transparent and accessible method of reporting results, that can be transferred from one region to another (Ewing & Cervero, 2001).
- There are major theoretical issues regarding the direction of causality that have still to be resolved in the research. For example, does an increase in density lower vehicle trip generation rates, or do more dense places attract people who tend to make fewer vehicle trips? For the purposes of this analysis, however, the distinction is unimportant. The key issue (using the same example) is that more dense places are associated with fewer vehicle trips.
- Local planning controls and development economics are assumed to provide an important "reasonableness" check on the recommended trip reductions. For example, reductions in parking supply will not normally be allowed unless the local jurisdiction is confident that complementary trip reduction measures will be applied. Equally, it is unlikely that frequent transit service will be provided to a destination with low potential ridership, given competing demands on an agency for service.

About the Trip Generation Manual

At its heart, the URBEMIS mitigation component is a tool for modifying the average trip rates reported in the Institute for Transportation Engineers' *Trip Generation* manual to make

them more accurate, so that they fairly reflect the particular characteristics of a proposed development. Before modifying these average rates, it is therefore useful to understand the manual itself: how the average rates were derived; the original data sources that underlie the manual; and the manual's own recommendations about when, and why, its average trip generation rates should be modified. Some key points are these:

- The ITE manual normally predicts trip generation from new buildings using just two variables. Typically, the user first selects a broad *land use type* (e.g. "High-Rise Residential Condominium/Townhouse"). Second, the user inputs the *quantity* of that land use type (e.g. "100 dwelling units").
- An important advantage of this simple approach is that very little information about a project is needed to predict trip generation, and trip generation calculations are simple.
- A primary disadvantage of such two-variable formulas is that they do not take into account the multiple other variables (parking price, transit service, etc.) that transportation research has shown to strongly affect trip generation, and so the variation in trip rates *within* each land use category is frequently very high.

Recognizing these points, the *Trip Generation* manual therefore advises the reader that the average trip generation rates reported in the manual "represent weighted averages from studies conducted throughout the United States and Canada since the 1960s. Data were primarily collected at suburban locations having little or no transit service, nearby pedestrian amenities, or travel demand management (TDM) programs. At specific sites, the user may wish to modify trip generation rates presented in this document to reflect the presence of public transportation service, ridesharing or other TDM measures, enhanced pedestrian and bicycle trip-making opportunities, or other special characteristics of the site or surrounding area."

However, while the studies may have been *primarily* conducted at such suburban sites, it appears from the sources referenced that for some land uses, particularly higher density residential land uses, many sites studied included at least some transit service, sidewalks, and other characteristics associated with lower vehicle trip rates. For the "High-Rise Residential Condominium/Townhouse", for example, the manual's text shows that sites were surveyed in such cities as Vancouver, Canada: a city where it is difficult to find high-density condominiums that lack sidewalks, transit service, and a mix of uses nearby.

As part of our research, we made several calls to and exchanged correspondence with the staff at the Institute for Transportation Engineers. The staff was unable to provide any additional data (beyond the text of the manual itself) on the characteristics of the developments used in its trip generation studies, and was also unable to provide the actual studies – the original data – which underlie the manual's conclusions. Therefore, it is not possible to define with certainty the precise characteristics of an "average site".

Given this paucity of information available on the original sources for the *Trip Generation* manual's, conclusions about the average characteristics of the different land uses in the manual (e.g., average residential density, or the percentage of neighborhood streets with sidewalks) necessarily must be estimated, rather than precisely calculated. Fortunately, a large body of other research on travel behavior and land use is available, and reasonable estimates can be made based upon this research.

Recommendations

1. Combine "environmental factors" and "mitigation measures."

URBEMIS 2002 distinguishes between "environmental factors" for pedestrians, cyclists and transit (i.e., the character of the existing neighborhood), and "mitigation measures" (i.e. those added by the development). The environmental factors both provide a mitigation measure in themselves (e.g. the credit for existing or planned transit service), and are also used to weight the mitigation measures (i.e., a lower credit is given for a mitigation measure in an area that has a low environmental factor).

The distinction does make it easier to give credits for specific mitigation measures (e.g. bus bulbs, sidewalks and bicycle parking). However, we recommend that the distinction be removed, since it also brings several important disadvantages. Most of these relate to either complexity, or the relative advantages of infill vs. greenfield development, as follows:

- The pedestrian environmental factors appear to be given less weight than the mitigation measures, even when it is taken into account that the environmental factors are also used to weight the mitigation measures. The credit for the surrounding pedestrian environment is 2%, compared to the maximum allowable reduction of 9%. This means that smaller, infill developments will be eligible for lower credits, since by their nature they will be more dependent on the surrounding environment and have more limited ability to fund mitigation measures.
- On a related point, the importance of the environmental factors compared to mitigation measures is largely a function of scale, i.e. development size. Larger projects, particularly on greenfield sites, will be starting from a "blank sheet," and on-site mitigation measures will be paramount. The appropriate trip reductions for smaller, infill developments, in contrast, will be more a function of the surrounding environment.
- Combining the environmental factors and mitigation measures would make the component easier to understand, particularly for inexperienced users. At present, the separation can be confusing.

2. Scale

This question relates to the area that should be analyzed. We recommend that this should be either the area within a half-mile radius from the center of the project, or the entire project area, whichever is larger. This is the same approach taken in the existing URBEMIS mitigation component. In effect, the smaller the development, the greater the consideration given to the wider project area.

3. Provide Post-Modeling Adjustments to Reward Other Mitigation Measures

One of the impacts of these recommendations would be to narrow the range of mitigation measures that are considered in the analysis. Some potential mitigation measures are excluded even though they are likely to have a travel behavior impact, either because they cannot be readily quantified, or because this would risk double counting an impact already quantified elsewhere (i.e. another variable, such as intersection density, serves as a proxy). We therefore recommend consideration of how post-model adjustments can be used to provide financial incentives for developers to incorporate these mitigation measures. This may include all those that are in the current mitigation component, but are not recommended for continued inclusion, including:

- Street trees
- Traffic calming
- Design maximizing visual interest for pedestrians, and “eyes on the street”
- Zero building setbacks
- Direct pedestrian connections
- Street furniture and artwork
- Pedestrian signalization and signage
- Street lighting
- Low speed limits on bicycle routes
- Safe routes to schools
- Bicycle parking ordinance
- Transit stop amenities
- Route signs and displays
- Bus turnouts and bulbs
- Structured parking

4. Modifying Average Trip Generation Rates

In general, both the recommended trip rate modifications and the overall philosophy of the mitigation component are similar to those in the existing URBEMIS model, and build extensively off this work. The major differences between the existing mitigation component and these recommendations are found in (a) the input variables, which are

designed to be more quantitative and less subjective, and are fewer in number, and (b) the formulas, which take advantage of the latest research on residential travel behavior.

Neighborhood-level trip generation and vehicle miles traveled vary by more than 80% in California cities (Figure 1). As the documentation for the existing mitigation component recognizes, areas with low trip generation and VMT levels have the highest development densities, a wide variety of uses within walking distance, safe and comfortable pedestrian access, paid parking requirements, and a high level of transit service.

Similarly, residential trip rates reported in the *Trip Generation* manual vary widely, both *within* individual land use types, and *between* land use types (Figure 2). For the land use type "Single Family Detached Housing", for example, reported rates ranged from a low of 4.31 daily trips per dwelling unit, to a high of 21.85 daily trips. The *Trip Generation* manual reports that, "This land use included data from a wide variety of units with different sizes, price ranges, locations and ages. Consequently, there was a wide variation in trips generated within this category." Between residential land use categories, the variation is still greater, as would be expected. For example, the average trip rate for the "Residential Condominium/Townhouse" land use type is 5.86 (or 39% lower than the average single-family detached house), while the lowest trip rate is 1.83 (or 80.9% lower). At the extremes, considering all residential land uses, the highest residential rate reported (21.85 trips/day) is more than ten-fold higher than the lowest rate reported (1.83 trips/day).

Figure 1 Daily Trips by Density, San Francisco Bay Area

	Households/Residential Acre					
	< 2	**2-5**	**5-10**	**10-20**	**20-50**	**> 50**
Mean Households/Residential Acre	1.4	3.6	6.7	13.5	30.6	121.9
Daily Vehicle Trips/Household	6.4	5.9	5.0	3.8	2.9	1.2
% Reduction in Daily Vehicle Trips/Household compared to lowest density areas	0%	9%	23%	41%	55%	82%

Source: MTC Household Travel Survey, 1990, cited in Holtzclaw, 2002

Figure 2 ITE Trip Rates for Selected Residential Land Uses

Land Use Code	Land Use Type	ITE Trip Rate		
		Low	Average	High
210	Single-Family Detached Housing	4.31	9.57	21.85
221	Low-Rise Apartment	5.1	6.59	9.24
230	Residential Condominium/Townhouse	1.83	5.86	11.79
222	High-Rise Apartment	3	4.2	6.45
232	High-Rise Residential Condo./Townhouse	3.91	4.18	4.93

Based on these data in Figures 1 and 2, and a wide range of additional transportation research, we have developed a set of formulas for modifying the average trip rates for residential land uses has been developed. For the URBEMIS user, the procedure for modifying residential trip generation rates will remain generally similar to the existing process, with three basic steps:

1. In the "Land Use Selection" screen, the user will enter the land use types (e.g. "Apartment, Low-Rise") and the number of dwelling units of each type.
2. Next, if the mitigation component is used, the user will be prompted to review the default values for several key variables (e.g. residential density, level of transit service) for each residential land use type. If the project's land uses have characteristics that are different from the default values (as they usually will be), the user will enter the correct values, in place of the default values.
3. Within the program, the formulas described hereafter will be used to calculate the resulting trip generation rates.

In keeping with the conclusions of current transportation research, a single set of formulas is used to modify the trip rates for all residential land use types. The input variables for these formulas assess five key land use characteristics (or "mitigation measures", in URBEMIS terms):

- Net residential density (measured by Households per Residential Acre)
- Mix of uses (using a jobs/housing measure)
- Presence of local-serving retail
- Level of transit service (measured by a transit service index)
- Bicycle and pedestrian friendliness (measured by an "pedestrian factor" index based on intersection density, sidewalk completeness, and bike lane completeness)

For each ITE residential land use type, a set of default values for these variables has been defined. If the default values for a residential land use type are left unchanged when running the mitigation component, then the resulting trip generation rate will be the standard ITE average trip generation rate for that land use type. For single-family detached housing, for example, the default values include a residential density of three units per residential acre, a transit service index score of 0 (representing no transit service within one-quarter mile of the site), and an intersection density of 250 intersections per square mile (typical of post-war cul-de-sac residential subdivisions). Figure 4 shows the default values for each land use type.

To achieve the lowest residential trip rate reported in *Trip Generation* (a manual which primarily measures stand-alone, single-use projects with little or no transit service), the input values required would include a density of 160 units per residential acre, the maximum level of transit service, the best possible mix of uses and local retail, and a pedestrian score equivalent to a complete sidewalk coverage with a network of blocks no larger than 300 feet on a side. This would result in a rate of 1.83 trips/day, or an 81% reduction from the average single-family house rate).

This is similar to the 82% difference in household trip generation between the lowest density areas with the poorest transit service (6.4 vehicle trips per household per day), and the highest-density areas with good transit and a higher quality pedestrian environment (1.2 vehicle trips per household per day), as shown in Figure 1. Figure 4 shows the input values that would be required to achieve this rate, as well as the input values required to achieve maximum possible reduction allowed.

In theory, choosing the maximum possible values for each of the *physical design variables* described above could result in a residential trip generation rate as low as 0.9 daily trips per unit. This represents a 90% reduction from the average rate for a single-family detached house. To achieve this rate, however, a neighborhood would have to have remarkable characteristics, similar to Manhattan or Hong Kong: a density of 380 units per acre, or more than three times the average density of San Francisco's densest neighborhoods (North Beach and Chinatown), the highest possible level of transit service, and so on.2

The recommended reductions for the individual physical design mitigation measures for residential uses are summarized in Figure 3. The remainder of the memorandum discusses the justification for these levels, along with the mitigation measures for non-residential uses. In general, the recommended maximums for individual components have been set at a level so that this overall 90% maximum reduction from the average single-family house

2 While rare in California, these extreme cases of Manhattan-like densities can be seen in projects such as San Francisco's single-room occupancy hotels for very low income residents, which achieve such densities by omitting parking and providing very small living quarters.

rate is maintained for residential land uses. While a greater reduction may sometimes seem warranted for an individual measure, a lower value has been selected to stay within this 90% maximum – a practice that helps avoid the considerable dangers of double counting.

In addition to the variables above, which primarily measure physical design characteristics, the formulas include mitigation measures that assess *demand management programs and similar measure*s. A maximum additional reduction of 7.75% from the average single-family house rate is possible through these measures.

Non-Residential Land Uses

For non-residential land uses, the general procedure for modifying rates is similar, and based upon many of the same research results. To modify non-residential trip generation rates, the following procedure is used:

1. For *physical design* mitigation measures, the formulas to determine percentage reductions are identical to the formulas for residential land uses, except for the 'Residential Density' measure, which cannot apply.
2. Additional mitigation measures are applied for *demand management programs and similar measures.* For non-residential uses, the number of available demand management measures is greater, as is the possible percentage reduction.

However, there is a key difference between the formulas used to modify residential rates, and the formulas used to modify non-residential rates:

1. For residential land uses, the percentage reductions shown for each mitigation measure refer to the percentage reduction from 9.57 trips per day (the rate for single family homes). The default values for each residential land use (Figure 4) are set at levels such that keeping these values generates the average trip rate for that land use.

2. For non-residential land uses, the percentage reductions shown for each mitigation measure refer simply to the percentage reduction from the average ITE trip generation rate for that land use. No special default values are required: they are simply set to create a 0% reduction as the starting value.

Figure 3 Summary of Recommended Trip Reductions

	Residential	Non-Residential	Comments
Physical Measures			
Net Residential Density	Up to 55%	N/A	
Mix of Uses	Up to 9%	Up to 9%	
Local-Serving Retail	2%	2%	
Transit Service	Up to 15%	Up to 15%	
Pedestrian/Bicycle Friendliness	Up to 9%	Up to 9%	
Physical Measures sub-total	*Up to 90%*	*Up to 35%*	
Demand management and similar measures			
Affordable Housing	Up to 4%	N/A	
Parking Supply	N/A	No limit	Only if greater than sum of other trip reduction measures
Parking Pricing/Cash Out	N/A	Up to 25%	
Free Transit Passes	25% * reduction for transit service	25% * reduction for transit service	
Telecommuting	N/A	No limit	Not additive with other trip reduction measures (see text)
Other TDM Programs	N/A	Up to 2%, plus 10% of the credit for transit and ped/bike friendliness	
Demand Management sub-total3	*Up to 7.75%*	*Up to 31.65%*	

3 This sub-total excepts the measures for parking supply and telecommuting, which have no limit.

Figure 4 Default Values for Residential Land Use Trip Generation Formulas

Default Values for Residential Trip Rate Formulas

Land Use Code	Land Use Type	Residential Density	Housing Units	Employees	Retail?	Transit Service	Intersection Density	Sidewalks	Bike Lanes	Ped factor	ITE Trip Rate Low	ITE Trip Rate Average	ITE Trip Rate High
210	Single-Family Detached Housing	3	100	17	no	0.00	250	0	0	0.06	**4.31**	**9.57**	**21.85**
221	Low-Rise Apartment	16	100	26	no	0.06	250	0.5	0	0.23	**5.1**	**6.59**	**9.24**
230	Residential Condominium/Townhouse	16	100	60	yes	0.10	400	1	0	0.44	**1.83**	**5.86**	**11.79**
223	Mid-Rise Apartment	38	100	60	yes	0.14	400	1	0	0.44	**NA**	**4.68**	**NA**
222	High-Rise Apartment	62	100	60	yes	0.14	400	1	0	0.44	**3**	**4.2**	**6.45**
232	High-Rise Residential Condo./Townhouse	64	100	60	yes	0.14	400	1	0	0.44	**3.91**	**4.18**	**4.93**

Trip Rates Resulting When Default Values Are Used

Land Use Code	Land Use Type	Reductions: Residential Density	Mix of Uses	Local Retail	Transit	Bike/Ped	Total	Resulting Trip Rate
210	Single-Family Detached Housing	0.0%	-0.6%	0.0%	0.0%	0.6%	0.0%	9.57
221	Low-Rise Apartment	27.9%	0.5%	0.0%	0.6%	2.1%	31.1%	6.59
230	Residential Condominium/Townhouse	27.9%	3.9%	2.0%	1.1%	3.9%	38.8%	5.86
223	Mid-Rise Apartment	39.8%	3.9%	2.0%	1.5%	3.9%	51.1%	4.68
222	High-Rise Apartment	44.8%	3.9%	2.0%	1.5%	3.9%	56.1%	4.20
232	High-Rise Residential Condo./Townhouse	45.1%	3.9%	2.0%	1.5%	3.9%	56.3%	4.18

Example Residential Trip Rate Calculations

Land Use Code	Land Use Type	Residential Density	Housing Units	Employees	Retail?	Transit Service	Intersection Density	Sidewalks	Bike Lanes	Ped factor	ITE Trip Rate Low	ITE Trip Rate Average	ITE Trip Rate High
210	"Worst Case" Single-Family	0.1	100	0	no	0.00	80	0	0	0.02	-	**-**	**21.85**
230	"Best Case" Res. Condo/Townhouse	160	100	150	yes	1.00	1300	1	0	0.67	**1.83**	-	**-**
NA	Maximum Possible Reduction	380	100	150	yes	1.00	1300	1	1	1.00	**NA**	**NA**	**NA**

Trip Rates Resulting When Example Values Are Used

Land Use Code	Land Use Type	Reductions: Residential Density	Mix of Uses	Local Retail	Transit	Bike/Ped	Total	Resulting Trip Rate
210	"Worst Case" Singe-Family Detached	-20.7%	-3.0%	2.0%	0.0%	0.2%	-21.5%	11.63
230	"Best Case" Res. Condo/Townhouse	51.4%	9.0%	2.0%	12.5%	6.0%	80.9%	1.82
NA	Maximum Possible Reduction	55.0%	9.0%	2.0%	15.0%	9.0%	90.0%	0.95

5. Data Requirements

Figure 5 shows the inputs that are required to complete the mitigation component in full, along with suggested data sources. Note, however, that the mitigation component can still be run, even if some of these inputs are missing. While no reduction would be granted for the particular mitigation measure for which the input was required, credits could be granted for other trip reduction measures.

Figure 5 Data Requirements and Suggested Sources

Required Input	Suggested Source		Comments
	Project	Surrounding Development	
Net residential density	Project plans	Block-level census data	Net residential data excludes land not devoted to residential uses
Number of housing units	Project plans	Block-level census data	Same basic source as for net residential density
Number of jobs	Project plans	Census Transportation Planning Package. Local jurisdiction may provide more current or fine-grained data	If data are only available per square foot, US Dept. Energy produces figures on average employee density
Local serving retail	Project plans	Site observations	
Below-market-rate units	Project plans	N/A	
Parking supply	Project plans	N/A	
Transit service	Transit agency maps/schedules		
Intersection density	Project plans	Street plans	Count can be automated if available in GIS
Sidewalk completeness	Project plans	Site observations	Count can be automated if available in GIS
Bike lane completeness	Project plans	Site observations	Count can be automated if available in GIS
Parking pricing	Development agreement or similar	Site observations (if applicable)	
Free transit pass provision	Development agreement or similar	N/A	
Telecommuting/flexible work schedules	Development agreement or similar	N/A	
Other TDM programs	Development agreement or similar	N/A	

6. Procedure for Small Projects

For developments in an established urban area below a certain size threshold, we recommend allowing them to adjust their trip generation rates based on the mode share in that census tract. This would avoid a disproportionate burden in gathering the data to document their likely trip reduction. (The analyst would need to certify that the project was similar in character to the existing development.) The recommended threshold is 50 average daily baseline vehicle trips, with the baseline being that calculated by URBEMIS before any of the reductions from mitigation measures are applied.

7. Substitute Methodologies

The recommended mitigation levels are, in our judgment, the most appropriate for a model that must apply to an extremely wide range of projects and geographic contexts. However, it must be recognized that there may be "special cases," where these standard reductions may not apply. For this reason, we recommend that any methodology for calculating reductions in VMT and vehicle trips may be substituted, provided that this is mutually agreed between the Air District and project proponent.

8. Measures Reducing VMT

The existing mitigation component allows for reductions in VMT (but not trip generation) for park-and-ride lots and satellite telecommuting centers. We do not recommend any changes to this aspect of the mitigation component.

9. Correction Factors

The existing mitigation component provides for trip type correction factors, based on evidence suggesting that certain trips are more likely to be captured by one mode rather than another. We do not recommend any changes to this aspect of the mitigation component.

A second correction factor in the existing mitigation component relates to trip distance, because, the documentation argues, bicycle and walking trips replace mostly shorter automobile trips. We recommend that this correction factor be eliminated, as there is little evidence to suggest that this phenomenon exists. Indeed, more complex changes in travel behavior are likely, such as mode shift to bicycling and walking trips being accompanied by a shift to closer destinations. For example, rather than drive to a grocery store on a freeway interchange, a household may walk to a smaller store in the neighborhood. Mixed use, compact neighborhoods are characterized by short overall trip lengths (see, for example, Kuzmyak et. al., 2003). Further evidence comes from the elasticities for trip reduction with respect to density, which are the same for both vehicle trips and VMT (Ewing & Cervero, 2001), suggesting that there is no impact on trip length.

Detailed Justification of Recommended Mitigation Levels

Default Values for Residential Land Uses

To develop the default values for residential land uses shown in Figure 4, we had to overcome a significant hurdle: ITE retains no data on the characteristics of the developments used in their trip generation studies. Default values for average density, transit service levels, and other variables had to be estimated using two alternative methods. First, we reviewed representative projects through research of literature and discussions with professionals in the fields of architecture and town planning, to ascertain typical ranges for density and other characteristics of each land use type (for useful summaries, see Calthorpe, 1993, and Local Government Commission,2002).

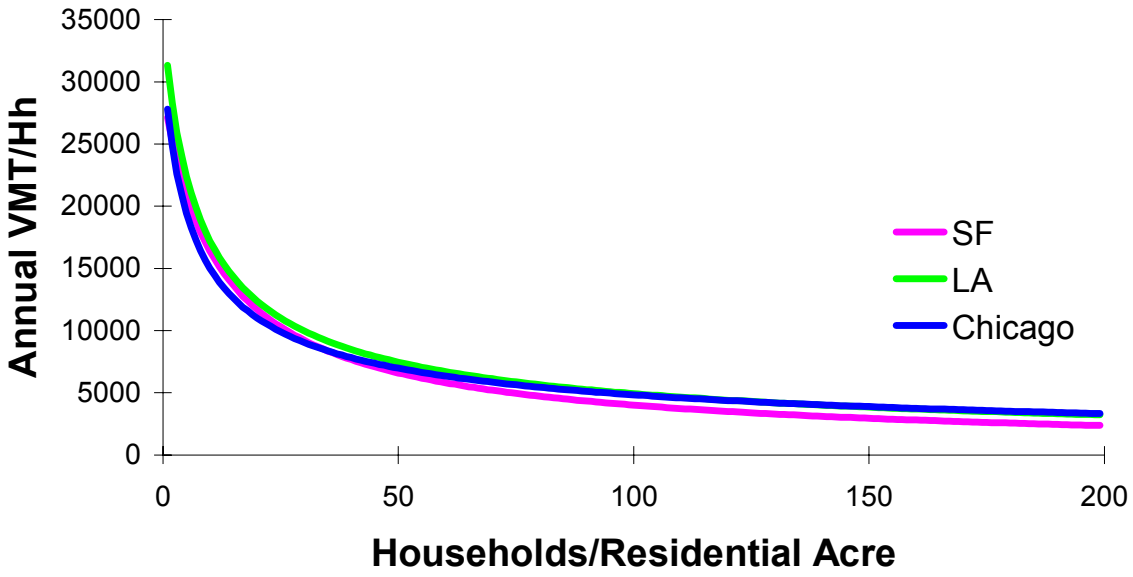
Second, these ranges of values were plugged into the formulas for the mitigation measures, and adjusted until the baseline values for each characteristic equaled the average ITE trip generation rates for each land use. For example, baseline density for Mid-Rise Apartments (64 units per residential acre) falls within the typical range observed from research of 45 to 125 units/acre, and when combined with other baseline characteristics for the land use, results in a 56.1% reduction in trip generation from the average rate for single family homes – the average reduction set forth in the ITE manual.

Finally, since the *Trip Generation* manual provides no daily trip generation rate for the "Mid-Rise Apartment" land use, we estimated a rate by extrapolating from the daily trip rate for the "High-Rise Apartment" land use type. The PM peak hour trip rate of 0.39 trips per unit for mid-rise apartments is 11.4% higher than the PM peak hour rate for high-rise apartments (0.35 trips/unit). Therefore, the daily trip rate for the "Mid-Rise Apartment" land use was estimated to be 4.68 trips per unit, or 11.4% higher than the daily trip for high-rise apartments (4.2 trips/unit).

Density

A considerable volume of research has investigated the links between density, particularly residential density, and travel behavior (for summaries, see Kuzmyak et. al, 2003; Boarnet & Crane, 2001). Overall, the conclusions can be summarized thus: there is a significant, quantifiable relationship between residential density and automobile use (see Figure 6), but there is uncertainty regarding the degree to which this effect is due to the inherent effects of density, as opposed to factors for which density serves as a proxy, such as parking price, local retail, transit service frequency and pedestrian friendliness.

Figure 6 Residential Density Vs. Vehicle Travel



Source: Holtzclaw et. al. (2002).

Fewer studies have attempted to disentangle the effects of density itself. Three of the main exceptions are:

- Typical elasticities for vehicular travel with respect to density are –0.1 to –0.04. These elasticities refer to the effect of density itself, isolated from variables that tend to be correlated with density such as transit frequency, and are additive to elasticities of other built environment factors. When these factors are not isolated, typical elasticities for VMT with respect to density are –0.22 to –0.27 (Kuzmyak et. al, 2003).
- The elasticity of density, when isolated from three other variables (diversity, design and destinations), is –0.043 with respect to vehicle trips, and – 0.035 with respect to VMT (Criterion and Fehr & Peers, 2001). However, this does not control for transit service levels.
- Cervero & Ewing (2001), in an update to this work, suggest a slightly higher elasticity of –0.05 with respect to both vehicle trips and VMT.

Note that density has been shown to have a nonlinear relationship with vehicle travel, with a threshold value of 25-30 units per acre below which the travel impacts of increased density are particularly large (Holtzclaw et. al, 2002). Holtzclaw et. al found that the best single variable equations to predict household vehicle travel (VMT per household, or

VMT/Hh) relied on Households per Residential Acre (Hh/RA). For the Los Angeles region, San Francisco and Chicago regions, these equations varied only slightly, producing the curves shown in Figure 6. For the Los Angeles region, this formula takes the form:

$$\frac{\text{VMT}}{\text{Hh}} = 19749\left(\frac{4.814 + \text{Hh/RA}}{4.814 + 7.140}\right)^{-0.639}$$

Based on this formula, the following elasticity formula is recommended for vehicle trips with respect to density. It is the same as Holtzclaw et. al' work, but reduced by 40% to take account of the fact that much of this impact will be realized through transit service, mix of uses and bicycle and pedestrian levels (which tends to correlate with density). The baseline assumed to correspond to a zero percent trip reduction is three units per acre, at which density the Holtzclaw formula results in 25,914 annual vehicle miles traveled per household. This translates into the following formula:

Trip reduction
$= 0.6*(1-(19749*((4.814 + \text{households per residential acre})/(4.814+7.14))^{-0.639})/25914)$

An apartment development of 16 units per residential acre, for example, would be estimated to generate 27.9% fewer trips than a three unit per acre project. The maximum allowable reduction recommended is 55% (equivalent to a 380 unit per acre development).

With this formula, "negative" reductions also apply, with less dense developments below the baseline level of three units per acre (for example large-lot housing) resulting in higher trip generation rates. (However, as long as the mitigation component is optional for developers or project proponents to complete, they will be unlikely to use it for projects whose overall score, for all components, will result in a finding to their disadvantage. For purposes of more accurately predicting vehicle trips and emissions, however, this negative reduction is useful and reflects the findings of the research literature.

Trip generation at the non-residential end is also influenced by density, but to a much lesser degree (Cervero, 1989, cited in Kuzmyak et. al, 2003). There are also far fewer studies investigating this relationship, and there is no comparable dataset to that for residential density. No reduction is recommended here.

Mix of Uses

Many references point to the impact of "diversity" or mix of uses on travel behavior. This is true both at the macro-scale, e.g. jobs-housing balance, and the micro-scale, e.g. the availability of services within walking distance. Key references, related to both the direction and magnitude of this relationship, include:

- Higher densities are most beneficial to transit ridership when they result in a mix of residential, commercial and office uses (Lund et. al., 2004).
- The elasticity of vehicle trips with respect to "diversity" is –0.051. The elasticity of VMT is –0.032. In this case, "diversity" is a measure of how the project affects regional population/employment balance. (Criterion and Fehr & Peers, 2001)
- Typical elasticities for vehicle trips with respect to local diversity (mix) are –0.03, and those for VMT are –0.05 (Ewing & Cervero, 2001).
- A balance of 1.5 jobs per household is estimated to produce a bus mode share 2 percentage points over the share for a single use area, although the degree of mix is not a useful estimating variable (Messenger & Ewing, 1996, cited in Kuzmyak et. al, 2003).
- Suburban activity centers with some on-site housing had 3-5% more transit, bike and walk commute trips (Cervero, 1989, cited in Kuzmyak et. al, 2003).
- The presence of retail reduces auto mode share by 2-5%, depending on neighborhood density. (Parsons Brinkerhoff, 1996, cited in Kuzmyak et. al, 2003).
- At suburban activity centers, the presence of retail in office buildings lowers vehicle trip rates by 6-8% (NTI, 2000, cited in Kuzmyak et. al, 2003).
- Employment sites with "good" nearby retail and commercial services have a vehicle trip rate 21.5% below the ambient rate. Sites with "fair" services showed an 8.3% reduction, and those with "poor" services a 5.3% reduction. This is attributed not just to the presence of these services, but the fact that they make TDM programs more likely to succeed (Comsis, 1994, cited in Kuzmyak et. al, 2003).

The analysis is complicated by the fact that some of the most beneficial developments from this perspective may be single-use, in an area where another use is predominant (e.g. residential in an employment area). To take this into account, the following procedure is proposed (adapted from Criteron and Fehr & Peers, 2001):

$$\text{Trip reduction} = (1- (\text{ABS} (1.5 * h – e) / (1.5 * h + e)) – 0.25) / 0.25 * 0.03$$

Where: h = study area households (or housing units)
e = study area employment

Negative reductions of up to 3% can result, and should be included.

This formula assumes an "ideal" housing balance of 1.5 jobs per household, based on Messenger & Ewing (1996), and a baseline diversity of 0.25. The maximum possible reduction using this formula is 9%.

This reduction takes into account overall jobs-population balance. The presence of local serving *retail* can be expected to bring further trip reduction benefits, and an additional reduction of 2% is recommended. This is towards the lower end of the values presented in the research discussed above, in order to avoid double counting with the diversity indicator.

Transit

The existing URBEMIS 2002 mitigation model places its primary emphasis on mode, i.e. whether service is provided by high-speed rail, commuter rail or bus. Within this framework, consideration is given to frequency (e.g. bus headways of 15 minutes or less score more highly than headways of 15-30 minutes).

For example, the current mitigation component would award the maximum score of 100 to a development 0.5 miles from a BART station, even if no other transit were available. A part of the city with several bus lines offering 10-minute service, in contrast, would score much lower, even though these transit lines would carry many more passengers.

Current transit planning thinking, however, emphasizes that frequency and speed are two of the most important factors determining mode choice, rather than whether the service is provided by bus, bus rapid transit, or rail. Researchers have found that there is no *inherent* preference for rail over bus, provided that the quality of service is the same (for example, Ben-Akiva & Morikawa, cited in Transportation & Land Use Coalition, 2002).

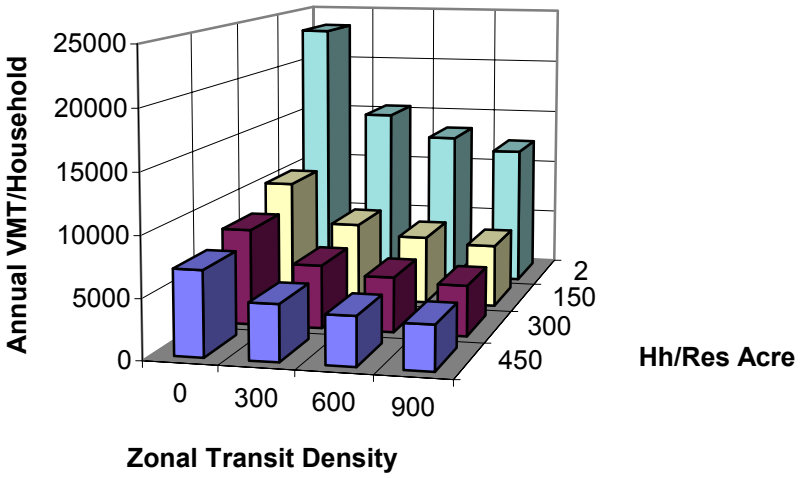
Key references include:

- The average elasticity of ridership with respect to frequency is +0.3 to +0.5. Higher elasticities of +1.0 have been observed in suburban systems, with the +0.3 value more typical of urban systems. (Kittselson & Associates et. al, 2003).
- Pratt et. al. (2003) suggest an elasticity of ridership with respect to service hours (i.e. a combined measure of frequency and service span) of +0.5. Ridership is most sensitive to frequency changes when the past service was infrequent.
- Modeling in Massachusetts suggests that halving transit service headways from 30 to 15 minutes leads to an 8% drop in vehicle trips. A further decrease to 5 minutes leads to a further 4% drop in vehicle trips (Pratt et. al., 2003).
- Holtzclaw et. al. (2002) show that vehicle travel falls as transit service levels increase, even when holding density constant (Figure 7). In the San Francisco Bay Area, a doubling of transit service from 300 to 600 (using the index described below) is associated with a 13% drop in VMT. An increase from 300 to 900 is associated with a 20% drop in VMT. In the Los Angeles region, the decreases in VMT are 12% and 18% respectively. However, the variable was omitted from the

vehicle travel model presented in this paper, since density was used as a proxy for transit service.

- The maximum distance that people are willing to walk to transit tends to be 0.25 miles for bus, and 0.5 miles for rail (and, presumably bus rapid transit). (Kittelson & Associates et. al, 2003). It is unclear whether there is a "distance decay" effect, whereas people are more likely to use transit at closer distances within this range (see Lund et. al, 2004).

Figure 7 VMT vs. Residential Density and Transit Use, San Francisco Bay Area



Source: Holtzclaw et. al. (2002).

Unfortunately, the elasticity of service with respect to transit ridership is difficult to convert to vehicle trip reduction, firstly because the baseline ridership needs to be known, and secondly because only a proportion (18-67% is cited by Pratt et. al., 2003) of new transit trips were formerly made by private auto. While it is clear that there is a direct correlation between transit service and vehicle trips, it is difficult to employ these elasticities directly. For this reason, the approach here is more in line with the existing mitigation component, which assumes a maximum percentage reduction for transit, and then reduces this based on a transit environment factor.

Various frequency-based transit service indices have been developed which have shown strong correlations with ridership. For example:

- In Los Angeles, the quality of four components of transit service (MTA rail, Rapid Bus, local bus and regional services) were rated on a scale of 0-3 for each community area, and then summed to provide the Transit Service Index on a scale of 0-12. (Nelson\Nygaard, 2002b).
- The studies by Holtzclaw et. al. (2002) used Zonal Transit Density, defined as the daily average number of buses or trains per hour times the fraction of the zone within 1/4 mile of the bus stop, or 1/2 mile of the rail station or ferry terminal, summed for all transit routes in or near the zone.

The Transit Service Index recommended here would combine the important features of all these approaches, with emphasis on frequency but with greater weighting given to rail services. Greater weight is also given to dedicated shuttles, in recognition of the fact that these are likely to be more closely targeted to the needs of the development. The Transit Service Index would be determined as follows:

- Number of average daily weekday buses stopping within 1/4 mile of the site; plus
- *Twice* the number of daily rail or bus rapid transit trips stopping within 1/2 mile of the site
- *Twice* the number of dedicated daily shuttle trips
- Divided by 900, the point at which the maximum benefits are assumed. (This equates to a BART station on a single line, plus four bus lines at 15-minute headways.)
- Developments that are larger than 0.5 miles across in any direction must be broken into smaller units for purposes of determining the transit service index. The average of all units would then be used.

Figure 8 shows some examples of how service frequencies translate into Transit Service Index scores (note these are additive, if a location has more than one component).

Figure 8 Example Transit Service Index Scores

Transit Service	Score	Assumptions
BART (single line)	0.33	150 trips per day (15-20 minute headways in each direction from 4 AM-12 AM)
15-minute bus, 5 AM – 12 AM	0.17	
30-minute bus, 5 AM – 7 PM	0.06	
Amtrak San Joaquin	0.03	6 trips per day in each direction
Dedicated commute shuttle	0.02	5 trips per commute period (single direction)

As well as existing service, planned and funded transit service would be included in the calculation. Purely demand responsive service would not be included.

A maximum trip reduction of 15% is recommended. This is the same as the existing URBEMIS 2002 trip reduction for existing and planned transit service.

In order to account for non-motorized access to transit, we also recommend that half the reduction be dependent on the pedestrian/bicycle friendliness score (calculated in the following section), similar to the approach taken in the existing mitigation component. This ensures that places with good pedestrian and bicycle access to transit are rewarded.

Trip reduction = t * 0.075 + t * ped/bike score * 0.075

Where t = transit service index

Bicycle and Pedestrian

Since bicycle mode share and pedestrian mode share depend on similar neighborhood characteristics, such as a fine-grained street grid, we recommend that a single factor be used to account for both modes. The bicycle and pedestrian components of the URBEMIS 2002 mitigation component are already well developed. However, the inputs are largely subjective, and there is still little evidence to justify the precise amount of credits for many of the individual mitigation measures (e.g. street trees).

Many street design factors have, however, been shown to promote walking and cycling. These include:

- Street connectivity, with traditional street networks that are more New Urbanist or grid-like, as opposed to the loops, lollipops and cul-de-sacs of most conventional subdivision. There are various measures of connectivity (summarized in Dill, 2003), such as:
    - Block length, size or density
    - Intersection density
    - Street density
    - Connected node ratio (number of street intersections divided by the number of intersections plus cul-de-sacs)
    - Link-node ratio (links are roadway or pathway segments between two nodes, which are intersections or cul-de-sac ends)
    - Grid pattern (percentage of intersections that are four- or more way).
    - Pedestrian Route Directness (ratio of route distance to straight line distance)
    - Effective Walking Area (% of parcels within 1/4 mile, that are also within 1/4 mile walking distance)

- Human-scale streetscapes with adequate pedestrian amenities, access to shopping and other amenities, and higher densities (Lund et. al., 2004)

Other relevant research includes:

- A composite indicator, the "Pedestrian Environment Factor," provides a statistically significant correlation with trip generation and VMT. It is comprised of four inputs (Parsons Brinkerhoff, 1993):
    - Ease of street crossings
    - Sidewalk continuity
    - Local street characteristics (grid vs. cul de sac)
    - Topography
- In Portland, OR, an increase in the PEF from "pedestrian hostile" to "almost average" reduces daily vehicle trips by 0.4 per household (7%). An increase from "almost average" to "fairly good" provides a daily reduction of 0.2 trips (Parsons Brinkerhoff, 1993, cited in Kuzmyak et. al, 2003).
- Sidewalk completeness, route directness and network density together have a vehicle trip elasticity of –0.05 (Ewing & Cervero, 2001).
- For a high degree of walkability, block lengths of approximately 300 feet are recommended. Short blocks provide more pedestrian crossing opportunities and direct walking routes, and mean that traffic is more likely to be dispersed. Downtown Los Angeles, for comparison, has about 150 intersections per square mile. (Ewing, 1999).

There is a strong tradeoff here between simplicity and low data requirements on the one hand, and robustness and accuracy on the other. Pedestrian and bicycle level of service work for the Florida Department of Transportation and FHWA, for example, has shown that there are numerous statistically significant factors that can be included to assess the quality of the bicycle and pedestrian environment. These include motor vehicle volumes and speeds, truck volumes, roadway widths, urban design, and lateral separation between pedestrians and motor vehicles (for example, FHWA, 1998; Landis et. al, 2001).

However, we recommend that in order to keep data requirements to a minimum, one or two of the street design indicators discussed by Dill (2003) and Ewing and Cervero (2001) be used, together with a single bicycle measure. Since route directness and network density measure similar characteristics, we recommend the use of one of these (network density, which is inversely related to block size) plus sidewalk completeness and bicycle network completeness. The pedestrian/bicycle factor would then be calculated as follows:

Ped/bike factor =
(network density + sidewalk completeness + bike lane completeness) / 3

Where:

Network density = intersections per square mile / 1300 (or 1.0, whichever is less)

Note: In most GIS applications, intersections are counted based on the number of line segment terminations, or each "valence." Intersections have a valence of 3 or higher – a valence of 3 is a "T" intersection, 4 is a four-way intersection, and so on.4 (Georgia Institute of Technology, 2002). Therefore, if intersections are counted manually on a map or project plan, care needs to be taken to distinguish between 3-, 4- and 5-way intersections, and factor them up accordingly. The 1,300 value roughly equates to a dense grid with four-way intersections every 300 feet, per the recommendation of Ewing (1999). Intersections with dedicated routes for pedestrians and/or bicyclists should be included in this calculation.

Sidewalk completeness =

% streets with sidewalks on both sides + 0.5 * % streets with sidewalk on one side

Bike lane completeness =

% arterials and collectors with bicycle lanes, or where suitable, direct parallel routes exist

A maximum reduction of 9% is proposed, based on the existing URBEMIS mitigation component.5 The trip reduction would then be calculated as:

Trip reduction = 9% * ped/bike factor

No reduction should be allowed if the entire area within a half-mile walk of the project center consists of a single use. (Note that this applies to a half-mile walk, rather than straight-line distance, to account for barriers such as freeways.) However, the ped/bike factor can still be used to calculate pedestrian access to transit, as part of the transit mitigation measure.

Affordable and Senior Housing

A significant amount of evidence points to the fact that lower-income households and senior citizens own fewer vehicles and drive less. Research includes:

4 A valence of 1 indicates that a line segment has terminated, e.g. in a cul-de-sac. A valence of 2 means that the street is continuing.

5 Note that this excludes the bicycle reduction in the current mitigation component. However, this compensates for the fact that the reductions recommended for the mixed use and density variables will be realized in practice through pedestrian and bicycle mode share.

- Russo (2001) cites evidence from the San Francisco Bay Area travel survey, which shows that households earning under $25,000 per year make 5.5 vehicle trips per day, compared to a regional average of 7.6. High income households (earning more than $75,000 per year) make an average of 10.5 trips. Note that this data does not control for other factors, such as density and transit access.
- In the San Francisco Bay Area, Los Angeles and Chicago, income was one of four variables with sufficient independent explanatory power to include in the model of VMT and vehicle ownership (Holtzclaw et. al., 2002).

Obviously, it is difficult if not impossible to account for the exact incomes of residents in URBEMIS, most obviously because the occupants are not known at the pre-development stage. However, the percentage of deed-restricted below-market-rate (BMR) housing does offer a way to incorporate this effect.

We recommend a 3% reduction in vehicle trips for each deed-restricted BMR unit.6 Thus, the total reduction is as follows:

Trip reduction = % units that are BMR * 0.04

A development with 20% BMR units would thus gain a 0.8% reduction. A development with 100% BMR units would gain a 4% reduction.

Parking Supply

Significant correlations between parking supply and employee mode split have been observed. For example, a study of the link between parking availability and transit use in eight Canadian downtowns found an extremely high elasticity of –0.77 (Morrall & Bolger, 1996, cited in Kuzmyak et. al., 2003b). In California, the number of parking spaces per worker was found to be one of the main two elements of a binomial logit model predicting transit mode share among TOD office workers (Lund et. al, 2004).

As with residential density, the extent to which parking supply itself is a causal factor is uncertain. In practice, it probably serves as a proxy for variables such as price, high quality public transit, mix of uses, and pedestrian friendliness (Kuzmyak et. al., 2003b). Indeed, in practice there is a two-way relationship between parking supply and mode split. Free parking, for example, can be seen as both a cause of high parking supply (more parking is

6 Calculated from Holtzclaw et. al. (2002), assuming 12,000 average annual VMT per vehicle, median per capita income of $33,000 (2002 figures per California State Department of Finance), and an average income in BMR units 25% below median. Holtzclaw calculate the coefficient of -0.0565. Therefore, expected VMT reduction can be calculated as 0.0565 * 33,000 * 0.25 / 12,000 = 4%

needed to satisfy the greater demand), and a consequence (the market price of parking is zero once an effectively unlimited supply is provided) (see, for example, Shoup, 1999).

Theoretically, it is possible to reduce parking provision to below the level of actual demand, should drivers park in neighboring lots or on-street in surrounding areas. However, planning approval is not likely to be granted for developments that significantly under-provide parking, unless complementary Residential Permit Parking programs or other measures to combat this type of overspill are introduced. Indeed, the main reason for minimum parking requirements levied by local jurisdictions is to address these overspill issues (Shoup, 1999).

Similarly, market realities are likely to prevent a developer from providing too little parking. The challenges in persuading lenders to finance developments that have below-code parking are difficult enough to overcome, even where there is clear, documented evidence to show that parking supply will be enough to meet demand (see for example, Parzen & Sigal, 2004). In contrast, the opposite tendency is likely to be apparent – that developments are prevented from taking full advantage of the opportunities to reduce parking supply by zoning codes (see, for example, Nelson\Nygaard, 2002).

The measure proposed here uses the Institute of Transportation Engineers' *Parking Generation* handbook as the baseline. This is assumed to equate to unconstrained demand. The trip reduction can therefore be calculated as follows:

Trip reduction = Actual parking provision / ITE Parking Generation rate

Since ITE parking generation rates use the same land use codes as the trip generation rates, these could be provided within the URBEMIS model itself. The user would only be required to enter the actual parking provision for each land use.

For land uses with rates for both weekday and weekend, the formula will use whichever rate is higher. The *Parking Generation* handbook covers most common land uses. For some land uses, however, no parking generation rates are available: in these cases, this particular mitigation measure may not be used.7 Those land uses without parking generation rates include:

- Single Family Detached Housing
- Mid-rise Apartments
- High-rise Condominium/Townhouse

7 The next edition of *Parking Generation,* currently under development by an ITE Task Force, is likely to provide date for some of these missing land uses. While it would be ideal to have parking generation data for every single land use before introducing this mitigation measure into URBEMIS, the data does not yet exist. Rather than abandoning this mitigation measure entirely until perfect data exists, we recommend allowing the measure to be used for the many land uses where reasonable data is available.

- Mobile Home Parks
- Residential Planned Unit Development (PUD)
- Day-care center
- Elementary school
- Junior High school
- Library
- City Park
- Discount Superstore
- Discount Club
- Electronic Superstore
- Home Improvement Superstore
- Gas/Service Station
- Pharmacy/Drugstore with and with/out Drive Through
- Medical Office Building
- General Heavy Industry

To avoid double counting with other trip reduction measures, the impacts of parking supply are proposed to be assessed in conjunction with all other non-residential trip reduction measures as follows:

- The total of all other non-residential trip reduction measures should be used if this is greater than or equal to the trip reduction from parking supply measures. For example, if parking supply is reduced 10% from ITE levels, and transit, mixed use and pedestrian/bicycle trip reductions amount to 20%, the 20% figure would be used.
- If the total of all other non-residential trip reduction measures (r_1) is less than the trip reduction from parking supply measures (r_2), the total trip reduction is as follows:

  $$r_1 + 0.5 * (r_2 - r_1)$$

  In effect, the parking supply reduction is only used if it is greater than the impact from other trip reduction measures, and the difference is discounted by 50%. For example, if parking supply is reduced 25% from ITE levels, and transit, mixed use and pedestrian/bicycle credits amount to 15%, the total reduction would be:

  $$15 + 0.5 * (25\text{-}15) = 20\%.$$

This reduction should only be granted if measures to control overspill are in place, such as Residential Permit Parking programs, time limits or meters.

Transportation Demand Management

Transportation Demand Management programs have been shown to have a major impact on travel behavior. Site-level employee vehicle trip reductions of up to 38% have been achieved, particularly for programs that have included parking pricing (Shoup & Willson, 1980; Comsis, 1993; Valk & Wasch, 1998; Pratt, 2000). Parking price elasticities of –0.1 to –0.3 have been reported (Pratt, 2000).

This component of the existing URBEMIS 2002 mitigation component is well developed. However, there is considerable scope to adapt it in two ways:

- Provide greater emphasis for the three elements that have the greatest impact on travel behavior – parking pricing/cash out; free transit passes; and telecommuting.
- Simplify the remaining elements, through offering broader options such as "major program", "minor program", and "no program," for elements that are likely to have a smaller trip reduction potential.

We recommend that none of these reductions be permitted, unless they form part of a legally enforceable agreement specifying, for example, minimum parking prices and other TDM measures. This might form part of a development agreement, be enforced through any TDM ordinance in the local jurisdiction, or consist of another mechanisms mutually agreed by the air district and project proponent. Otherwise, there is little to guarantee that some of the promised measures (e.g. parking pricing) will actually be implemented and maintained.

Parking Pricing and Cash Out

We recommend that a maximum trip reduction of 25% be applied to projects that commit to introducing parking pricing. This is based on the approximate midpoint of observed reductions, which range from 15% to 38% (Shoup & Willson, 1990; Comsis, 1993; Pratt, 2000). Note that most of these studies apply to before-after or with-without comparisons, with no increase in transit service or other measures to reduce vehicle trips. This maximum reduction should apply to prices of $6 per day or greater (in 2004 dollars).

The trip reduction will therefore be as follows:

Trip reduction = daily parking charge / 6 * 0.25

If the parking charge is more than $6, the 25% reduction is taken. If parking charges do not apply to all trips to a site (e.g. customers are exempt), the reduction is pro-rated by the percentage of trips that the charges apply to. If little or no on-site parking is provided, the parking charges should be those of surrounding public facilities.

Parking cash-out programs should be eligible for 50% of the reduction for direct parking charges, in recognition of the fact that their impacts tend to be significantly lower (Pratt, 2000). This is partly due to the fact that cash-out payments are a taxable benefit.

Free Transit Passes

Some California transit agencies, most notably VTA in Santa Clara County, have EcoPass or similar programs, whereby employers or property managers bulk-purchase transit passes for (free) distribution to their employees or tenants. Eco Pass programs have been shown to increase transit ridership by 50-79% (City of Boulder, undated; Caltrans, 2002), and reduce vehicle trips by 19% (Shoup, 1999). (Note that many of these new riders were making new trips, or ones previously made by walking or cycling.)

We therefore recommend that any project committing to providing free transit passes would receive an additional credit equivalent to 25% of the reduction granted for transit service. Thus, the credit is more valuable in places that have good transit service. This reduction would only apply to the portion of trips generated by those granted the free transit passes (e.g. residents and/or employees, but excluding shoppers and other visitors).

Telecommuting

We recommend the retention of the reductions granted for telecommuting and compressed work schedules in the existing mitigation component, with two clarifications:

- As with the reductions for other mitigation measures, there must be an enforceable commitment (e.g. development agreement), which covers both the take-up rate (employees actually telecommuting or using compressed work schedules) as well as the provision of the option.
- The percentage reduction should not be additive (in contrast to most other trip reduction measures). For example, if 20% of employees telecommute, and other trip reduction measures are estimated to reduce vehicle trips from 1,000 to 800 per day, the 20% reduction would apply to the 800 trips, not the original 1,000.

Other TDM Programs

Other TDM program elements, that do not include financial incentives, tend to have a smaller impact on travel behavior. We recommend that reductions be based on the number of the following elements incorporated into the program, per Figure 7:

- Secure bicycle parking (at least one space per 20 vehicle parking spaces)
- Showers/changing facilities
- Guaranteed Ride Home

- Car-sharing services
- Information on transportation alternatives, such as bus schedules and bike maps
- Dedicated employee transportation coordinator
- Carpool matching programs
- Preferential carpool/vanpool parking

The impact of a TDM program will also depend on the travel alternatives available. A program will have more impact if the site is served by frequent transit, for example (although note that a TDM program can do much to promote carpooling even in other locations). For this reason, we recommend that part of the TDM credit be used to adjust the credits granted for transit service and pedestrian/bicycle friendliness (see Figure 9).

Figure 9 Recommended TDM Program Reductions

Level	Number of Elements	Recommended Reduction
Major	At least 5 elements	2%, plus 10% of the credit for transit and pedestrian/bike friendliness
Minor	At least 3 elements	1%, plus 5% of the credit of transit and pedestrian/bike friendliness
No program	None	None

Examples

It is important to recognize that any type of calibration is beyond the scope of this analysis, which relies on existing references to build on the ranges established in the existing mitigation component. Figure 10, however, does provide some examples to indicate the trip reductions that would apply to specific places.

The data are drawn from the database compiled for the Location Efficient Mortgage program (for details, see Holtzclaw et. al., 2002), and from the San Francisco Bay Area Metropolitan Transportation Commission's TAZ files. For these reasons, the examples are limited to the San Francisco Bay Area. Transit service was estimated from schedules and route maps. Sidewalk and bike lane completeness were estimated based on local knowledge. For these reasons of limited data, the examples are intended as illustrations only, rather than to refer to a particular project.

The reductions are calculated for the physical and environmental factors only, for residential uses. They exclude any additional reductions from TDM programs and affordable housing.

The final column compares average vehicle miles traveled (no vehicle trip data were readily available) in these neighborhoods to the Brentwood baseline, as a rough

comparison to the reductions granted through the proposed trip reductions for URBEMIS. As can be seen, while there are significant discrepancies, the overall correspondence is acceptable for this type of sketch planning model.

Figure 10 Example Trip Reductions

								% Reduction in VMT from Brentwood
Example	TAZ	Residential Density	Mix of Uses	Local Retail	Transit	Ped/bike friendliness	Total Reduction	
Brentwood	899	1.4%	-3.0%	0.0%	0.1%	1.7%	0.3%	0.0%
Orinda	831	-9.5%	5.8%	0.0%	3.7%	1.4%	1.4%	5.6%
Pleasant Hill BART	806	14.4%	7.2%	3.0%	8.3%	3.3%	36.3%	40.2%
Emeryville	723	39.0%	1.7%	3.0%	4.4%	4.9%	53.1%	47.8%
Downtown Palo Alto	245	19.8%	4.4%	3.0%	6.1%	7.5%	40.8%	50.6%

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APPENDIX E

Cost Effectiveness Analysis for Proposed Rule 9510 (Indirect Source Review) and Rule 3180 (Administrative Fees for Air Impact Assessment Applications)

November 17, 2005

I. INTRODUCTION

California Health and Safety Code (CH&SC) Section 40920.6(a) requires the San Joaquin Valley Unified Air Pollution Control District (District) to conduct a cost effectiveness analysis of the proposed control options prior to the adoption of the proposed rules. The purpose of conducting a cost effectiveness analysis is the evaluation of the possible economic effect of the pollution control measures (rules). The analysis also serves a guideline in developing the control requirements for the rule.

II. SUMMARY AND CONCLUSION

The CH&SC section cited above requires a cost effectiveness analysis for the most likely compliance scenario, and an incremental cost effectiveness analysis on an alternative compliance scenario. Absolute cost effectiveness of a control option for traditional rules are typically determined by taking the added annual cost (in $/year) of the control technology or technique, divided by the emission reduction achieved (in tons/year). The costs can include capital equipment costs, engineering design costs, installation costs, and any cost savings, such as from decreased energy usage and decreased maintenance costs.

Rule 9510 would require developers to reduce the following project's operational and area source emissions: 33.3% of NOx emissions and 50% of the PM10 emissions, over a ten-year period. Rule 9510 would also require the developers to reduce emissions from equipment used during the construction phase by 20% for NOx and 45% for PM10 emissions compared to the statewide average. The construction emissions may be reduced on-site by using newer fleets than the statewide construction average, using add-on controls, and/or by using clean fuels. The rules are structured to allow flexibility in complying with the rule requirements due to various requirements and limitations imposed by local agencies in the projects' jurisdiction. Methods of compliance include the following: achieving the necessary reductions entirely through on-site emission reduction measures; reducing, in varying degrees, partially on-site and partially off-site through the off-site emission reduction fee; reducing entirely off-site through the payment of an off-site emission reduction fee. The fee for emissions not reduced in the design of the project or with equipment controls would fund off-site emission reduction projects. The fee for these off-site projects would be calculated by multiplying the required emission reductions by a cost effectiveness factor. This rule differs from traditional rules, in that a cost effectiveness value is predetermined and the control costs are based on that cost effectiveness value.

Cost effectiveness is a primary criterion for the District to fund emission reduction projects. Cost effectiveness of a off-site emission reduction project is based on the amount of pollution (per pound or ton of a pollutant) the project eliminates for each

dollar spent. There are different methodologies to determine cost effectiveness for different programs, but in general, cost effectiveness is determined by dividing the cost of the project by the amount of emissions reduced. Several factors are used to determine the emission reductions for a particular mitigation project, including: the age of the vehicle or engine being replaced, project life (how long in terms of time the emission reductions can be expected to be surplus), and activity level, which is usually represented in annual hours of operation or mileage. Project life allows the District to determine how many emission reductions can occur per year. This is important in determining timelines for emission reductions and will assist the District in attaining the ozone and PM10 standards.

To determine the cost effectiveness for the ISR Program, District staff identified NOx emission reduction projects that have previously been funded and the costs associated with each project. Table E–1*, Estimated NOx Emission Reductions from Current and Historical Grant Programs by the District* summarizes the grant programs.

Table E-1
Estimated NOx Emission Reductions from Current and Historical Grant Programs

	Emissions Tons	Emissions Pounds	Grant Funded Dollar Amounts	Cost Effectiveness* $/Pound	Cost Effectiveness* $/Ton
All External Projects					
1992 -1993	400	800,000	$3,665,200	$4.58	$9,163.00
1993 -1994	525	1,050,000	$4,773,814	$4.55	$9,092.98
1994 - 1995	590	1,180,000	$3,594,486	$3.05	$6,092.35
1995 - 1996	650	1,300,000	$3,688,311	$2.84	$5,674.32
1996 - 1998	885	1,770,000	$6,309,952	$3.56	$7,129.89
1998 - 2004	30,419	60,838,805	$60,798,609	$1.00	$1,998.68
Total	***33,469***	***66,938,805***	***$82,830,372***	***$3.26***	***$6,525.20***
REMOVE Program					
1992 - 1993 Phase I	400	800,000	$3,665,200	$4.58	$9,163.00
1993 - 1994 Phase II	525	1,050,000	$4,773,814	$4.55	$9,092.98
1994 - 1995 Phase III	590	1,180,000	$3,594,486	$3.05	$6,092.35
1995 - 1996 Phase IV	325	650,000	$2,688,311	$4.14	$8,271.73
1996 - 1998 Phase V	360	720,000	$5,309,952	$7.37	$14,749.87
1998 - 1999 Phase VI	104	208,247	$2,556,403	$12.28	$24,551.64
1999 - 2000 Phase VII	304	607,640	$2,422,741	$3.99	$7,974.26
2002 - 2003 Phase VIII	156	311,059	$1,210,648	$3.89	$7,784.04
Total	*2,608*	*5,526,946*	*$26,221,555*	*$5.48*	*$10,959.98*
Vehicle Buy-Back					
1995 - 1996	325	650,000	$1,000,000	$1.54	$3,076.92
1997 - 1998	525	1,050,000	$1,000,000	$0.95	$1,904.76
Total	*850*	*1,700,000*	*$2,000,000*	*$1.25*	*$2,490.84*
Heavy-Duty Program					
1997 - Jan 2004	29,811	59,622,859	$53,381,817	$2.28	$4,564.13
Lt. & Med.-Duty Vehicle Program					
2001 - Jan 2003	22	43,000	$750,000	$17.44	$34,883.72
1999 Lawnmower Replacement Program					
2001 - 2002	23	46,000	$477,000	$10.37	$20,739.13

Please note that beginning in 1995-96 vehicle buy-back was no longer included in the REMOVE Program. A separate program for heavy-duty vehicle projects was established beginning in 1997.

III. GRANT PROGRAMS

This section identifies the existing grant programs and different types of projects that are funded under those programs that are possible candidates for any off-site emission reduction fees collected under Rule 9510. In addition, this section identifies additional projects that may be funded through the ISR program. The District will also consider projects and programs for funding in addition to the ones discussed in this section, when other projects and programs are identified.

REMOVE/REMOVE II

The Reduce Motor Vehicle Emissions (REMOVE) Program was the first District grant program implemented in 1992 to fund projects that reduced emissions associated with motor vehicle trips. Due to the lengthy REMOVE evaluation committee process, the District's Governing Board approved the revised REMOVE II Program on March 13, 2005. The REMOVE II Program awards grant funding on a first-come, first-serve basis and consists of a broad range of mobile source incentive projects. The following separate components within the REMOVE II Program have established parameters and funding caps to achieve prudent cost effectiveness levels: E-Mobility (Telecommunications) Incentive Component; Public Transportation and Commuter Vanpool Passenger Subsidy Component Bicycle Infrastructure Component; Light and Medium Duty Incentive Component. The components establish guidelines to maximize the emission reduction potential for individual projects. The criterion for evaluating potential projects is ARB's methodology for calculating cost effectiveness and emission reductions. Additionally, the District has established requirements for applicants to validate the emission reductions generated by REMOVE II incentive program components.

The E-Mobility Component of the REMOVE II Program provides funding for the development or expansion of electronic telecommunications services in municipal government and public education. The electronic technology will serve as direct replacement of vehicle trips to public sites for conferencing, document transactions, general information, work functions, school instruction, and related applications. E-Mobility projects include: distance-learning technology, telecommute center equipment, teleconference systems, E-government technology, E-court technology and related electronic applications.

The Public Transportation and Commuter Vanpool Passenger Subsidy Component of the REMOVE II Program, provides funding to attract new participants to public transportation and commuter vanpools. The passenger subsidies will serve to attract new participants to public transportation and commuter vanpools as an alternative to single occupant vehicle (SOV) commutes. Passenger subsidy projects include: incentives for transit bus agencies, shuttles, commuter vanpools, rail, and park-and-ride lot construction.

The Bicycle Infrastructure Component of the REMOVE II Program will fund the development of a comprehensive bicycle transportation network. The component will

support the expansion and linkage of bicycle transportation facilities that promotes the practice of commuter bicycling as a safe and viable transportation alternative. Bicycle infrastructure projects may include the development of Class I Bicycle Paths (construction) and Class II Bicycle Lanes (striping).

The Light and Medium Duty Incentive Component of the REMOVE II Program will fund a portion of the purchase cost of low-emission light-duty and medium-duty motor vehicles for public agencies. The purpose for the component is to encourage and increase the introduction of reduced emission alternative fuel vehicles. Low-emission vehicles may include Zero Emission Vehicles, Super Ultra Low Emission Vehicles, Ultra Low Emission Vehicles, and Electric Bicycles based on ARB emission standards.

Heavy-Duty Program

The Heavy-Duty Engine Emission Reduction Incentive Program (Heavy-Duty Program) initially evolved from REMOVE in 1997 and the District continues to administer the program. The Heavy-Duty Program replaces older model high polluting engines with newer and cleaner burning engines. The Heavy-Duty Program also encourages the early introduction of on-road and off-road heavy-duty motor vehicles with engines that include reduced-emission technologies. Eligible project types funded under this program include: marine vessels, forklifts, agricultural pump engines, on-road and off road vehicles and equipment, agricultural harvesters, hay bailers, tractors, delivery trucks, sprayers, yard spotters, earthmovers, line haul trucks, back hoes, dump trucks, earth movers and drills, transit and school buses, and forklifts. This program has been expanded to assist in the development of alternative fuel infrastructure, particulate filters on eligible diesel school buses, and idle reduction technologies for heavy-duty vehicles.

Emission reductions are obtained when the project applicant purchases vehicles and engines that are cleaner than required by current emission standards or installs an emission certified retrofit kit on an existing engine. The District pays the differential cost of purchasing the lower emitting technology compared to conventional technology. Emission reduction, calculations, and horsepower categories are used to determine an incentive amount. Project monitoring is conducted to verify eligibility, to ensure proper use of public funds and to validate the emission reductions. Applicants are required to enter into contracts with the District and are required to submit annual usage reports for five years after the technology is purchased.

The Heavy Duty Program is primarily aimed at NOx reductions, but many projects also achieve particulate matter (PM10) reductions. Historically, this incentive program has been exceptionally cost effective, replacing approximately 4,484 engines[1].

[1] *SJVAPCD Heavy-Duty Engine Incentive Program Database*

PM10 Incentive Program

The District currently does not have an incentive program that primarily targets PM10 emissions reductions, however an incentive program will be needed for Rule 9510. Initially, District staff surveyed the PM10 emissions inventory to determine the largest sources of emissions and related factors, the extent of existing or planned control, and types of control options that are available. District staff identified unpaved traffic surfaces and unpaved shoulders as the most viable options for emission reduction projects. Other potential sources include the use of PM10-efficient street sweepers and fireplace retrofits/replacement. The District is proposing to develop an Unpaved Road and Traffic Surface Program that would fund or partially fund the treating or paving of unpaved roads or unpaved shoulders within the San Joaquin Valley Air Basin, in time to implement and achieve the reductions committed to for this rule. Once that program is established, the District will continue to explore and develop other PM10 incentive programs, such as PM10-efficient street sweepers, fireplace retrofits/replacement, and/or leaf blowers.

The duration of the contract will vary depending on the project. Some contracts will be completed upon installation, while others may require reporting for 5 years. For example, a road-paving project would have a contract that is completed upon installation, whereas an engine contract typically contains a 5-year reporting requirement. The staff report will be amended to include this information.

IV. RULE 9510 ESTIMATED COST EFFECTIVENESS

The District's future prospects for funding the most cost effective NOx reduction projects are currently declining. Many of engines that qualify for the Heavy-Duty Program incentive funds have been replaced or retrofitted. Diesel engines greater then 50 horsepower are being regulated by the State and the District resulting in cleaner operating engines with lower emissions. Consequently, the most cost-effective projects (e.g. diesel engines manufactured before 1996) have previously been funded resulting in projects that will cost more in the future to fund.

To determine future cost effectiveness for NOx emission reduction projects, staff reviewed previously funded projects' NOx cost effectiveness, the types of projects, and the future availability of those projects. Attachment 1 compiles the necessary information and determines the resulting cost effectiveness. The general concept for NOx projects in Attachment 1, is that the types of grant applications received will move from the heavy duty projects to lighter duty projects at a rate of 5% per year, and that the cost of heavy duty projects will increase approximately $2000 more per ton. Attachment 1, can be summarized as follows:

NOx Cost-Effectiveness

Year	Cost to Reduce One ton of NOx
2006	$4,650.00
2007	$7,100.00
2008 and beyond	$9,350.00

Presently, most of the Districts incentive funds have been used to fund NOx emission reductions. In order to determine future cost effectiveness for PM10 emission reduction projects, District staff researched PM10 emissions and reductions. Initially, the PM10 emissions inventory was surveyed to determine the largest sources of emission factors, the extent of existing or planned control, and types of control options that are available. District staff identified unpaved traffic surfaces and unpaved shoulders as the most viable options for emission reduction projects. Other potential sources include the use of PM10-efficient street sweepers and fireplace retrofits/replacement.

Once the sources were identified, each source was analyzed in terms of emission factors, thresholds, available control effectiveness, and costs of those controls. Attachment 1 also compiles the necessary information and determines the resulting cost effectiveness for PM10 projects. There are several concepts for PM10 projects that are incorporated in Attachment 1. Initially, the District is anticipating that it will receive a high number of applications to treat or pave unpaved roads, with the most cost effective projects coming in the first few years. The District is also expecting the cost to treat or pave unpaved roads to increase by 75% each year for each ton reduced. The District is anticipating receiving a higher number of applications for unpaved shoulders and street sweepers, each year. Attachment 1, can be summarized as follows for PM10:

PM10 Cost-Effectiveness

Year	Cost to Reduce One ton of PM10
2006	$2,907.00
2007	$5,594.00
2008 and beyond	$9,011.00

V. SOURCES OF COST DATA

District staff used cost effectiveness information derived from actual NOx emissions reduction projects administered by the District. This data is sent to the California Air

Resources Board (ARB) on an annual basis. The following data sources were used for the PM10 analysis:

1. Effectiveness Demonstration of Fugitive Dust Control Methods for Unpaved Roads and Unpaved Shoulders on Paved Roads
   DRI document No. 685-5200.1F1
   Desert Research Institute
   December 31, 1996

2. Methods to find Cost-effectiveness of Funding Air Quality Projects: For Evaluating Motor Vehicle Registration Fee Projects and Congestion Mitigation and Air Quality Improvement (CMAQ) Projects
   California Air Resources Board
   2003 Edition

3. Final BACM Technological and Economic Feasibility Analysis
   Sierra Research, Inc.
   Prepared for the SJVAPCD
   March 2003

4. Entrained Road Dust from Paved Road Travel: Emission Estimation Methodology, Background Document
   Section 7.9
   California Air Resources Board
   Updated July 1997

5. Unpaved Road Dust (non-farm roads, SJV only)
   Section 7.10 SJV
   California Air Resources Board
   Patrick Gaffney
   Updated May 2004

6. Spreadsheet used for San Joaquin Valley Air Pollution Control District PM10 SIP, 2003
   Spreadsheet, “Unpaved1999Mar_13_2003Final.xls”
   California Air Resources Board
   Patrick Gaffney

7. Conversations and E-mail correspondence with Mel Zeldin, consultant

Attachment 1
Anticipated Use of ISR Funds
for Determining Cost Effectiveness

For 2006					
	Projected % of Fund Use	Cost Effectiveness ($/ton reduced)			
		Likely Minimum	Cap[1]	Representative Cost Effectiveness[2]	Weighted Representative Factor
PM10					
Unpaved Roads/Traffic Areas	90%	$1,694	$15,000	$1,819	
Unpaved Shoulders	5%	$11,838	$15,000	$12,907	
Street Sweepers	5%	$10,000	$15,000	$12,500	
Overall PM10		**$1,694**	**$15,000**	**$9,075**	**$ 2,907**
NOx					
Heavy Duty Program	95%	$3,000	$5,000	$4,000	
REMOVE	5%	$14,000	$20,000	$17,000	
Overall NOx		**$3,000**	**$20,000**	**$10,500**	**$ 4,650**

For 2007					
	Projected % of Fund Use	Cost Effectiveness ($/ton reduced)			
		Likely Minimum	Cap[1]	Representative Cost Effectiveness[2]	Weighted Representative Factor
PM10					
Unpaved Roads/Traffic Areas	75%	$1,900	$15,000	$3,183	
Unpaved Shoulders	20%	$11,838	$15,000	$12,907	
Street Sweepers	5%	$10,000	$15,000	$12,500	
Overall PM10		**$1,900**	**$15,000**	**$9,530**	**$ 5,594**
NOx					
Heavy Duty Program	90%	$5,000	$7,000	$6,000	
REMOVE	10%	$14,000	$20,000	$17,000	
Overall NOx		**$5,000**	**$20,000**	**$11,500**	**$ 7,100**

Anticipated Use of ISR Funds
for Determining Cost Effectiveness

For 2008					
	Projected % of Fund Use	Cost Effectiveness ($/ton reduced)			
		Likely Minimum	Cap[1]	Representative Cost Effectiveness[2]	Weighted Representative Factor
PM10					
Unpaved Roads/Traffic Areas	55%	$1,900	$15,000	$5,571	
Unpaved Shoulders	35%	$11,838	$15,000	$13,419	
Street Sweepers	10%	$10,000	$15,000	$12,500	
Overall PM10		**$1,900**	**$15,000**	**$10,497**	**$ 9,011**
NOx					
Heavy Duty Program	85%	$7,000	$9,000	$8,000	
REMOVE	15%	$14,000	$20,000	$17,000	
Overall NOx		**$7,000**	**$20,000**	**$12,500**	**$ 9,350**

For 2009					
	Projected % of Fund Use	Cost Effectiveness ($/ton reduced)			
		Likely Minimum	Cap[1]	Representative Cost Effectiveness[2]	Weighted Representative Factor
PM10					
Unpaved Roads/Traffic Areas	55%	$1,900	$15,000	$9,749	
Unpaved Shoulders	35%	$11,838	$15,000	$13,419	
Street Sweepers	10%	$10,000	$15,000	$12,500	
Overall PM10		**$1,900**	**$15,000**	**$11,889**	**$ 11,308**
NOx					
Heavy Duty Program	80%	$9,000	$12,000	$10,500	
REMOVE	20%	$14,000	$20,000	$17,000	
Overall NOx		**$9,000**	**$20,000**	**$13,750**	**$ 11,800**

Anticipated Use of ISR Funds
for Determining Cost Effectiveness

For 2010					
	Projected % of Fund Use	Cost Effectiveness ($/ton reduced)			
		Likely Minimum	Cap[1]	Representative Cost Effectiveness[2]	Weighted Representative Factor
PM10					
Unpaved Roads/Traffic Areas	45%	$1,900	$15,000	$14,682	
Unpaved Shoulders	40%	$11,838	$15,000	$13,419	
Street Sweepers	15%	$10,000	$15,000	$12,500	
Overall PM10		**$1,900**	**$15,000**	**$13,534**	**$ 13,850**
NOx					
Heavy Duty Program	75%	$11,000	$13,000	$12,000	
REMOVE	25%	$14,000	$20,000	$17,000	
Overall NOx		**$11,000**	**$20,000**	**$14,500**	**$ 13,250**

1 The cost effectiveness cap in this column represents the cap that this program would require, not necessarily the historical cap.

2 The representative cost effectiveness is the anticipated cost effectiveness for that year. This is based on district staff forecast.

APPENDIX E
Attachment 1

Project Spending Plan for Proposed Rule 9510 (Indirect Source Review)

November 17, 2005

I. INTRODUCTION

The purpose of this document is to demonstrate that any funds collected by the District will meet their intended purpose of reducing emissions caused by new development in the air basin. It provides a plan for spending any funds generated by the rule in a cost-effective and responsible manner.

Rule 9510 is projected to generate up to $103 million between 2006 and 2008. After 2008 the District will provide a new estimate based on experience with the program and the amount of development occurring in the San Joaquin Valley. The new estimates may be higher or lower than the amounts currently in the rule. To demonstrate the capability to distribute these funds to cost-effective projects, the District has analyzed the potential emission reduction projects available that meet requirements for being surplus, quantifiable, and enforceable. Once the potential projects were identified, staff performed additional research into the cost of individual projects and the potential for owners of the equipment, vehicles, etc. to take advantage of incentive funding.

The District plans on using existing grant programs that are available for immediate funding of projects and to develop new programs for non-traditional sources not eligible for other funding sources such as DMV Surcharge Fees and California Carl Moyer Program funds.

II. Existing Programs

The following existing programs and programs where the District has operated programs in the past are described in Appendix E.

- **Heavy-Duty Engine Incentive Program**
- **REMOVE II Program**
- **Lawnmower Buyback Program**
- **Light and Medium Duty Vehicle Program**
- **Voluntary Accelerated Vehicle Retirement**

The Heavy-Duty Engine Incentive Program and REMOVE II Program are currently in operation and can be used as an outlet for funds from ISR immediately. Other programs where the District has past experience can be implemented quickly.

III. New Programs

Stationary Source Incentive Program

Program concept: Some control options that are in excess of current rule requirements and best available control technology (BACT) thresholds can be implemented with the help of incentive funding. These options typically exceed BACT cost-effectiveness limits or were not required by the rule due to economic impacts; however, relatively cost-effective control options may be available in a variety of industries.

All projects would be required to demonstrate that they are:

- Surplus to all federal, state, and local requirements
- Quantifiable – emission reductions can be determined
- Enforceable – a mechanism is available to ensure that reductions occur
- Permanent – reductions are maintained for the life of the credit

There are several potential ways in which stationary source operators would be attracted to the incentive program:

- Applicant initiated - Applicant proposing expansion or equipment replacement approaches the District with equipment or control technologies in excess of requirements.

- District initiated - District permit engineers identify control technology in excess of BACT requirements and rule requirements during project review and suggest to applicant the potential for going beyond requirements with the help of incentive funding.

- Ongoing program - The District identifies specific equipment or technologies in excess of requirements in a grant program and open application process.

Stationary Source Project Review Process Outline:

1. For projects identified during BACT analysis required under Rule 2201, permit engineers identify potential control technology that exceeds BACT requirements and is surplus of all regulations.
2. The engineer contacts Emission Reduction Incentive Program (ERIP) staff to forward cost effectiveness analysis. *Note: the cost effectiveness performed for ERIP purposes is not the BACT cost effectiveness*.
3. ERIP determines whether project meets ISR funding criteria and contacts PSD and applicant.
4. If not, the project, as initially proposed, is processed by Permit Staff.
5. If yes, 3-parts meeting (ERIP, PSD, Applicant) to review feasible options (technical aspects and funding).

6. Project, as initially proposed, is on hold, waiting for ERIP and applicant final approval/decision.
7. Applicant determines whether the project would be feasible at their facility.
8. If not, the project, as initially proposed, is processed by Permit Staff.
9. If yes, ERIP staff initiates incentive funding application process.
10. For eligible projects, the applicant would complete an application providing contact information and complete project and cost information.
11. Initial project amended to incorporate new proposed control technology.
12. The application would be approved by ERIP and Permit Service Division (PSD).
13. ERIP staff would prepare a contract for the project between the applicant and the District.
14. PSD would incorporate the new controls and emission amounts into the applicant's permit application.
15. PSD issues an Authority to Construct (ATC) allowing the applicant to install the new control.
16. Compliance staff conducts an inspection, that may include a source test for some projects, to verify the emission reductions.
17. Compliance notifies PSD and ERIP that the installation is complete.
18. ERIP approves claim for payment for the contract.
19. Finance issues payment for the project to the applicant.
20. Long term monitoring and reporting is accomplished through the normal process for permitted equipment.
21. ERIP reports emission reductions in periodic reports to the Governing Board.

Projects may also enter the system that are initiated by operators of the permitted sources. In these cases, PSD will conduct an assessment to determine technological feasibility and if the project is surplus and enforceable. PSD would then turn the project over to ERIP for application processing and contracting. Project types that have the potential for large numbers of applications may become an ongoing program component with outreach to recruit applicants.

Example Projects

The following are examples of projects that illustrate the potential to obtain emission reductions through a stationary source incentive program. All projects listed would require additional research and analysis prior to offering incentives.

Example: Replace natural gas fired boilers/burners with cleaner model.

Under District Rule 4306, boilers rated from greater than 5 up to 20 MMBTU per hour are required to achieve a NOx emission rate of 15 ppm. If the applicant currently operated a 30 ppm boiler, when it comes time to replace the boiler, he would be required to install a 15 ppm boiler. Due to advances in technology there are now 9 ppm ultra-low NOx burners available. The cost is in excess of the District's BACT threshold, so the applicant is not required to purchase the 9 ppm boiler. The increment between

the 15 ppm boiler and the 9 ppm boiler are therefore surplus reductions. The incentive amount would be set to cover the extra cost of installing the cleaner boiler. There are approximately 420 units between 5 to 20 MMBTU per hour that are subject to Rule 4306. Complete new burner unit costs are in the range of $28,000 to $57,000 depending on size, based on contact with venders. The differential cost between low emitting and high emitting burners ranges from $5,000 to $7,000

Another possible source of surplus reductions may occur from boilers rated from 2 to 5 MMBTU per hour and subject to proposed Rule 4307, which has a NOx limit of 30 ppm. Some boilers that currently operate above 30 ppm may be exempt from rule retrofit requirements now under development, so the surplus reductions for those units may be calculated from the uncontrolled emissions of 55 ppm down to 9 ppm. The incentive would need to cover 100 percent of the cost of the installation. There are no increased operating costs expected with the 9 ppm burners. There could be more than 300 of these exempt units eligible for an incentive. Unit costs for 2.5 MMBtu/hr 9 ppm burners are about $41,000 based on contact with vendors.

Example: Electrification of stationary non-emergency IC engines.

Stationary engines are required to meet a NOx emission limit specified by Rule 4702. Installing an electric motor in place of the engine would result in a surplus reduction for the increment between the emission limit and the zero emission electric motor. Depending on the current electric rate and price of fuel, there may be a cost increase from changing to electric. The incentive would need to cover the cost of replacing the engine with an electric motor and increased operating costs. There are hundreds of units installed that could take advantage of this program with sufficient incentive amounts. Costs have not been researched.

Example: Install SCR at a flat glass melting furnace.

Glass melting furnaces are required to meet NOx emission limits specified in Rule 4354 when the furnace is next rebuilt. These furnaces are rebuilt approximately every 7 years. The rule requirements can be exceeded with installation of selected catalyst reduction. The surplus reductions can be achieved by using SCR instead of oxy fuel or in addition to oxy fuel in some cases. The cost of control may exceed $10 million per unit, but the large potential emission reductions result in relatively good cost-effectiveness. SCR has high operating costs and would most likely require incentives to cover increased operating costs. There are two potential candidates for this project in the San Joaquin Valley.

Example: Install plenum chambers or additional cyclone separators in cotton gins.

Cotton gins are required to reduce PM10 emissions produced during the ginning process under Rule 4204. Additional controls may be possible for some gins if an

incentive were provided. Installing a plenum chamber before the required cyclone separators may provide reductions if there is room for the equipment in the building. After the cyclone separators there may be potential to add either cyclone separators in or a bag house in series. Feasibility will depend on the gin configuration. There are increased operating costs with adding cyclone separators and bag houses that may impact cost-effectiveness of these options.

PM10 Public Agency Road and Unpaved Surface Program

The District has identified several sources of fugitive PM10 from paved and unpaved roads that provide significant emission reduction potential for the ISR rule. The most promising projects are:

- Paving unpaved roads
- Paving unpaved road shoulders
- Long-term contracts for chemical suppressants on unpaved roads
- Long-term contracts for chemical dust suppressants on unpaved road shoulders
- Purchase of PM10 Efficient Street Sweepers

Program Concept

The District envisions this program as a coordinated effort between the District, Valley Transportation Planning Agencies, city and county road agencies, and public works departments. The funds collected for PM10 will be spent in the county of origin to the extent possible.

The District will develop an application process and evaluation procedure for funding road projects. Some of the key features are outlined below:

General Program Features

1. Each county and the cities within each county will be competing for funds generated in the county
2. The Council of Governments/Transportation Planning Agencies may coordinate the process of identifying funding priorities among the local member jurisdictions.
3. The primary consideration in funding priorities is cost-effectiveness.
4. Projects must not supplant funding from any source.
5. A mix of projects with higher cost-effectiveness may be funded as long as the average cost-effectiveness for the year is consistent with the District's annual target.
6. Once a list of eligible projects is created and ranked, funding would be allocated twice each year as fees are collected by the District.

Unpaved Roads

1. Provide a list of unpaved road segments in descending average daily trip (ADT) sequence (same data used for compliance with Rule 8061).
2. Indicate road segments that will be paved or chemical treated in compliance with Rule 8061.
3. If economic hardship is claimed for Rule 8061, provide justification.
4. As a general rule, the highest ADT road segments should be paved or treated first.
5. Other factors to consider in scoring projects:
   Roads with significant truck traffic should receive added points
   Roads in or near to urban areas should receive added points
6. Payment will be made to the agency after the project is complete.
7. Suppressant projects would be paid annually under a continuing agreement.
8. A single project could be based on total miles of road segments from a jurisdiction so that different roads could be done under one contract.

Paved Road Shoulder Paving Projects

1. Provide a list of unpaved road shoulders in descending average daily trip (ADT) sequence (same list used for compliance with Rule 8061).
2. Indicate road shoulder segments that will be paved or chemical treated in compliance with Rule 8061.
3. Other criteria should be same as unpaved road projects

PM10 Efficient Street Sweepers

1. Provide a description of the existing street sweeping program if any, including sweeping schedule and types of sweepers (PM Efficient or Standard)
2. Demonstrate compliance with Rule 8061 sweeper purchase requirements or provide economic hardship justification.
3. Provide an estimate of the curb miles that will be swept by the new sweeper(s).
4. Projects proposing natural gas vehicles may be eligible for additional funding based on NOx and PM10 exhaust emission reductions.

Agricultural Project Incentive Program

The District has identified several potential projects for agricultural equipment and emission sources not currently eligible for other funding sources. The projects must be surplus to agricultural regulations and be able to demonstrate quantifiable emission reductions.

Program Concept: Although many agricultural sources are now regulated, there are some opportunities for early implementation of controls that are scheduled far enough in the future to result in surplus reductions. In some cases, it is possible to go beyond

current regulations. For example, measures in addition to those required by the Agricultural Conservation Management Program rule.

Agricultural Projects:

- ❖ Lower emitting almond harvester purchase
- ❖ Chippers and shredder purchases as alternative to burning

Project descriptions:

New almond harvesters that emit 35 to 70 percent less PM10 than older units are currently available. Field-testing results completed for the harvesters is currently under analysis by UC Davis. Early introduction of lower emitting almond harvesters will result in significant reductions.

Chipping and shredding wood waste in the orchard instead of burning results in substantial reductions of PM10, NOx, and ROG. Although Rule 4103 phases out most burning by 2010, some will be exempt due to lack of an economic alternative to burning. The District would purchase chippers and shredders for growers that were unable to implement an alternative to burning and had not selected this as a practice for their CMP Plan.

IV. Potential Projects Lists for NOx and PM10

The following tables list potential projects along with estimates of the number of potential projects, costs, emission reductions and cost-effectiveness for each type of project. The purpose of the list is to show that sufficient projects are available at a cost-effectiveness to achieve program goals. The list is not all inclusive. There are many Heavy-Duty Engine Incentive Program and REMOVE II eligible projects that could also be funded. New projects may also become available as retrofit devices are certified and new technologies are released to the market. The conclusion that can be drawn from this information is that projects well in excess of projected funding are available for the ISR program.

Tables are also provided for 2006, 2007, and 2008 containing a demonstration that the cost-effectiveness targets can be met with the types of projects that are available. This is not intended as a funding allocation system. Participation in grant programs is voluntary and on a first come, first served basis. The District may perform targeted outreach and may set up funding pots for the most cost-effective projects if necessary to achieve emission reduction commitments.

NOx Project Availability

	Individual Project Cost	Annual Reduction (t/y)	Project Life	Lifetime Reductions	Project CE $/ton	Projects Available	Total Cost	Cumulative Cost	Category Reductions Life (tons)	Total Reductions t/d	Cumulative Reductions tons	Cumulative CE
Marine Vessels (Harbor Craft) 04 repower	$197,850	7.6	16	121.6	1627.5	1	$197,850	$197,850	121.57	0.02	121.6	$1,627.46
Ag Irrigation Pump Electrification	$21,558	3.0	10	29.9	720.8	142	$3,061,273	$3,259,124	4247.22	0.58	4368.8	$746.00
Marine Vessels (Harbor Craft) 03 repower	$69,288	3.3	16	52.8	1313.3	1	$69,288	$3,328,412	52.8	0.01	4421.6	$752.77
Ag Irrigation Pumps Portable Diesel Repowers	$27,144	2.3	7	15.9	1705.0	50	$1,357,198	$4,685,610	796.0	0.11	5217.6	$898.05
HDD Trucks Idle Reduction	$9,883	0.6	5	3.0	3316.3	320	$3,162,411	$7,848,021	953.6	0.13	6171.2	$1,271.73
Open Burning Chippers Almond	$227,182	5.7	10	57.2	3971.7	1	$227,182	$8,075,203	57.2	0.01	6228.4	$1,296.52
Off-Road Vehicles/Equipment large ag	$48,382	1.7	7	11.8	4100.2	10	$483,820	$8,559,023	118.0	0.02	6346.4	$1,348.65
Auxiliary Power Units (Transportation Refridgeration Units)	$12,518	0.4	5	1.8	6878.1	294	$3,680,348	$12,239,371	535.1	0.07	6881.4	$1,778.61
Ag non self-propelled ICE	$9,200	0.1	7	1.0	8846.2	10	$92,000	$12,331,371	10.4	0.00	6891.8	$1,789.27
On-Road HD Vehicles - Fleet Modernization	$88,756	1.0	10	10.2	8744.4	1000	$88,755,962	$101,087,334	10150.0	1.39	17041.8	$5,931.72
Glass Melting Furnaces - SCR	$22,120,500	239.0	10	2390.0	9255.4	1	$22,120,500	$123,207,834	2390.0	0.33	19431.8	$6,340.52
Off-Road Vehicles/Equipment small ag repowers	$12,677	0.2	7	1.3	9981.9	20	$253,540	$123,461,374	25.4	0.00	19457.2	$6,345.27
Ag non self-propelled ICE - repowers	$15,500	0.2	7	1.5	10402.7	12	$186,000	$123,647,374	17.9	0.00	19475.1	$6,348.99
Small Boilers, Steam Generators, and Process Heaters - replacement	$13,000	0.1	10	1.2	10743.8	1207	$15,691,000	$139,338,374	1460.5	0.20	20935.6	$6,655.58
School Bus Replacement	$110,000	0.3	10	3.1	35483.9	1000	$110,000,000	$249,338,374	3100.0	0.42	24035.6	$10,373.72
Locomotives	$1,414,286	6.0	18.6	111.7	12664.7	10	$14,142,857	$263,481,231	1116.7	0.15	25152.3	$10,475.44
Small Boilers, Steam Generators, and Process Heaters - replacement	$6,000	0.0	10	0.3	18181.8	552	$3,312,000	$266,793,231	182.2	0.02	25334.5	$10,530.85
Forklifts (Electric, ICE, SI)	$44,457	0.4	5	2.0	22798.7	50	$2,222,873	$269,016,104	97.5	0.01	25432.0	$10,577.88
Airport Ground Support Equipment - Electric replacements	$27,889	0.2	5.0	1.1	24753.5	73	$2,035,889	$271,051,993	82.2	0.01	25514.2	$10,623.57
Open Burning Chippers Figs	$185,212	0.6	10	5.7	32379.7	12	$2,222,544	$273,274,537	68.6	0.01	25582.8	$10,681.95
Gross Polluter - VAVR	$3,000	0.1	1	0.08	37500.0	100	$300,000	$273,574,537	8.0	0.00	25590.8	$10,690.33
Old Vehicle - VAVR	$3,000	0.02	3	0.06	50000.0	5000	$15,000,000	$288,574,537	300.0	0.04	25890.8	$11,145.82
									25890.8	3.55		

PM10 Project Availability

	Individual Project Cost	Annual PM10 Reduction (t/y)	Project Life	Lifetime Reductions	Project CE $/ton	Projects Available	Total Cost	Cumulative Cost	Category Reductions Life (tons)	Total Reductions t/d	Cumulative Reductions tons	Cumulative CE
Unpaved Roads - City and County												
Paving 75 ADT roads	$290,000	27.1	20	542.0	535.1	10	$2,900,000	$2,900,000	5420	0.7	5420	$535.06
Paving 25 ADT roads	$290,000	9.0	20	180.7	1605.2	90	$26,100,000	$29,000,000	16260	2.2	21680	$1,337.64
Paving 10 ADT roads	$290,000	3.6	20	72.0	4027.8	100	$29,000,000	$58,000,000	7200	1.0	28880	$2,008.31
Suppressants 10 year contract	$140,080	3.5	10	35.0	4002.3	100	$14,008,000	$72,008,000	3500	1.0	32380	$2,223.84
Paved Roads											32380	
Paving Shoulders	$100,000	0.2	20	3.8	26315.8	500	$50,000,000	$122,008,000	1900	0.5	34280	$3,559.16
Suppresants on Shoulder 10 yr	$48,370	0.2	10	1.6	30231.3	500	$24,185,000	$146,193,000	800	0.2	35080	$4,167.42
PM Efficient Street Sweepers	$152,000	0.9	8	7.3	20821.9	15	$2,280,000	$148,473,000	109.5	0.0	35189.5	$4,219.24
Stationary Source Projects												
Cotton Gin - Install barrel cyclone before master trash 1D3D cyclone	$7,500	1.6	10	16.3	460.1	12	$90,000	$148,563,000	195.6	0.0	35275.6	$4,211.49
Cotton Gin - Install barrel cyclone or 1D2D cyclone before mote system 1D3D cyclone	$60,000	2.8	10	27.6	2173.9	12	$720,000	$149,283,000	331.2	0.0	35606.8	$4,192.54
Cotton Gin - Install plenum chamber before the unloading system and the drying/cleaning systems	$70,000	2.8	10	27.6	2536.2	12	$840,000	$150,123,000	331.2	0.1	35938	$4,177.28
Charbroiler Replacement	$6,600	0.2	10	2.4	2750.0	135.0	$891,000	$151,014,000	324	0.1	36262	$4,164.52
Other Ag Projects												
Almond Harvester Purchase	$145,000	3.6	10	35.7	4061.6	260	$37,700,000	$188,714,000	9282	2.5	45220	$4,173.24
										8.5		

NOx Cost-Effectiveness Demonstration

NOx Project Mix in 2006 to achieve an average cost effectiveness of $4650/ton with $6,006,379 available

	Project Cost	Annual Reduction (t/y)	Project Life	Life Reductions	Total No. Projects Available	Number of Projects in 2006	Total cost	Total tons	Project CE $/ton
Ag Projects									
Ag Irrigation Pump Electrification	$21,558	3.0	10	29.9	142	20	$431,165	598.2	721
Ag Irrigation Pumps Portable Diesel Repowers	$27,144	2.3	7	15.9	50	10	$271,440	159.2	1,705
Off-Road Vehicles/Equipment large ag repowers	$48,382	1.7	7	11.8	10	4	$193,528	47.2	4,100
Ag non self-propelled ICE repowers hay bayler	$9,200	0.1	7	1.0	10	1	$9,200	1.0	8,846
Ag non self-propelled ICE repowers spray rig	$15,500	0.2	7	1.5	12	2	$31,000	3.0	10,403
Off-Road Vehicles/Equipment small ag repowers	$12,677	0.2	7	1.3	20	3	$38,031	3.8	9,982
Open Burning - Chipping Almonds	$227,182	5.7	4	22.9	1	1	$227,182	22.9	9,921
Open Burning - Chipping Figs	$185,212	0.6	4	2.28	12	1	$185,212	2.3	81,233
Marine Projects									
Marine Vessels (Harbor Craft) 03 repower	$69,288	3.3	16	52.8	1	1	$69,288	52.8	1,313
Marine Vessels (Harbor Craft) 04 repower	$197,850	7.6	16	121.6	1	1	$197,850	121.6	1,627
HD Truck/Bus Projects									
HDD Trucks Idle Reduction	$9,883	0.6	5	3.0	320	0	$0	0.0	#DIV/0!

NOx Cost-Effectiveness Demonstration

NOx Project Mix in 2006 to achieve an average cost effectiveness of $4650/ton with $6,006,379 available

HD Truck/Bus Projects *Cont*									
Auxiliary Power Units (Transportation Refridgeration Units) repowers	$12,518	0.4	5	1.8	294	20	$250,364	36.4	6,878
On-Road HD Vehicles Fleet Modernization	$88,756	1.0	10	10.2	1000	10	$887,560	101.5	8,744
School Bus Replacement	$110,000	0.3	10	3.1	1000	9	$990,000	27.9	35,484
Locomotives Tier 0 to Tier 2 or hybrid	$1,414,286	6.0	18.6	111.7	10	1	$1,414,286	111.7	12,665
Stationary Source Projects									
Glass Melting Furnaces	$22,120,500	239.0	10	2390.0	1	0	$0	0.0	#DIV/0!
Small Boilers, Steam Generators, and Process Heaters Replace Existing units with new	$13,000	0.1	10	1.2	1207	1	$13,000	1.2	10,744
Small Boilers, Steam Generators, and Process Heaters Replace Existing units with new	$6,000	0.0	10	0.33	552	12	$72,000	4.0	18,182
Off-Road Mobile									
Forklifts (Electric, ICE, SI)	$44,457	0.4	5	1.95	50	5	$222,287	9.8	22,799
Airport Ground Support Equipment - Electric	$27,889	0.2	5	1.13	73	3	$83,667	3.4	24,753
Other Mobile									
Gross Polluter - VAVR	$3,000	0.1	1	0.08	100	0	$0	0.0	#DIV/0!
Old Vehicle - VAVR	$3,000	0.02	3	0.06	5000	150	$450,000	9.0	50,000
				Overall cost and average CE for 2006			**$6,037,059**	**1316.7**	**4,585**

NOx Project Mix in 2007 to achieve an average cost effectiveness of $7100/ton with $14,407,974 available

	Project Cost	Annual Reduction (t/y)	Project Life	Life Reductions	Total No. Projects Available	Number of Projects in 2007	Total cost	Total tons	Project CE $/ton
Ag Projects									
Ag Irrigation Pump Electrification	21,558	3.0	10	29.9	122	20	$431,165	598.2	721
Ag Irrigation Pumps Portable Diesel Repowers	27,144	2.3	7	15.9	40	20	$542,879	318.4	1,705
Off-Road Vehicles/Equipment large ag repowers	48,382	1.7	7	11.8	6	4	$193,528	47.2	4,100
Ag non self-propelled ICE repowers hay bayler	9,200	0.1	7	1.0	9	4	$36,800	4.2	8,846
Ag non self-propelled ICE repowers spray rig	15,500	0.2	7	1.5	10	4	$62,000	6.0	10,403
Off-Road Vehicles/Equipment small ag repowers	12,677	0.2	7	1.3	17	4	$50,708	5.1	9,982
Open Burning - Chipping Almonds	227,182	5.7	3	17.2	0	0	$0	0.0	#DIV/0!
Open Burning - Chipping Figs	185,212	0.6	3	1.71	11	0	$0	0.0	#DIV/0!
Marine Projects									
Marine Vessels (Harbor Craft) 03 repower	69,288	3.3	16	52.8	0	0	$0	0.0	#DIV/0!
Marine Vessels (Harbor Craft) 04 repower	197,850	7.6	16	121.6	0	0	$0	0.0	#DIV/0!
HD Truck/Bus Projects					0				
HDD Trucks Idle Reduction	9,883	0.6	5	3.0	320	0	$0	0.0	#DIV/0!
Auxiliary Power Units	12,518	0.4	5	1.8	274	40	$500,728	72.8	6,878

NOx Project Mix in 2007 to achieve an average cost effectiveness of $7100/ton with $14,407,974 available

HD Truck/Bus Projects *Cont.*									
On-Road HD Vehicles - Fleet Modernization	88,756	1.0	10	10.2	990	45	$3,994,018	456.8	8,744
School Bus Replacement	110,000	0.3	10	3.1	991	40	$4,400,000	124.0	35,484
Locomotives	1,414,286	6.0	18.6	111.7	9	2	$2,828,571	223.3	12,665
Stationary Source Projects					0				
Glass Melting Furnaces	22,120,500	239.0	10	2390.0	1	0	$0	0.0	#DIV/0!
Small Boilers, Steam Generators, and Process Heaters Replace Existing units with new	13,000	0.1	10	1.2	1206	2	$26,000	2.4	10,744
Small Boilers, Steam Generators, and Process Heaters Replace Existing units with new	6,000	0.0	10	0.33	540	6	$36,000	2.0	18,182
Off-Road Mobile									
Forklifts (Electric, ICE, SI)	44,457	0.4	5	1.95	45	3	$133,372	5.9	22,799
Airport Ground Support Equipment - Electric	27889	0.2	5.0	1.13	70	4	$111,556	4.5	24,753
Other Mobile									
Gross Polluter - VAVR	$3,000	0.1	1	0.08	100	5	$15,000	0.4	37,500
Old Vehicle - VAVR	$3,000	0.02	3	0.06	4850	350	$1,050,000	21.0	50,000
				Overall cost and average CE for 2007			**$14,412,326**	**1892.0**	**7,617**

NOx Project Mix in 2008 to achieve an average cost effectiveness of $9350/ton with $22,373,287 available

	Project Cost	Annual Reduction (t/y)	Project Life	Life Reductions	Total No. Projects Available	Number of Projects in 2008	Total cost	Total tons	Project CE $/ton	Comments
Ag Projects										
Ag Irrigation Pump Electrification	21,558	3.0	10	29.9	102	18	$388,049	538.4	721	
Ag Irrigation Pumps Portable Diesel Repowers	27,144	2.3	7	15.9	20	10	$271,440	159.2	1,705	
Off-Road Vehicles/Equipment large ag repowers	48,382	1.7	7	11.8	2	2	$96,764	23.6	4,100	
Ag non self-propelled ICE repowers hay bayler	9,200	0.1	7	1.0	5	5	$46,000	5.2	8,846	
Ag non self-propelled ICE repowers spray rig	15,500	0.2	7	1.5	6	6	$93,000	8.9	10,403	
Off-Road Vehicles/Equipment small ag repowers	12,677	0.2	7	1.3	13	8	$101,416	10.2	9,982	
Open Burning - Chipping Almonds	227,182	5.6	2	11.1	1	1	$227,182	11.1	20,467	Rule 4103 2010 Implementation
Open Burning - Chipping Figs	185,212	0.6	2	1.14	11	0	$0	0.0	#DIV/0!	Rule 4103 2010 Implementation
Marine Projects										
Marine Vessels (Harbor Craft) 03 repower	69,288	3.3	16	52.8	0	0	$0	0.0	#DIV/0!	
Marine Vessels (Harbor Craft) 04 repower	197,850	7.6	16	121.6	0	0	$0	0.0	#DIV/0!	
HD Truck/Bus Projects					0					
HDD Trucks Idle Reduction	9,883	0.6	5	3.0	320	50	$494,127	149.0	3,316	Idle Aire req. min order of 50 units

NOx Project Mix in 2008 to achieve an average cost effectiveness of $9350/ton with $22,373,287 available

HD Truck/Bus Projects *Cont.*										
Auxiliary Power Units - Repower	12,518	0.4	5	1.8	234	40	$500,728	72.8	6,878	
On-Road HD Vehicles - Fleet Modernization	88,756	1.0	10	10.2	945	66	$5,857,894	669.9	8,744	
School Bus Replacement	110,000	0.3	10	3.1	951	50	$5,500,000	155.0	35,484	
Locomotives	1,414,286	6.0	18.6	111.7	7	4	$5,657,143	446.7	12,665	
Stationary Source Projects					0					
Glass Melting Furnaces	22,120,500	239.0	10	2390.0	1	0	$0	0.0	#DIV/0!	
Small Boilers, Steam Generators, and Process Heaters Replace Existing units with new	13,000	0.1	10	1.2	1204	60	$780,000	72.6	10,744	
Small Boilers, Steam Generators, and Process Heaters Replace Existing units with new	6,000	0.0	10	0.33	534	60	$360,000	19.8	18,182	
Off-Road Mobile					0					
Forklifts (Electric, ICE, SI)	44,457	0.4	5	1.95	42	5	$222,287	9.8	22,799	
Airport Ground Support Equipment - Electric	27889	0.2	5.0	1.13	10	5	$139,444	5.6	24,753	
Other Mobile					0					
Gross Polluter ID & Replace - VAVR	$3,000	0.1	1	0.08	95	50	$150,000	4.0	37,500	
Old Vehicle - VAVR	$3,000	0.02	3	0.06	4500	500	$1,500,000	30.0	50,000	
				Overall cost and average CE for 2008			**$22,385,473**	**2391.7**	**9,359**	

NOx Cost Effectiveness Demonstration

Year	Nox Projected Revenue	NOx CE $/ton
2006	$6,006,379	4,650
2007	$14,407,974	7,100
2008	$22,373,287	9,350
Total	$42,787,640	

PM10 Cost-Effectiveness Demonstration

Project Mix in 2006 to achieve an average cost effectiveness of $2907/ton with $5,941,908 available

	Project Cost	Annual Reduction (t/y)	Project Life	Life Reductions	Total No. Projects Available	Number of Projects in 2006	Total cost	Total tons	Project CE $/ton
Unpaved Roads									
Paving 75 ADT roads	$290,000	27.1	20	542	10	2	$580,000	1084.0	535
Paving 25 ADT roads	$290,000	9.0	20	180.7	90	2	$580,000	361.3	1,605
Paving 10 ADT roads	$290,000	3.6	20	72.0	100	4	$1,160,000	288.0	4,028
Suppressants 10 year contract	$140,080	3.5	10	35.0	100	6	$840,480	210.0	4,002
Paved Roads									
Paving Shoulders	$100,000	0.2	20	3.8	500	14	$1,400,000	53.2	26,316
Suppresants on Shoulder 10 yr	$48,370	0.2	10	1.6	500	16	$773,920	25.6	30,231
PM Efficient Sweeper Purchase	$152,000	0.9	8	7.3	25	2	$304,000	14.6	20,879
Cotton Gins									
Install barrel cyclone before master trash 1D3D cyclone	$7,500	1.6	10	16.3	12	2	$15,000	32.6	460
Install barrel cyclone or 1D2D cyclone before mote system 1D3D cyclone	$60,000	2.8	10	27.6	12	2	$120,000	55.2	2,174
Install plenum chamber before the unloading system and the drying/cleaning systems	$70,000	2.8	10	27.6	12	2	$140,000	55.2	2,536
Other Ag Equipment									
Almond Harvester Purchase	$145,000	3.6	10	35.7	260	0	$0	0.0	#DIV/0!
Average CE in 2006						**Overall cost and CE for 2006**	**$5,913,400**	**2179.7**	**2,713**

Project Mix in 2007 to achieve an average cost effectiveness of $5594/ton with $20,861,575 available

	Project Cost	Annual Reduction (t/y)	Project Life	Life Reductions	Total No. Projects Available	Number of Projects in 2007	Total cost	Total tons	Project CE $/ton
Unpaved Roads									
Paving 75 ADT roads	$290,000	27.1	20	542	8	0	$0	0.0	#DIV/0!
Paving 25 ADT roads	$290,000	9.0	20	180.7	88	5	$1,450,000	903.3	1,605
Paving 10 ADT roads	$290,000	3.6	20	72.0	96	22	$6,380,000	1584.0	4,028
Suppressants 10 year contract	$140,080	3.5	10	35.0	94	16	$2,241,280	560.0	4,002
Paved Roads					0				
Paving Shoulders	$100,000	0.2	20	3.8	486	55	$5,500,000	209.0	26,316
Suppresants on Shoulder 10 yr	$48,370	0.2	10	1.6	484	50	$2,418,500	80.0	30,231
PM Efficient Sweeper Purchase	$152,000	0.9	8	7.3	23	12	$1,824,000	87.4	20,879
Cotton Gins									
Install barrel cyclone before master trash 1D3D cyclone	$7,500	1.6	10	16.3	10	2	$15,000	32.6	460
Install barrel cyclone or 1D2D cyclone before mote system 1D3D cyclone	$60,000	2.8	10	27.6	10	2	$120,000	55.2	2,174
Install plenum chamber before the unloading system and the drying/cleaning systems	$70,000	2.8	10	27.6	10	2	$140,000	55.2	2,536
Other Ag Equipment									
Almond Harvester Purchase	$145,000	3.6	10	35.7	260	2	$290,000	71.4	4,062
Average CE in 2007						**Overall cost and CE for 2007**	**$20,378,780**	**3638.1**	**5,602**

Project Mix in 2008 to achieve an average cost effectiveness of $9011/ton with $33,883,309 available

	Project Cost	Annual Reduction (t/y)	Project Life	Life Reductions	Total No. Projects Available	Number of Projects in 2008	Total cost	Total tons	Project CE $/ton
Unpaved Roads									
Paving 75 ADT roads	$290,000	27.1	20	542	8	1	$290,000	542.0	535
Paving 25 ADT roads	$290,000	9.0	20	180.7	83	5	$1,450,000	903.3	1,605
Paving 10 ADT roads	$290,000	3.6	20	72.0	74	10	$2,900,000	720.0	4,028
Suppressants 10 year contract	$140,080	3.5	10	35.0	78	5	$700,400	175.0	4,002
Paved Roads					0				
Paving Shoulders	$100,000	0.2	20	3.8	431	175	$17,500,000	665.0	26,316
Suppresants on Shoulder 10 yr	$48,370	0.2	10	1.6	434	160	$7,739,200	256.0	30,231
PM Efficient Sweeper Purchase	$152,000	0.9	8	7.3	11	11	$1,672,000	80.1	20,879
Cotton Gins					0				
Install barrel cyclone before master trash 1D3D cyclone	$7,500	1.6	10	16.3	8	2	$15,000	32.6	460
Install barrel cyclone or 1D2D cyclone before mote system 1D3D cyclone	$60,000	2.8	10	27.6	8	2	$120,000	55.2	2,174
Install plenum chamber before the unloading system and the drying/cleaning systems	$70,000	2.8	10	27.6	8	2	$140,000	55.2	2,536
Other Ag Equipment									
Almond Harvester Purchase	$145,000	3.6	10	35.7	258	6	$870,000	214.2	4,062
Average CE in 2008						**Overall cost and CE for 2008**	**$33,396,600**	**3698.6**	**9,029**

PM10 Cost-Effectiveness Demonstration

Year	PM10 Projected Revenue	PM10 CE $/ton
2006	$5,941,908	2,907
2007	$20,306,433	5,594
2008	$33,883,309	9,011
Total	$60,131,650	

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APPENDIX F

Socioeconomic Analysis for Proposed Rule 9510 (Indirect Source Review) and Rule 3180 (Administrative Fees for Air Impact Assessment Applications)

November 17, 2005

SOCIOECONOMIC ANALYSIS PROPOSED INDIRECT SOURCE RULE: DRAFT RULES 9510 AND 3180

4 November 2005

Prepared for

San Joaquin Valley Unified Air Pollution Control District
1990 E. Gettysburg Avenue
Fresno, CA 93726

Prepared by

Applied Development Economics
2029 University Avenue • Berkeley, California 94704 • (510) 548-5912
1029 J Street, Suite 310 • Sacramento, California 95814 • (916) 441-0323
www.adeusa.com

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1. EXECUTIVE SUMMARY

The San Joaquin Valley Unified Air Pollution Control District ("District") seeks to adopt New Rule 9510 and 3180 to meet certain United States Environmental Protection Agency (US EPA) mandates and timelines with regards to improved air quality in the region. This section of the report summarizes the findings of the socioeconomic analysis of Rules 9510 and 3180.

The analysis indicates that while the worst-case residential fee that a typical residential development would pay under Draft Rule 9510 and 3180 can increase the amount of household income required to finance the purchase of a new home, the estimated increase represents a small fraction of the original household income required to finance a new home in the event no air quality fees were in place. The affect of the fees on rents is similarly small.

The analysis also examines the question of housing affordability from the vantage point of low- and moderate-income households. The analysis demonstrates that, even before the imposition of an air quality fees, most low-income and households in the Central Valley are priced out of newly constructed multifamily unit market, the rents for which need to be at levels that account for price of land, development costs, developer fees, and an adequate level of profit, among other things. The analysis discusses how public subsidies can assist in enhancing the financial feasibility of a real estate project in which a certain portion of units are set-aside as below-market rental units.

The analysis also examines the impacts of proposed worst-case off-site emission reduction fees on commercial, industrial and institutional projects. While a typical non-residential development can absorb the 2006 and 2008 fees, projects will have to recover the cost of the fee over a period of time.

It is important to note that any fee identified in the report is the estimated maximum fee in the worst-case scenario for a typical development project, with the understanding that the

actual fee will vary with the particulars of any project. Any fee in the report is presented for the purposes of analyzing potential impacts given costs associated with reducing quantifiable emissions resulting from what constitutes typical residential, commercial and industrial developments. It is also important to note that the developer may reduce fees by incorporating on-site emission reduction measures into the projects. There may or may not be costs associated with on-site measures. In any event, it is anticipated that the developer will choose the least costly option.

2. INTRODUCTION

This report describes the socioeconomic impacts of Rule 9510 (Indirect Source Review – ISR) and 3180 (Administrative Fees for Indirect Source Review). Following this introduction, the report summarizes the proposed amendments and describes the methodology for the socioeconomic analysis. In Section 5, the report describes the economic characteristics of sources affected by Rule 9510 and 3180. The sixth section analyzes the socioeconomic impacts of compliance costs on the regional economy.

The report is prepared pursuant to the provisions of AB2051 (Section 40728.5 of the California Health and Safety Code), which requires an assessment of socioeconomic impacts of proposed air quality rules. The findings in this report can assist District staff in understanding the socioeconomic impacts of Rules 9510 and 3180, and can assist staff in preparing a refined version of the rule. A final report will be presented at the Governing Board hearing by District staff in December 2005. Figure 1 is a map of the eight-county region that comprises the San Joaquin Valley Air Basin. As indicated in the map, Kern County is not completely in the District.

FIGURE 1
San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD) Air Basin



3. DESCRIPTION OF NEW RULES 9510 & 3180

The San Joaquin Valley Air Basin (SJVAB) is classified as a nonattainment area for the state and federal health based ambient ozone and PM 10 standards by the California Air Resources Board (ARB) and the U.S. Environmental Protection Agency (EPA). The SJVAB is currently classified as serious nonattainment for the 24-hour and annual National Ambient Air Quality Standards (NAAQS) for particulate matter 10 microns in size and smaller (PM10), extreme nonattainment for the federal 1-hour ozone standard, serious nonattainment for the new federal 8-hour ozone standard, and severe nonattainment for the 1-hour state ozone standard.

The San Joaquin Valley Unified Air Pollution Control District's (District) adopted 2003 PM10 Plan projects attainment of NAAQS for PM10 at the earliest practicable date of December 31, 2010. The Indirect Source Rule[1] (ISR) is one of the commitments contained in the 2003 PM10 Plan to achieve these emissions reductions. The ISR commitment will be implemented through Rules 9510 and 3180. The purpose of Draft Rule 9510 is to reduce emissions of NOx and PM10 from new development projects. The purpose of Draft Rule 3180 is to recover the costs of administering Draft Rule 9510. Implementation of these draft rules is expected to reduce NOx and PM10 emissions by 5.4 and 5.8 tons per day respectively.

The District identified several examples of air pollution agencies in California that are currently reviewing land use projects for indirect source impacts and/or collecting mitigation fees in their districts. District staff reviewed programs being implemented by the Mendocino County and Shasta County Air Quality Management Districts and the Great Basin, Colusa County, and Placer County Air Pollution Control Districts. District staff also considered a number of

[1] Indirect Sources are land uses that attract or generate motor vehicle trips.

program types including District permitting, city/county review, District review, and simple fee.

Despite significant air pollution reductions from both mobile and stationary sources, the District exceeds state and federal air quality standards for ozone and PM10. Although today's new cars pollute about 90 percent less than models produced 25 years ago (due to California's strict vehicle emissions standards), large increases in population and driving partially offset the benefits these cleaner-burning vehicles provide. The District's total population increased by 22 percent between 1990 and 2000; and, California's Department of Finance projects that the SJVAB's population will increase by 24 percent between 2000 and 2010. With increased population, there is an increase in emissions from area sources, such as consumer products, fuel combustion, landscape maintenance equipment, etc.

The total number of vehicle miles traveled (VMT) in the District has increased at a rate faster than population growth. The district witnessed a nine percent increase between 1999 and 2002, and is expecting a 27 percent increase from 2002 to 2010. Entrained and re-entrained paved road dust and corresponding PM10 emissions increase as VMT increases.

To reduce emissions of NOx and PM10, Draft Rule 9510 would apply to development projects that will seek to gain a discretionary approval for projects that, upon full build-out will include any one of the following: 50 residential units, 2,000 square feet of commercial space, 25,000 square feet of industrial space, 20,000 square feet of medical office space, 39,000 square feet of general office space, 9,000 square feet of educational space, 10,000 square feet of government space, 20,000 square feet of recreational space, or 9,000 square feet of unidentified space. Certain transportation projects, transit projects, reconstruction projects that result from a natural disaster, and development projects whose primary source of emissions are subject to District Rule 2201 or 2010 would be exempt from this Draft Rule. Also, development projects that have a mitigated baseline below two tons per year for each pollutant would be exempt from the emission reduction requirements of the rule.

Draft Rule 9510 would require new development project applicants to submit an Air Impact Assessment application to the District prior to or at application for a project's final discretionary approval with a public agency. The application would include an assessment, project location and description, an on-site emission reduction checklist, a proposed Monitoring and Reporting Schedule (MRS), and a fee deferral agreement if necessary. The District would have 10 days to determine whether or not the application is complete. After deeming an application complete, the district would have 30 days to approve the application and notify the applicant of the fee amounts.

Draft Rule 9510 would require developers to reduce cumulative NOx emissions in excess of 50 percent of the project's first-year operational baseline emissions until the emissions reach 50 percent of the first-year baseline emissions (approximately 10 years). Developers would be required to reduce PM10 emissions equal to half of the first-year emissions after build-out for the same time period required for NOx reductions. Developers would also be required to reduce emissions from construction equipment NOx by 20%, and PM10 by 45% compared to the statewide fleet average. Emissions could be reduced through on-site emission reduction measures, by paying the District a fee to fund emission reduction projects off-site, or through a combination of the two.

To recover the costs of administering Draft Rule 9510, Draft Rule 3180 would include a non-refundable application filing fee to be paid when an application is submitted to the District. Once an application and application fee are received, District staff would log the total staff hours spent on the project. So that only the cost of the actual hours spent on the project is recovered, the cost of the hours spent on the project (hours multiplied by a weighted average labor rate) would be subtracted from the application fee. Draft Rule 3180 would also contain a fee, payable when the off-site emission reduction fees are collected, equal to four percent of the off-site fees to recover the cost of administering off-site emission reduction projects.

4. METHODOLOGY

The socioeconomic analysis involves the use of information provided directly by affected sources, as well as secondary data used to describe the industries affected by the proposed provisions of Rule 9510 and 3180. The approach is briefly described below.

This report relies heavily on the most current data available from a variety of sources. For commercial-industrial prices, this report relies on Dataquick, Loopnet.com and Realtor.com. For construction trends, this report relied on the Construction Industry Research Board. When estimating cost of construction, we used "Commercial Square Foot Building Costs: 2004", by Deloitte Saylor Publication, as well as per square foot cost of construction estimates used by many cities when estimating the value of a project. For purposes of estimating profits, ADE relied on Dun and Bradstreet, as well as corporate reports of major home builders and developers of commercial-industrial space operating in California and the Central Valley.

With the above information, ADE was able to estimate profit ratios for sources affected by the draft rule. ADE calculated ratios of profit per dollar of revenue for affected industries. The result of the socioeconomic analysis shows what proportion of profits the compliance costs represent. Based on assumed thresholds of significance, ADE discusses in the report whether the affected sources are likely to pass on costs to consumers or to reduce jobs as a means of recouping the cost of rule compliance or as a result of reducing business operations. To the extent that such job losses appear likely, the indirect multiplier effects of the jobs losses are estimated using a regional IMPLAN input-output model.

When analyzing the socioeconomic impacts of proposed new rules and amendments, ADE works closely within the parameters of accepted methodologies discussed in a 1995 California Air Resources Board report called "Development of a Methodology to Assess the Economic Impact Required by SB513/AB969" (by Peter Berck, PhD, UC Berkeley

Department of Agricultural and Resources Economics, Contract No. 93-314, August, 1995). The author of this report reviewed a methodology to assess the impact that California Environmental Protection Agency proposed regulations would have on the ability of California businesses to compete. The California Air Resources Board (ARB) has incorporated the methodologies described in this report in its own assessment of socioeconomic impacts of rules generated by ARB. One methodology relates to determining a level above or below which a rule and its associated costs is deemed to have significant impacts. When analyzing the degree to which its rules are significant or insignificant, ARB employs a threshold of significance that ADE follows. Berck reviewed the threshold in his analysis and wrote, "The Air Resources Board's (ARB) use of a 10 percent change in [Return on Equity] ROE (i.e. a change in ROE from 10 percent to a ROE of 9 percent) as a threshold for a finding of no significant, adverse impact on either competitiveness or jobs seems reasonable or even conservative."

5. IMPACT INDUSTRIES SUBJECT TO NEW RULES 9510 & 3180 (INDIRECT SOURCE RULE)

This section of the socioeconomic analysis describes demographic and economic trends in the San Joaquin Valley region. The first part of this section compares the San Joaquin Valley region against California as a whole, and provides a context for understanding demographic and economic changes that occurred within the San Joaquin Valley region between 1998 and 2003. Starting with sub-section 5.2, the second part of this section narrows the focus of the socioeconomic analysis to industries affected by New Rules 9510 and 3180. The second part of this section describes the economic characteristics of potentially impacted industries that might be subject to Rules 9510 and 3180.

In this report, the San Joaquin Valley region is defined as Fresno, Kern, Kings, Madera, Merced, San Joaquin, Stanislaus and Tulare counties. Data for Kern County in Tables 1 and 2 are for all of Kern County, although Kern County is only partially in the San Joaquin Valley Air Basin. Starting with Table 3, data for Kern County are for the part of Kern County that is in the San Joaquin Valley Air Basin.

5.1 REGIONAL DEMOGRAPHIC AND ECONOMIC TRENDS

REGIONAL DEMOGRAPHIC TRENDS

The San Joaquin Valley region experienced tremendous population growth during the 1990s. Many came to this area because of affordable housing. As a result, population increased significantly. The eight-county region's population increased by 22 percent (or approximately 2.0 percent annually), from 2.9 million in 1993 to 3.6 million in 2003. While the State of California's population increased by 15 percent (or approximately 1 percent annually), all the counties in the region experienced faster rates of growth, and two counties grew at rates that were triple the State's growth rate, as Table 1 shows. While by many standards Madera County continues to be a small county– at 135,262 residents

according to the Department of Finance–it still experienced a 35 percent growth in population during the last decade (or three percent annually). Kings County also grew by three percent per year. As demonstrated in the following section on regional economic trends, the demographic changes that occurred in the San Joaquin Valley region during the 1990s significantly influenced the economy of this eight-county region.

TABLE 1
Population Growth: San Joaquin Valley Region, 1993 - 2003

	1993	1998	2003	Distribution, 2003	Annual Per. Chng 93-98	Annual Per. Chng 98-03	Annual Per. Chng 93-03
California	31,303,452	32,670,019	36,144,267		1%	2%	1%
SJV Region	2,959,911	3,192,439	3,615,696	10%	2%	3%	2%
Fresno	722,608	781,936	862,642	24%	2%	2%	2%
Kern	593,087	637,227	724,883	20%	1%	3%	2%
Kings	109,648	120,957	141,434	4%	2%	3%	3%
Madera	100,297	114,137	135,262	4%	3%	3%	3%
Merced	191,883	203,181	232,141	6%	1%	3%	2%
San Joaquin	507,170	546,852	630,577	17%	2%	3%	2%
Stanislaus	400,417	428,272	491,929	14%	1%	3%	2%
Tulare	334,801	359,877	396,828	11%	1%	2%	2%

Source: Applied Development Economics, based on California Department of Finance

Housing construction in the San Joaquin Valley Air Basin has paralleled this increase in population. Low interest and the availability of land at prices lower than in coastal areas of California has fueled construction activity in the Central Valley. Tables 2 and 3 track building permits for single-family and multi-family homes. According to the California Construction Industry Research Board, home-builders typically take out building permits only when they are ready to construct housing. Thus, building permits is a good indicator of housing production. As Table 2 shows, the amount of single-family building permits increased by 14 percent annually between 1998 and 2003 in the Central Valley, easily surpassing the statewide annual rate of eight percent. Almost forty percent of all single family building permits was for projects in San Joaquin and Stanislaus County in 2003. As the tables below show, the amount of new construction for single-family homes greatly exceeds new

construction for multi-family housing, for reasons related to market demand, availability of land, and historically low-interest rates, among other reasons.

TABLE 2
Single-Family Residential Building Permit Trends:
San Joaquin Valley, 1993-2003

	---------- SFU Building permits ----------						
	1993	1998	2003	Distribution, 2003	Annual Per. Chng 93-98	Annual Per. Chng 98-03	Annual Per. Chng 93-03
California	69,901	94,298	138,762		6%	8%	7%
SJV Region	15,055	14,280	27,080	20%	-1%	14%	6%
Fresno	3,743	2,742	4,479	17%	-6%	10%	2%
Kern	3,082	3,025	5,529	20%	0%	13%	6%
Kings	530	526	835	3%	0%	10%	5%
Madera	694	473	1,144	4%	-7%	19%	5%
Merced	1,087	960	2,489	9%	-2%	21%	9%
San Joaquin	2,545	3,170	6,727	25%	4%	16%	10%
Stanislaus	1,835	1,997	3,884	14%	2%	14%	8%
Tulare	1,539	1,387	1,993	7%	-2%	8%	3%

Source: Applied Development Economics, based on Construction Industry Research Board

TABLE 3
Multi-Family Residential Building Permit Trends: San Joaquin Valley, 1993-2003

	---------- MFU Building permits ----------						
	1993	1998	2003	Distribution, 2003	Annual Per. Chng 93-98	Annual Per. Chng 98-03	Annual Per. Chng 93-03
California	14,755	31,409	56,920		16%	13%	14%
SJV Region	1,309	1,403	3,699	6%	1%	21%	11%
Fresno	404	292	1,520	41%	-6%	39%	14%
Kern	314	428	583	16%	6%	6%	6%
Kings	13	231	143	4%	78%	-9%	27%
Madera	105	160	90	2%	9%	-11%	-2%
Merced	20	72	457	12%	29%	45%	37%
San Joaquin	83	59	225	6%	-7%	31%	10%
Stanislaus	148	93	284	8%	-9%	25%	7%
Tulare	222	68	397	11%	-21%	42%	6%

Source: Applied Development Economics, based on Construction Industry Research Board

While the value of single-family unit building permits in the Central Valley is lower by almost $40,000 than the value of single family building permits for the state as a whole, it is worth noting that between 1998 and 2003 average values rose

faster in the region as compared to the state (see Table 4). Using average construction cost figures adjusted for regional and historical variations, local officials estimate the value of single-family, multi-family and commercial and industrial building permits for reasons related to calculating fees and maintaining departmental budgets. The actual price of housing on the market is typically higher than the estimated value of the building permit, though changes in the value of building permits are a good indication as to the trajectory of change in the actual housing market.

TABLE 4
Average Value of Single-Family Unit Building Permit, San Joaquin Valley

	---------- Average Value ----------					
	1993	1998	2003	Annual Per. Chng 93-98	Annual Per. Chng 98-03	Annual Per. Chng 93-03
California	$183,559	$218,055	$217,271	4%	0%	2%
SJV Region	$130,879	$141,956	$170,604	2%	4%	3%
Fresno	$135,736	$150,044	$183,122	2%	4%	3%
Kern	$130,191	$130,167	$149,816	0%	3%	1%
Kings	$141,740	$136,190	$119,485	-1%	-3%	-2%
Madera	$100,791	$102,214	$150,562	0%	8%	4%
Merced	$135,439	$140,674	$153,139	1%	2%	1%
San Joaquin	$143,809	$161,303	$197,209	2%	4%	3%
Stanislaus	$119,981	$143,309	$176,566	4%	4%	4%
Tulare	$118,658	$122,141	$153,456	1%	5%	3%

Source: Applied Development Economics, based on Construction Industry Research Board

Table 5 below identifies the median price for for-sale owner-occupied housing in the Central Valley. The data comes from Dataquick. In the last two years, the median selling price of homes sold on the market has increased substantially. Dataquick's median housing price data cover transactions involving newly built homes, reselling of older homes, and condominiums and townhouses. At almost $300,000 the median price of a home in Madera County is almost twice what is was in July 2003.

TABLE 5
Median Home Sale Prices: San Joaquin Valley, 2003-2005 ($2005)

	July 2003	July 2004	July 2005	03-04	04-05
Fresno County	$171,220	$220,955	$265,000	29%	20%
Kern County	$136,353	$176,041	$236,500	29%	34%
Madera County	$151,811	$242,638	$299,500	60%	23%
Merced County	$207,151	$242,638	$335,000	17%	38%
San Joaquin County	$247,295	$320,075	$403,000	29%	26%
Stanislaus County	$245,165	$278,775	$360,000	14%	29%
Tulare County	$131,494	$159,005	$215,500	21%	36%
	$184,356	$234,304	$302,071	27%	29%

Source: Applied Development Economics, based on Dataquick

REGIONAL ECONOMIC TRENDS

The influx of people moving into the region in search of homes that are more affordable than homes in the San Francisco Bay Area affects more than the housing market. The affect of more people in the San Joaquin Valley region can also be seen in the changing economic profile of the region.

Economic development practitioners and planners have traditionally divided economies into two broad industrial categories—the economic base and local support industries. Economic base industries are the drivers of local and regional economies in that these industries draw income into a local economy by selling products outside of the local economy, much like the export industries of a national economy. Accrued earnings then circulate throughout the local area in the form of wages and salaries, investments, purchases of fixed assets, and goods and services, generating more jobs and wealth.

The economic base is typically comprised of industries within the manufacturing, minerals-resource extraction, and agricultural sectors. There are also the "local support industries" such as retail or service sectors, the progress of which is a function of the economic base and demographic changes, and more so the latter than the former. As population increases in a given area, demand for services–such as realtors, teachers, and healthcare–increases, as does

demand for basic retail items like groceries, gas for commuting, or clothing at the local apparel shops.

Agriculture is the economic base of the San Joaquin Valley region by virtue of the amount of goods this sector produces and exports throughout the nation and the globe. Fourteen percent of all workers in the region are employed by industries within agriculture, as Table 2 shows. However, in 1998 the proportion of workers in agriculture was 18 percent. In fact, over the five-year period between 1998 and 2003, employment in agriculture declined by three percent per year, or by 15 percent over five years.

Between 1998 and 2003, local support industries gained in prominence within the San Joaquin Valley region. Service-rendering industries employed the most workers as a proportion of total employment in the region. As Table 2 shows, excluding wholesale, retail and transportation, service-rendering industries comprise the largest employment sector in the region, at 647,100 or 53 percent of all jobs. With retail, transportation and wholesale, services accounts for slightly over 70 percent of all jobs. In 1998, service-rendering industries represented 50 percent of all jobs, and when including retail, wholesale and transportation in the mix, 67 percent.

Increases in employment in service-rendering industries are consistent with regional population growth. In the region, local support industries of construction, education and health, financial activities, and government increased annually by six percent, four percent, three percent and three percent respectively between 1998 and 2003.

TABLE 6
Employment Profile Of The San Joaquin Valley Region 1998 – 2003

MAJOR SECTORS	San Joaquin Valley Region Employment 1998	San Joaquin Valley Region Employment 2003	San Joaquin Valley Region Employment Distribution, 2003	Annual Percent Change 1998 to 2003	California Employment Distribution, 2003	Annual Percent Change 1998 to 2003
Agriculture	204,200	174,900	14%	-3%	3%	-2%
Resources, Mining and Construction	57,400	78,100	6%	6%	5%	5%
Manufacturing	114,300	110,300	9%	-1%	10%	-4%
Wholesale	34,400	39,000	3%	3%	4%	1%
Retail	121,400	133,200	11%	2%	11%	2%
Transportation/Warehousing/Utilities	37,600	45,700	4%	4%	3%	-1%
Information	15,000	14,200	1%	-1%	3%	-0.5%
Financial Activities	40,400	46,600	4%	3%	6%	3%
Professional and Business Services	88,000	95,100	8%	2%	14%	1%
Educational and Health Services	101,500	122,200	10%	4%	10%	3%
Leisure, Hospitality and Other Srvcs	112,500	116,400	9%	1%	13%	2%
Government	221,200	252,600	21%	3%	16%	2%
Total Employment	**1,147,900**	**1,228,300**	**100%**	**1%**	**100%**	**1%**

Source: Applied Development Economics, based on data from California Employment Development Department LMID

The emergence of local support industries in the San Joaquin Valley region mirrors and leads statewide trends, as Table 6 shows. In the region, construction, health-education, and government increased annually by six percent, four percent and three percent, whereas, statewide, these industries grew by five percent, three percent and two percent per year between 1998 and 2003. In short, while agriculture remains the leading edge of the economy, the San Joaquin Valley region's economy has become more diverse, with the growth occurring within population-driven local support industries rather than the export-focused economic base industries of manufacturing and agriculture.

5.2 DESCRIPTION OF AFFECTED INDUSTRIES

The analysis below examines trends of industries that will be likely affected by Draft Rules 9510 and 3180. According to the rule, developers of applicable development projects will have to pay a fee to reduce emissions related to the project that are not reduced on-site. The analysis below seeks to understand the possible impact of the fee on the economics of a development project, particularly with respect to project profitability and with respect to impacts on the final user,

which, in the case of housing, is the homebuyer or renter. The report takes into consideration existing fees that are already in place, meaning that the analysis is on the incremental impact of the new fee on top of existing fees.

The following section reviews residential and commercial-industrial trends in certain number of cities in the eight-county region. The report focuses on 27 cities in the region. Table 7 below organizes the 27 cities into different typologies. The consultant obtained information regarding existing fees on residential and commercial development from many of these jurisdictions. In addition, the report references a report issued by State of California's Housing and Community Development Department, called "Pay to Play." This report also tracks residential development fees for many cities in the Central Valley.

TABLE 7
Select Central Valley Cities By Type

Type	Cities
Large Urban	Fresno, Bakersfield
Bay Area Commuter Shed	Stockton, Modesto, Manteca, Lodi, Tracy
Medium	Visalia, Clovis, Merced, Turlock, Hanford, Porterville, Tulare
Small/Med Bedroom Community	Ceres, Sanger, Atwater, Selma, Linden
Small Rural/Farming	Mendota, Wasco, Firebaugh, Avenal, Taft, Orange Cove, Oakhurst, Shafter

Source: San Joaquin Valley Unified Air Pollution Control District

HOUSING TRENDS IN SELECT CITIES

Table 8 below identifies the population for the 27 cities that are the focus of this analysis. These cities consist of over 2 million residents, or 55 percent of all people in the eight-county San Joaquin Valley region. Between 1998 and 2003, population in these cities grew by three percent annually, which is consistent with annual population growth rates for the region as a whole (see Table 1).

TABLE 8
Population Trends of Select Cities in the San Joaquin Valley Region, 1993-2003

			------ Population ------				
	City	County	1993	1998	2003	1993-1998	1998-2003
Large Urban	Bakersfield	Kern	192,351	220,771	268,914	3%	4%
	Fresno	Fresno	385,914	409,070	450,614	1%	2%
			578,265	**629,841**	**719,528**	**2%**	**3%**
Bay Area Commuter Shed	Lodi	San Joaquin	52,936	55,844	60,317	1%	2%
	Manteca	San Joaquin	42,833	47,256	57,485	2%	4%
	Modesto	Stanislaus	176,241	182,929	203,498	1%	2%
	Stockton	San Joaquin	222,992	241,777	262,553	2%	2%
	Tracy	San Joaquin	39,913	47,687	69,987	4%	8%
			534,915	**575,493**	**653,840**	**1%**	**3%**
Medium	Clovis	Fresno	57,036	67,291	76,545	3%	3%
	Hanford	Kings	33,892	39,012	44,833	3%	3%
	Merced	Merced	59,270	61,705	68,155	1%	2%
	Porterville	Tulare	32,310	36,286	42,181	2%	3%
	Tulare	Tulare	37,342	40,848	46,538	2%	3%
	Turlock	Stanislaus	46,481	50,958	62,256	2%	4%
	Visalia	Tulare	84,725	93,856	99,460	2%	1%
			351,056	**389,956**	**439,968**	**2%**	**2%**
Small/Med Bedroom Community	Atwater	Merced	22,528	22,944	26,216	0.4%	3%
	Ceres	Stanislaus	29,331	32,289	36,449	2%	2%
	Linden	San Joaquin	1,090	1,068	1,046	-0.4%	-0.4%
	Mendota	Fresno	7,287	7,521	8,203	1%	2%
	Sanger	Fresno	17,927	18,557	19,993	0.7%	2%
	Selma	Fresno	16,462	17,937	21,003	2%	3%
			94,625	**100,316**	**112,910**	**1%**	**2%**
Small Rural/Farming	Avenal	Kings	11,459	12,178	15,428	1%	5%
	Firebaugh	Fresno	5,031	5,565	6,201	2%	2%
	Oakhurst	Madera	2,570	2,519	2,833	0%	2%
	Orange Cove	Fresno	5,709	7,095	8,782	4%	4%
	Shafter	Kern	10,771	11,182	13,443	0.8%	4%
	Taft	Kern	6,508	7,375	9,027	3%	4%
	Wasco	Kern	17,212	20,083	22,400	3%	2%
			59,260	**65,996**	**78,114**	**2%**	**3%**
San Joaquin Valley Air Basin			**1,618,121**	**1,761,601**	**2,004,360**	**2%**	**3%**

Source: Applied Development Economics, based on California Department of Finance and US Census

Table 9 identifies the number of single-family dwelling unit building permits issued by the 27 cities. As the table shows, the cities issued 17,641 single-family building permits in 2003, which represents almost two-thirds of all single-family building permits issued in the eight-county region as a whole. Table 10 identifies the number of multi-family dwelling units issued by the 27 cities. The amount of these permits represents almost 80 percent of all multi-family building permits issued in the region as a whole in 2003. For these reasons, the cities are representative of the larger region.

TABLE 9 Single-Family Dwelling Units Building Construction Permits, San Joaquin Valley Region 2000-2003

	2000		2001		2002		2003		2000 - 2003	
	Nos. of Permits	Avg. Value	Nos. of Permits	Avg. Value	Nos. of Permits	Avg. Value	Nos. of Permits	Avg. Value	Annual Change in Permits	Annual Change in Avg. Value
01 Large Urban	3,381	$132,038	4019	$132,089	4083	$137,988	5162	$152,257	15%	5%
02 Bay Area Commuter Shed	6,223	$161,757	4699	$172,165	6084	$172,996	6208	$176,852	-0.1%	3%
03 Medium	2,705	$125,488	3585	$141,040	4178	$153,806	5218	$156,243	24%	8%
04 Small/Med Bedroom Community	365	$105,702	542	$112,427	651	$118,285	801	$128,044	30%	7%
05 Small Rural/Farming	190	$83,956	262	$87,732	314	$85,667	252	$98,046	10%	5%
	12,864	$143,580	13107	$147,205	15310	$154,305	17641	$160,217	11%	4%

TABLE 10 Multi-Family Dwelling Units Building Construction Permits, San Joaquin Valley Region 2000-2003

	2000		2001		2002		2003		2000 - 2003	
	Nos. of Permits	Avg. Value	Nos. of Permits	Avg. Value	Nos. of Permits	Avg. Value	Nos. of Permits	Avg. Value	Annual Change in Permits	Annual Change in Avg. Value
01 Large Urban	177	$67,079	182	$73,639	454	$61,259	1150	$67,333	87%	0%
02 Bay Area Commuter Shed	84	$56,183	368	$59,905	514	$65,380	275	$69,075	48.5%	7%
03 Medium	206	$63,512	27	$64,680	155	$76,627	1119	$77,362	76%	7%
04 Small/Med Bedroom Community	51	$48,135	7	$38,617	71	0	162	$22,627	47%	-22%
05 Small Rural/Farming	83	$40,584	135	$36,997	4	$48,978	194	$56,369	33%	12%
	601	$59,067	719	$59,052	1,198	$61,344	2900	$68,137	69%	5%

Source: Applied Development Economics, based on Construction Industry Research Board

Table 11 identifies the average selling price of a new 3 to 4 bedroom home in the select cities. As expected, housing prices in the Bay Area Commuter Shed tend to be higher, in large part because of the close proximity to the San Francisco Bay Area housing market. Prices there are on average $402,644 per 3-4 bedroom unit, versus almost $250,000 for new units in Small/rural farming communities such as Avenal (Kings County) or Orange Cove (Fresno County).

TABLE 11 Average Selling Price of New Single-Family and Multi-Family Housing San Joaquin Valley Region 2005

	------ Single-Family Units ------				------ Multi-Family Units ------		
	Avg 3-4 BR SFU Values	Avg 3-4 BR SFU Size	Lot Size 3-4 BR SFU	Value Per SQFT	Average MFU Values	Average MFU Size	Value Per SQFT
01 Large Urban	$338,047	1,893	5,407	$179	$146,914	1,071	$137
02 Bay Area Commuter Shed	$402,664	2,112	6,034	$191	$180,603	1,071	$169
03 Medium	$296,428	1,779	5,083	$167	$137,357	1,071	$128
04 Small/Med Bedroom Community	$314,030	1,883	5,379	$167	$136,062	1,071	$127
05 Small Rural/Farming	$247,836	1,644	4,697	$151	$125,482	1,071	$117
	$323,966	1,862	5,320	$171	$145,283	1,071	$136

Source: Applied Development Economics, based on Realtor.com, Dataquick, and California Housing and Community Development, "Pay to Play"

Table 12 identifies existing fees on residential development in the 27 cities. As the table shows, fees amount to approximately five to six percent of values for single- and multi-family units. Data for fees comes from a variety of sources, including local jurisdictions and the California Department of Housing and Community Development (HCD), which issued a detailed report on residential developer fees of many cities throughout California. In using the HCD figures, this report adjusted the amount for general inflation and housing price inflation.

TABLE 12 Existing Fees On A Per Unit Basis

	Existing Fees On 3-4 BR SFU Unit	All Fees As Percent of Value	Existing Fees On MFU Unit	All Fees As Percent of Value
01 Large Urban	$17,796	5%	$6,149	4%
02 Bay Area Commuter Shed	$24,576	6%	$8,093	4%
03 Medium	$19,266	6%	$7,355	5%
04 Small/Med Bedroom Community	$21,162	7%	$11,883	9%
05 Small Rural/Farming	$12,689	5%	$5,969	5%
	$18,552	6%	$7,890	5%

Source: Applied Development Economics, based on Realtor.com, Dataquick, and California Housing and Community Development, "Pay to Play"

Tables 13 and 14 compare existing fees against other development costs, including the price of land, to estimate profit and a profit rate. The profit rates calculated below are similar to what would be found in corporate reports of national homebuilders, particularly Centex Homes, Kaufman and Broad, Lennar, and Pulte Homes, whose combined average profit rate is approximately eight percent.[2]

TABLE 13 Home Prices, Construction Costs, Fees and Profit: Single Family Housing

Community Types	Avg 3-4 BR SFU Values	Land Value Per 3-4 BR SFU Unit	All Fees Per 3-4 BR SFU Unit	Site Development Cost Per 3-4 BR Unit	Building Construction Costs Per 3-4 BR Unit	TOTAL COSTS	Profit per Unit	Profit as % Value
Large Urban	$338,047	$77,124	$21,759	$40,233	$167,600	**$306,716**	$31,330	9%
Bay Area Commuter Shed	$402,664	$93,015	$26,957	$46,410	$200,828	**$367,210**	$35,454	9%
Medium-Sized Cities	$296,428	$50,069	$19,266	$37,346	$159,484	**$266,165**	$30,263	10%
Small\Medium Bedroom Communities	$314,030	$74,468	$21,162	$34,570	$157,136	**$287,336**	$26,694	9%
Small Rural\Farming Communities	$247,836	$47,847	$12,689	$28,825	$131,024	**$220,386**	$27,450	11%
	$323,966	$68,505	$20,367	$38,373	$166,739	**$293,983**	$29,982	9%

[2] www.sec.gov see Form 10-K

TABLE 14 Home Prices, Construction Costs, Fees and Profit: Multi-Family Housing

Community Types	Avg MFU Values	Land Value Per MFU Unit	All Fees Per MFU Unit	Site Development Cost Per MFU Unit	Building Construction Costs Per MFU Unit	TOTAL COSTS	Profit per Unit	Profit as % Value
Large Urban	$146,914	$12,999	$6,149	$20,324	$81,295	**$120,767**	$26,147	18%
Bay Area Commuter Shed	$180,603	$14,794	$8,093	$23,116	$92,464	**$138,467**	$42,136	23%
Medium-Sized Cities	$137,357	$10,831	$7,355	$19,519	$80,260	**$117,964**	$19,393	14%
Small\Medium Bedroom Communities	$136,062	$12,868	$11,883	$19,435	$80,926	**$125,113**	$10,949	8%
Small Rural\Farming Communities	$125,482	$10,955	$5,969	$17,085	$77,658	**$111,666**	$13,815	11%
	$145,283	$12,489	$7,890	$20,140	$83,179	**$123,698**	$21,585	15%

Commercial-Industrial Trends

Table 15 below estimates the value, costs and profit associated with developing one acre of commercial, industrial and office development. Information for the table comes from a variety of sources, including Realtor.com and Loopnet.com for current price of new industrial and commercial projects in the Central Valley. When estimating cost of construction, we used "Commercial Square Foot Building Costs: 2004", by Deloitte Saylor Publication, as well as per square foot cost of construction estimates used by many cities when estimating the value of a project. In determining the amount of fees on a commercial-industrial development, we asked building officials in five cities to calculate the amount of fees that would be generated by a 10,000 square feet light industrial development on a 2.5-acre parcel and by a 10,000 square feet retail project on a similarly-sized piece of land. We converted the fees into a per acre amount. The per acre values in the table below were calculated after having calculated the development costs, based on a profit of ten percent, and these values were checked against what we found on Loopnet.com and Realtor.com. The 10 percent profit is based on a review of Deloitte-Saylor's "Commercial Square Foot Building Costs: 2004." It is also based on a review of corporate reports of Catellus (industrial developer) and ProLogis (warehouse

distribution developer). It should be noted that while data in the residential section above represents trends in 27 cities in the Central Valley, information in this section is for five cities that fit the different city types.

As Table 15 shows, existing fees on commercial and office developments are significantly higher than on industrial projects. This is so because of the traffic generated by retail and office is much higher than traffic generated by industrial users, which then requires a corresponding amount of reduction via fees.

TABLE 15 Commercial-Industrial Trends: San Joaquin Valley Region, 2005

		Avg. Value Per Acre (Land and Building)	Unimproved Land Value Per Acre	Fees Per Acre	Site Development Cost Per Acre	Building Construction Costs Per Acre	TOTAL Costs per Acre	Est. Profit Per Acre	Profit As percent of Value
Large Urban									
	Industrial	$1,594,742	$157,518	$14,726	$60,768	$1,202,256	$1,435,268	$159,474	10%
	Commercial	$1,910,201	$546,032	$35,306	$45,576	$1,092,267	$1,719,181	$191,020	10%
	Office	$2,828,107	$546,032	$35,306	$45,576	$1,918,382	$2,545,296	$282,811	10%
Bay Area Commuter Shed									
	Industrial	$1,679,815	$200,905	$47,904	$60,768	$1,202,256	$1,511,833	$167,981	10%
	Commercial	$2,011,879	$522,536	$150,312	$45,576	$1,092,267	$1,810,692	$201,188	10%
	Office	$2,929,785	$522,536	$150,312	$45,576	$1,918,382	$2,636,807	$292,979	10%
Medium-sized Cities									
	Industrial	$1,546,952	$100,000	$29,233	$60,768	$1,202,256	$1,392,257	$154,695	10%
	Commercial	$1,748,583	$303,178	$132,704	$45,576	$1,092,267	$1,573,724	$174,858	10%
	Office	$2,666,489	$303,178	$132,704	$45,576	$1,918,382	$2,399,840	$266,649	10%
Small/Medium Bedroom Community									
	Industrial	$1,631,301	$130,700	$74,447	$60,768	$1,202,256	$1,468,171	$163,130	10%
	Commercial	$1,668,338	$280,576	$83,085	$45,576	$1,092,267	$1,501,504	$166,834	10%
	Office	$2,586,244	$280,576	$83,085	$45,576	$1,918,382	$2,327,619	$258,624	10%
Small Rural\Farming Communities									
	Industrial	$1,877,846	$350,642	$76,395	$60,768	$1,202,256	$1,690,061	$187,785	10%
	Commercial	$1,653,475	$217,800	$136,292	$41,769	$1,092,267	$1,488,127	$165,347	10%
	Office	$2,567,106	$217,800	$132,444	$41,769	$1,918,382	$2,310,395	$256,711	10%

6. SOCIOECONOMIC IMPACTS

This section of the report compares the economic characteristics of affected industries against the possible Rule 9150 and 3180 air quality fees. The first part of this section discusses annual compliance cost. Section 6.2 discusses general business responses to compliance costs. Section 6.3 analyzes the socioeconomic impacts of Draft Rules 9510 and 3180.

6.1 NEW RULE 9510 AND 3180 FEE

Tables 16 through 18 identify the worst-case fees associated with New Rules 9510 and 3180. To reduce emissions of NOx and PM10, Draft Rule 9510 would apply to development projects that will seek to gain a final discretionary approval for projects that, upon full build-out will include any one of the following: 50 residential units, 2,000 square feet of commercial space, 25,000 square feet of industrial space, 20,000 square feet of medical office space, 39,000 square feet of general office space, 9,000 square feet of educational space, 10,000 square feet of government space, 20,000 square feet of recreational space, or 9,000 square feet of unidentified space. Certain transportation projects, transit projects, reconstruction projects that result from a natural disaster, and development projects whose primary source of emissions are subject to District Rule 2201 or 2010 would be exempt from this Draft Rule. Also, development projects that have a mitigated baseline below two tons per year for each pollutant would be exempt from the emission reduction requirements of the rule.

It is important to note that any fee identified below are the estimated maximum fee in the worst case scenario for a typical residential, commercial and or industrial development, with the understanding that the actual fee will vary with the particulars of any project. Any fee below is presented for the purposes of analyzing potential impacts given costs associated with reducing quantifiable emissions resulting from what constitutes typical applicable developments. The fee amounts

identified include all off-site emission reduction fees and all administrative fees.

In the worst case, the fee that a typical residential development will pay is estimated at $784 per unit starting in 2006, climb to $1,268 the following year, and above $1,772 in the years starting in 2008. The fee could be lower depending on the strategies that a developer employs to reduce emissions.

TABLE 16
Worst Case Estimate: Fee That Corresponds to A Typical Residential Development

Year	Per Unit
2006	$784.12
2007	$1,268.09
2008	$1,772

TABLE 17
Worst Case Estimate: Fee That Corresponds To The Typical Industrial Development

Use	Average Acres	Corresponding Fee Total
2006		
Heavy Industrial	300.0	$357,394.75
Light Industrial	75.0	$240,508.75
Warehouses	25.0	$83,645.68
Misc. Industrial (industrial park)	39.0	$143.797.05
2008		
Heavy Industrial	300.0	$747,626
Light Industrial	75.0	$518,237
Warehouses	25.0	$179,956
Misc. Industrial	39.0	$309,965

TABLE 18
Worst Case Estimate: Fee That Corresponds To a Typical Commercial Development

TYPE OF SHOPPING CENTERS	SIZE RANGE	TYPICAL SIZE (sq ft)	Corresponding Fee Total
	2006		
convenience shopping center	up to 30,000	20,000	$24,524.94
neighborhood shopping center	30,000 to 100,000	50,000	$61,599.54
community shopping center	100,000 to 450,000	150,000	$184,647.45
super community shopping center	200,000 to 300,000	250,000	$403,546.91
regional shopping center	300,000 to 700,000	450,000	$626,791.07
superregional shopping center	500,000 to 2 million	900,000	$1,253,582.15
	2008		
convenience shopping center	up to 30,000	20,000	$52,971.24
neighborhood shopping center	30,000 to 100,000	50,000	$131,689.99
community shopping center	100,000 to 450,000	150,000	$397,483.34
super community shopping center	200,000 to 300,000	250,000	$872,322.57
regional shopping center	300,000 to 700,000	450,000	$1,353,824.12
superregional shopping center	500,000 to 2 million	900,000	$2,708,116.82

6.2 BUSINESS RESPONSES TO PROPOSED FEES

Industries impacted by the proposed new rule may respond in a variety of ways when faced with new regulatory costs. These responses may range from simply absorbing the costs and accepting a lower rate of return, to shutting down the affected business operation altogether and, where practical, shift from lower-value to higher-value product. Affected sources may also seek to renew efforts to increase productivity and reduce costs elsewhere in their operation in order to recoup the regulatory costs and maintain profit levels. Based on the discussion during a focus group meeting held in July, 2005, industries impacted by the new rules will in all likelihood seek to pass the costs on to homebuyers and renters in the case of residential fees, to the extent that the market allows.

6.3 IMPACTS ON AFFECTED INDUSTRIES

This section of the report analyzes revenues and profits of affected industries against anticipated costs associated with

implementation of the draft rule. The analysis first examines impacts on builders of single-family homes. Then, it analyzes impacts on builders of multi-family units. In addition to impacts on homebuilders, the section analyzes how changes in price affect prospective homebuyers and renters. Finally, the section below examines impacts on non-residential developments, particularly commercial retail, industrial, and office projects.

Single-Family Dwelling Units

Tables 19 through 21 compare the fee that a typical residential development would pay in the year 2006, 2007 and 2008, or $784, $1,268 and $1,772, against estimated profits. In calculating the impacts of the fee, we have included the additional $400 administrative cost associated with Rule 3180. As Tables 19, 20 and 21 show, the fees do not significantly impact affected builders of single-family homes in a negative manner. The fee amounts to approximately three, four and six percent of estimated net profits, meaning that affected stakeholders would still garner between 94 sand 97 percent of their original profit. Moreover, the impact is below the ten percent significance threshold employed in this analysis.

TABLE 19 Impact Analysis of 2006 Air Quality Fee on Typical Single-Family Development: $784 per unit

Community Types	(1) Profit as % Value	(2) Air Quality Fee on New Res. Cons. @ $.421/sqft	(3) Impact on Profit	(4) Impact Significance	(5) Modified Profit as Percent of Value	(6) Initial Home Value @ 5.85%, 30 yrs and 20% down	(7) Home Value @ 5.85%, 30 yrs and 20% down: With Air Fee	(8) Initial Home Value @ 6.85%, 30 yrs and 20% down	(9) Home Value @ 6.85%, 30 yrs and 20% down: With Air Fee	(10) Affect of Fee	(11) Affect of 1% Change in Interest Rate
Large Urban	11.5%	$797	-2.1%	<significant	11.3%	$93,624	$93,846	$101,737	$101,979	$223	$8,113
Bay Area Commuter Shed	10.8%	$889	-2.1%	<significant	10.6%	$111,520	$111,768	$121,184	$121,454	$248	$9,664
Medium-Sized Cities	8.3%	$749	-3.1%	<significant	8.0%	$82,097	$82,307	$89,212	$89,439	$209	$7,114
Small\Medium Bedroom Communities	8.5%	$793	-3.0%	<significant	8.2%	$86,972	$87,194	$94,509	$94,750	$221	$7,537
Small Rural\Farming Communities	10.6%	$692	-2.7%	<significant	10.3%	$68,639	$68,833	$74,587	$74,798	$193	$5,948
All Select Cities Average	9.3%	$784	-2.6%	<significant	9.0%	$89,724	$89,943	$97,499	$97,737	$219	$7,775

TABLE 20 Impact Analysis of 2007 Air Quality Fee on Typical Single-Family Development: $1,268 per unit

Community Types	(1) Profit as % Value	(2) Air Quality Fee on New Res. Cons. @ $.681/sqft	(3) Profit as % Value	(4) Impact Significance	(5) Modified Profit as Percent of Value	(6) Initial Home Value @ 5.85%, 30 yrs and 20% down	(7) Home Value @ 5.85%, 30 yrs and 20% down: With Air Fee	(8) Initial Home Value @ 6.85%, 30 yrs and 20% down	(9) Home Value @ 6.85%, 30 yrs and 20% down: With Air Fee	(10) Affect of Fee	(11) Affect of 1% Change in Interest Rate
Large Urban	11.5%	$1,289	-3.3%	<significant	11.2%	$93,624	$93,983	$101,737	$102,127	$359	$8,113
Bay Area Commuter Shed	10.8%	$1,438	-3.3%	<significant	10.5%	$111,520	$111,920	$121,184	$121,619	$400	$9,664
Medium-Sized Cities	8.3%	$1,212	-5.0%	<significant	7.9%	$82,097	$82,435	$89,212	$89,578	$337	$7,114
Small\Medium Bedroom Communities	8.5%	$1,282	-4.8%	<significant	8.1%	$86,972	$87,329	$94,509	$94,897	$357	$7,537
Small Rural\Farming Communities	10.6%	$1,120	-4,3%	<significant	10.2%	$68,639	$68,951	$74,587	$74,925	$312	$5,948
All Select Cities Average	9.3%	$1,268	-4.3%	<significant	8.9%	$89,724	$90,007	$97,499	$97,883	$353	$7,775

TABLE 21 Impact Analysis of 2008 Air Quality Fee on Typical Single-Family Development: $1,772 per unit

Community Types	(1) Profit as % Value	(2) Air Quality Fee on New Res. Cons. @ $.952/sqft	(3) Profit as % Value	(4) Impact Significance	(5) Modified Profit as Percent of Value	(6) Initial Home Value @ 5.85%, 30 yrs and 20% down	(7) Home Value @ 5.85%, 30 yrs and 20% down: With Air Fee	(8) Initial Home Value @ 6.85%, 30 yrs and 20% down	(9) Home Value @ 6.85%, 30 yrs and 20% down: With Air Fee	(10) Affect of Fee	(11) Affect of 1% Change in Interest Rate
Large Urban	11.5%	1,802	-4.6	<significant	11.0%	$93,624	$94,125	$101,737	$102,281	$501	$8,113
Bay Area Commuter Shed	10.8%	2,011	-4.6	<significant	10.3%	$111,520	$112,079	$121,184	$121,791	$559	$9,664
Medium-Sized Cities	8.3%	1,694	-6.9	<significant	7.7%	$82,097	$82,568	$89,212	$89,723	$471	$7,114
Small\Medium Bedroom Communities	8.5%	1,792	-6.7	<significant	7.9%	$86,972	$87,471	$94,509	$95,050	$498	$7,537
Small Rural\Farming Communities	10.6%	1,565	-6.0	<significant	10.0%	$68,639	$69,074	$74,587	$75,060	$435	$5,948
All Select Cities Average	9.3%	1,773	-5.9	<significant	8.7%	$89,724	$90,217	$97,499	$98,035	$493	$7,775

TABLE 22 Median Home Sale Prices in Small to Medium Communities, 2003-2005

		July 2003	July 2004	July 2005	03-04 Change	04-05 Change	03-04 Per Chg	04-05 Per Chg
Medium	Merced (Merced)	$204,341	$226,741	$322,500	$22,400	$95,759	11%	42%
	Tulare (Tulare)	$125,379	$161,146	$204,000	$35,767	$42,854	29%	27%
	Turlock (Stanislaus)	$240,088	$284,330	$369,500	$44,242	$85,170	18%	30%
	Visalia (Tulare)	$154,723	$185,938	$270,000	$31,215	$84,062	20%	45%
Small/Medium Bedroom Community	Atwater (Merced)	$207,009	$232,422	$324,250	$25,413	$91,828	12%	40%
	Mendota (Fresno)		$77,438	$120,000		$42,563		55%
	Sanger (Fresno)	$161,659	$171,734	$276,500	$10,075	$104,766	6%	61%
	Selma (Fresno)	$123,245	$177,158	$249,250	$53,912	$72,092	44%	41%
Small Rural/Farming	Oakhurst (Madera)	$209,143	$273,742	$306,000	$64,599	$32,258	31%	12%
	Taft (Kern)	$82,697	$77,474	$110,000	-$5,223	$32,526	-6%	42%
	Wasco (Kern)	$93,101	$103,299	$132,000	$10,198	$28,701	11%	28%
		$160,139	$179,220	$244,000	$19,082	$64,780	12%	36%

Source: Applied Development Economics, based on Dataquick

A close review of Tables 19 through 21 reveals that the fees under consideration could potentially impacts different community types in different ways. For Medium-sized communities, Small\medium bedroom communities, and Small rural\farming communities, the impact of the possible fee on profits is slightly higher than impact to home builders operating in the large urban and Bay Area Commuter Shed markets. This is so because prices of new homes are higher in the latter markets. To understand the influence of the $784, 1,268 or $1,772 fee on home prices in the Medium-sized cities, Small\medium bedroom communities, and Small rural\farming communities, it is worthwhile to compare the fees against recent changes in home prices in cities in these three community types.

Table 22 above includes recent data from Dataquick. Among other things, it shows that between July 2003 and July 2004 and July 2004 and July 2005, median prices of homes increased by $19,000 and $65,000 in specific cities in Medium-sized cities, Small\medium bedroom communities, and Small rural\farming communities. Table 22 includes all homes sold, not just newly constructed three-to-four bedroom homes. While the fee could raise home prices by $784 to $1,772, it is apparent that larger market forces are the primary culprit behind the increase in housing prices in these three community types. The fee associated with Draft Rules 9510 and 3180 would amount to, at most, three percent of recent change in housing prices in these three community types (or $1,772 divided by $65,000).

Tables 19 through 21 above also include an analysis on how the $784, $1,268 or $1,772 fee would impact potential homebuyers. In other words, we assume that the homebuilder will pass this cost on to homebuyers to the fullest extent possible allowed by the market. As Table 11 above previously showed, the price of a new three-to-four bedroom home in the San Joaquin Valley region is approximately $324,000. In large urban areas of Bakersfield and Fresno, the average price of a new three-to-four bedroom home is $338,000, while in the Bay Area Commuter Shed, it is even higher at $402,700. Housing is more affordable in rural communities such as Avenal, where the

average price of a new home is $247,800 (see Table 11 above).

In Column Six of Tables 19 though 21, we estimate the minimum household income required to qualify for conventional financing for new three-to-four bedroom homes in the different market types. We assume that the potential homebuyer is a first-time homebuyer, meaning that there are no proceeds from the sale of a previous home to put towards the purchase of the new home. We assume that the potential homebuyer will have a downpayment equal to 20 percent of the market value of the unit. We also factor in a 5.85 interest rate, monthly bills, homeowners insurance, and property taxes when calculating the minimum household income needed to qualify for a new three-to-four bedroom home in the San Joaquin Valley.

To qualify for financing for a $324,000 home in the Central Valley, a prospective first-time home buying household would need to earn approximately $89,724 annually. Columns Seven and Ten to the tables above show the extent to which the different fees raise the minimum qualifying household income. As a result of the $784, $1,268 and $1,772 fees, minimum qualifying incomes for the region as a whole would rise, on average, by $219, $353, and $493 respectively. The $219 to $493 amount is less than one percent of the original income needed to qualify for a new three-to-four bedroom home in the Central Valley.

For comparative purposes, Tables 19 through 21 include Columns Eight and Eleven, which show what would happen if interest rates rose from 5.85 percent to 6.85 percent. If this occurred, the minimum qualifying income would rise from $89,724 to $97,499, or by $7,775. In other words, while the fees have the potential to increase the amount of income required to qualify for financing, larger market forces such as interest rates and market-driven price fluctuations play a significantly greater role in determining the income level needed to qualify for a new three-to-four bedroom home.

Multi-Family Dwelling Units

Tables 23 through 25 show the affects of the fees on construction of multi-family dwelling units. Small\medium

bedroom communities and Small rural\farming communities are affected negatively more so than the other communities, because the price of multi-family dwelling units elsewhere are higher than in these community types. Columns Six and Seven in each of the tables below estimate the minimum income required to purchase a multi-family unit such as a condominium or townhouse, and the extent to which the impact fee could raise this amount, in the event developers of multi-family units pass costs onto the consumers. The fee could raise the minimum income needed to qualify for financing for the purchase of a condominium or townhouse valued at $145,300 (see Table 14 above), from $40,237 to $40,455 ($784 fee), $40,589 ($1,268 fee) or at most $40,696 ($1,772 fee), which represent at most a one percent change. Tables 23 through 25 below show that the fee would only slightly affect rents, in the event units were rented out as opposed to sold.

TABLE 23 Impact Analysis of 2006 Fee on Typical Multi-Family Housing Development: $784 per unit

Community Types	(1) Profit as % Value	(2) Air Quality Fee on New Res. Cons. @ .732/sqft	(3) Impact on Profit	(4) Impact Significance	(5) Modified Profit as Percent of Value	(6) Initial Condo-Townhouse Value @ 5.85%, 30 yrs and 20% down	(7) Condo-Townhouse Value @ 5.85%, 30 yrs and 20% down: With Air Fee	(8) Minimum Rent without Air Fee	(9) Minimum Rent with Air Fee	(10) Qualifying Rental Household without Air Fee	(11) Qualifying Rental Household with Air Fee
Large Urban	17.7%	$788	-3.0%	<significant	17.3%	$40,689	$40,907	$1,150	$1,157	$41,453	$41,675
Bay Area Commuter Shed	23.3%	$788	-1.9%	<significant	22.9%	$50,019	$50,237	$1,414	$1,420	$50,958	$51,180
Medium	14.1%	$788	-4.1%	<significant	13.5%	$38,042	$38,260	$1,076	$1,082	$38,756	$38,978
Small/Med Bedroom Community	8.0%	$788	-7.2%	<significant	7.5%	$37,683	$37,901	$1,065	$1,072	$38,391	$38,613
Small Rural/Farming	11.0%	$788	-5.7%	<significant	10.4%	$34,753	$34,971	$983	$989	$35,405	$35,628
All Select Cities Average	14.9%	$788	-3.6%	<significant	14.3%	$40,237	$40,455	$1,138	$1,144	$40,992	$41,215

TABLE 24 Impact Analysis of 2007 Fee on Typical Multi-Family Housing Development: $1,268 per unit

Community Types	(1) Profit as % Value	(2) Air Quality Fee on New Res. Cons. @ $1.184/sqft	(3) Impact on Profit	(4) Impact Significance	(5) Modified Profit as Percent of Value	(6) Initial Condo-Townhouse Value @ 5.85%, 30 yrs and 20% down	(7) Condo-Townhouse Value @ 5.85%, 30 yrs and 20% down: With Air Fee	(8) Minimum Rent without Air Fee	(9) Minimum Rent with Air Fee	(10) Qualifying Rental Household without Air Fee	(11) Qualifying Rental Household with Air Fee
Large Urban	17.7%	$1,268	-4.9%	<significant	16.9%	$40,689	$41,041	$1,150	$1,160	$41,453	$41,812
Bay Area Commuter Shed	23.3%	$1,268	-3.0%	<significant	22.6%	$50,019	$50,371	$1,414	$1,424	$50,958	$51,317
Medium	14.1%	$1,268	-6.6%	<significant	13.2%	$38,042	$38,394	$1,076	$1,086	$38,756	$39,115
Small/Med Bedroom Community	8.0%	$1,268	-11.6%	significant	7.1%	$37,683	$38,035	$1,065	$1,075	$38,391	$38,749
Small Rural/Farming	11.0%	$1,268	-9.2%	<significant	10.0%	$34,753	$35,105	$983	$993	$35,405	$35,764
All Select Cities Average	14.9%	$1,268	-5.9%	<significant	14.0%	$40,237	$40,589	$1,138	$1,148	$40,992	$41,351

TABLE 25 Impact Analysis of 2008Fee on Typical Multi-Family Housing Development: $1,772 per unit

Community Types	(1) Profit as % Value	(2) Air Quality Fee on New Res. Cons. @ 1.655/sqft	(3) Impact on Profit	(4) Impact Significance	(5) Modified Profit as Percent of Value	(6) Initial Condo-Townhouse Value @ 5.85%, 30 yrs and 20% down	(7) Condo-Townhouse Value @ 5.*5%, 30 yrs and 20% down: With Air Fee	(8) Minimum Rent without Air Fee	(9) Minimum Rent with Air Fee	(10) Qualifying Rental Household without Air Fee	(11) Qualifying Rental Household with Air Fee
Large Urban	17.7%	$1,657	-6.3%	<significant	16.7%	$40,689	$41,148	$1,150	$1,150	$41,453	$41,920
Bay Area Commuter Shed	23.3%	$1,657	-3.9%	<significant	22.4%	$50,019	$50,478	$1,414	$1,427	$50,958	$51,426
Medium	14.1%	$1,657	-8.5%	<significant	12.9%	$38,042	$38,501	$1,076	$1,089	$38,756	$39,224
Small/Med Bedroom Community	8.0%	$1,657	-15.1%	significant	6.8%	$37,683	$38,142	$1,065	$1,078	$38,391	$38,858
Small Rural/Farming	11.0%	$1,657	-12.0%	significant	9.7%	$34,753	$35,212	$983	$996	$35,405	$35,873
All Select Cities Average	14.9%	$1,657	-7.7%	<significant	13.7%	$40,237	$40,696	$1,138	$1,151	$40,992	$41,460

Affordable Housing For Low-and Moderate Income Households

The discussion above focused on how fees would affect first-time homebuyers of single-family and multi-family units, as well as potential renters. In that context, housing affordability refers to the minimum income required to qualify for either a mortgage or the minimum income needed to pay a certain rent, with the understanding that the annual housing payment must not exceed one-third of annual household income. The federal agency called the Department of Housing and Urban Development (HUD) and private lenders use the one-third threshold as a way to gauge housing affordability. Anyone paying more than one-third of his or her income on housing is living in an unaffordable situation.

Affordable housing also refers to the extent to which low-income and moderate-income households can access housing at affordable rents. Every year, the federal government issues guidelines as to what constitutes low-income and moderate-income households, particularly for the purposes of qualifying households for federal housing programs such as Section 8 or the Low-Income Housing Tax Credit program. In turn, state and local agencies adopt these guidelines when carrying out their respective housing programs.

Table 26 below identifies the federal Housing and Urban Development's (HUD) 2005 income guideline for most of the Central Valley, and this guideline adjusts for number of people in a household. A single individual earning no more than $27,500 is a low-income individual, while a single individual make $27,502 would be a moderate-income person.

TABLE 26 HUD Income Guidelines, 2005

	Low Income		Moderate	
	Minimum	Maximum	Minimum	Maximum
1 person	$0	$27,500	$27,501	$41,250
2 persons	$0	$31,400	$31,401	$47,100
3 persons	$0	$35,350	$35,351	$53,025
4 persons	$0	$39,300	$39,301	$58,950
5 persons	$0	$42,400	$42,401	$63,600
6 persons	$0	$45,550	$45,551	$68,325
7 persons	$0	$48,700	$48,701	$73,050
8 or more persons	$0	$51,850	$51,851	$77,775

Source: Applied Development Economics, based on Department of Housing and Urban Development

More importantly for the purposes of this analysis, a single person making no more than $27,500 a year and who, at the same time, pays a rent that does not exceed one-third of her or his income lives in an affordable situation. Conversely, a single individual making no more than $27,500 who is paying a rent that exceeds one-third of his or her income is living in an unaffordable situation. Table 27 below calculates the rents that would be affordable to low- and moderate-income households. For the most part, rents that low-income households should pay are substantially below the rents that typical new multi-family units constructed in the region should command, even before the imposition of the air fee. For example, 2-person low-income households should pay no more than $785 on rent. As Tables 23 through 25 showed, rent for a newly constructed apartment unit should be $1,138, which is unaffordable to 2-person low-income households by standards established by HUD. On the other hand, a two-person moderate-income household that paid the $1,138 would be living in an affordable situation, since the maximum rent for purposes of calculating affordability is $1,178. A one-person moderate-income household should pay no more than $1,031 toward rent; thus the $1,138 rent calculated in Table 23 through 25 would constitute unaffordable housing.

TABLE 27 Affordable Monthly Rents

	Affordable Rent: Low Income		Affordable Rent: Moderate Income	
	Minimum	Maximum	Minimum	Maximum
1 person	$0	$688	$689	$1,031
2 persons	$0	$785	$786	$1,178
3 persons	$0	$884	$885	$1,326
4 persons	$0	$983	$984	$1,474
5 persons	$0	$1,060	$1,061	$1,590
6 persons	$0	$1,139	$1,140	$1,708
7 persons	$0	$1,218	$1,219	$1,826
8 or more persons	$0	$1,296	$1,297	$1,944

Without public subsidies to either the renting households or to housing developers, most low-income households in the Central Valley are priced out of newly constructed multifamily units, the rents for which need to be at a level to take into account price of land, development costs, developer fees, and an adequate level of profit, among other things. For the region as a whole, the market rate rent for a typical multi-family unit is calculated at $1,138, though rents are higher or lower depending on the community type, with Large Urban communities and the Bay Area Commuter Shed requiring higher rents (see Tables 23 through 25 Column Eight). Moderate-income households consisting of no more than three persons should be able to afford newly constructed multi-family units with monthly rents at or about $1,138, although the same cannot be said for moderate-income households consisting of four or more persons, who will need higher-priced living quarter with additional rooms.

There are a number of housing programs and policies that can assist low- and moderate-income households to live in market rate housing. Federal housing programs such as Section 8 provide the difference between the amount[3] that a low-income household can pay and the actual rent for an apartment in the private sector that is willing to accept Section 8. However, local governments receive only a limited number of Section 8 vouchers from the federal government,

[3] The amount that a Section 8 tenant contributes toward rent on an out of pocket basis must not exceed one-third of the tenant's annual income.

resulting in waiting lists consisting of many households waiting a relatively long time. Other public subsidies are aimed at encouraging the private sector to set-aside some, if not all, newly constructed housing as affordable to low- and moderate-income households. The federal Low-Income Housing Tax Credit (LIHTC) or, at the local level, the twenty percent housing redevelopment tax increment set-aside are just two revenue sources that can increase the feasibility of setting aside units at below market rents for low- and moderate-income households. Like the Section 8 program, there are some inherent limitations to the LIHTC and the tax increment set-aside programs. The financing via the federal LIHTC program is not readily available as it is accessed on a competitive basis. Not all cities have redevelopment agencies, and, of those with such agencies, it takes some time to generate the necessary amount of revenues (also known as tax increment) for a successful housing set-aside program.

Some cities have what are called "inclusionary housing" policies, meaning that in order to obtain approval for this or that housing project, the developer must guarantee that a certain portion (typically 15 percent) is reserved for low- and moderate-income households. Some cities sweeten their inclusionary policies with public financing, and some do not. It is argued that "inclusionary housing" policies without public subsidies result in overall higher rents or home prices, as developers required to set-aside housing at below-market levels for some units make up the difference by driving up the price of rest of the bulk of the units in a project.[4]

Non-Residential Development

Table 28 below analyzes the impacts of the Draft Rule 9510 and 3180 commercial and industrial fees on a per acre basis. In 2006, the fee on a typical retail and office development will amount to $15,286 and $7,914 per acre respectively. In the year 2008, fees on a per acre basis are expected to increase to $33,008 (retail) and $17,099 (office). As the table shows, in

4 Home Builders Association of Northern California - HBA News, (www.hbanc.org/ news2000/ JulAug2001/ JulAug01feat2.html) / "The Inclusionary Housing Debate - Who Really Pays for Affordable ..." (www.realtor.org/sg3.nsf/Pages/housingdebatepays?OpenDocument)

the year 2006 possible off-site emission reduction fees on new typically-sized commercial and office developments will not exceed the threshold of significance. The possible off-site fee amounts to an estimated 21 percent of profits in the year 2006. In 2008, the possible air off-site fees on new typically-sized commercial retail developments will exceed the threshold of significance by six to ten percent, depending on the community in which development occurs. The dollar amount in excess of the threshold in the year 2008 ranges from $12,889 to $16,324 per acre for commercial developments.

TABLE 28 Impact Analysis of 2006 and 2008 Fee on Typical Commercial-Industrial Project

	Avg. Value Per Acre	Est. Profit Per Acre	Profit as percent of Value	Est. Fees Per Acre		Est. Fees As % of Profit		Percent Above Significance Threshold		Dollar Amount Above Significance Threshold	
				2006	2008	2006	2008	2006	2008	2006	2008
Large Urban											
Industrial	$1,594,742	$159,474	10%	$1,880	$4,000	1%	3%	< sig.	< sig.		
Commercial	$1,910,201	$191,020	10%	$15,286	$33,008	8%	17%	< sig.	7%		$13,906
Office	$2,828,107	$282,811	10%	$7,914	$17,099	3%	6%	< sig.	< sig.		
Bay Area Commuter Shed											
Industrial	$1,679,815	$167,981	10%	$1,880	$4,000	1%	2%	< sig.	< sig.		
Commercial	$2,011,879	$201,188	10%	$15,286	$33,008	8%	16%	< sig.	6%		$12,889
Office	$2,929,785	$292,979	10%	$7,914	$17,099	3%	6%	< sig.	< sig.		
Medium-sized Cities											
Industrial	$1,546,952	$154,695	10%	$1,880	$4,000	1%	3%	< sig.	< sig.		
Commercial	$1,748,583	$174,858	10%	$15,286	$33,008	9%	19%	< sig.	9%		$15,522
Office	$2,666,489	$266,649	10%	$7,914	$17,099	3%	6%	< sig.	< sig.		
Small/Medium Bedroom Community											
Industrial	$1,631,301	$163,130	10%	$1,880	$4,000	1%	2%	< sig.	< sig.		
Commercial	$1,668,338	$166,834	10%	$15,286	$33,008	9%	20%	< sig.	10%		$16,324
Office	$2,586,244	$258,624	10%	$7,914	$17,099	3%	7%	< sig.	< sig.		
Small Rural\Farming Communities											
Industrial	$1,877,846	$187,785	10%	$1,880	$4,000	1%	2%	not sig.	not sig.		
Commercial	$1,653,475	$165,347	10%	$15,286	$33,008	9%	20%	not sig.	10%		
Office	$2,567,106	$256,711	10%	$7,914	$17,099	3%	7%	not sig.	not sig.		

It is not clear how the development community will adjust to the additional costs. Rather than absorb the costs, the developer (or a subsequent owner of an affected project site) might seek to pass costs onto commercial tenants in the form of rent increases. Table 29 translates the amount of the total fee into a per square foot rent for significantly impacted commercial uses. While the 2006 fee does not significantly impact developers of commercial uses, the 2008 fee significantly impacts these developers to the tune of $13,905. This amounts to almost one cent per square foot, which developers will pass onto future commercial tenant.

It is worth noting that the 2006 and 2008 fee, in effect, sets the bar slightly higher with respect to lease rates on all new commercial developments in the region. Comparable office developments that have been in place prior to the new fees could conceivably raise monthly rents by one cent. In addition, comparable retail sites in place prior to the new fees could conceivably raise rents by two cents in 2008.

TABLE 29
2006 and 2008 Fee on Typical Commercial-Industrial Project: Affect of Fee on Monthly Rent

	2006 Dollar Amount Significance Threshold	Fee as a Percent of Profit	Amount Above Significance Threshold	2006 Fee Per SqFt	2006 Per Sqft Fee As Monthly Rent Increase Over Typical Amortization Period (15 years)	2008 Dollar Amount Significance Threshold	Fee as a Percent of Profit	Amount Above Significance Threshold	2008 Fee Per SqFt	2008 Per Sqft Fee As Monthly Rent Increase Over Typical Amortization Period (15 years)
Large Urban										
Industrial	< sig.	1%	< sig.			< sig.	3%	< sig.		
Commercial	< sig.	8%	< sig.			$13,906	17%	7%	$1.28	$0.007
Office	< sig.	3%	< sig.			< sig.	6%	< sig.		
Bay Area Commuter Shed										
Industrial	< sig.	1%	< sig.			< sig.	2%	< sig.		
Commercial	< sig.	8%	< sig.			$12,889	16%	6%	$1.18	$0.007
Office	< sig.	3%	< sig.			< sig.	6%	< sig.		
Medium-sized Cities										
Industrial	< sig.	1%	< sig.			< sig.	3%	< sig.		
Commercial	< sig.	9%	< sig.			$15,522	19%	9%	$1.43	$0.008
Office	< sig.	3%	< sig.			< sig.	6%	< sig.		
Small/Medium Bedroom Community										
Industrial	< sig.	1%	< sig.			< sig.	2%	< sig.		
Commercial	< sig.	9%	< sig.			$16,324	20%	10%	$1.50	$0.008
Office	< sig.	3%	< sig.			< sig.	7%	< sig.		
Small Rural\Farming Communities										
Industrial	< sig.	1%	< sig.			< sig.	2%	< sig.		
Commercial	< sig.	9%	< sig.			$16,473	20%	10%	$1.51	$0.008
Office	< sig.	3%	< sig.			< sig.	7%	< sig.		

6.4 IMPACT ON SMALL BUSINESSES

In addition to analyzing the various impacts of the Proposed Indirect Source Rule (Draft Rules 9510 and 3180) that are discussed above, state legislation requires that the socioeconomic analysis assess whether small businesses are disproportionately affected by air quality rules. This section discusses how fees that are assessed on developers of residential and commercial projects are typically passed onto the consumer. Because of the additional costs associated with the proposed off-site emission reduction fee, prospective buyers must either increase their respective household incomes or produce a downpayment that is larger than the typical 20 percent. Thus, prospective homebuyers may have to delay purchasing goods and services as a result of the need to raise additional downpayment, resulting in impacts to local stores, particularly small businesses. This section discusses potential small business impacts resulting from Draft Rule 9510 and 3180.

Off-Site Emission Reduction Fees, Minimum Household Income, and the Downpayment

As the analysis above demonstrated, the 2006, 2007 and 2008 off-site emission reduction fee under consideration could slightly raise the minimum qualifying incomes for obtaining a conventional loan by, on average, $219, $353, and $493. In other words, to finance a new three to four bedroom home valued at $323,966 in the region, a first-time homeowner would need an income of at least $89,724.[5] The 2006 fee could raise this minimum by a slight $219, to $90,217

What if a lender is inflexible and will not extend a loan to household that is $219 to $493 short of the minimum income needed to qualify for financing? In cases such as this, the prospective homeowner will have to produce a larger downpayment or pay a higher interest rate. The table below identifies the amount of additional downpayment above the

[5] This minimum will change depending on the housing market, with households in Large Urban and Bay Area Commuter Shed communities needing more income than households in other part of the region.

amount generated by the typical 20 percent downpayment rate.

As Table 30 shows, in the region in general, a household with at least $89,724 in income can afford to purchase a newly constructed three to four bedroom unit priced at $323,966 so long it has a downpayment in the amount of $64,793, or 20 percent of the value of the home. In general, the 2006 through 2008 off-site emission reduction fees will require prospective homeowners to produce an additional $970 to $2,147 that will go towards the downpayment, in the event a lender is unwilling to exercise flexibility with respect to minimum income needed to qualify for a loan. The amount of additional downpayment differs between housing markets, with households in the Large Urban communities and the Bay Area Commuter Shed having to pay more.

Table 30 Potential Per Household Impact of Off-Site Emission Reduction Fees On Downpayment: Single Family Unit

	Initial Qualifying Household Income Prior to Fee: SFU	Initial Downpayment	Additional Downpayment (2006 fee: $784)	Additional Downpayment (2007 fee: $1,268)	Additional Downpayment (2008 fee: $1,772)
Large Urban	$93,624	$67,609	$1,008	$1,616	$2,231
Bay Area Commuter Shed	$111,520	$80,533	$1,188	$1,906	$2,629
Medium-Sized Cities	$82,097	$59,286	$894	$1,434	$1,980
Small\Medium Bedroom Communities	$86,972	$62,806	$947	$1,519	$2,097
Small Rural\Farming Communities	$68,639	$49,567	$761	$1,221	$1,686
All Select Cities Average	$89,724	$64,793	$970	$1,556	$2,147

Table 31 is similar to Table 30, although it focuses on the additional amount of downpayment required of prospective buyers of townhouses and condominiums. In general, the 2006 through 2008 off-site emission reduction fees will require prospective homeowners to produce an additional downpayment ranging from $932 to $1,948.

Table 31 Potential Per Household Impact of Off-Site Emission Reduction Fees On Downpayment: Multi-Family Unit

	Initial Qualifying Household Income Prior to Fee: MFU	Initial Downpayment	Additional Downpayment (2006 fee: $784)	Additional Downpayment (2007 fee: $1,268)	Additional Downpayment (2008 fee: $1,772)
Large Urban	$40,907	$29,383	$940	$1,529	$1,966
Bay Area Commuter Shed	$50,237	$36,121	$1,119	$1,818	$2,336
Medium-Sized Cities	$38,260	$27,471	$890	$1,447	$1,860
Small\Medium Bedroom Communities	$37,901	$27,212	$883	$1,435	$1,846
Small Rural\Farming Communities	$34,971	$25,096	$827	$1,344	$1,730
All Select Cities Average	$40,455	$29,057	$932	$1,515	$1,948

Prospective Homebuyers and Small Business Disproportionate Impact Analysis

Faced with the need to increase the amount of downpayment, a household will have to save by cutting back on expenditures, which could result in a decline in purchases of discretionary items from local retail and services establishments. Consumers may stop spending altogether, or shift their spending toward lower-priced goods and services. As we shall see, there is ample reason to believe that impacts associated with the decline in spending that corresponds to the 2006, 2007 and 2008 fees will be temporary. Before engaging in that discussion, below is a brief summary of what constitutes a small business for the purposes of analysis.

For purposes of qualifying small businesses for bid preferences on state contracts and other benefits, the State of California defines small businesses in the following manner[6]. To be eligible for small business certification, a business:

- Must be independently owned and operated;
- Cannot be dominant in its field of operation;
- Must have its principal office located in California

[6] State of California. Department of General Services. "California Small Business Certification" (http: www.pd.dgs.ca.gov/smbus/sbcert.htm)

- Must have its owners (or officers in the case of a corporation) domiciled in California; and
- Together with its affiliates, be either:
  - A business with 100 or fewer employees, and an average gross receipts of $10 million or less over the previous tax years, or
  - A manufacturer with 100 or fewer employees

Data is available as to the number of retail and services establishments in the eight-county region, and with this data we can estimate sales by stores with 100 or fewer employees. Table 32 below provides an estimate on the number of retail, accommodations-food services, and arts-entertainment-recreation establishments in the region, including estimates on their respective sales. Data comes from the County Business Patterns and the US Economics Census.

TABLE 32
Number of Commercial Establishments That Sell Goods and Select Discretionary Services: San Joaquin Valley Air Basin, 2002

	Total Establishments	Sales	Total Nos. Small Businesses	Sales By Small Businesses
Commercial				
Retail*	8,792	$21,790,159,759	8,601	$14,971,588,578
Accommodations and Food Services	627	$532,590,300	615	$365,953,623
Arts, Entertainment and Recreations	5,139	$3,048,315,000	5,108	$2,809,025,816
Gasoline stations	1,044	$2,909,895,000	1,044	$2,909,895,000
	15,602	$28,280,960,059	15,368	$21,056,463,017

* Apparel, groceries, home improvement, specialty retail, auto (except gas stations)

As Table 32 shows, in 2002 there were 15,602 stores that sold consumer goods and select number of discretionary services (such as entertainment venues and restaurants) and, of these, 15,368 employed less than 100 workers. These small stores generated approximately $21.1 billion in sales. Based on a review of ten-year's worth of data from Dun and Bradstreet, we estimate that retail generates after tax net profits that amount to 2.2 percent of sales, while both accommodations-

food services and arts-entertainment-recreations generate returns of 5.1 percent of sales. Combined, these industries generated an estimated $548.6 million in net profits.

Table 33 estimates the aggregate amount of additional dollars that households will have to set aside as a result of the 2006, 2007 and 2008 off-site emission reduction fees. The additional downpayment per household is multiplied against the number of new single-family units that are built in the region. According to the California Department of Finance, the eight-county region grew by an average of 15,000 single-family units per year between 1995 and 2005. This amount is somewhat consistent with data in Table 2, which shows that between 1993 and 2003, homebuilders took out building permits to construct 15,000 and 27,000 single-family homes in those years, for an annual average of 18,800 single-family homes. In calculating the aggregate amount of additional dollars that all households will need to set aside because of the air quality fees, we adjusted for the fact that not all are first-time homebuyers.[7]

TABLE 33
Aggregate Amount of Dollars All Households Will Need to Set Aside As A Result of Off-Site Emission Reduction Fees

		Additional Downpayment (2006 fee)	Additional Downpayment (2007 fee)	Additional Downpayment (2008 fee)
		$970	$1,556	$2,147
Scenario 1: Low	15,000 units	$5,820,000	$9,336,000	$12,882,000
Scenario 2: Mid	19,000 units	$7,760,000	$12,448,000	$17,176,000
Scenario 3: High	30,000 units	$11,640,000	$18,672,000	$25,764,000

If 15,000 newly constructed single-family units are sold in 2006, then the aggregate additional downpayment amount attributable to first-time homebuyers will equal $5.8 million, as Table 33 shows. If the number of units goes as high as 30,000, then the additional downpayment will equal $11.6 million. In the highest scenario in year 2008, the aggregate

[7] Scenario 1 2006 fee = (15,000 x 40% rate of rentership) x $970 = $5,820,000

amount of additional downpayment could equal $25.8 million. Thus, local retail and services establishments, particularly small businesses, could lose anywhere between $5.8 million to $25.8 million.

Table 34 below compares the amounts in Table 33 against the estimated net profits of retail and services establishments that employ less than 100 workers. As the table shows, the aggregate amount of additional dollars that households will need to set aside as a result of the off-site emission reduction fee amounts to one to five percent of net profits of small retail and select services establishments. These impacts are below the ten percent threshold of significance employed in this and other socioeconomic analyses for the purposes of evaluating proposed air quality rules.[8] It is worth noting that the analysis assumes that all of the dollars in Table 33 are spent at small business establishments, which, in reality, would not be the case. As a result, the table below overstates impacts on small businesses. Thus, the proposed rule does not disproportionately impact small businesses.

TABLE 34
Impact on Net Profits of Small Business Retail and Select Services Establishments

		Additional Downpayment (2006 fee)	Additional Downpayment (2007 fee)	Additional Downpayment (2008 fee)
		$970	**$1,556**	**$2,147**
Scenario 1: Low	15,000 units	1%	2%	2%
Scenario 2: Mid	19,000 units	1%	2%	3%
Scenario 3: High	30,000 units	2%	3%	5%

In all likelihood, the impacts identified in Table 34 are temporary. More than likely, the purchase of a new home will spur additional spending at retail and services establishments in excess of what is shown in Table 33. A

[8] It should be noted that the report does not include a corresponding analysis for multi-family units because the impacts on net profits were significantly less than one percent, in large part because the number of newly constructed and sold new townhouses in the eight-county region is so low, ranging from 50 to 100 units per year.

recent Pittsburgh Post-Gazette newspaper article on spending habits of new homeowners quotes the web-site of a marketing data company, which indicated that "New homeowners are golden opportunities for the enterprising businessman. These prospects are full of hope and ready to spend money."[9] Clickdata.com reports that many new homeowners purchase a new car within the first year at their new address.[10]

New homeowners are in a spending mood not simply because of the number of new credit cards and or other financing instruments that lenders eagerly extend to households that have demonstrated the financial wherewithal to purchase something as significant as a new home. For some, a new home represents a new phase in the life cycle of a household, including the addition of new family members such as children or a spouse. Others simply need bigger and better space. Inevitably, the new stage in the life cycle involves corresponding needs for goods and services from retail and service establishments, including small businesses.

Small Business Disproportionate Impact Analysis and Non-Residential Developments

The section directly above examined potential impacts on small businesses that sell retail items to consumers, particularly as the impacts relate to how households shift from funds from spending to saving. The section concludes that impacts will be temporary and more than compensated for when a household purchases a home. New Rule 9510 and 3180 could potentially impact small businesses in other ways as well. In particular, small business may not be able to absorb rent increases contemplated in Section 6.3 above.

This section evaluates the impacts of rent increases discussed in Section 6.3 on small businesses, particularly those that occupy commercial developments. As Section 6.3 demonstrated, new commercial development and are potentially significantly impacted by the proposed new rule.

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[9]Caitlin Cleary, "New homeowners welcomes with onslaught of new mail" (Pittsburgh Post-Gazette), 10-15-05

[10]www.clickdata.com/consumer/newequity.asp

For purposes of analysis, commercial development refers to retailers, restaurants, and entertainment and recreation venues.

The analysis below examines how all commercial small businesses are impacted, not just new ones. As Section 6.3 noted, comparable commercial developments that have been in place prior to the new fees could conceivably have their monthly rents raised by one cent per square foot starting in 2008.

If small businesses cannot pass costs onto consumers, and if they are unable to increase sales, then these businesses will have to absorb the additional rent, resulting in a decline in net profits. Lease rates for new and older but well-maintained commercial space is approximately $1.50 per square foot in the San Joaquin Valley region. Scant data on arts and entertainment space suggest these areas go for $1.25 per square foot a month.[11] Older buildings away from busy commercial corridors will in all likelihood command less than the $1.50 that new buildings in busy areas command. Thus, in using the $1.50 (retail and restaurants), $1.10 (gas stations) and $1.25 (arts and entertainment), we will overstate the cost in relation to net profits.

Table 35 shows that the 2008 fee will impact net profits of commercial small businesses by 1.5 percent. The bulk of impacts are borne by small businesses because these entities comprise almost 98 percent of commercial businesses and gas stations in the region.[12] However, the impacts are less than significant. Thus, small businesses are not disproportionately impacted by the rule.

[11] For the purposes of analysis, we assume that all commercial spaces pay these rents. Similar to the analysis directly above, commercial space refers to retail and select services such as restaurants and arts and entertainment venues. Select services exclude office space for industries such as accounting, medical, legal assistance, etc., because office uses are significantly impacted by the rule, as shows in Section 6.3.

[12] 15,368dividedby15,602 = 98%

TABLE 35
Small Business Impact of Additional Rent Resulting From Proposed Air Quality Mitigation Fee

Total Number of Retail and Select Services Establishments	15,602
Total Number of Small Business Retail and Select Services Establishments	14,324
Total Number of Small Business Retail and Select Services: Sales	$18,146,568,017
Total Number of Small Business Retail and Select Services: Net Profits	$485,376,512
Dollar Amount of One Cent Rent Increase (2008 fee: commercial)	$7,230,586
Impact of One Cent Rent Increase on Net Profit of commercial uses (2008 fee)	1.5%
Impact of One Cent Rent Increase on Net Profit of commercial uses (2008 fee)	Less than significant

APPENDIX A: ECONOMIC BENEFITS ASSOCIATED WITH DRAFT RULE 9510 AND 3180

The San Joaquin Valley Air Pollution Control District (SJVUAPCD) will use the Off-Site Emission Reduction Fees will be used to fund off-site emission reduction projects located within the San Joaquin Valley. Besides providing a health benefit to all Valley residents by reducing overall emissions in the air basin, the funding projects would benefit the Valley's economy. Potential projects for funding through this program are numerous and varied ranging from public works construction project such as road paving, procuring cleaner vehicles and equipment for businesses and local government agencies, to school bus upgrades. If all projects that go through the ISR program only reduce emissions through the off-site fee, the District may receive approximately $11 million dollars in 2006 and approximately $56 million in 2008 (allowing for fee deferrals) for use in the off-site emission reduction program. All of the money received as an off-site fee will be spent on projects within the region that make the air cleaner. The program would benefit the economy through three beneficial impacts:

LOCAL PURCHASES

Projects that require a purchase of equipment, materials, or services will result in money being re-circulated into the regional economy. The District cannot guarantee that the manufacturer or provider would be located within the Valley, but it can be expected that the majority will be Valley businesses that benefit. For example, road-paving projects would require asphalt and similar materials that would be provided by Valley businesses. A project that buys a cleaner engine would benefit the Valley engine dealer that sells the engine.

LOCAL PROJECTS

It has already been stated that the program would fund local projects. This means that the school, city, industry or private group that receives the funding for an emission reduction

project would benefit economically from the program. For example, a school district may receive a new, cleaner school bus. A manufacturing facility may receive assistance in procuring a new, cleaner piece of equipment or pollution control device not required by District rules and regulations. A city or county would receive money that makes a road-paving project possible or enables their fleets to operate cleaner new vehicles.

JOB CREATION

The off-site funding program made possible by the ISR Program may also lead to short-term and perhaps long-term job creation. For a financially strapped company or public agency, the funding allows for the purchase and installation or construction of the item (be it a school bus or road project). The installation and construction aspects of the program may benefit the local economy through short-term job creation. Since the ISR program will provide ongoing funding as development occurs over time, it is expected to continue to provide this type of benefit while the rule is in effect. In addition, more efficient equipment may reduce costs and may allow for later expansion that can create long-term jobs.

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APPENDIX G

Rule Consistency Analysis for Proposed Rule 9510 (Indirect Source Review) and Rule 3180 (Administrative Fees for Air Impact Assessment Applications)

November 17, 2005

RULE CONSISTENCY ANALYSIS FOR DRAFT RULE 9510 (INDIRECT SOURCE REVIEW) AND RULE 3180 (ADMINISTRATIVE FEES FOR AIR IMPACT ASSESSMENT APPLICATIONS)

I. REQUIREMENTS OF ANALYSIS

Pursuant to Section 40727.2 of the California Health and Safety Code, prior to adopting, amending, or repealing a rule or regulation, the District is required to perform a written analysis that identifies and compares the air pollution control elements of draft Rules 3180 and 9510 with the corresponding elements of existing or proposed District and United States Environmental Protection Agency (US EPA) rules, regulations, and guidelines that apply to the same source category.

For this analysis, the comparison with other District and US EPA rules and guidelines mainly cover the rules' purpose and applicability. Unlike other District prohibitory rules, Rule 9510 reduces emissions from area sources, not from distinct units considered as point sources that are amenable to analysis in terms of emissions limits, source testing, or recordkeeping requirements. This approach analyzes whether Rule 9510 is in conflict or is redundant with the purpose of other District or federal rules and guidelines already in place, and it also clarifies the applicability of other rules relevant to the development projects covered by Rule 9510.

II. RESULTS OF ANALYSIS

A. District Rules

Consistency with District Fee Rules

The stated purpose of Rule 3180 is to recover District cost for administering the requirements of Rule 9510 and the applicability of Rule 3180 is specific to developments projects subject to the requirements of Rule 9510. There are no other District fee rules with a similar purpose and applicability. The fee requirements stated in District Rule 3100 (California Environmental Quality Act Fee) is specifically for permitted sources subject to District rules and regulations and does not apply to development projects subject to Rule 9510. The process for Rule 9510 is different from the District Permit Program---development projects are required to submit an Air Impact Assessment application, which the District evaluates and approves, and assesses a off-site emission reduction fee if emissions are not reduced on-site. The exact role Rule 9510 in the CEQA process will be determined when the District revises its Guidelines for Assessing and Mitigating the Air Quality Impacts (GAMAQI) document.

Consistency with Rule 2010 (Permits Required)

The applicability of Rule 9510 concerns development projects that have not been traditionally under the purview of District Permit Requirements. In lieu of permitting requirements, development projects covered by Rule 9510 are required to submit an Air Impact Assessment application, which the District evaluates and approves, and assesses a off-site emission reduction fee if emissions are not reduced on-site. There may be some new developments that could be subject to Rule 2010 for particular piece(s) of equipment, however, Rule 9510 will only apply to the area and operational (motor vehicle) emissions, and will not apply to the stationary sources of emissions from a particular development. Therefore, Rule 9510 requirements will not duplicate the requirements in Rule 2010.

Consistency with Rule 9110 (General Conformity)

Proposed Rule 9510 is designed to reduce emissions of PM10 and PM10 precursors and fulfills commitments in the 2003 PM10 Plan, which has been SIP-approved. After Rule 9510 is adopted, it will be submitted for SIP approval. With the approval of Rule 9510 into the SIP, District Rule 9110 (General Conformity) is triggered. The District's Rule 9110 adopted by reference the federal conformity rule which states that (40 CFR 51.850): "No department, agency or instrumentality of the Federal Government shall engage in, support in any way or provide financial assistance for, license or permit, or approve any activity which does not conform to an applicable implementation plan." Therefore any development project subject to Rule 9110 (General Conformity) must make a determination of conformity with the District's SIP-approved rules and regulations, including Rule 9510. A federal actions that result in direct and indirect emissions equal to or exceeding 10 tons of ozone precursors (VOCs or NOx) in extreme nonattainment areas or 70 tons of PM10 in serious nonattainment areas is required to perform conformity determination (40 CFR 51.853).

There is no provision in Rule 9510 exempting federal actions in total. Federally sanctioned actions subject to Rule 9110 are exempt from the requirements of Rule 9510 if they fall under any of the following categories: (1) transportation projects that meet specific conditions, (2) transit projects, (3) reconstruction of any development project that is damaged or destroyed and is rebuilt to essentially the same use, or (4) a development project whose primary emission source are from stationary sources subject to Rule 2201 (New and Modified Stationary Source Review) and Rule 2010 (Permits Required). In the event that a project that is subject to Rule 9110 and 9510, any action or emissions used to demonstrate general conformity, can also be used as credit towards the required emission reductions, as long as they meet the requirements in Rule 9510. In the event that there is a shortfall in meeting the emission reduction requirements, the project will need to reduce the remaining emissions either with additional on-site measures or with off-site measures to be in full compliance with the requirements of Rule 9510.

Consistency with Regulation VIII Rules

The baseline emissions for construction, as used in this rule's emission reduction analysis, do not include emissions from fugitive dust, as required by Regulation VIII. However, any control technique performed for purposes of complying with Regulation VIII that reduces the project's construction equipment exhaust emissions will reduce the required reduction and the corresponding fee amount required under Rule 9510.

Consistency with Other District Rules

The baseline emissions attributed to sources subject to Rule 9510 include emissions from area sources that are assumed to be already in compliance with the requirements of other District rules (for residential sources) such as: Rule 4601 (Architectural Coatings), Rule 4901 (Wood Burning Fireplaces and Wood Burning Heaters), Rule 4902 (Residential Water Heaters), and Proposed Rule 4905 (Residential Central-Heating Furnaces). These rules don't require permits for affected units, and the enforcement mechanism is through certification by manufacturers or distributors prior to the sale and installation of these units within the San Joaquin Valley. Other District rules, which regulate non-residential sources and apply to and control specific stationary or area source emissions that are assumed to be already in compliance with other District rules requirements, are not included in the emissions baseline for Rule 9510. These include but may not be limited to: Rule 4351, 4305, 4306 (Boilers, Steam Generators, and Process Heaters), Rule 4622 (Gasoline Transfer into Motor Vehicle Fuel Tanks), Rule 4672 (Petroleum Solvent Dry Cleaning Operations), Rule 4692 (Commercial Charbroiling), and other process-specific District rules.

Consistency with Rule 1070

Rule 1070 provides the basis of authority for the District enforcement activities such as site inspections to verify compliance with mitigation measures.

B. US EPA RULES AND GUIDELINES

There are no specific federal guidelines applying to development projects as a source of NOx, PM10, or PM10 precursors in terms of New Source Performance Standards (NSPS), Control Technique Guidelines (CTG), Maximum Achievable Control Technology (MACT) and National Emission Standards for Hazardous Pollutants (NESHAP).

As previously mentioned, District's Rule 9110 adopted by reference the federal conformity rule which states that (40 CFR 51.850): "No department, agency or instrumentality of the Federal Government shall engage in, support in any way or provide financial assistance for, license or permit, or approve any activity which does not conform to an applicable implementation plan." Its relationship to Rule 9501 is discussed above.

BEFORE THE GOVERNING BOARD OF THE
SAN JOAQUIN VALLEY UNIFIED
AIR POLLUTION CONTROL DISTRICT

IN THE MATTER OF: PROPOSED RULE 9510 (Indirect Source Review) and PROPOSED RULE 3180 (Administrative Fees for Indirect Source Review)) **RESOLUTION NO.** 05-12-16

WHEREAS, the San Joaquin Valley Unified Air Pollution Control District (District) is a duly constituted unified district, as provided in California Health and Safety Code (CH&SC) Sections 41050 to 40161; and

WHEREAS, said District is authorized by CH&SC Section 40702 to make and enforce all necessary and proper orders, rules, and regulations to accomplish the purpose of Division 26 of the CH&SC; and

WHEREAS, Section 40716 of the CH&SC authorizes the District to adopt and implement regulations to reduce or mitigate emissions from indirect and areawide sources of pollution; and

WHEREAS, Section 42311(g) of the CH&SC authorizes districts to adopt a schedule of fees on areawide or indirect sources which are regulated, but for which permits are not issued, to cover the costs of District programs related to this source; and

WHEREAS, Section 40604 of the CH&SC (SB 709), directs the San Joaquin Valley Unified Air Pollution Control District to adopt a schedule of fees to be assessed on areawide or indirect sources of emission; and

WHEREAS, pursuant to Section 107 of the Clean Air Act and pursuant to Section 39608 of the CH&SC, the San Joaquin Valley Air Basin has been classified as a nonattainment area for the national and state health based ambient ozone and particulate matter 10 microns in size and smaller (PM10); and

WHEREAS, the District's 2004 Extreme Ozone Attainment Demonstration Plan as amended by the Governing Board on October 20, 2005 and the District's 2003 PM10 Plan as amended by the Governing Board on December 18, 2003 and May 19, 2005 commits the District to adopt and implement control measures to reach attainment; and

SJVUAPCD
)90 E. Gettysburg Ave.
Fresno, CA 93726
(559) 230-6000

WHEREAS, the Indirect Source Program is a control strategy contained in both the District's 2004 Extreme Ozone Attainment Demonstration Plan and 2003 PM10 Plan to be implemented through Rule 9510 (Indirect Source Review), and Rule 3180 (Administrative Fees for Indirect Source Review); and

WHEREAS, a public hearing for adopting Rule 9510 and Rule 3180 was duly noticed for public hearing on November 3, 2005 in accordance with CH&SC Sections 40725 and 40727.2.

NOW, THEREFORE, BE IT RESOLVED AS FOLLOWS:

1. The Governing Board hereby adopts Rule 9510 (Indirect Source Review), and Rule 3180 (Administrative Fees for Indirect Source Review) as set forth in the attached hereto and incorporated herein by this reference. Said rules shall become effective on December 15, 2005.

2. The Governing Board hereby finds, based on the evidence and information presented at the hearing upon which its decision is based, all notices required to be given by law have been duly given in accordance with CH&SC Section 40725, Section 42311(e) and Section 40727.2, and the Board has allowed public testimony in accordance with CH&SC Section 40726.

3. In connection with the proposed requirements of said rules, the Board makes the following findings as required by CH&SC Section 40727:

a. **NECESSITY.** The Governing Board finds, based on the staff report, public and industry testimony on the record for this rulemaking proceeding, that a need exists for the adoption of Rule 9510 (Indirect Source Review) and Rule 3180 (Administrative Fees for Indirect Source Review). Said action is necessary to meet the commitments of the submitted State Implementation Plan and requirements of the federal Clean Air Act.

b. **AUTHORITY.** The Governing Board finds that it has the legal authority to adopt said rules under the California Health & Safety Code Sections 40000 and 40001.

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c. **CLARITY.** The Governing Board finds that said rules are written or displayed so that their meaning can be easily understood by those persons or industries directly affected by them.

d. **CONSISTENCY.** The Governing Board finds that said rules are in harmony with, and not in conflict with or contradictory to, existing statutes, court decisions, or state or federal regulations.

e. **NONDUPLICATION.** The Governing Board finds that said rules do not impose the same requirements as any existing state or federal regulation.

f. **REFERENCE.** The Governing Board finds that said rulemakings implement Section 40604 of the California Health and Safety Code.

4. The Governing Board hereby finds that the requirements of the California Health and Safety Code Section 40728.5 have been satisfied to the greatest extent possible, and that the Governing Board has actively considered and made a good faith effort to minimize any adverse socioeconomic impacts associated with the proposed rulemakings.

5. The District has completed an Initial Study for said rules that indicate that the project will not result in any significant adverse effects to the environment, and a Proposed Negative Declaration has been prepared and properly noticed pursuant to the California Environmental Quality Act Guidelines (CEQA). The Governing Board of the District has duly considered said Initial Study and Proposed Negative Declaration. Accordingly, the Governing Board of the District (a) certifies that the Initial Study and Negative Declaration reflect the independent judgment of the District; (b) finds that the above-described project will have a de minimis impact on fish and wildlife resources; and (c) approves and adopts a Negative Declaration for said rulemaking effort pursuant to CEQA requirements. In accordance with the provisions of Section 15075 of the *California Environmental Quality Act Guidelines*, the Executive Director/Air Pollution Control Officer is hereby directed to cause to be

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filed a Notice Determination with the County Clerks of each of the counties in the District.

6. To the maximum extent feasible, the offsite emission reduction fees collected by the District shall be expended in a manner that provides for localized air quality benefits commensurate with the emissions from the new development projects.

7. The District shall explore support of legislative initiatives that provide appropriate litigation relief on air quality issues in conjunction with the California Environmental Quality Act (CEQA) process for new development projects that satisfy the District emission reduction requirements of Rule 9510 or more stringent standards set by local communities and land use agencies.

8. No later than December 31, 2010, and after holding at least one series of public workshops, the Air Pollution Control Officer shall submit Rules 9510 and 3180 to the District Governing Board for reevaluation and reauthorization.

9. The District shall prepare an annual report that will be available to the public regarding the expenditure of offsite fee funds, and shall include the following: total amount of offsite fees received; total monies spent; total monies remaining; any refunds distributed; a list of all projects funded; total emissions reductions realized, and; the overall cost-effectiveness factor for the projects funded.

10. The Executive Director/Air Pollution Control Officer is directed to file with all appropriate agencies certified copies of this resolution and the rules adopted herein and is directed to maintain a record of this rulemaking proceeding in accordance with CH&SC Section 40728.

11. The Air Pollution Control Officer is directed to transit Rule 9510 (Indirect Source Review) to the California Air Resources Board for incorporation in the State Implementation Plan.

12. The Governing Board authorizes the Air Pollution Control Officer to

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include in the submittal or subsequent documentation any technical corrections, clarifications, or additions that may be needed to secure EPA approval, provided such changes do not alter the substantive requirements of the approved rule.

THE FOREGOING was passed by the following vote of the Governing Board of the San Joaquin Valley Unified Air Pollution Control District this 15th day of December 2005, to wit:

AYES: Patrick, Anderson, Worthley, Barba, Nelson, Dominici, Sieglock, Prince, Maggard and Mayfield.

NOES: None.

ABSENT: Armentrout.

SAN JOAQUIN VALLEY UNIFIED
AIR POLLUTION CONTROL DISTRICT

By: _____
Thomas W. Mayfield, Chair
Governing Board

ATTEST:

By: _____
Sissy Smith

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING

Guidance for Assessing and Mitigating Air Quality Impacts

March

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See District Rule 2301 at *www.valleyair.org/rules/1ruleslist.htm*

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To[illegible]i[illegible]Air[illegible]Conta[illegible]inant[illegible]TAC[illegible] [illegible] contaminates (TACs) and are listed in the AB2588 Air Toxic "Hot Spots" and Assessment Act's "Emissions [illegible]" [illegible]

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[illegible] Introduction [illegible]

[illegible] *Figure 1 – San Joaquin Valley Air Pollution Control District Boundaries* [illegible] these counties represent approximately 16 percent of California's geographic area, [illegible]

Figure 1: San Joaquin Valley Air Pollution Control District Boundaries



The San Joaquin Valley's (SJV) topography and [illegible] $PM_{2.5}$ [illegible] $PM_{2.5}$ [illegible]

The region also houses the State's major arteries for [illegible] Another compounding factor is the region's [illegible]

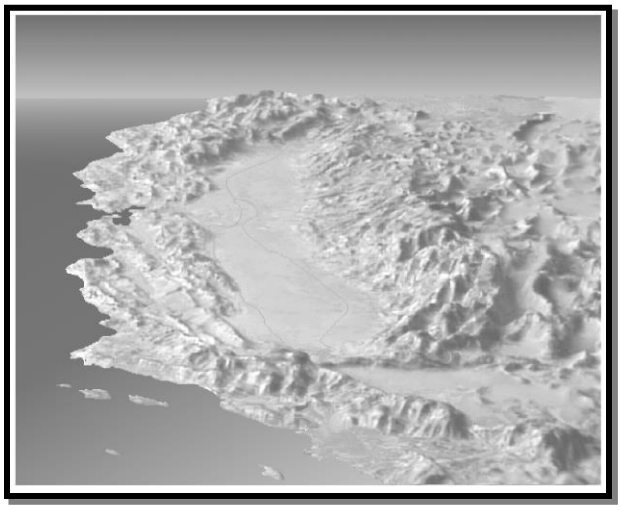
[illegible] sources account for about 80% of the Valley's total NOx emissions inventory. Since NOx [illegible]

[illegible]

[illegible] Topography

[illegible] *Aerial View of the San Joaquin Valley Air Basin* [illegible]

Figure 2: Aerial View of the San Joaquin Valley Air Basin



[illegible]

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[illegible] increase with temperature. However, extremely hot temperatures can “lift” or “break” the inversion layer. Typically, if the inversion layer doesn’t lift to allow the buildup of [illegible]

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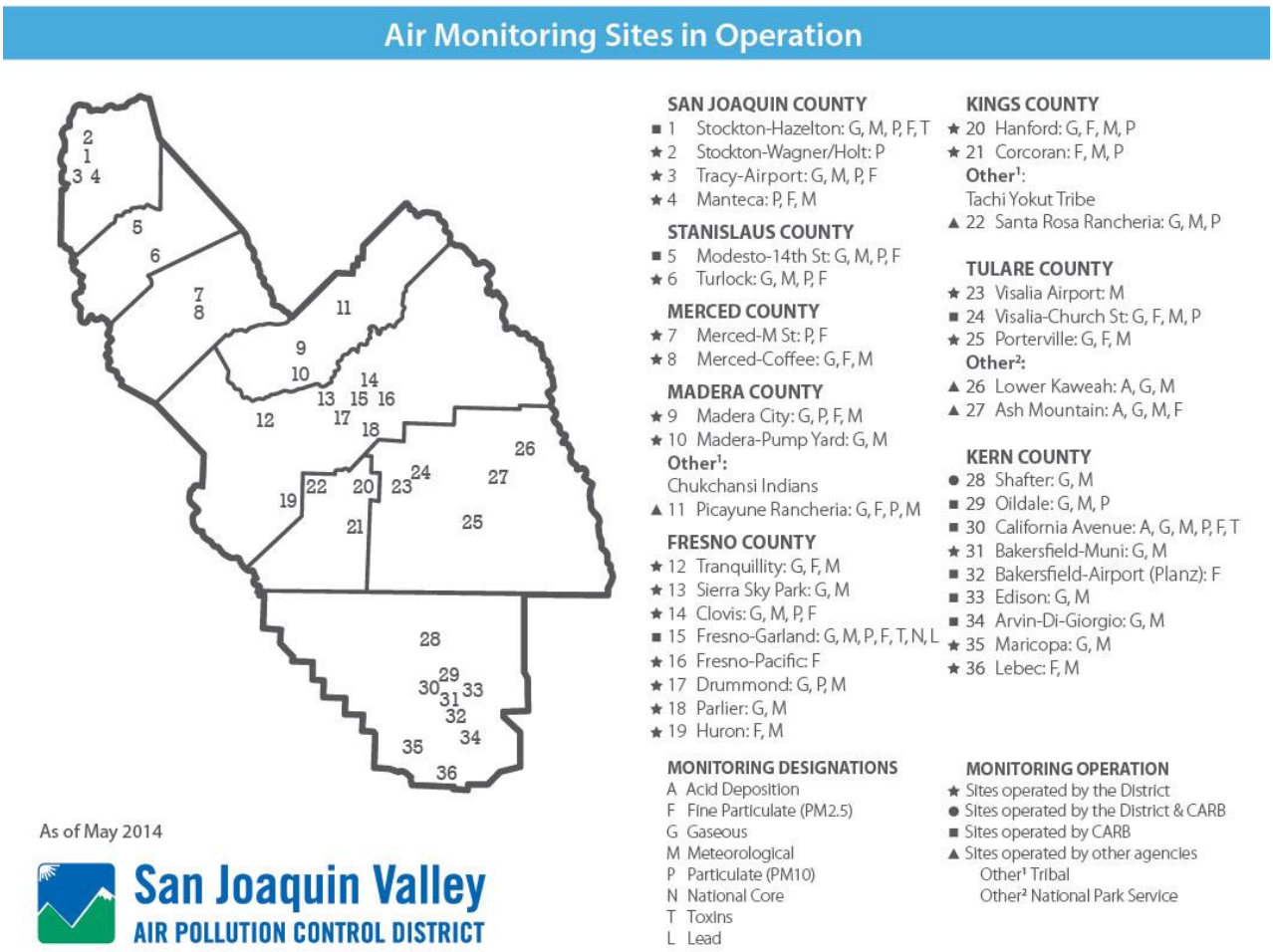
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The District periodically updates this map at
www.valleyair.org/aqinfo/MonitoringSites.htm

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Figure 3: District Ambient Air Quality Monitoring Sites



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The Emissions Inventory Data Guide is available on the District's website at http://www.valleyair.org/transportation/Guidelines_for_General_Plans.htm

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[illegible] Introd[illegible]tion[illegible]

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[illegible]

[illegible] standards as “nonattainment”. The Federal CAA further clas[illegible]

[illegible]

[illegible]

[illegible]

[illegible] Criteria [illegible]o[illegible]tant [illegible]

[illegible]

[illegible]

[illegible] Criteria Pollutants (NAAQS Pollutants) as “Affected Pollutants”.

[illegible] pollutants transported into the Valley. It is thought that the bulk of the Valley’s summer [illegible] $PM_{2.5}$ [illegible]

[illegible]

[illegible]

[illegible]

[illegible]

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[illegible]

[illegible]

[illegible] **Other Important** [illegible]

[illegible]

description of the pollutants' physical properties, health and other effects, sources, and [illegible]

[illegible]

[illegible] Attain[illegible]ent[illegible]tat[illegible]

[illegible]



Current Federal and State Ambient Air Quality Standards can be found on ARB's website at www.arb.ca.gov/research/aaqs/aaqs2.pdf or www.arb.ca.gov/desig/desig.htm

The District's attainment [illegible] The District's attainment status does change. *San Joaquin Valley Attainment Status*.

The District's current attainment status can be found on the District's website at www.valleyair.org/aqinfo/attainment.htm

Table 1: *San Joaquin Valley Attainment Status*

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More information about Federal and State air quality standards and the District's current attainment status can be found at
www.valleyair.org/aqinfo/attainment.htm

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[illegible] Introd[illegible]tion[illegible]

[illegible] infrared range, trapping heat in the earth's atmosphere. There are no "attainment" [illegible]

[illegible] Co[illegible] [illegible]on[illegible]reen[illegible]o[illegible]e[illegible]a[illegible]e[illegible]

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Additional information on GHG and global climate change can be found in the staff report titled "Addressing GHG Emissions Impacts under CEQA" at www.valleyair.org/Programs/CCAP/CCAP_idx.htm

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[illegible] Introduction [illegible]

[illegible] pollutants transported into the Valley. It is thought that the bulk of the Valley's summer [illegible]

[illegible] Point [illegible] Stationary [illegible]



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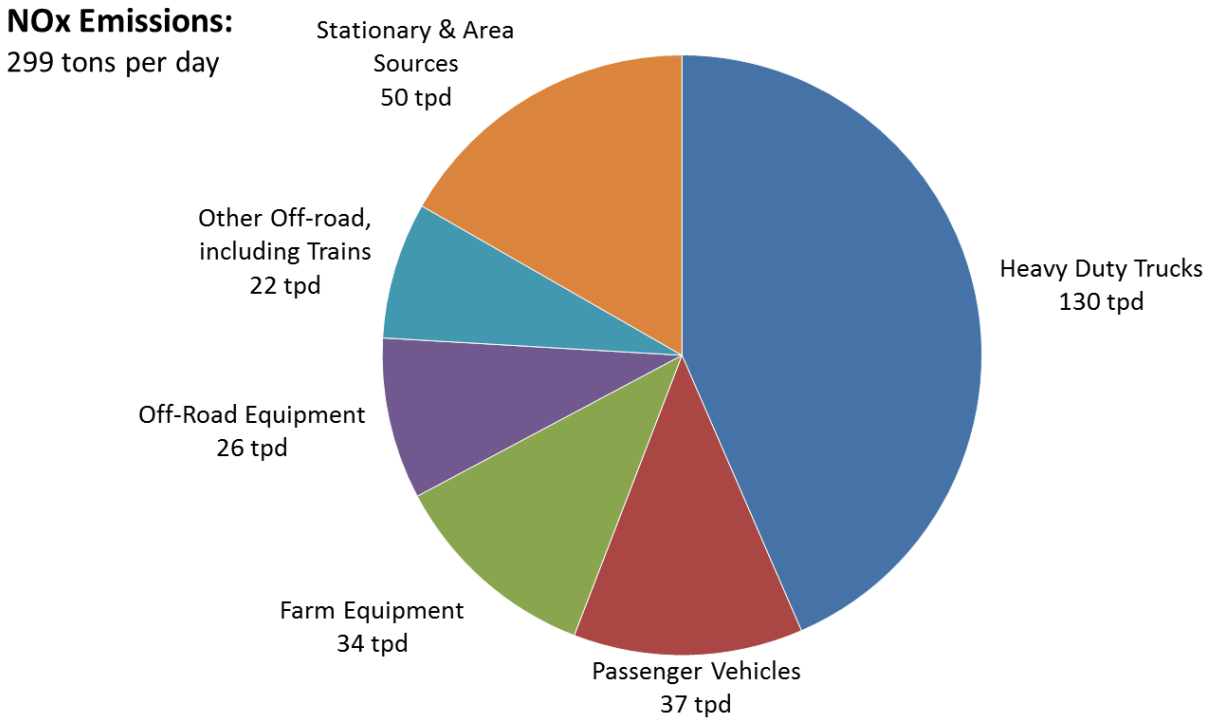
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Figure 4: Sources of NOx Emissions within the San Joaquin Valley Air Basin



[illegible]

[illegible] and [illegible]

[illegible]

The District's Air Quality Attainment Plans include measures to promote air quality [illegible]

[illegible] District's *Air Quality Guidelines for General Plans* [illegible] is the "constitution" for [illegible]

- [illegible]
- [illegible]
- [illegible]
- [illegible]
- [illegible]
- [illegible]

- [illegible]

[illegible]

- [illegible]
- [illegible]
- [illegible]

The Air Quality Guidelines for General Plans is available on the District's website at www.valleyair.org/transportation/Guidelines_for_General_Plans.htm

[illegible] **A[illegible]e[illegible]b[illegible]Bi[illegible]Re[illegible]e[illegible]AB[illegible]**

[illegible] revisions of a jurisdiction's housing element. As required in §65302.1.b, cities and [illegible]

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These documents are available on the District's website at www.valleyair.org/transportation/Guidelines_for_General_Plans.htm

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Technical resources for District Rule 9510, including a list of approved on-site emission reduction measures and tools for calculating project specific emissions are available at www.valleyair.org/ISR/ISRHome.htm

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The CAPCOA Guidance document, Health Risk Assessment for Proposed Land use Projects, can be found at http://www.capcoa.org/documents and the ARB Handbook, Air Quality and Land Use Handbook: A Community Health Perspective, can be found at www.arb.ca.gov/ch/landuse.htm



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"Project" under CEQA

The CEQA Statutes (PRC §21065) define "project" as the whole of an activity, which may [illegible]

- [illegible]
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[illegible] CEQA "*Steps*" [illegible]

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The model is available at www.caleemod.com [illegible] http://www.valleyair.org/transportation/air_quality_models.htm Assistance with operating the model is available by contacting the District at (559) 230-6000, or hramodeler@valleyair.org

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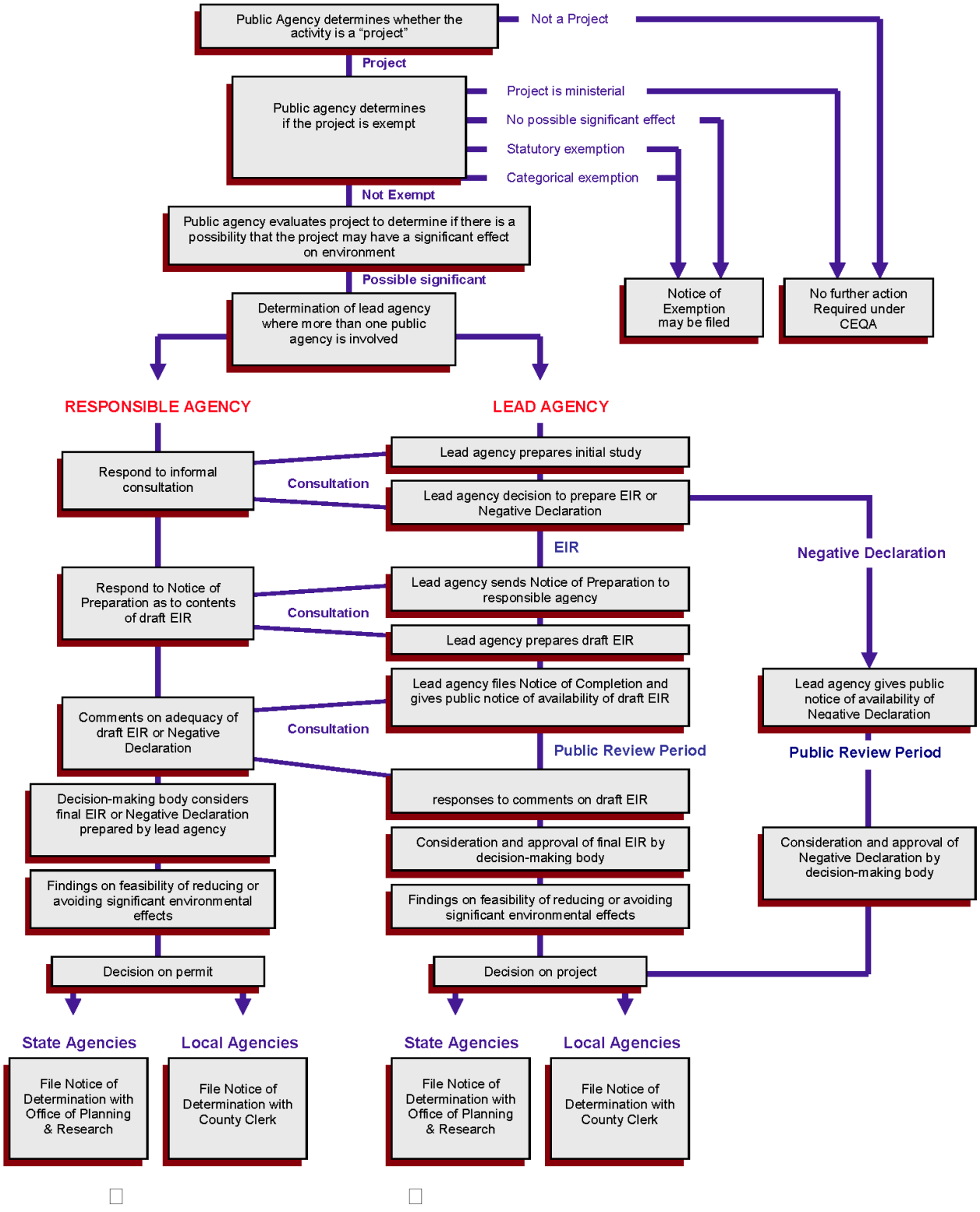
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Figure 5: CEQA Process Flowchart



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- Conformance with ARB's *Recommendations on Siting New Sensitive Land Uses*
- A copy of the Lead Agency's Initial Study, if prepared
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[illegible]

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[illegible] [illegible] [illegible] [

[illegible] **Conflict with or Obstruct Implementation of the Applicable Air Quality Plan**

[illegible] District [illegible] [illegible] [illegible]

[illegible] [illegible] [illegible] [

[illegible]

The intensity of an odor source's operations and its proximity to sensitive receptors [illegible]

[illegible]

[illegible] Notice of Intent to Adopt a Negative Declaration or Mitigated Negative Declaration [illegible]

[illegible]

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[illegible] Consideration and Discussion of Mitigation Measures

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Specific information for assessing significance, including screening tools and modeling guidance is available at the District's website: www.valleyair.org/ceqa

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Information on District Rule 9510 can be found on the District's website:
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Detailed information regarding the eTrip rule can be found at
www.valleyair.org/Programs/Rule9410TripReduction/eTRIP_main.htm

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[illegible] **Basin or Air Quality Trend Toward Ozone Attainment**

[illegible] District [illegible] and [illegible] [illegible] District Rules [illegible] [illegible] [illegible] Rules [illegible] [illegible] [illegible]

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The most current SPAL is available at
www.valleyair.org/ceqa

[illegible] **Construction [illegible] ission[illegible]**

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[illegible] Operational Provision – Permitted Equipment and Activities

The District's permitting process [illegible] ensures that [illegible] new or modified sources of air contaminants are properly controlled such that emissions are reduced or mitigated to below the District's thresholds of significance. District [illegible] Rules and [illegible] Regulation [illegible] require that [illegible] and modified [illegible] sources of air contaminants [illegible] obtain an Authority to Construct [illegible] and Permit to Operate [illegible] before [illegible] operation. [illegible] Permits to Operate [illegible] are valid for [illegible] and must be renewed [illegible] to ensure [illegible] continued compliance with [illegible] applicable rules and regulations. [illegible] Permits to Operate may contain [illegible] conditions [illegible] to limit emissions [illegible] below [illegible] thresholds [illegible] and to ensure [illegible] compliance with [illegible] applicable rules and regulations. [illegible] Permits to Operate [illegible] are issued [illegible] after [illegible] the District [illegible] has verified [illegible] that [illegible] the equipment [illegible] is constructed [illegible] and operated [illegible] according to the [illegible] specifications [illegible] submitted [illegible] with the [illegible] Authority to Construct application. [illegible] Permits to Operate [illegible] may be [illegible] revoked [illegible] if the [illegible] District determines [illegible] that [illegible] the equipment [illegible] is not being [illegible] operated [illegible] in compliance [illegible] with [illegible] applicable rules [illegible] and regulations.

[illegible] Authority to Construct [illegible] and Permit to Operate [illegible] for [illegible] permitted [illegible] equipment [illegible] and activities [illegible] are considered [illegible] a project [illegible] under [illegible] the California Environmental Quality Act (CEQA) [illegible] and [illegible] the District [illegible] is the [illegible] lead agency. [illegible] The District's environmental document (Negative Declaration, Mitigated Negative Declaration, [illegible] Environmental Impact Report) [illegible] must [illegible] address [illegible] the [illegible] impacts [illegible] from [illegible] the [illegible] construction [illegible] and [illegible] operation [illegible] of [illegible] the [illegible] permitted [illegible] equipment [illegible] and activities. [illegible] Mitigation measures [illegible] must be [illegible] identified [illegible] for [illegible] any [illegible] significant [illegible] impacts [illegible] and [illegible] must be [illegible] implemented [illegible] as a [illegible] condition [illegible] of [illegible] approval [illegible] for [illegible] the [illegible] Authority to Construct [illegible] and Permit to Operate.

[illegible] Operational Provision – Non-permitted Equipment and Activities

[illegible] Sources Exempt [illegible]

[illegible] Equipment [illegible] and [illegible] activities [illegible] that [illegible] emit [illegible] air [illegible] contaminants [illegible] but [illegible] are [illegible] exempt [illegible] from [illegible] District [illegible] permit [illegible] requirements because they fall below the District's emission thresholds for requiring permits is [illegible] required [illegible] to [illegible] comply [illegible] with [illegible] applicable [illegible] rules [illegible] and [illegible] regulations [illegible] and [illegible] may be [illegible] subject [illegible] to [illegible] inspection [illegible] by [illegible] District [illegible] staff.

Mobile Sources

[illegible] Many [illegible] of the [illegible] construction [illegible] equipment [illegible] and [illegible] vehicles [illegible] that [illegible] will be [illegible] used [illegible] during [illegible] the [illegible] construction [illegible] phase [illegible] of [illegible] the [illegible] project [illegible] are [illegible] mobile [illegible] sources [illegible] that [illegible] are [illegible] not [illegible] subject [illegible] to [illegible] District [illegible] permit [illegible] requirements. [illegible] Mobile [illegible] sources [illegible] are [illegible] regulated [illegible] by [illegible] the [illegible] California [illegible] Air [illegible] Resources [illegible] Board [illegible] (CARB) [illegible] and [illegible] the [illegible] United [illegible] States [illegible] Environmental [illegible] Protection [illegible] Agency [illegible] (EPA). [illegible] Mobile [illegible] sources [illegible] are [illegible] required [illegible] to [illegible] comply [illegible] with [illegible] applicable [illegible] CARB [illegible] and [illegible] EPA [illegible] regulations [illegible] and [illegible] may [illegible] be [illegible] subject [illegible] to [illegible] inspection [illegible] by [illegible] CARB [illegible] staff.

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The most current ambient air quality standards are available online at
www.arb.ca.gov/research/aaqs/aaqs2.pdf □r
www.arb.ca.gov/research/aaqs/aaqs.htm

The most current SILs are listed in Attachment B of District Policy APR 1925 at
http://www.valleyair.org/policies_per/Policies/APR-1925.pdf

Table 3: Ambient Air Quality Standards

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1. California standards for ozone, carbon monoxide (except 8-hour Lake Tahoe), sulfur dioxide (1 and 24 hour), nitrogen dioxide, and particulate matter (PM10, PM2.5, and visibility reducing particles), are values that are not to be exceeded. All others are not to be equaled or

exceeded. California ambient air quality standards are listed in the Table of Standards in Section 70200 of Title 17 of the California Code of Regulations.

2. National standards (other than ozone, particulate matter, and those based on annual arithmetic mean) are not to be exceeded more than once a year. The ozone standard is attained when the fourth highest 8-hour concentration measured at each site in a year, averaged over three years, is equal to or less than the standard. For PM10, the 24 hour standard is attained when the expected number of days per calendar year with a 24-hour average concentration above 150 µg/m3 is equal to or less than one. For PM2.5, the 24 hour standard is attained when 98 percent of the daily concentrations, averaged over three years, are equal to or less than the standard. Contact the U.S. EPA for further clarification and current national policies.

3. Concentration expressed first in units in which it was promulgated. Equivalent units given in parentheses are based upon a reference temperature of 25°C and a reference pressure of 760 torr. Most measurements of air quality are to be corrected to a reference temperature of 25°C and a reference pressure of 760 torr; ppm in this table refers to ppm by volume, or micromoles of pollutant per mole of gas.

4. Any equivalent measurement method which can be shown to the satisfaction of the ARB to give equivalent results at or near the level of the air quality standard may be used.

5. National Primary Standards: The levels of air quality necessary, with an adequate margin of safety to protect the public health.

6. National Secondary Standards: The levels of air quality necessary to protect the public welfare from any known or anticipated adverse effects of a pollutant.

7. Reference method as described by the U.S. EPA. An “equivalent method” of measurement may be used but must have a “consistent relationship to the reference method” and must be approved by the U.S. EPA.

8. To attain the 1-hour national standard, the 3-year average of the annual 98th percentile of the 1-hour daily maximum concentrations at each site must not exceed 100 ppb. Note that the national standards are in units of parts per billion (ppb). California standards are in units of parts per million (ppm). To directly compare the national standards to the California standards the units can be converted from ppb to ppm. In this case, the national standards of 53 ppb and 100 ppb are identical to 0.053 ppm and 0.100 ppm, respectively.

9. On June 2, 2010, a new 1-hour SO2 standard was established and the existing 24-hour and annual primary standards were revoked. To attain the 1-hour national standard, the 3-year average of the annual 99th percentile of the 1-hour daily maximum concentrations at each site must not exceed 75 ppb. The 1971 SO2 national standards (24-hour and annual) remain in effect until one year after an area is designated for the 2010 standard, except that in areas designated nonattainment for the 1971 standards, the 1971 standards remain in effect until implementation plans to attain or maintain the 2010 standards are approved.

Note that the 1-hour national standard is in units of parts per billion (ppb). California standards are in units of parts per million (ppm). To directly compare the 1-hour national standard to the California standard the units can be converted to ppm. In this case, the national standard of 75 ppb is identical to 0.075 ppm.

10. The ARB has identified lead and vinyl chloride as 'toxic air contaminants' with no threshold level of exposure for adverse health effects determined. These actions allow for the implementation of control measures at levels below the ambient concentrations specified for these pollutants.

11. The national standard for lead was revised on October 15, 2008 to a rolling 3-month average. The 1978 lead standard (1.5 µg/m3 as a quarterly average) remains in effect until one year after an area is designated for the 2008 standard, except that in areas designated nonattainment for the 1978 standard, the 1978 standard remains in effect until implementation plans to attain or maintain the 2008 standard are approved.

12. In 1989, the ARB converted both the general statewide 10-mile visibility standard and the Lake Tahoe 30-mile visibility standard to instrumental equivalents, which are "extinction of 0.23 per kilometer" and "extinction of 0.07 per kilometer" for the statewide and Lake Tahoe Air Basin standards, respectively.

[illegible] Basis for Thresholds [illegible]

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Table 4: AAQA Analysis Screening Levels For Development Project

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Project Construction Emissions

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More information on ambient air quality and associated modeling can be found online at http://www.valleyair.org/busind/pto/Tox_Resources/AirQualityMonitoring.htm

Project Operational Emissions

[illegible]

[illegible]

[illegible]

More information on ambient air quality and associated modeling can be found online at http://www.valleyair.org/busind/pto/Tox_Resources/AirQualityMonitoring.htm

[illegible] **Ambient Air Quality and Carbon Monoxide [illegible]**

[illegible] either the state or national CO standard recorded at any of the SJVAB's moni[illegible]

[illegible] "hotspots", while concentrations at the close[illegible]

[illegible]

[illegible]

- [illegible]

- [illegible]

[illegible]

[illegible]

Even if the two above criteria are met, the project's influence on any given [illegible]

[illegible]

[illegible] Thresholds of Significance – Toxic Air Contaminants

The District's [illegible] for [illegible] are [illegible] in Table 5. [illegible] [illegible] [illegible] [illegible] [illegible] [illegible] [illegible] [illegible] [illegible]

Table 5: *Air Quality Thresholds of Significance – Toxic Air Contaminants*

[illegible]	Maximum [illegible] Exceeded [illegible]
[illegible]	**Acute** [illegible] Hazard Index exceeds 1.0 for the Maximally Exposed Individual
	Chronic [illegible] Hazard Index exceeds 1.0 for the Maximally Exposed Individual

[illegible] [illegible] [illegible] [illegible] [illegible] [illegible] [illegible] [illegible] [

[illegible]

[illegible]

[illegible]

[illegible] Basis for Risk Threshold [illegible]

The District's risk management objectives for permitting and [illegible]

- M[illegible]
- [illegible]
- [illegible]

[illegible] The District's risk [illegible] The District's comprehensive [illegible] significantly reduced the public's exposure to air toxics [illegible]

[illegible] District's threshold of [illegible] known activities (risk of occurrence in an individual's lifetime):

[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]

[illegible] the District's [illegible]

[illegible]5[illegible] [illegible] [illegible]

[illegible] [illegible] [illegible] [

[illegible] Thresholds of Significance – Odor[illegible]

[illegible] [illegible] [illegible] [

Sources [illegible]

[illegible] *Screening Levels for Potential Odor Sources* [illegible] to qualitatively assess a project's potential to adversely affect area receptors. This list of [illegible]

Table 6: Screening Levels for Potential Odor Sources

Type of Facility	Distance
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]
[illegible]	[illegible]

The most current screening tools are available on-line at the District's website www.valleyair.org/ceqa

[illegible], the Lead Agency or consultant should contact the District's Compliance Division [illegible]

[illegible]

[illegible] District's Compliance Division should be contacted. The Compliance Division will provide [illegible]

[illegible]

- [illegible]
- [illegible]

[illegible]

[illegible] Treatment – Accidental Release [illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible] [illegible] [illegible] [illegible] [illegible] [illegible]
[illegible] [illegible] [illegible] [illegible] [illegible] [

[illegible] [illegible] [illegible] [

[illegible] [illegible] [illegible] [

[illegible] D[illegible] [illegible] [illegible] [illegible] [illegible] [illegible] sources are individually significant when above the District's criteria pollut[illegible]

D[illegible]

[illegible] [illegible] [illegible] [illegible] [illegible] [

[illegible] Cumulatively Significant Toxic Air Contaminant (TAC) Emissions [illegible]

[illegible] [illegible] [illegible] [

- [illegible]
- When a project's greenhouse gas emissions may be significant, [illegible]
- [illegible]
- [illegible]
- CEQA mandates analysis of a proposed project's potential energy use [illegible]

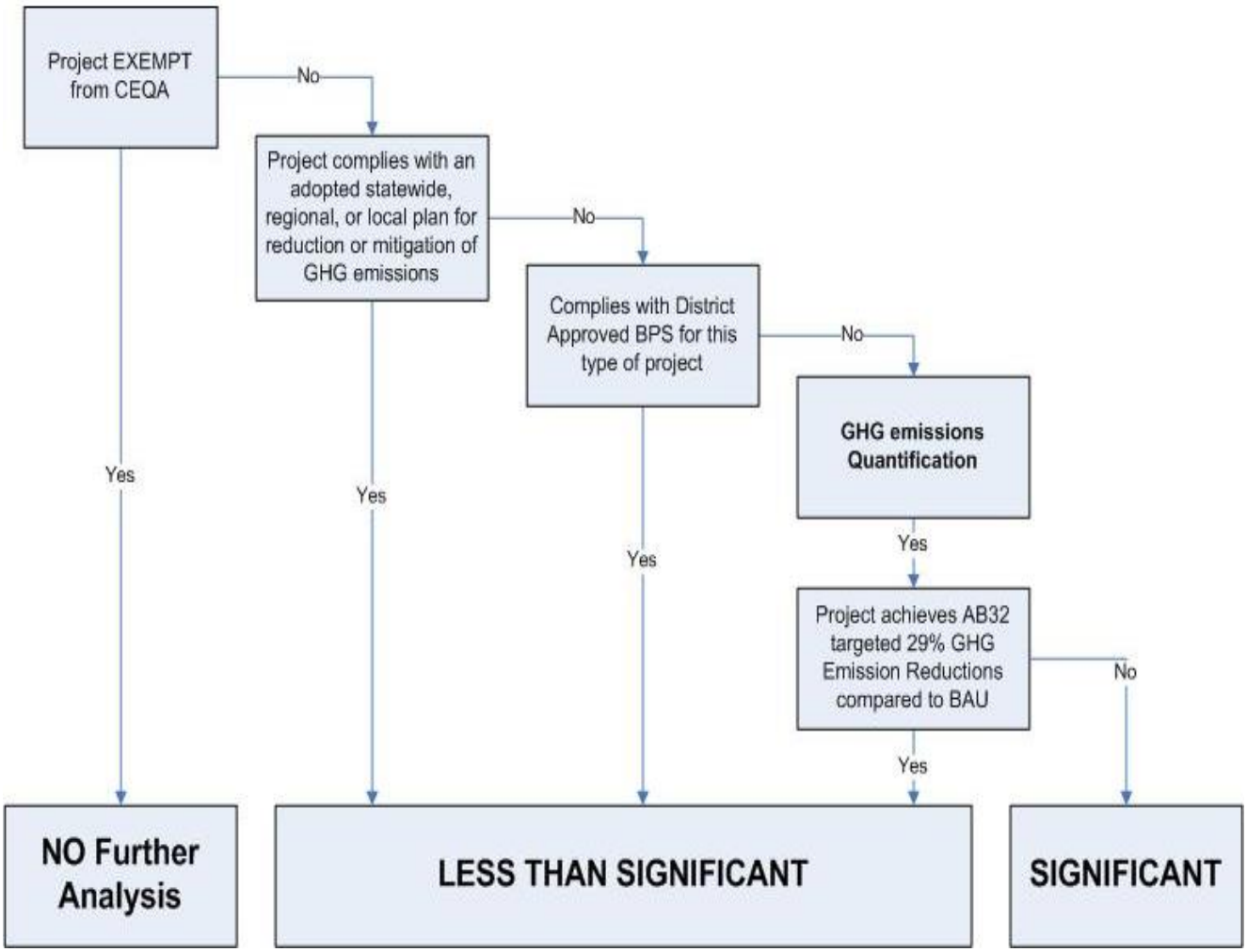
[illegible]

[illegible]

[

[illegible]
[illegible] [illegible] [illegible] [

Figure 6: Process of Determining Significance of Greenhouse Gas Emissions



C□A□T□R□□□

MITI□ATIO□ □M□A□□R□□□

[illegible] Introd[illegible]tion[illegible]

[illegible] r[illegible] [illegible]d [illegible] [illegible] [illegible] [illegible] [illegible]d [illegible] [illegible] [illegible] [illegible]

[illegible] [illegible] [illegible] [illegible] [illegible] [illegible] [illegible]
[illegible] [illegible] [illegible] [illegible] [illegible] [illegible] [

[illegible]

[illegible]

[illegible] proponents to mitigate project specific emissions since 2005. It is the District's [illegible]

[illegible] final approval of the CEQA document. This allows [illegible]

[illegible]

[illegible] approaches are available: "p[illegible]ollutant" and "net zero".

[illegible]

[illegible] The "net zero" concept is limited to the three pollut[illegible] District considers "net zero" mitigation to result in a less tha[illegible]

[illegible]

The District strongly recommends the "net-zero" approac[illegible] [illegible] [illegible] [

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]r[illegible]– [illegible]r[illegible]d [illegible]

[illegible]r[illegible] [illegible] [illegible]r[illegible]d [illegible] [illegible]d [illegible]r [illegible]d [illegible] [illegible]r[illegible]d [illegible]r[illegible]d [illegible]r[illegible]d

- □□□□□□□r□ □□ □□□□□□ R□d□□□□□ □□r□□□ □□□□ □□ d□□□□□□□□d □□□□□□□ □□□□□ □□ □□□r□□□ □□□□ □□□□□r□d □□ □□□□ □r□□□□□ □ r□□□□□□□□□ □□d □□□□ D□□r□□□ □□□ □ □□□□□ □□□□ □r□□□□□ □r□□□□□□□□□ □r□□d□□ □□□□□d□□□r□□□□□d □ □□□□□□□□□□ □□□ □r□ □□□ □□□□□□□□□ □□□r□□□□□ □□□r□□□□ □ □r□□□□□□ □□□□□ □□□□d □□d □□□ □□□□□ □□□□ □□□ □□□□□□□□ r□d□□□□□□□ □r□□□□□□□□ □□□d □□□□ □□□□□d □□□ □□□ □ □□□□□□□□□□□□ □ □□□□□□□□□□□ □ □□□□□r□ □□r □ □□□□ d□□□□□□□□ □□□□□r□□□□□□□

More measures are available on the District's website at:
http://www.valleyair.org/transportation/GAMAQI-Mitigation-Measures.pdf

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[illegible] Mitigation for Hazardous Air Pollutants [illegible]

[illegible] [illegible] [illegible] [

[illegible]

[illegible]

[illegible]

[illegible] [illegible] [illegible] [illegible] [illegible] [illegible] [illegible]
[illegible] [illegible] [illegible] [illegible] [illegible] [illegible] [

- [illegible]
- [illegible]
- [illegible]
- [illegible]

More design guidelines are available at www.valleyair.org/ceqa/designguidelines

[illegible] Quantifying Mitigation Measures

[illegible] Because the measures' effectiveness will depend greatly on the specific characteristics of [illegible]

[illegible]

The model is available at www.caleemod.com and at http://www.valleyair.org/ISR/ISRResources.htm#Models
Assistance with operating the model is available by contacting the District at (559) 230-6000, or hramodeler@valleyair.org

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Appendix C
Biological Resources

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C.1 Biological Resources Technical Report

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CarbonFrontier Project

Biological Resources Technical Report

October 17, 2023

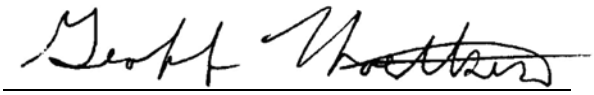
Prepared for:

Aera Energy LLC
10000 Ming Avenue
Bakersfield, CA 93311

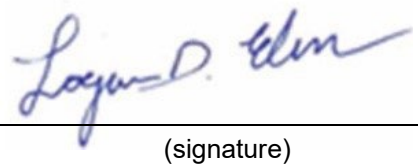
Prepared by:

Stantec Consulting Services Inc.
5500 Ming Avenue Suite 410
Bakersfield, CA 93309

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Prepared by  (signature)

Geoff Hoetker, Senior Biologist

Reviewed by  (signature)

Logan Elms, Senior Biologist

Approved by  (signature)

Eric K. Snelling, Principal Environmental Planner

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Abbreviations

Aera Energy	Aera Energy LLC
afy	Acre-feet per year
API	American Petroleum Institute
APN	Assessor's Parcel Number
BMP	Best management practices
BNLL	Blunt-nosed leopard lizard
BO	Biological Opinion
BPD	Barrels per day
BRTR	Biological Resources Technical Report
BSA	Biological Study Area
BWSD	Belridge Water Storage District
C_{3+}	Heavy hydrocarbons
CalGEM	California Geologic Energy Management Division
CARB	California Air Resources Board
CCH	Consortium of California Herbaria
CCS	carbon capture and sequestration
CDFG	California Department of Fish and Game
CDFW	California Department of Fish and Wildlife
CEQA	California Environmental Quality Act
CFR	Code of Federal Regulations
CNDDB	California Natural Diversity Database
CNPS	California Native Plant Society
COGEN	Cogeneration Facility
CRPR	California Rare Plant Rank
CUP	Conditional Use Permit



CWA	Clean Water Act
DOC	California Department of Conservation
DOGGR	California Department of Oil, Gas, and Geothermal Resources
DAS	distributed acoustic sensors
DTS	distributed temperature sensors
ERRP	Emergency and Remedial Response Plan
ESA	Endangered Species Act
FSZ	Farmland Security Zone
GIS	Geographic Information System
GKR	giant kangaroo rat
GP	Gas Plant
GPS	Global Positioning System
H_2S	hydrogen sulfide
HCP	Habitat Conservation Plan
HMMP	Habitat Mitigation and Monitoring Plan
ITP	Incidental Take Permit
Kern County	Kern County Planning and Natural Resources Department
km/hr	kilometers per hour
kV	kilovolt
MCVII	Manual of California Vegetation, 2nd Edition
MBTA	Migratory Bird Treaty Act
MDB&M	Mount Diablo Base and Meridian
MM Mt	million metric tons
NEPA	National Environmental Policy Act
NOP	Notice of Preparation
NPPA	Native Plant Protection Act
NRCS	Natural Resources Conservation Service
OHWM	ordinary high water mark



PG&E	Pacific Gas and Electric
PHMSA	Pipeline and Hazardous Materials Safety Administration
Post-C	post-combustion
ppm	parts per million
Pre-C	pre-combustion
Project	CarbonFrontier Project
psig	pounds per square inch in gauge
PVC	polyvinyl chloride
ROW	right-of-way
RWQCB	Regional Water Quality Control Board
SCADA	supervisory control and data acquisition
Secretary	Secretary of the Interior
SGS	Steam Generator Setting
SJAS	San Joaquin antelope squirrel
SJKF	San Joaquin kit fox
SOX	sulfur oxide
SSC	California Species of Special Concern
Stantec	Stantec Consulting Services Inc.
SWPPP	Stormwater Pollution Prevention Plan
SWRCB	State Water Resources Control Board
UIC	Underground Injection Control
USACE	United States Army Corps of Engineers
USDW	Underground source of drinking water
USEPA	U.S. Environmental Protection Agency
USFWS	U.S. Fish & Wildlife Service
USGS	U.S. Geological Survey
WQC	Water Quality Certification



1.0 INTRODUCTION

Aera Energy LLC (Aera Energy) is proposing to construct and implement the CarbonFrontier Project (Project), which includes carbon capture and sequestration (CCS) in the South and North Belridge oil fields south of Blackwells Corner and west of State Route (SR) 33 in Kern County, California (Figure 1). The proposed Project is designed to capture carbon dioxide (CO_2) from existing produced gas streams and emissions from existing stationary oil field infrastructure sources within Aera Energy's South Belridge Oil Field, and transport the CO_2 through a system of pipelines to the North Belridge Oil Field for injection into dedicated Class VI injection wells for geologic sequestration. It is anticipated that the proposed Project would capture and sequester up to 2 million metric tons (MM Mt) of CO_2 per year beginning in 2027 and will contribute to the goal of California for carbon neutrality by 2045 (Executive Order B-55-18) by reducing industrial CO_2 emissions.

Aera Energy has submitted an application to the Kern County Planning and Natural Resources Department to request approval of a Zone Change and Conditional Use Permit (CUP) for the construction and operation of the Project. Implementation of the Project would also require permits from the United States Environmental Protection Agency (USEPA) for nine injection wells in compliance with the Underground Injection Control (UIC) program Class VI geologic sequestration regulations. The proposed CO_2 related facilities, pipelines, Class VI injection wells and associated CO_2 monitoring wells would be located within the CUP boundary (Figure 2).

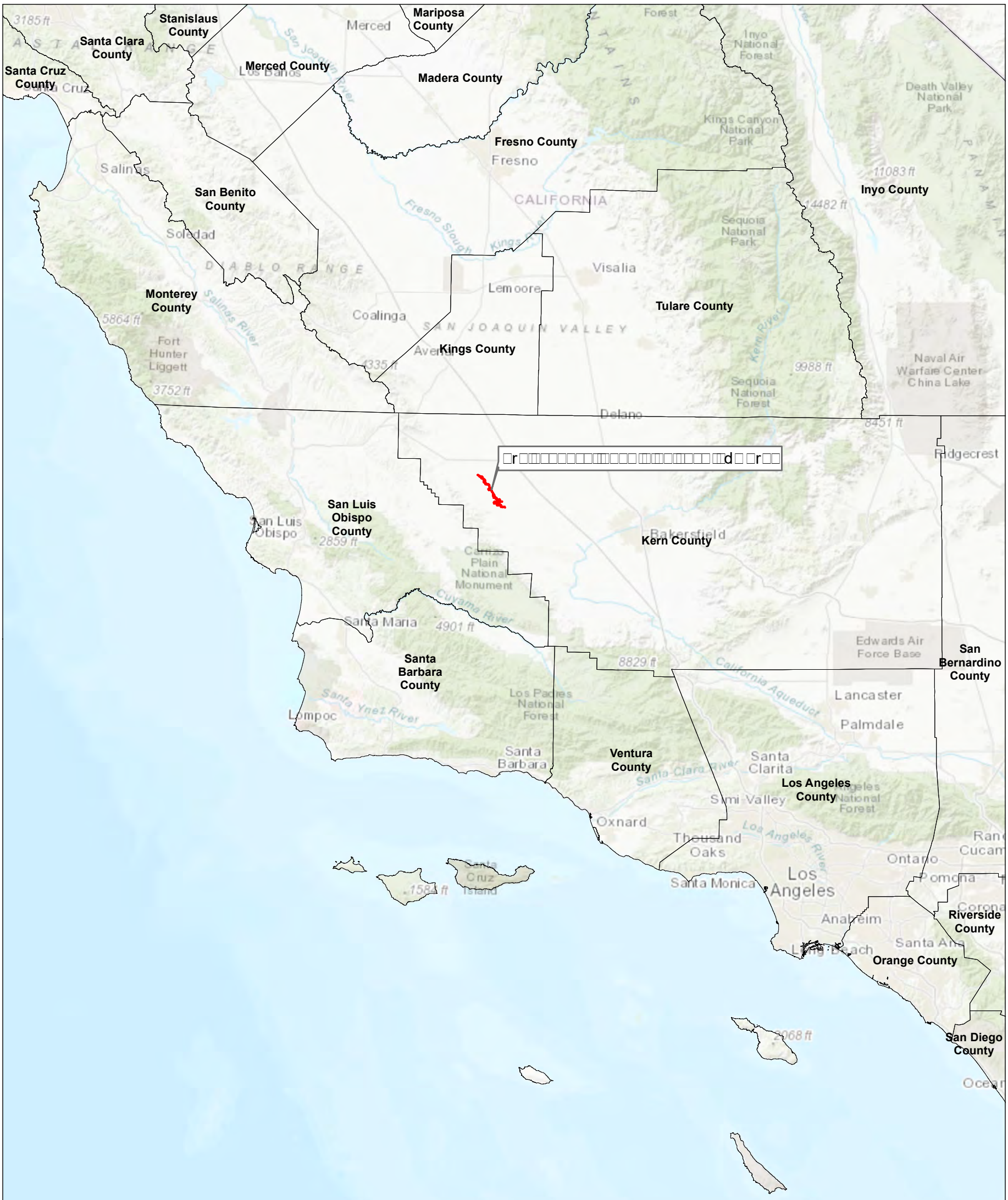
1.1 PURPOSE OF THE REPORT

This Biological Resources Technical Report (BRTR) is intended to document the biological resources that are associated with the Project. The goal of this report is to document the current baseline environmental conditions for biological resources that occur within the Biological Study Area (BSA) to support future California Environmental Quality Act (CEQA) documentation for the Project. This BRTR will provide an emphasis on special-status plant and wildlife species, wildlife corridors, and special-status/sensitive natural communities, and in addition, evaluate the potential for these species to occur within the BSA.

1.2 BIOLOGICAL STUDY AREA (BSA)

The BSA includes all areas that could be directly and indirectly affected by the Project. The BSA for the Project totals approximately 3,252 acres, and is shown in Figure 3. The BSA includes the Project footprint, the proposed construction areas, all areas of temporary and permanent impacts, and the areas within a 500-foot buffer extending outward from the Project construction area and facilities, including on either side of the pipeline alignment and around all Project related infrastructure. The 500-foot buffer was chosen to include potential direct and indirect Project impacts on plant and wildlife species from construction activity.





Notes

1. [illegible]
2. [illegible]
3. [illegible]

[illegible]

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Project Location

[illegible]

Client/Project

[illegible]

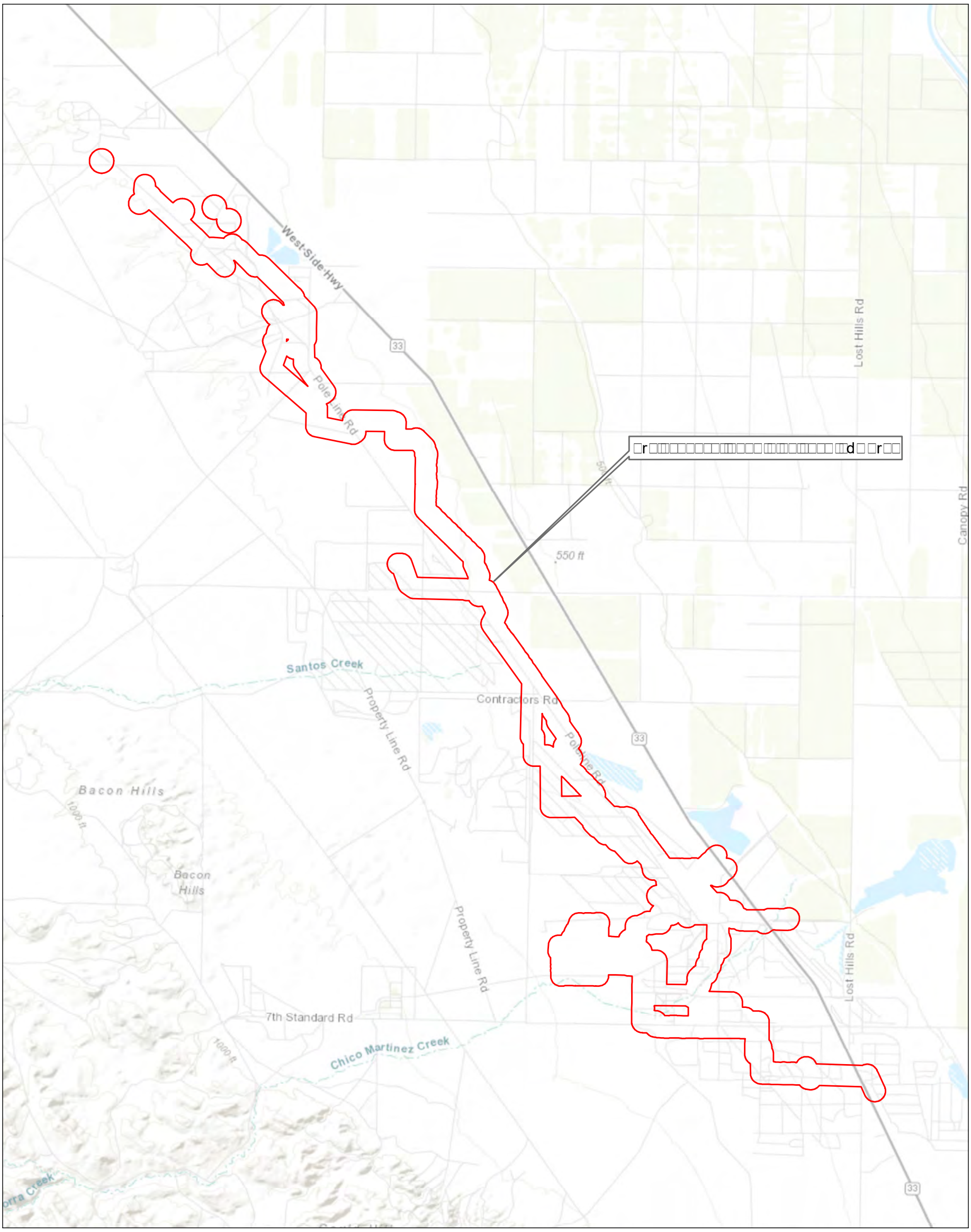
Figure No.

1

Title

Regional Location and Biological Study Area (BSA)

[illegible]



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1. [illegible]
2. [illegible]
3. [illegible]

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Project Location

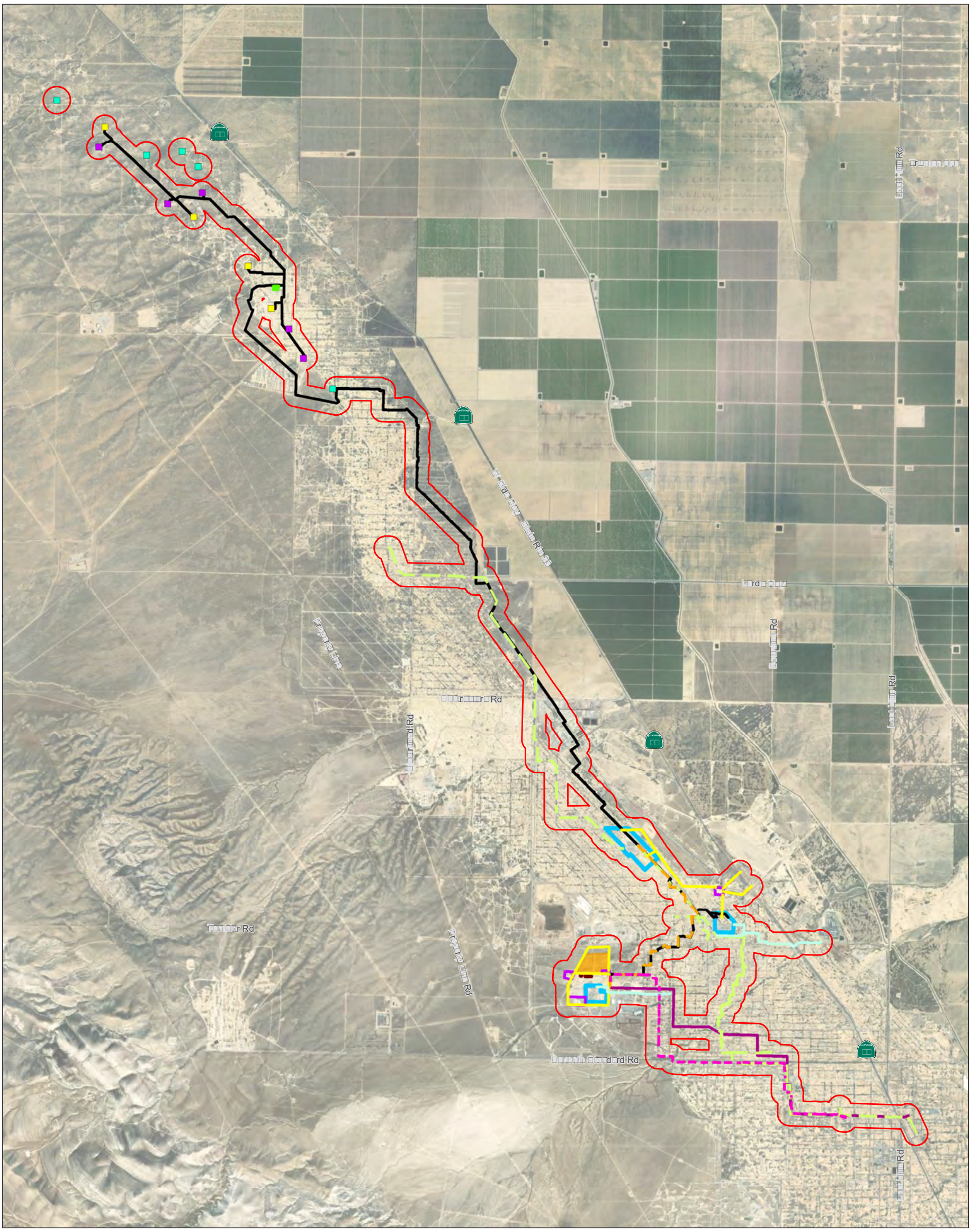
Client/Project

Figure No.

2

Title

Project Location/ Biological Study Area (BSA)


Loop 1604 Rd
Loop 1604 Rd
Loop 1604 Rd

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2.0 PROJECT DESCRIPTION

2.1 PROJECT PURPOSE

The purpose of the Project is to substantially reduce Aera Energy's CO_2 emissions from the existing South Belridge Oil Field. The proposed Project is expected to capture and sequester significant amounts of CO_2 over the life of the Project, and contribute to California's goal of carbon neutrality by 2045 (Executive Order B-55-18).

Aera Energy's Project Objectives are as follows:

- Construct and operate facilities and infrastructure to capture, transport, inject, and permanently sequester up to 37.5 million MM Mt of CO_2 in a safe, secure, and economically feasible manner for storage, not enhanced hydrocarbon recovery;
- Minimize new disturbance by siting and designing Project facilities and infrastructure within the existing developed oil field footprint;
- Reduce the carbon intensity of Aera Energy's produced oil and gas by capturing CO_2 from produced gas (pre-combustion) and stationary sources (post-combustion);
- Generate environmental, social, and economic benefits for Kern County and the State of California by implementing low carbon technologies, developing CCS infrastructure, and providing living-wage jobs in the region; and
- Contribute to California's goal to achieve carbon neutrality by 2045 (Executive Order B-55-18) by integrating carbon capture in existing operations as well as ending oil and gas production from select reservoirs and repurposing them for the permanent storage of CO_2.

2.2 PROJECT LOCATION

The Project is located within the Central Valley portion of western Kern County in Aera Energy's Belridge oil fields (see Figures 1 and 2). Aera Energy is the primary operator of both oil fields. The South Belridge and North Belridge oil fields are contiguous and located approximately seven miles southwest of the community of Lost Hills and just west of SR 33 (see Figure 2). The main entrance to the South Belridge Oil Field is located at the private Oasis Road along Seventh Standard Road west of SR-33.

The BSA is contained within the following Sections of the South and North Belridge oil fields: Sections 26, 27, 28, 34, 35, and 36 of Township 27 South, Range 20 East; Sections 1, 2, and 12 of Township 28 South, Range 20 East; Sections 6, 7, 17, 18, 19, 20, 27, 28, 29, 32, and 33 of Township 28 South Range 21 East, and Section 2, 3, and 4 of Township 29 South, Range 21 East, Mount Diablo Base and Meridian, County of Kern, State of California, in the U.S. Geological Survey (USGS) Blackwells Corner, Carneros Rocks, and Belridge 7.5-minute topographic; approximately 7 miles southwest of the community of Lost Hills, Kern County, California.

The proposed CO_2 capture facilities would be located within the developed portion of the South Belridge Oil Field, which comprises a total of about 16,218 acres, while the proposed CO_2 sequestration field would be located in the North Belridge Oil Field, which is about 5,801 acres total. The Sequestration Field



refers to an underground geologic formation, situated at a depth of approximately 8,500 feet, where the CO_2 would be stored. The proposed CO_2 capture facilities would be spread out through the South Belridge Oil Field. The proposed CO_2 sequestration field (approximately 2,636 acres) in the North Belridge Oil Field is made up of privately owned parcels predominately developed with oil and gas production and accessory facilities and infrastructure. Together, the two Belridge oil fields cover an area of approximately 22,019 acres, approximately 13 miles long and up to 3 miles wide. The Project footprint, which includes areas of temporary and permanent impacts, and locations of all Project facilities, is approximately 308 acres.

2.2.1 Environmental Setting

CO_2 capture and compression equipment would be constructed adjacent to four existing facilities within the South Belridge Oil Field. The proposed CO_2 sequestration field is contained within approximately 2,636 acres of land within the North Belridge Oil Field. The proposed Project location is not designated by the California Department of Conservation (DOC) as Prime Farmland, Farmland of Statewide Importance, or Unique Farmland. However, the proposed Project footprint has two parcels (Assessor's Parcel Number [APN]: 068-220-26 and 085-210-42) subject to Farmland Security Zone (FSZ) contracts and three parcels subject to Williamson Act Land Use Contracts; one parcel (APN: 068-210-13) designated as non-prime; one (1) parcel (APN: 068-200-33) designated as mixed; and one parcel (APN: 085-220-37) designated as prime.

The BSA is not located within a Kern County-designated mineral recovery zone (excluding oil and gas); however, the South and North Belridge oil fields are designated by the Kern County General Plan for Mineral and Petroleum exploration and extraction.

The nearest residences closest to the BSA include one residence located east of SR-33 adjacent to the North Belridge Oil Field (this property has been purchased by Aera Energy), a small housing tract on Lost Hills Road, north of Lerdo Highway and roughly three miles east of the BSA, and the community of Lost Hills located approximately seven miles northeast of the BSA.

2.3 PROJECT OVERVIEW

Aera Energy proposes to construct and operate a carbon capture and sequestration project, with the CO_2 capture facilities located within the South Belridge Oil Field, and transport the CO_2 by pipeline to the North Belridge Oil Field for permanent sequestration via CO_2 injection wells into a designated underground sequestration zone, known as the 64 Zone, at depths of approximately 8,500 feet below ground surface.

New processing facilities and field systems would be constructed to implement the Project. Processing facilities would include: 1) carbon capture facilities constructed adjacent to existing oil field equipment within the South Belridge Oil Field; 2) pipelines to transport the CO_2 stream to the North Belridge Oil Field, and 3) dedicated injection wells within North Belridge to inject CO_2 into the dedicated CO_2 sequestration zone. Existing oil wells that penetrate the dedicated CO_2 sequestration zone would be permanently plugged and abandoned (including the removal of surface wellheads) in accordance with applicable laws and regulations or repurposed for injection or monitoring activities.



Field systems would include: 1) additional pipelines to convey produced gas, water, and steam within South Belridge; and 2) electrical power distribution and supervisory control and data acquisition networks and control rooms. The Project would also include maintenance of existing access roads. Monitoring systems would be constructed, including re-purposing of existing wells, to monitor the CO_2 injection operations in accordance with state and federal requirements. Details of the new processing facilities, infrastructure, and field systems is outlined further in the following sections.

Aera Energy would operate the field under a well-established and proven management system that incorporates many processes, plans and programs to ensure public and worker health and safety, environmental protection, regulatory compliance, and community involvement. These programs include Spill Prevention, Incident Response, Site Safety, Site Security, Pollution Prevention, Species Protection, Environmental Compliance, Environmental Training, Safety Training, and Community Involvement.

2.3.1 Project Permits and Approvals

Aera Energy has submitted a land use application package to the Kern County Planning and Natural Resources Department (Kern County) to request approval of a Zone Classification Change and CUP and would obtain any other required approvals for the construction and operation of a CCS Project in the South and North Belridge oil fields. The proposed Project would require approvals for additions and improvements to the existing oil field facilities (gas separation, compression, and pumping equipment), new CO_2 pipelines located primarily aboveground utilizing existing pipeline corridors, UIC Class VI geologic sequestration injection wells, CO_2 monitoring wells, and an underground carbon sequestration field for the storage of CO_2 in accordance with appropriate financial assurance mechanisms that ensure permanence in compliance with applicable regulatory standards. Implementation of the Project would also require permits from the USEPA for up to nine Class VI injection wells in compliance with the UIC program Class VI geologic sequestration regulations, including five re-purposed wells and four new injection wells.

2.4 PROPOSED PROJECT COMPONENTS

The following sections provide additional details and discussion regarding each of the Project components. Project plans include construction of four CO_2 capture facilities, construction of pipelines to convey CO_2 from the capture facilities to the proposed sequestration field, and construction or re-purposing of nine injection wells within the North Belridge Oil Field. The proposed Project also includes construction of monitoring wells, new field systems, and utility connections and delivery lines. Each of the components are described in the following subsections and are depicted on Figure 3.

The proposed Project includes the following components:

- CO_2 Capture and Processing Facilities - one pre-combustion capture facility and three post-combustion capture facilities (Figure 4).





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Stantec AERA

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Figure No.
4

Title
Proposed CO_2-Related Facilities

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- Pipelines – an approximately 10-mile main CO_2 pipeline, CO_2 distribution lines to each injection well, and produced gas, water and steam pipelines. The majority of the new pipelines would be installed on pipe supports between two to four feet above the ground. Pipe supports are typically spaced 15 to 30 feet apart depending on the size and the weight of the pipeline. New pipelines may be installed on existing pipe supports or on new pipe supports.

- Subsurface Wells – Development/Conversion and operation of up to nine CO_2 injection wells, including four new injection wells and five existing re-purposed wells, and up to nine monitoring wells. As part of the proposed Project, up to 55 existing oil wells would be plugged and abandoned within the North Belridge Oil Field in accordance with state and federal requirements to prevent leakage of CO_2 from the sequestration zone. Up to 40 additional wells, previously abandoned within the North Belridge Oil Field, would be re-abandoned to meet current state and federal plugging requirements. Additionally, 21 existing wells that are adjacent to Steam Generator Setting (SGS) 2868 and SGS 2972 would need to be plugged and abandoned prior to construction of the CO_2 capture facilities at these two locations.

- Access Roads – Maintenance and repair of existing field access roads.

- Water Systems – Construction of water treatment facilities at each of the CO_2 capture facilities.

- Electrical Transmission – Construction of approximately 6,840 feet of 115 kilovolt (kV) overhead transmission lines from the existing Aera Energy -owned electrical supply grid to two new electrical substations located adjacent to the CO_2 capture facilities.

- Networks – Electrical power distribution, and supervisory control and data acquisition (SCADA) networks.

2.4.1 CO_2 Capture and Processing Facilities

Proposed CO_2 capture facilities include facilities and processes needed for the separation, dehydration, compression, and cooling of CO_2 from both pre-combustion (Pre-C) produced gas stream and from post-combustion (Post-C) flue gas. Pre-C and Post-C components are outlined below.

2.4.1.1 Pre-Combustion Components

Del Sur to Gas Plant (GP) 32 Pipeline. An existing 16-inch diameter Wet Gas pipeline operating at approximately 150 pounds per square inch in gauge (psig). It is known as the Del Sur line to GP 32 and would be utilized to supply produced gas to GP 32. The Tulare Associated gas stream would need to go through the Del Sul Compressor Station to increase pressure before being transported to GP 32. A new 200-foot long “jumper” line would be constructed to feed Tulare gas from a 10-inch diameter pipeline (operating at less than 25 psig) into the Del Sur Compressor Station. The compressors would then connect the Tulare gas into the Del Sur line which currently transports Diatomite gas, at an increased pressure of over 125 psig. The existing pipeline is made of carbon steel with a corrosion-resistant internal coating, is situated aboveground on pipe supports, and crosses Seventh Standard Road. One existing



idle compressor at the Del Sur Compressor Station would be put back in service to accommodate the Tulare gas. The Del Sur compressors would also be upgraded with new materials/trim for corrosion resistance.

Tulare CVR to GP 32 Pipeline. Alternatively, gas produced from existing wells in the Tulare Formation would be transported by installing a new 12-inch to 16-inch diameter 3.5-mile pipeline extending from the SOX 2-3 facility east of SR 33 to the existing SOX 3-2 facility, terminating at the GP32 location. The proposed pipeline would be installed primarily aboveground on pipe supports. The pipeline would cross SR 33 and Seventh Standard Road using horizontal boring techniques.

The compressed, mixed stream from Del Sur would be further integrated with the balance of the Diatomite Produced Gas from the other Compressor Stations at sulfur oxide (SOX) 32. At SOX 32, total sulfur content would be reduced. After the sulfur is reduced, the treated gas is passed from the SOX 32 facility to the carbon processing facility within GP 32. The de-sulfurized stream would be then cooled and chilled to reduce water content and condense heavy hydrocarbons (C_{3+}).

Pre-C Facility. In the pre-C CO_2 capture and processing facility, the produced gas would be cooled, then passed through an absorber column where an absorbent chemically reacts with and binds about 90% of the CO_2. The rich absorbent carrying CO_2 is piped to the regenerator column, where through the application of heat, the CO_2 would be released and captured in relatively pure concentration. The CO_2 would then be compressed, dehydrated, removed of oxygen, and piped to the sequestration storage site. Following CO_2 release, the lean absorbent would be recycled back to the absorber column. The remaining natural gas would then be transferred to the steam generation facilities for use as fuel. Refer to Figure 5 for the proposed Pre-C Facilities Site Plan.

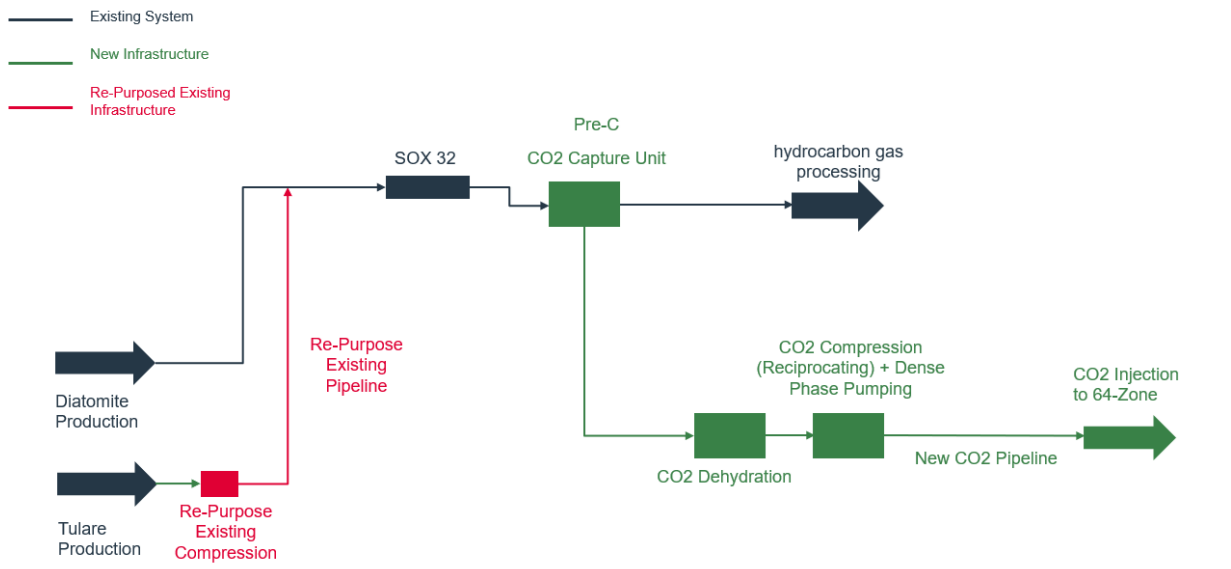


Figure 5. Use of Existing Infrastructure for Pre-C CO_2 Removal

The Pre-C process would use the existing facility infrastructure of GP 32. The figure above also indicates what is part of the existing system and what would be new. Figure 6 below shows the CO_2 processing facility, denoting existing infrastructure and proposed infrastructure.

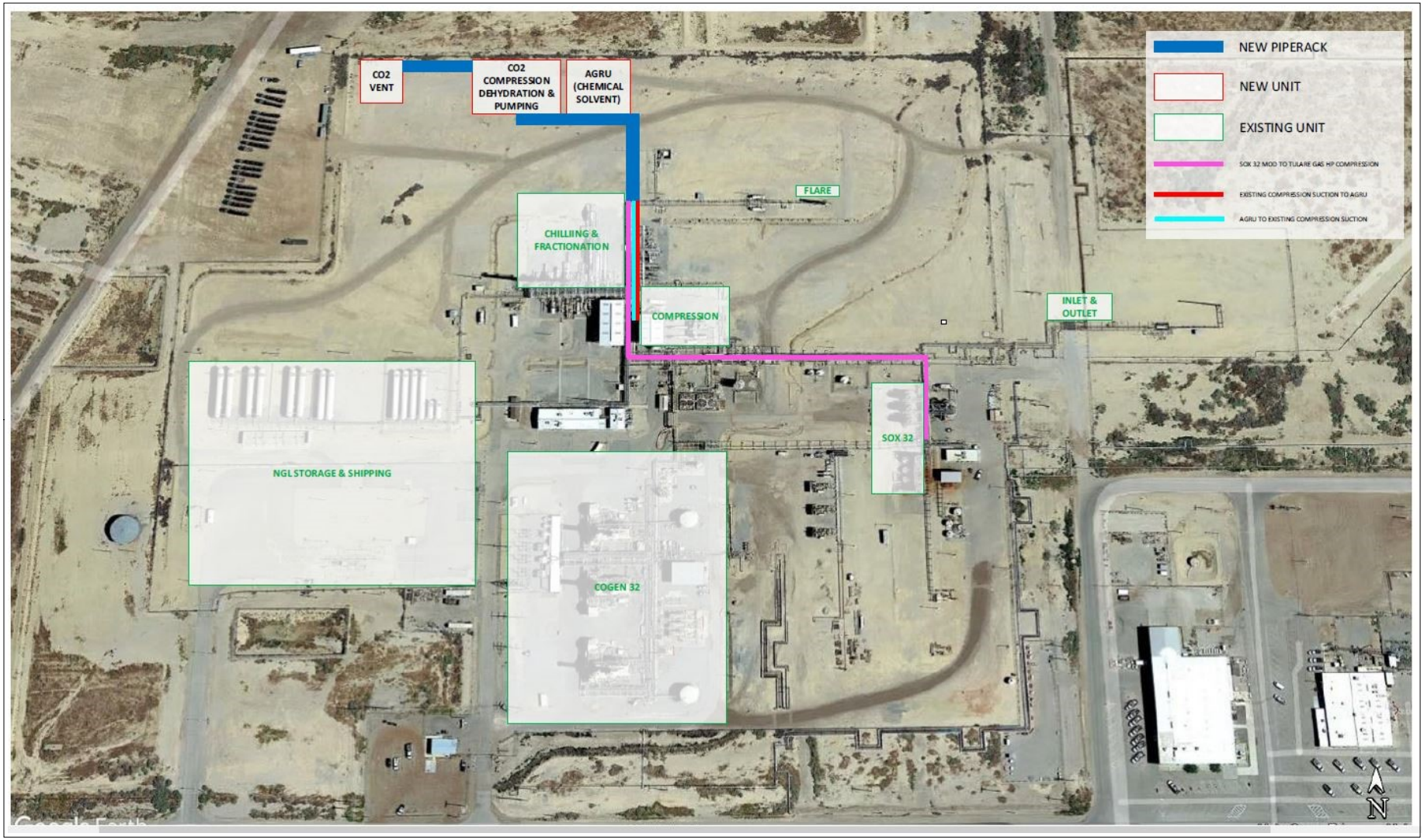
2.4.1.2 Post-Combustion Capture Facilities

Proposed CO_2 capture and processing facilities includes the separation, dehydration, compression, and cooling of CO_2 from flue gas emissions from existing stationary sources within South Belridge. A Post-C capture facility would be constructed at each of the three existing facilities: Cogeneration Facility (COGEN 32), SGS 2972, and SGS 2868. The flue gas emissions from each Post-C source would be ducted to its own CO_2 capture and processing facility.

In each of the three CO_2 capture and processing facilities, the flue gas would be cooled, then passed through an absorber column where an absorbent chemically reacts with and binds about 90% of the CO_2. The remaining flue gas (primarily oxygen, nitrogen, and the remaining uncaptured CO_2), would be vented to the atmosphere.

The rich absorbent carrying CO_2 is piped to the regenerator column, where through the application of heat, the CO_2 would be released and captured in relatively pure concentration. The CO_2 would then be compressed, dehydrated, removed of oxygen, and piped to the sequestration storage site. Following CO_2 release, the lean absorbent would be recycled back to the absorber column. The Post-C process would use the existing facility infrastructure of COGEN 32 at GP 32, SGS 2972, and SGS 2868. Figures 7, 8, and 9 below show the Post-C site plans including the proposed CO_2 processing facility (blue outline), proposed power line routes (yellow line), proposed CO_2 pipelines routes (black line), potential substation locations (purple outline), proposed steam line routes (green line), proposed water line routes (light blue line), proposed demolition sites (red shading), and existing infrastructure.





Notes
1. Data Sources: Aera Energy, 2022.
2. Basemap: Google Earth

Project Location
Kern County, California

Prepared by DL on 2023-10-09
TR by SET on 2023-10-09
IR by ES on 2023-10-09

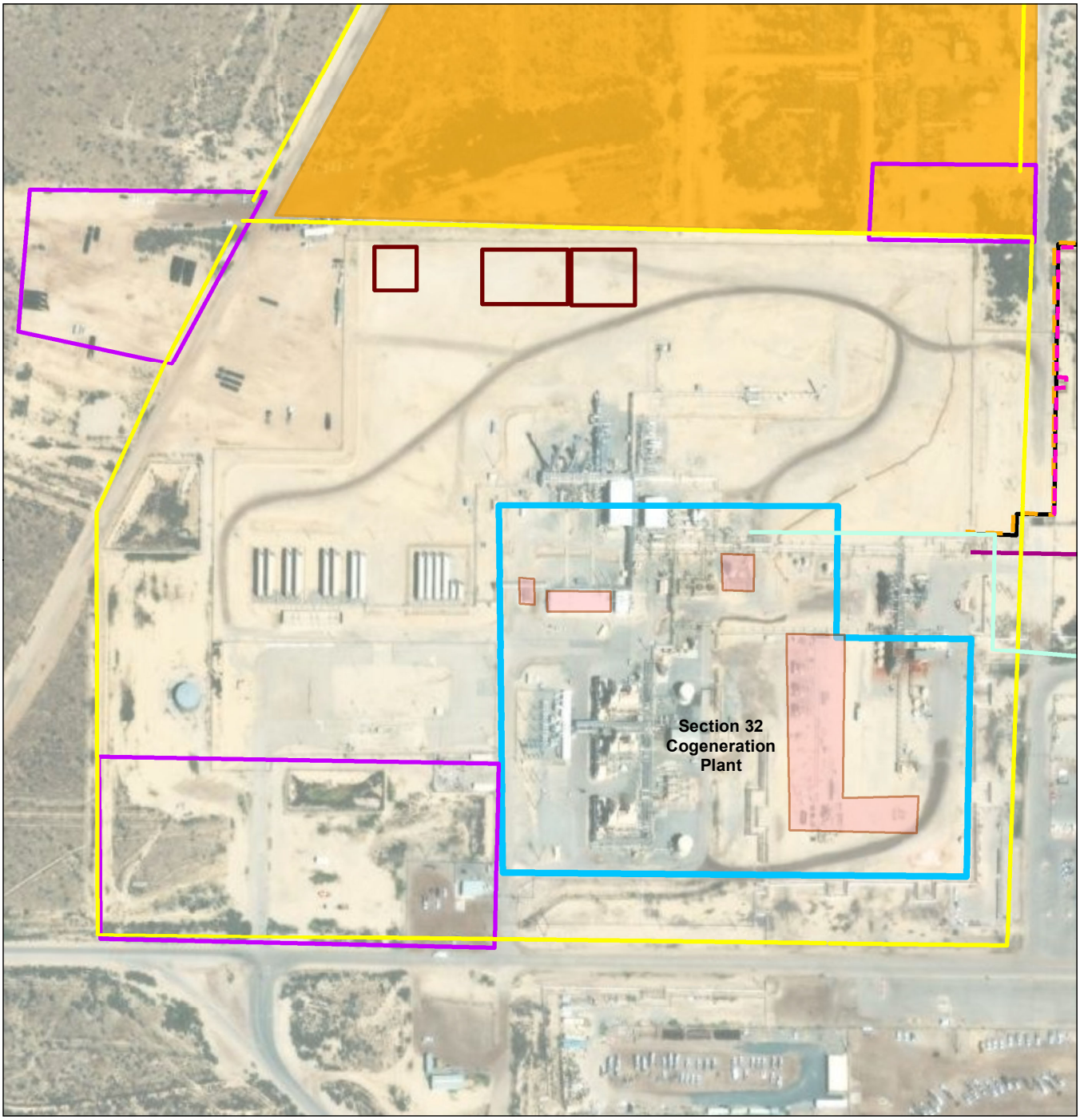
Client/Project
185805372
Aera Energy LLC
CarbonFrontier Project
Biological Resources Technical Report

Figure No.
6

Title
Pre-C Site Plan at GP32

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- Carbon Capture Facility Location
- Existing Del Sur Gas Line to Gas Plant 32
- Proposed CO_2 Pipelines
- Proposed Gas Pipeline (Gas Plant 32 to SGS 2972)
- Proposed Produced Water Lines Routes
- Proposed Power Line Routes
- Tulare CVR to GP32 Pipeline (Optional)
- Proposed Substation Locations
- Proposed Pre-Combustion Facilities
- Proposed Post-Combustion Capture Facility
- Proposed Staging Area Adjacent to Gas Plant 32

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Notes
1. Coordinate System: NAD 1983 StatePlane California V FIPS 0405 Feet
2. Data Sources: Aera Energy 2022, 2023. Stantec 2022,2023.
3. Background: Source: Esri, Maxar, Earthstar Geographics, and the GIS User Community. Imagery Dated 2021.

Stantec AERA

Project Location
Kern County,
California

Prepared by DL on 2023-10-09
TR by SET on 2023-10-09
IR by ES on 2023-10-09

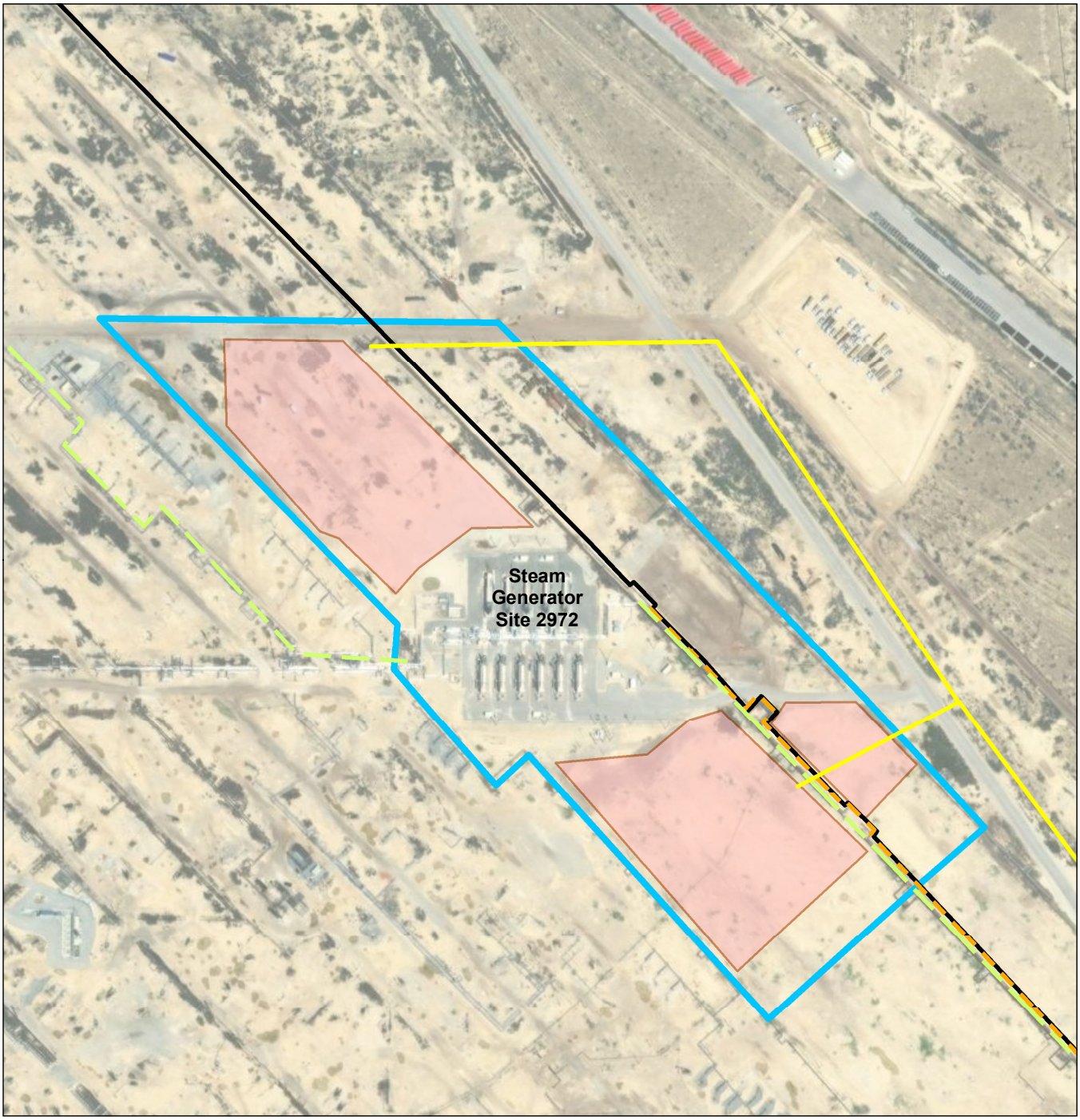
Client/Project
185805372
Aera Energy LLC
CarbonFrontier Project
Biological Resources Technical Report

Figure No.
7

Title
Post-C Site Plan at COGEN 32

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Carbon Capture Facility Location
Proposed CO_2 Pipelines
Proposed Gas Pipeline (Gas Plant 32 to SGS 2972)
Proposed Power Line Routes
Proposed Steam Line Routes
Proposed Post-Combustion Capture Facility

0 200 400 Feet

(At original document size of 8.5x11)
1:4,800

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Stantec AERA

Project Location
Kern County,
California

Prepared by DL on 2023-10-09
TR by SET on 2023-10-09
IR by ES on 2023-10-09

Client/Project 185805372
Aera Energy LLC
CarbonFrontier Project
Biological Resources Technical Report

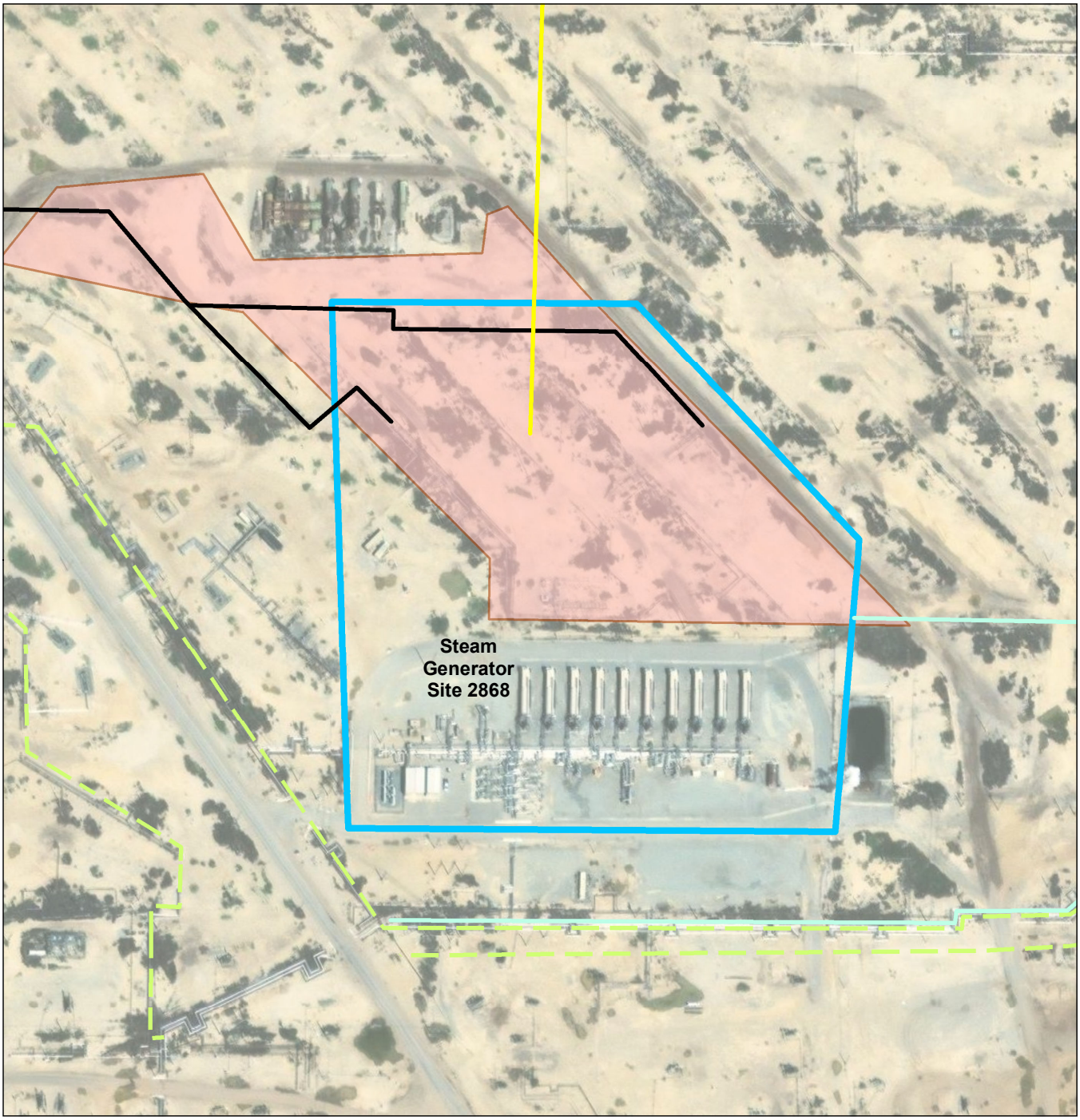
Figure No.
8

Title
Post-C Site Plan at SGS 2972

Notes
1. Coordinate System: NAD 1983 StatePlane California V FIPS 0405 Feet
2. Data Sources: Aera Energy 2022, 2023. Stantec 2022,2023.
3. Background: Source: Esri, Maxar, Earthstar Geographics, and the GIS User Community. Imagery Dated 2021.

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- Carbon Capture Facility Location
- Proposed CO_2 Pipelines
- Proposed Produced Water Lines Routes
- Proposed Power Line Routes
- Proposed Steam Line Routes
- Proposed Post-Combustion Capture Facility

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(At original document size of 8.5x11)
1:3,000

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Notes
1. Coordinate System: NAD 1983 StatePlane California V FIPS 0405 Feet
2. Data Sources: Aera Energy 2022, 2023. Stantec 2022,2023.
3. Background: Source: Esri, Maxar, Earthstar Geographics, and the GIS User Community. Imagery Dated 2021.

Stantec AERA

Project Location
Kern County,
California

Prepared by DL on 2023-10-09
TR by SET on 2023-10-09
IR by ES on 2023-10-09

Client/Project
185805407
Aera Energy LLC
CarbonFrontier Project
Biological Resources Technical Report

Figure No.
9

Title
Post-C Site Plan at SGS 2868

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2.4.2 CO_2 Pipelines

Main Pipeline. A new 10-mile, 6- to 12-inch pipeline would be constructed primarily aboveground on pipe supports to deliver CO_2 from the capture facilities to the proposed injection wells. The above-ground pipeline sections would be constructed on metal pipeline supports. Each support would have a concrete foundation approximately 6- to 12-feet deep. The pipe would rest on the pipe supports, which would be spaced at approximately 20-foot intervals along the pipeline length. The pipeline would be primarily installed aboveground, except where the pipeline would cross main access roads within the oil field properties. The pipelines would be installed below ground at the main access road crossings. Where pipelines are placed below ground at internal access road crossings, the proposed pipelines would be installed using conventional trenching techniques. The new pipeline would use existing pipeline routes to the maximum extent feasible to minimize ground disturbance and impacts in the BSA.

Booster Pump Station. A new booster pump station may be constructed adjacent to the existing Compressor Station 49, at each of the post-combustion recovery sites, or at Gas Conditioning Facility 32.

Distribution Pipelines. Distribution pipelines approximately 4 to 8 inches in diameter would extend from the main pipeline to the proposed injection wells. The distribution pipelines would be primarily aboveground on pipe supports, except where the pipelines cross main access roads within the oil field. The pipelines would be installed below ground at the main access road crossings.

The above-ground pipeline sections would be constructed on metal pipeline supports. Each support would have a concrete foundation approximately 6- to 12-feet deep. The pipe would rest on the pipe supports, which would be spaced at approximately 20-foot intervals along the pipeline length. Where pipelines are placed below ground at internal access road crossings, the proposed pipelines would be installed using conventional trenching techniques. Where the pipelines cross public roads, the pipelines would be installed using jack-and-bore techniques.

2.4.3 Subsurface Wells

Two types of wells are associated with the proposed Project: CO_2 injection wells and monitoring wells. Each well type is described below. Non-active wells that would be plugged and abandoned as part of the Project are also discussed below.

Injection Wells. A total of nine injection wells would be utilized for the proposed Project, including four new injection wells and five existing wells that would be re-purposed for CO_2 injection, in compliance with USEPA UIC regulations. Injection Well Design documents were submitted to USEPA, which included the well specific construction details, procedures, design criteria, current and planned wellbore schematics, and well surveys for all planned Class VI CO_2 injection and monitoring wells.

Monitoring Wells. Five existing wells are proposed to monitor the CO_2 injection operations and ensure that the CO_2 injection remains within the 64 Zone reservoir. Monitoring wells neither produce nor inject fluids. Up to an additional three monitoring wells, locations to be determined, may be proposed, pending



further evaluation. Monitoring wells would be used to monitor temperature, pressure, fluid levels, acoustic signals, and for the collection of fluid and gas samples.

Corrective Action Wells. A total of 172 unique deep wellbores in the area of interest of North Belridge were identified from an exhaustive search of Aera Energy's drilling records, Aera Energy's internal database, and CalGEM's WellSTAR database. Of the 117 permanently abandoned wells, up to 40 would need to be re-abandoned. Up to 55 operational wells would need to be abandoned. Aera Energy would complete the well abandonments/re-abandonments using existing well abandonment crews as part of its baseline annual well abandonment program.

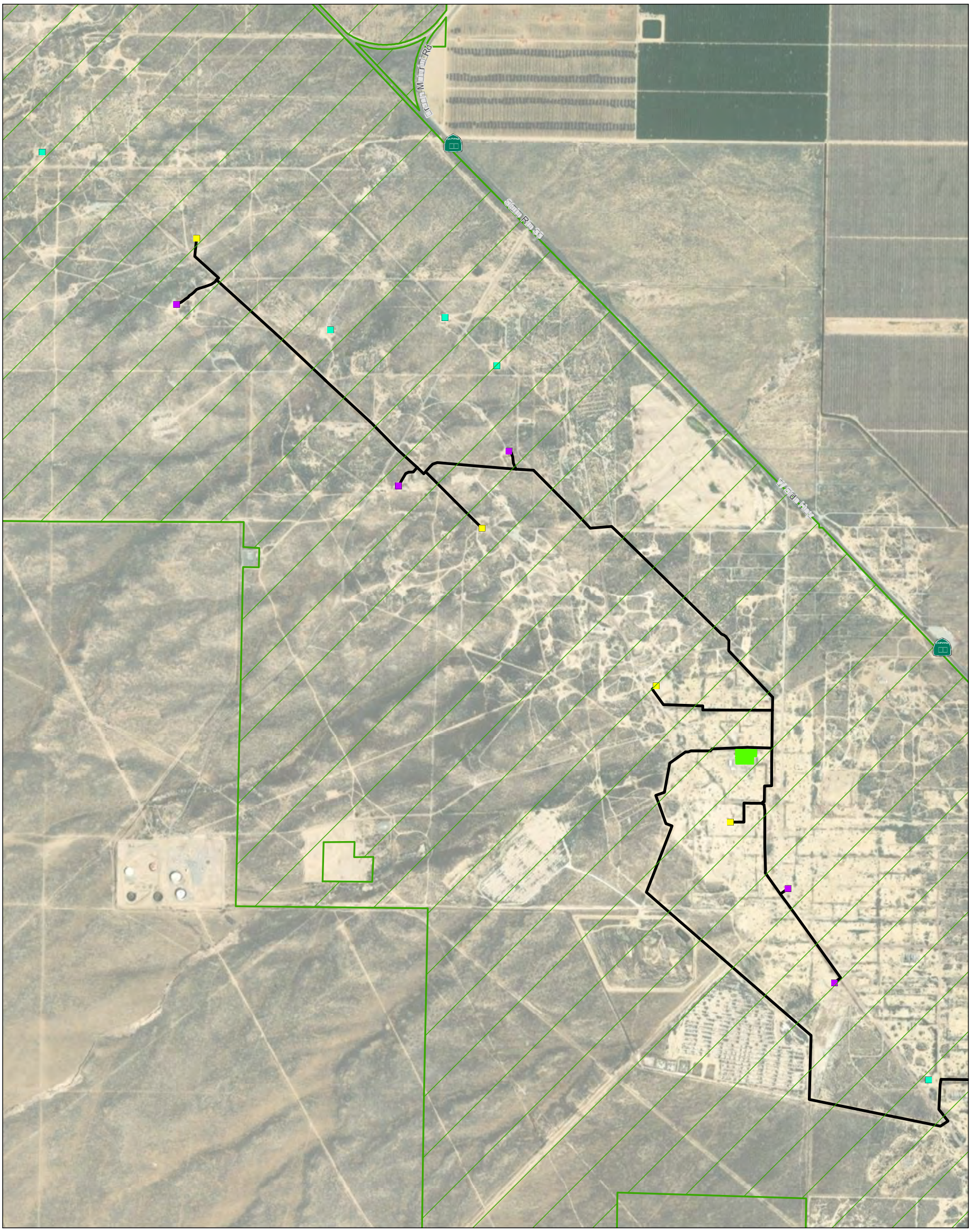
Table 1 below presents the listing of proposed injection and monitoring wells in the North Belridge Oil Field. Refer to Figure 10 for the proposed injection and monitoring well locations in the BSA.

Table 1. Injection and Monitoring Wells

Well Name	API Number	Use	Completion Formation	Surface Location Latitude	Surface Location Longitude
Existing Wells to be Re-purposed					
27R-27N	0402929616	Injection	64 Zone Sandstones	35°33'2.31"N	119°48'32.13"W
64-27N	0402935068	Injection	64 Zone Sandstones	35°32'38.10"N	119°47'54.56"W
55-26N	0402935057	Injection	64 Zone Sandstones	35°32'43.10"N	119°47'36.27"W
64-35N	0402935091	Injection	64 Zone Sandstones	35°31'44.24"N	119°46'48.50"W
9-1N	0402935107	Injection	64 Zone Sandstones	35°31'31.53"N	119°46'40.54 "W
1-28N	0402935069	Monitoring	Agua and 64 Zone Sandstones	35°33'22.65"N	119°48'54.97"W
25-26N	0402935053	Monitoring	Agua	35°33'1.13"N	119°47'47.39 "W
39-26N	0402935054	Monitoring	64 Zone Sandstones	35°32'54.69"N	119°47'38.62"W
27-1N	0402935115	Monitoring	64 Zone Sandstones	35°31'18.53"N	119°46'24.53"W
35X-27H	0402958271	Monitoring	Lower Carneros	35°32'59.15"N	119°48'6.38"W
New Wells					
CI1-64Z-27N	TBD	Injection	64 Zone Sandstones	35°33'9.37"N	119°48'29.90"W
CI2-64Z-35N	TBD	Injection	64 Zone Sandstones	35°32'33.09 "N	119°47'41.03"W
CI3-64Z-35N	TBD	Injection	64 Zone Sandstones	35°32'11.37"N	119°47'11.53 "W
CI4-64Z-35N	TBD	Injection	64 Zone Sandstones	35°31'55.30"N	119°46'55.31 "W

Latitude/Longitude datum: WGS 84







- Proposed Injection Well
- Proposed Monitoring Well
- Proposed Injection Well Monitoring Well
- Proposed Monitoring Well
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Figure No.

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Title

Proposed Injection and Monitoring Well Locations

Notes

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In addition to the construction and conversion of wells, 21 wells within the SGS 2868 and SGS 2972 areas would be plugged and abandoned. For the locations of GP 32, SGS 2972, SGS 2868, Compressor Station 49, and other Project infrastructure within the BSA, refer to Figure 11.

2.4.4 Field Systems

The proposed Project would include the installation of a system of onsite intra-field gathering and distribution lines for various co-located services, including steam distribution within South Belridge, water treatment facilities, source water gathering, produced gas distribution, softened water transfer, separated produced gas distribution, and installation of communication networks. Where pipelines are placed below ground at internal access road crossings, the proposed pipelines would be installed using conventional trenching techniques. Where the pipelines cross public roads, the pipelines would be installed using a combination of trenching and jack-and-bore techniques.

The field gathering and distribution system has been designed to monitor CO_2 injection operations and locate pipeline corridors on raised pipe supports to minimize external corrosion. Construction sequencing and timing for field systems would be concurrent with other additions and improvements to the existing oil field facilities.

One of the Project objectives is to reduce the carbon intensity of Aera Energy's produced oil and gas. Steam pipelines would be installed to distribute steam from the SGS 2972 and SGS 2868 sites to areas of the field where steam is currently generated without CO_2 capture. These new steam lines would allow Aera Energy to prioritize generating and supplying steam from the SGS 2972 and SGS 2868 sites with CO_2 capture. The steam lines would be constructed of pipeline in sizes ranging from 6- to 14- inches in diameter. The additional pipelines would be routed along access roads on raised pipe supports to minimize external corrosion. Where pipelines are placed below ground at internal access road crossings, the proposed pipelines would be installed using conventional trenching techniques. A total of approximately nine miles of new steam pipelines would be installed as part of the proposed Project.

2.4.5 Support Infrastructure

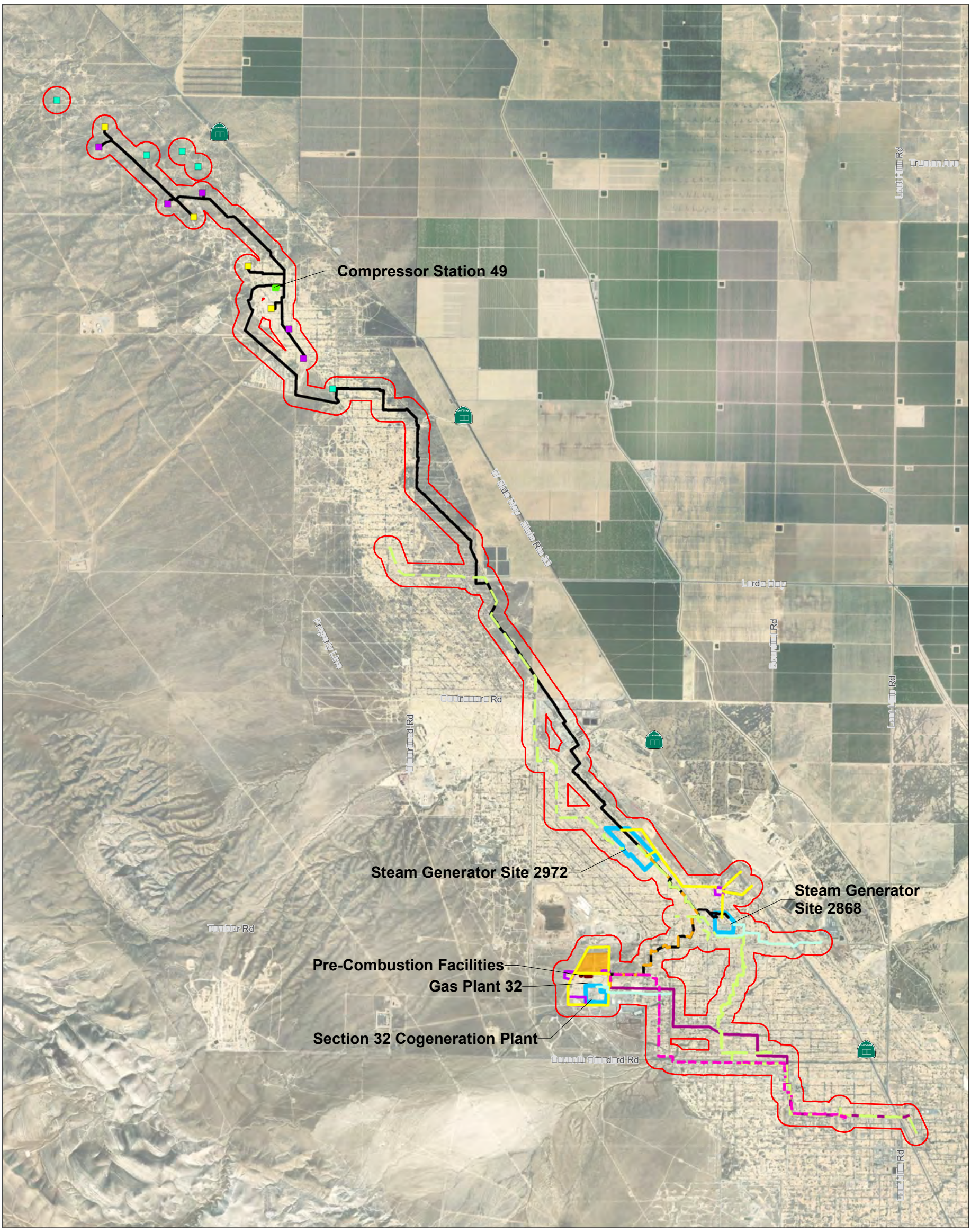
2.4.5.1 Buildings

The Project would utilize existing buildings, as well as new control rooms at the SGS 2972 and SGS 2868 capture facilities. During construction, and as needed during Project operational periods, temporary modular buildings may be used to provide any required offices space, meeting space, and storage space.

2.4.5.2 Domestic Water and Septic Systems

Existing available domestic water and septic systems are available at existing buildings. New domestic water from Aera Energy's existing groundwater wells located in the Buena Vista Water Storage District would be supplied to the two new control rooms. New septic systems or holding tanks would be installed at the new control rooms.




Compressor Station 49
Steam Generator Site 2972
Steam Generator Site 2868
Pre-Combustion Facilities
Gas Plant 32
Section 32 Cogeneration Plant

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2.4.5.3 Emergency Systems

Aera Energy has developed an Emergency and Remedial Response Plan (ERRP) specifically tailored to the proposed CO_2 operations for the Project. The ERRP describes actions that Aera Energy would take to address movement of the injection fluid or formation fluid in a manner that may endanger an underground source of drinking water (USDW) during the construction, operation, or post-injection site care periods for the proposed Project. The Plan is intended to meet the requirements of 40 Code of Federal Regulations (CFR) 146.94 Emergency and Remedial Response.

In some cases, particularly where life threatening safety is involved, Aera Energy would immediately cease injection. However, in some circumstances, Aera Energy would, in consultation with the UIC Program Director, determine whether gradual cessation of injection would be appropriate.

Control systems would be installed on individual injection and monitoring wells to monitor system performance and subsurface conditions. In the event of an emergency, Aera Energy operators would remotely activate closure of an emergency shutdown valve on the flowline from that well or for the entire pipeline system. The emergency shutdown valve protects the distribution system and other downstream pressure piping from overpressure. In the event of a system shutdown, the CO_2 may be vented to the atmosphere to protect against damage to facilities, pipelines, and wells.

2.4.5.4 Water Systems

The proposed Project would require, on average, up to approximately 1,223 acre feet per year (afy) (26,000 barrels [bbls] of water per day [BPD]) for use in the CO_2 capture facilities for approximately 20 years of operation. The proposed Project would primarily use produced water from the South Belridge Oil Field. Fresh water would be minimally used as potable water to control rooms, fire/emergency supply as needed, facility housekeeping, and only used in the process if sufficient water is allocated under Aera Energy's water rights. Water treatment facilities would be installed at the CO_2 capture facilities to treat produced water.

2.4.5.5 Access Roads

CO_2 capture facilities would be constructed immediately adjacent to the existing COGEN 32 and GP 32 facilities in the South Belridge Oil Field. The CO_2 facilities would be accessible by Main Camp Road, either from Oasis Road off Seventh Standard Road or directly from Seventh Standard Road.

Access roads within the South Belridge Oil Field would be improved (Figure 12) to allow for safe and efficient delivery of equipment to the carbon capture facility sites during the construction period and for ongoing maintenance and operating activities after start-up. Existing access roads within the North Belridge would be utilized to provide access for pipeline and well construction. The road would be repaired as needed to allow for safe and efficient access.



2.4.6 Utilities and Communications

2.4.6.1 Electrical Transmission Power Line Interconnection

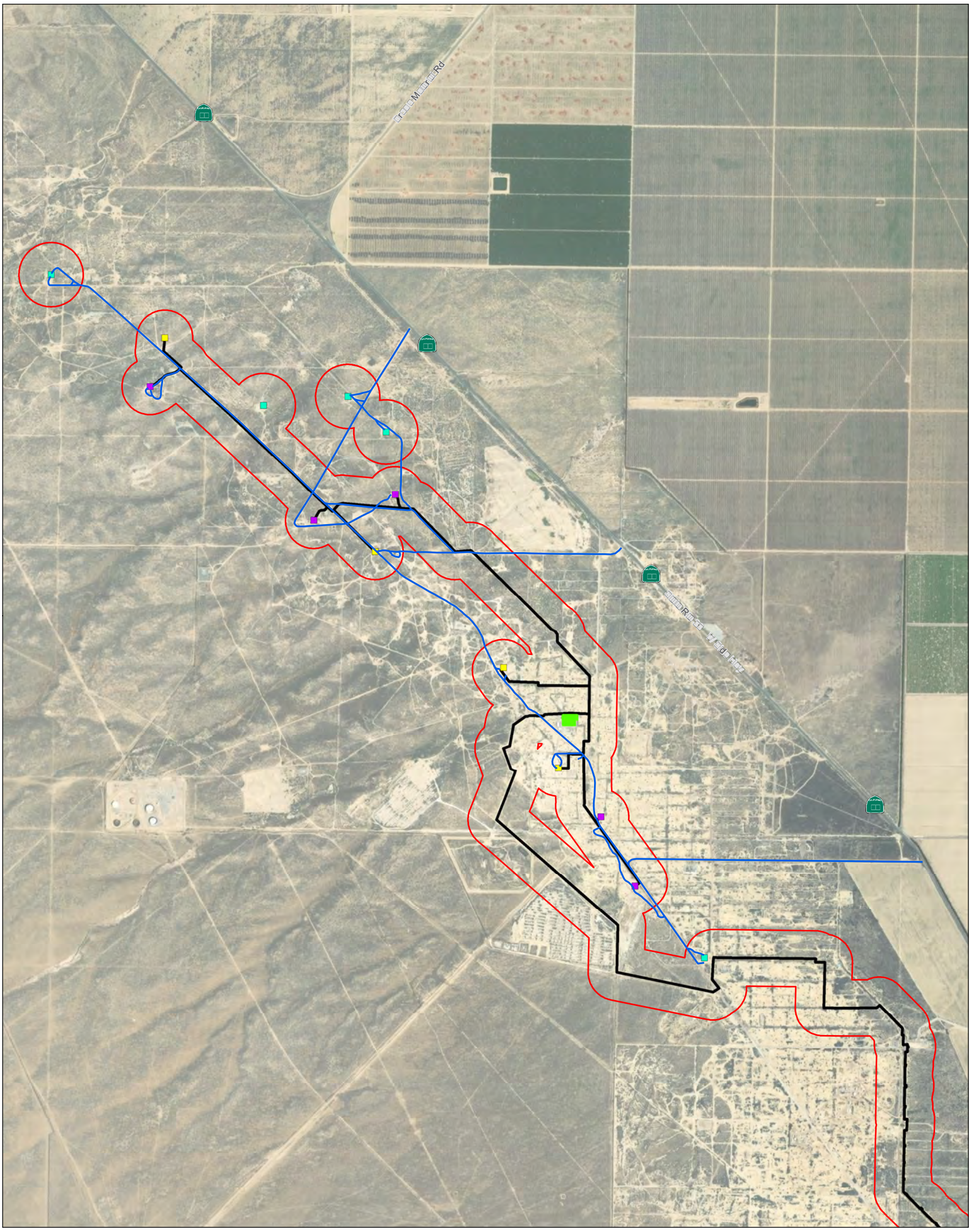
The existing facilities in the BSA are currently being served from Pacific Gas and Electric's (PG&E's) distribution system via existing substations. Power supplied by COGEN 32 is backed up by standby electrical service interconnection from PG&E. The Project would require transmission-level service interconnection as load demand increases. The expected maximum electric load of the Project is approximately 49 megawatts, via Aera Energy -owned equipment, to power all facility processing, pumps, maintenance, monitoring, control, and communication systems. Therefore, the proposed Project would include the construction of an Aera Energy -owned 115 kV transmission power line interconnection as well as two Aera Energy -owned 115 kV/12 kV substations. Additional improvements to off-site PG&E substations may also be necessary; however, those potential improvements have not been specified at this time.

Aera Energy's project includes two transmission lines to serve the CO_2 capture facilities; 1) an approximate 0.46-mile overhead transmission power line interconnect from Aera Energy's existing 115 kV power line along SR-33 to a new onsite Aera Energy-owned 115/12 kV substation; and 2) an approximate 0.8-mile overhead transmission power line interconnect from Aera Energy's existing 115 kV power line along Hill Road within the South Belridge Oil Field to a new on-site Aera Energy-owned 1225/12 kV substation adjacent to GP 32. The 115 kV power line would be constructed, operated, and maintained by Aera Energy. Pending final design of the electrical transmission line, improvements and modifications may also be required at the existing PG&E-owned substations within the South Belridge Oil Field. Work at existing PG&E-owned substations is expected to occur within the existing substation properties.

Interconnection of the proposed Aera Energy -owned 115/12 kV substations to the existing electric transmission grid would require construction of new 115 kV power line tap from the 115 kV power lines. Although design is preliminary, the Project would be supported by up to approximately 17 wooden poles spaced every 400 feet. The wooden poles would be embedded approximately six feet deep.

The substation would consist of incoming metering and switching equipment, transformers, and protective equipment to monitor and provide protection for the various circuits providing power to the new equipment. The incoming 115 kV power line would come into the Aera Energy -owned substations via overhead aluminum conductors terminating on an A-frame structure. Following the A-frame is the high voltage circuit breakers that protect the facility from over and under voltage conditions, as well as fault conditions (abnormal electric current) that may develop along the system.




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2.4.6.2 Electrical Distribution

Electrical power would be supplied from Aera Energy's 115 kV distribution system and would include new distribution lines to two new 115kv/12kV electrical substations. From the substations, new 12kV distribution lines would supply power to power distribution centers adjacent to each of the CO_2 capture facilities. The power distribution centers would include disconnects, breakers, transformers, and motor control centers. Electrical power from the motor control centers would be connected to the motor and lighting loads within the CO_2 capture facilities.

Electrical power to the field loads would run on a 12 kV primary/480-volt secondary overhead power distribution system. Pole or pad-mounted transformers would be located at the booster station and other ancillary facilities. Additionally, electrical power drops would be provided to each injection and monitoring well using nearby 12kV overhead electrical service.

2.4.6.3 SCADA Networks

A SCADA network is a control system comprising of computers, networked data communications and a graphical user interface for high-level supervision of processes. The Project would utilize a SCADA network for normal operation of CO_2 processing, pipeline, and injection equipment. Some individual equipment may also include programmable logic controllers. The distributed control system and programmable logic controllers would control equipment and processes and provide data on process conditions and performance. When applicable, distributed control system and programmable logic controller communication would utilize fiber optic networks.

Process control and monitoring stations would be in each of the CO_2 capture facilities. The monitoring and control stations would be configured to provide data and status information to assist operators to quickly identify and resolve issues. Field measurement and control equipment would be configured to be monitored and operated both locally and from the central processing facility control building. In the event of a serious out-of-normal-range condition, the distributed control system and local equipment programmable logic controllers would be programmed to safely shutdown equipment and processes.

2.4.6.4 Injection Monitoring Systems

Each monitoring well would be equipped with downhole monitoring equipment which would include pressure and temperature gauges and, on select wells, may also include fiber optic distributed temperature sensors (DTS) and/or distributed acoustic sensors (DAS). Pressure and temperature gauge lines would be strapped to the outside of the tubing for data transmission to surface for data collection and monitoring. In addition to logs, downhole samplers can be run through the tubing to recover fluid samples from the reservoir. The internal diameter of the tubing planned for injection wells is sized for the planned injection rate.



2.5 CONSTRUCTION PROCEDURES

This section describes the construction of the Project components discussed above in Section 2.4 (Proposed Project Components). The Project is proposed to be implemented in phases to maximize efficiency and help moderate construction activity levels. Most of the processing facility construction would occur over a three year time period, expected to start in 2025 after the applicable permits are issued.

CO_2 capture facility and infrastructure construction would occur for approximately three years, starting with the Pre-C facility construction at GP 32. Sequential construction would occur for construction of the Post-C facilities located at COGEN 32 and the two steam generator settings. Injection well pad construction, drilling and plugging and abandonment activities, and pipeline construction activities would begin concurrently with the start of facility construction. Installation of CO_2 distribution pipelines, installation of intra-field electrical distribution, water treatment facilities and pipelines, and well hookups would occur throughout the three year period.

2.5.1 Grading and Site Disturbance

The Project would require minor grading of the proposed CO2 capture facilities, totaling approximately 40 acres, most of which is previously disturbed area. The Project would maximize the use of existing roads, well pads, and cleared areas wherever possible. Proposed cut and fill volumes are approximately 203,000 cubic yards total. Each well pad would be approximately 145 feet by 280 feet in area. Each well pad would be cleared of vegetation and leveled to prepare it for well drilling. Any excess spoils would be transported to a designated fill location within the Project footprint for re-use as fill material or moved off-site to an appropriate soils disposal or reuse facility.

Additional ground disturbance would occur for construction of the utilities component of the Project including water pipelines and overhead power lines. The estimated disturbance from the Project pipelines would be minimized as most would be located aboveground, placed on existing and new pipe supports and along existing pipeline corridors. The estimated ground disturbance for the 115 kV and 12 kV power line would be approximately 2.1 acres. Refer to Table 2 below for a summary of the proposed Project's Site Disturbance Area. Note that some disturbance areas overlap. Refer to Table 5 for specific habitat impact area calculations.

Table 2. Site Disturbance Area

Project Component	Temporary Disturbance Area (acres)	Permanent Disturbance Area (acres)	Grading Volume (cubic yards)[a]
Pre-C Capture Facility (GP 32)	2	2	7,000
Post-C Facility at SGS 2868	12	9.6	39,000
Post-C Facility at SGS 2972	16	14	52,000

Project Component	Temporary Disturbance Area (acres)	Permanent Disturbance Area (acres)	Grading Volume (cubic yards)[a]
Post-C Facility at COGEN 32	9.7	9.7	32,000
Booster Pump Station	0.5	0.5	1,600
Injection Well Pads (9 total)	8.5	8.5	27,500
Monitoring Wells (9 total)	8.5	8.5	27,500
CO_2 Pipelines (15.8 mi.)	95.8	9.6[b]	NA
Gas Lines (5.1 mi.)	22.5	2.3[b]	NA
Water Lines (4.2 mi.)	21.4	2.1[b]	NA
Steam Lines (7 mi.)	42.5	4.3[b]	NA
Electrical Lines (1.3 mi.)	2.1	1	NA
Electrical Substations (2)	5	5	16,200
Staging Area	25	25	NA
TOTALS:	272[c]	102[c]	203,000

Notes:

[a] Assumes two feet of over-excavation and re-compaction.

[b] Assumes 5-foot wide permanent disturbance for above-ground piping.

[C] Some disturbance areas over-lap. Refer to Table 4 for Impact Area calculations.

NA – Not applicable

Some pipelines are co-located.

2.5.2 CO2 Capture and Processing Facilities

2.5.2.1 Removal and Demolition of Existing Facilities

The proposed CO_2 capture facility areas currently contain piping and other idle equipment that would be removed, and wells that would be permanently abandoned, prior to construction of the proposed facilities. There is some debris from former operations, such as broken concrete, in scattered locations throughout the Project footprint. Debris would be reused or recycled to the extent feasible. Five shipping pumps, two water tanks, two electrical transformers, a water heater, an electrical panel, and one moisture separator



would be removed or demolished on the land north of GP 32; all equipment is out of service. Demolition of various oil production facilities (old pipeline) and equipment (a production header) would occur on approximately nine acres of land around SGS 2868. Miscellaneous rubble piles would also be cleared. Demolition of various oil production facilities (including old foundations and pipeline) and equipment would occur around SGS 2972.

The proposed CO_2 capture facility areas also contain abandoned structures that would be demolished prior to construction of the proposed facilities. Demolition of a sulfur treatment facility, maintenance shed, old equipment yard, and a building would occur on approximately 1.5 acres of land at GP 32. The to-be-demolished building holds a former Control Room, Lab, Conference Room, and associated offices. The old equipment yard currently stores three gas compressors and five cylindrical gas tanks, which would be relocated prior to demolition. One storage building would be demolished on the land northeast of GP 32.

2.5.2.2 Processing Facilities Construction

Grading for the CO_2 capturing facilities would occur over an approximate 3-year construction period and would require approximately 40 total acres of disturbance on areas with pre-existing disturbance. The following outlines construction procedures associated with grading and installation of the processing facilities:

- **Environmental Survey**. Pre-activity biological surveys would be completed prior to initiating work.
- **Staging.** Material and equipment would be gathered on-site;
- **Inspection.** Material and equipment would be inspected for quality assurance. Construction equipment would be verified to meet applicable environmental regulations. Equipment operators and field workers would be verified to possess the proper qualifications;
- **Civil.** Soil would be graded and excavated. Concrete equipment foundations, pipe supports, pads and containment would be poured;
- **Equipment.** Major vessels and equipment would be set on foundations;
- **Supports.** Pipe supports would be installed;
- **Plant Piping.** Piping, valves, and instrumentation would be installed between equipment and vessels. Welds would be radiographed and connections strength tested;
- **Electrical.** Electrical panels, conduit, and power wiring would be installed;
- **Instrumentation.** Instrumentation signal wiring and tubing would be installed. Terminations would be made at the instrumentation and connections would be tested;
- **Corrosion Control.** Piping and non-galvanized structural steel would either be insulated or primed and painted. Buried steel piping would be coated or wrapped with protective coatings. Cathodic protection would be used in certain areas to protect buried steel piping from external corrosion. Insulating kits would be used to protect buried steel piping from external corrosion. Insulating kits would be used to isolate above-ground from buried piping;
- **Start-Up Preparation.** All valves and instrumentation would be put in normal operating positions/modes for start-up. All safety devices would be checked for proper operation;
- **Personnel Training.** Operators, mechanics, and instrument mechanics would be trained to operate and maintain the facilities;
- **Start-Up.** Plant would be started and tested for proper operation. Any problems or issues would be resolved; and



- **Operation.** Normal operation would commence.

2.5.2.3 Removal and Demolition of Existing Facilities

The proposed CO_2 capture facility areas currently contain piping and other idle equipment that would be removed, and wells that would be permanently abandoned, prior to construction of the proposed facilities. There is some debris from former operations, such as broken concrete, in scattered locations throughout the Project footprint. Debris would be reused or recycled to the extent feasible. Five shipping pumps, two water tanks, two electrical transformers, a water heater, an electrical panel, and one moisture separator would be removed or demolished on the land north of GP 32; all equipment is out of service. Demolition of various oil production facilities (old pipeline) and equipment (a production header) would occur on approximately nine acres of land around SGS 2868. Miscellaneous rubble piles would also be cleared. Demolition of various oil production facilities (including old foundations and pipeline) and equipment would occur around SGS 2972.

The proposed CO_2 capture facility areas also contain abandoned structures that would be demolished prior to construction of the proposed facilities. Demolition of a sulfur treatment facility, maintenance shed, old equipment yard, and a building would occur on approximately 1.5 acres of land at GP 32. The to-be-demolished building holds a former Control Room, Lab, Conference Room, and associated offices. The old equipment yard currently stores three gas compressors and five cylindrical gas tanks, which would be relocated prior to demolition. One storage building would be demolished on the land northeast of GP 32.

2.5.2.4 Proposed Grading and Site Development

The Project would require minor grading of the proposed CO_2 capture facilities, totaling approximately 40 acres, most of which are previously disturbed areas. The Project would maximize the use of existing roads, well pads, and cleared areas wherever possible. Proposed cut and fill volumes are approximately 203,000 cubic yards total. Well pads would be approximately 145 feet by 280 feet in area. Each well pad would be cleared of vegetation and leveled to prepare it for well drilling. Excess spoils would be transported to a designated fill location within the Project footprint for re-use as fill material or moved off-site to an appropriate soils disposal or reuse facility.

Additional ground disturbance would occur for construction of the utilities component of the Project including water pipelines and overhead power lines. The estimated disturbance from the Project pipelines would be minimized as most would be located aboveground, placed on existing new pipe supports and along existing pipeline corridors. The estimated ground disturbance for the 115 kV and 12 kV power line would be approximately 2.1 acres.

2.5.3 Well Construction, Drilling, Completion, and Decommissioning

The proposed Project includes re-purposing five existing oil wells and drilling four new wells to use for CO_2 injection activities. Additionally, five existing wells would be converted to monitoring wells to monitor the CO_2 plume.



2.5.3.1 Well Pads and Roadways

Well locations have been carefully selected to minimize disturbance by reusing existing well pads, where feasible, and to allow for the permanent CO_2 sequestration within the dedicated zone. Well pads have been designed to minimize the amount of surface disturbance while meeting the technical constraints of drilling and operating the wells. Areas within the designated well pad area would be cleared of all vegetation and other deleterious material utilizing heavy equipment. The proposed wells would be constructed on existing well pads; however, these pads may need to be cleared of encroaching vegetation or enlarged to meet Project requirements. Earthwork would be completed utilizing conventional equipment (e.g., dozers, loaders, scrapers, motor graders, excavators, sheep's foot compactors, smooth drum rollers, water trucks. etc.).

2.5.3.2 Injection Well Drilling and Completion

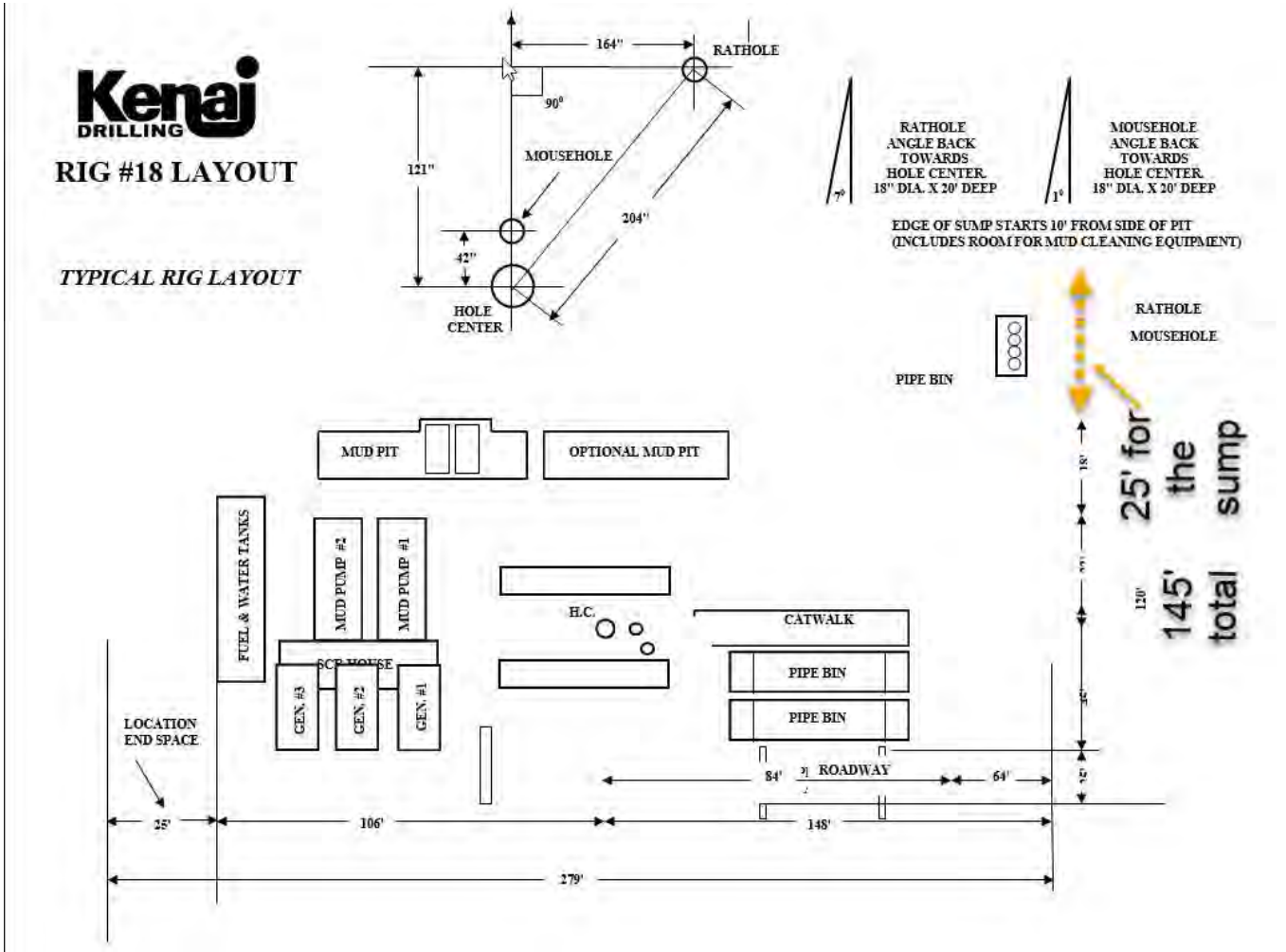
Pad Area and Drilling Rig

Well pad construction would minimize additional ground disturbance through use of existing pads and disturbed areas to the extent feasible. Approximately 8.4 acres would be permanently used and maintained for the injection well pads during the life of the Project. The selected monitoring wells are all existing wells. Minor well pad maintenance may be conducted at each monitoring well location.

Drilling rigs would operate 24 hours per day while drilling, and depending on the type of well, would operate consecutively for up to 14 days at each location. The specific rig has not been determined at this time, but the rig would be the equivalent to Kenai #18 (see Figure 13).

Additional drilling equipment for either rig would include: fluid handling equipment, waste storage containers, four generators, mud handling system, blow out prevention equipment, spill prevention equipment, hydrogen sulfide (H_2S) detection equipment, three mud pumps, cuttings bin, catwalk, trailer (also referred to as "doghouse") and others. Note, the equipment listed is for a typical drilling operation, the exact equipment list and layout may vary depending on the specific well to be drilled.





Notes

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Project Location
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Client/Project 185805372

Aera Energy LLC
CarbonFrontier Project
Biological Resources Technical Report

Figure No.
13

Title
Typical Rig Layout

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Construction Methodology

The proposed drilling and production operations would be performed in accordance with USEPA UIC Class VI well regulations. The installation and drilling of injection wells is a multi-step process. After a well drilling location is determined, a conductor pipe with diverter valves is installed. These valves would allow any fluid that flows into the wellbore during drilling to be diverted and controlled. The drilling rig and supporting drilling equipment is then set up on location and the drilling process begins. This is called the "spud" of a well.

To progressively deepen the wellbore, a downward force must be exerted on the drill bit. This downward force is provided by the drill pipe that is attached to the drill bit. As the bit continues to drill downward, more pipe is attached on top thereby increasing the weight on the bit. The drill bit rotates as it moves down the wellbore. The rotating action is produced by a rotary table, top drive, or motor; depending on which drilling rig type is being utilized.

Rock cuttings are generated as the drill bit spins on the rock formation it is drilling through. These cuttings must be removed from the wellbore by drilling fluids (drilling mud). The drilling fluids are pumped through the drill pipe, out of the openings in the drill bit and then back up between the space between the drill pipe and the hole (this is referred to as the annulus). The mud handling equipment at the surface separates the cuttings from the mud, and recycles the mud to be used again. In addition to circulating the drill cuttings, drilling mud provides lubrication and cooling to the drilling bit and well control by changes to the drilling mud weight.

Once the wellbore is drilled to a specified depth, the drill pipe is pulled out of the hole and casing is installed. The well casing is a pipe that is permanently installed in the wellbore to stabilize the hole, prevent entry of wellbore fluids, and help to prevent the exit of drilling muds out of the wellbore. Once the casing has been run to the specified program depth, it is then cemented in place. Cement is pumped down the inside of the casing string and circulated up the annulus. For this Project, casing and cementing specifications would follow the requirements of the USEPA's UIC Class VI well regulations (40 CFR 1467.81 et seq.).

A smaller drill bit is then placed into the wellbore and the well is drilled deeper. This process continues with subsequently smaller drill bits and smaller casing strings being installed until the completion depth is reached. Once the wellbore is drilled to a specified depth, the drill pipe is pulled out of the hole and casing is installed. Casing is a steel pipe that is permanently inserted into the wellbore to create a barrier to prevent fluid transmission. Once the casing has been run to the specified depth, it is then cemented in place, effectively sealing the outside of the casing to the wellbore. The casing also serves as the foundation for the blowout preventer.

A total of three casing strings would be installed on Project wells.

Next, the injection liner piping (long string casing), consisting of materials compatible with exposure to the injected fluid, would be drilling through the injection zone. The injection liner would be inserted into the well and cemented in place. The injection well would be completed by perforating the authorized injection



zones. Completion equipment consisting of a packer, monitoring equipment, and tubing would be installed.

Well Drilling Fluids and Cuttings Disposition

The drilling process would use a water-based drilling mud composition the primary components of which are gel and water. The drilling fluids and cuttings would either be reused onsite (i.e., cuttings may be used onsite for fill and road base material) or solidified and then transported to an approved facility for recycling or disposal.

Hydrogen Sulfide Monitoring

H_2S gas is known to occur in the 64 Zone and overlying formations. The Aera Energy "Hydrogen Sulfide Policy" would be followed throughout the drilling operations, which addresses monitoring equipment requirements, personnel responsibilities, first aid, and evacuation procedures. Continuous ambient air monitoring for both hydrogen sulfide and flammable gases would be in effect for the entire drilling process.

Blowout Prevention Equipment

Blowout prevention systems are safety systems that are used in the drilling of an oil and gas well. These systems prevent the uncontrolled release of reservoir fluids and shut off flow to prevent spills and material releases. Blowout prevention equipment would be used during drilling and removed once the well has been completed and secured. Blowout prevention equipment would conform to the California Department of Oil, Gas, and Geothermal Resources (DOGGR) (now CalGEM) publication M07 "Blowout Prevention Equipment in California, Equipment Selection and Testing" 2006 Edition (DOGGR 2006).

Lighting System

The drilling operation would provide sufficient lighting to ensure safe working conditions. Vapor proof lighting and wiring would meet the California Division of Occupational Safety and Health specifications. The top of the derrick would have a red beacon to address potential aviation hazards. Rig lighting would be aimed towards the Project footprint, and away from the night sky and neighboring properties.

Well Re-Purposing

Within existing wells to be converted to CO_2 injection wells, the completion equipment would be removed, and the well would be cleaned out to the required depth for injecting into the 64 Zone Sandstone sequestration zones. Casing inspection and annulus evaluation logs would be completed to confirm that the annulus seal through the confining layer is sufficient to prevent movement of fluids behind the existing long string casing. A new inner casing would be installed and cemented to the surface.

The injection well would be completed by perforating the authorized injection zones. Completion equipment consisting of a packer, monitoring equipment, and tubing would be installed.



2.5.3.3 Monitoring Well Modifications

The construction procedures for repurposing of existing wells to monitoring wells are similar to repurposing wells for injection. The differences include perforation intervals in the appropriate zones to be monitored, and smaller outside diameter tubing would be used if the tubing inside diameter is large enough to allow running wireline logging tools and downhole sampler equipment that are planned to meet periodic monitoring requirements as required by USEPA requirements.

2.5.3.4 Well Stimulation

Aera Energy believes that the injection zone (64 Zone Sandstones) would require stimulation in all Project injection and monitoring wells, including wells either repurposed to or newly drilled for Class VI service. The stimulation program would be necessary because depleted reservoir pressure in the sequestration zone would cause fluid losses during drilling and completion operations, and cement losses during primary cementing of injection liners. Stimulation to remove this initial near-wellbore damage would occur after well construction is finished but prior to the start of CO_2 injection.

Well stimulation may also be necessary on specific injectors after the start of CO_2 injection if low initial injectivity is encountered or if reductions in ongoing injectivity are observed.

The method used for all stimulation work would be matrix acidizing. Aera Energy would ensure that no new fractures develop during stimulation by limiting pump pressures to a maximum of 80% of the sequestration zone fracture gradient, measured or calculated during Pre-Operational Testing. Additionally, Aera Energy would ensure that no loss of containment occurs by maintaining at least 20 feet of separation between the base of the primary confining zone and the top wellbore opening to the injection zone below.

All chemical additives used in the stimulations would be tested and confirmed compatible with the injection and confining zones.

2.5.3.5 Downhole Monitoring Equipment

Injection and monitoring wells would be equipped with downhole devices and equipment to evaluate external mechanical integrity of the wells and monitor growth of the CO_2 plume. The wells would be designed to allow the use of these testing and monitoring devices and workover tools as required by USEPA regulation. Downhole monitoring equipment would include pressure and temperature gauges and, on select wells, may also include fiber optic DTS and/or DAS. Pressure and temperature gauge lines would be strapped to the outside of the tubing for data transmission to surface for data collection and monitoring. The DTS and/or DAS line would be cemented in the annulus between the inner (injection) casing and the outer casing. The annuli would be sized to allow for data lines and clamps to be installed for downhole monitoring devices lines.

The internal diameter of the tubing planned for observation monitoring wells would be sized to allow running wireline logs such as pulsed neutron, saturation, pressure, and noise. In addition to logs,



downhole samplers can be run through the tubing to recover fluid samples from the reservoir. The internal diameter of the tubing planned for injection wells is sized for the planned injection rate.

2.5.4 Well Decommissioning

Existing wells that require decommissioning (plugging and permanent abandonment) as part of the construction of the proposed Project would follow the decommissioning procedures listed below:

- Remove surface equipment (such as flowlines, sensor equipment, non-well control valves, and miscellaneous debris) from location.
- Move in subsurface equipment.
- Perform pre-cementing operations, kill the well, conduct pre-abandonment tests if required by regulations, and remove rods, tubing, pump, and other equipment.
- Clean out wellbore to total depth, or at least 25 feet within the perforation.
- Complete cementing operations, including the following. Set the bottom hole plug across perforations as specified in California laws or CalGEM regulations. Tag cement to confirm hardness per CalGEM regulations. Bring cement up to next marker. Perforate and isolate any un-cemented annuli if they exist at required zone tops through a variety of methods. If un-cemented annuli do exist, timeline for well abandonment would be extended. Tag cement at each relevant marker. Steps described previously would be repeated until cement is at surface.
- Top off cement with surface crew, if necessary.
- Cut-off well head 5 feet below grade.
- Weld metal plate with ending 5 digits of American Petroleum Institute (API) number on top of cemented well head.
- Restore location to original grade.

2.5.5 CO_2 Pipeline Construction

The Project would require the installation of a new approximately 10 mile, 6-inch to 12-inch diameter CO_2 pipeline that would connect the CO_2 capture facilities to the injection wells. The pipeline would be built primarily aboveground within Aera Energy's existing operating properties. The CO_2 pipeline would be in place prior to the first CO_2 injection.

Excess spoils generated during the course of the pipeline construction project would be transported to a designated fill location within the Project footprint for re-use as fill material as part of the Project or would be disposed at a permitted disposal site.



2.5.5.1 Access and Staging Areas for Pipeline Construction

The CO_2 pipeline component of the Project would be accessed from existing oil field access roads. No new roads would be constructed as part of this component of the Project and no existing roads would require additional grading or improvements for the pipeline construction activities. Existing disturbed areas would be utilized for pipeline construction staging areas.

2.5.5.2 Pipeline Construction Methodology

Construction and installation of the CO_2 pipeline would be construction primarily aboveground, resting either on existing pipe supports or new supports. At designated internal road crossings, the pipeline would be installed by conventional trenching (Figure 14, Typical Pipeline Construction). At public road crossings, the pipelines would be installed using jack and bore construction techniques. Refer to Figure 15 – Typical Jack and Bore Work Area. At ephemeral creek and drainage channel crossings, the pipelines would be span over the channel, with pipe supports placed outside of the active channel on either side.

The sequence of construction activities for the CO_2 pipeline component of the Project is summarized below. Construction of the CO_2 pipeline is scheduled to take approximately 6 months.

- **Mobilization and Staging:** Prior to construction, the contractor would mobilize the site and establish staging areas for materials and equipment storage. Construction equipment would be staged along the route and would progress with the pipe installation.

- **Surveying, Staking and Flagging:** The centerline would be marked at line-of-site intervals, at points of intersection (including offset stakes marking the edges of the construction right-of-way [ROW]), and at all known underground facilities. In addition, any environmentally sensitive areas (i.e., biological, cultural, and/or hydrological resources) would be clearly marked.

- **Clearing and Grading:** The majority of the temporary construction easement occurs along the previously disturbed pipeline corridors. Where necessary, existing vegetation would be cleared and the ground surface within the construction ROW would be graded and smooth to provide safe and efficient operation of construction equipment.

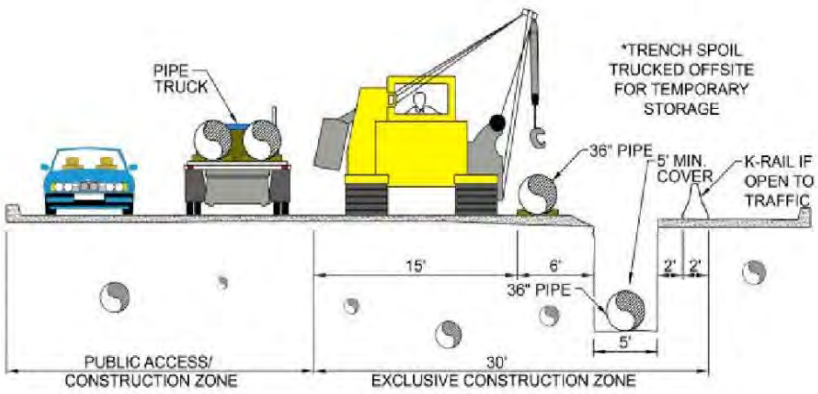
- **Hauling and Stringing:** The pipe would be hauled by truck to one of the staging areas where it would be offloaded by cranes and loaded onto stringing trucks to be delivered to the construction ROW.

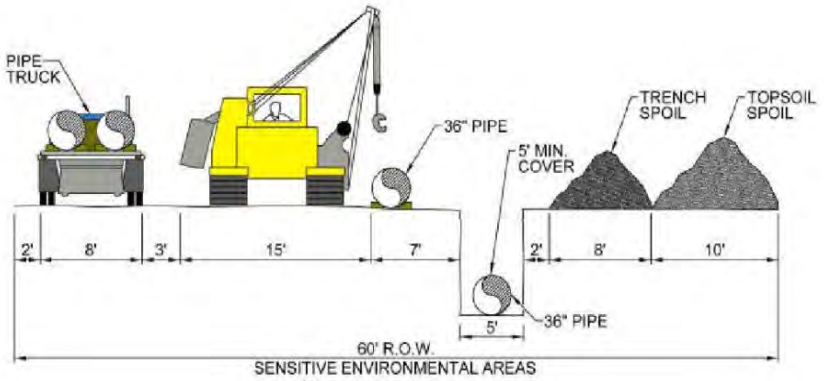
- **Pipe Supports:** Pipe supports would be constructed at approximately 20-foot to 30-foot intervals along the pipeline, as needed. A truck-mounted drill would be used to auger a 24-inch to 36-inch diameter hole approximately 6-8 feet deep. The pre-fabricated steel pipe support would be set into the hole and the hole would then be filled with concrete.

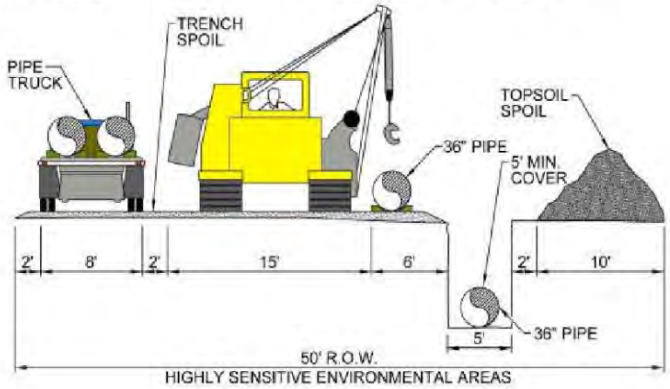


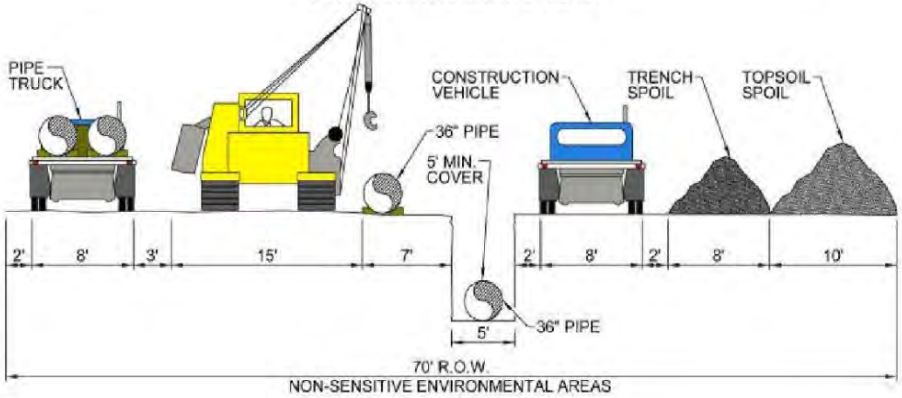
- **Trenching:** The typical trench would be approximately five feet deep and between two and five feet wide. Excavated soils may be preserved and used as backfill materials at the site of origin. Spoil piles would be placed along the trench in areas where a temporary construction easement is available. Materials deemed unsuitable for backfill would be disposed of offsite and/or transported to Aera Energy's Belridge road-mix facility for re-use in accordance with all applicable regulations.











Notes

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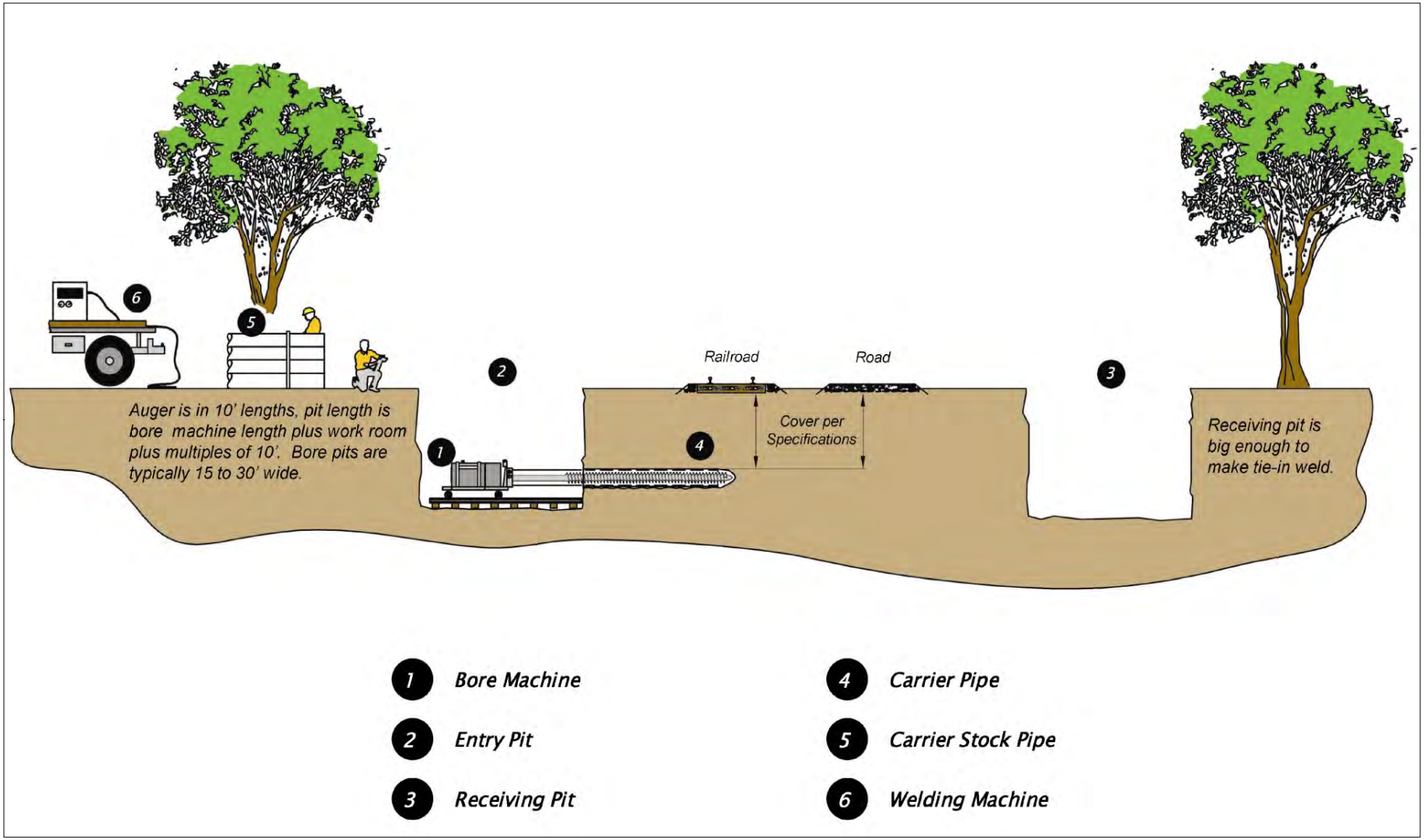
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CarbonFrontier Project
Biological Resources Technical Report

Figure No.
14

Title
Typical Pipeline Construction

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Notes

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Stantec AERA

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CarbonFrontier Project
Biological Resources Technical Report

Figure No.
15

Title
Typical Jack and Bore Work Area

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- **Jack-and-Bore:** Jack-and-bore tunneling would be utilized at road crossings, where required. This methodology is used for horizontal pipeline construction and entails the excavation of pits on either side of the crossing and use of a boring machine with a cutting 'head', auger, and casing. The auger and casing are pushed behind the 'head' as it cuts through the ground. The auger caries the debris back to the pit as the head cuts. Jack-and-bore horizontal tunneling is anticipated to take approximately 10 days to complete at each location. Additional locations may be added based on circumstances that are unknown at this time, such as utility conflicts or requirements imposed by the County or Caltrans. Typical horizontal bores are 10 feet deep and require entry pits of approximately 15 feet by 40 feet and receiving pits of approximately 10 feet by 15 feet. In any location where Jack and Bore is used, there is only one entry pit and one exit pit (Figure 15, Typical Jack and Bore Work Area).

- **Pipe Placement, Welding, and Coating:** New pipeline segments would be inspected to locate and repair any faults or voids in the pipeline coating prior to being lowered into the trench. In areas where the pipe is joined within the ditch, "bell holes" would be dug at each pipe joint to facilitate access for welding and joint coating application. These welds would typically be made in the ditch, with the pipe at its final elevation and alignment. Welding and Coating would apply to all areas throughout the Project.

- **Weld Inspection:** All welds would be inspected in accordance with state and federal welding requirements. When inspected radiographically all radiographs would be recorded and interpreted for acceptability in accordance with API 1104. All rejected welds would be repaired or replaced as necessary and re-radiographed. The inspection reports would be kept for the life of the pipeline.

- **Line Lowering, Backfill, and Compaction:** For conventional open trench segments, the welded pipe segments or individual pipe lengths would be lifted and lowered into the trench by side boom tractors. The native material excavated from the pipeline trench would either be reused as backfill, transported to Aera Energy's Belridge road-mix facility, or would be hauled and disposed offsite to at an approved landfill facility. Required backfill material would be compacted with compaction rollers and/or hydraulic tampers and undergo compaction testing to ensure that all trench locations are compacted in accordance with standard engineering practices and permit requirements. All trenches would either be fenced, backfilled, or covered with steel plates at the end of each workday.

- **Aboveground Equipment Installation:** The majority of aboveground equipment would be pre-fabricated at a staging area and then transported to the respective locations for final assembly and tie-in to the pipeline facilities. Valve and meter set assembly locations would be either paved or graveled. After installation, all above-grade piping and equipment would be painted and the valve would be enclosed by a chain-link fence.

- **Creek Crossings.** At creek crossings, the pipelines will be installed on pipe supports located outside of the bed and bank of the creek channel, and will be supported sufficiently so that they



span the creek. Construction activities will be conducted from outside of the creek channels where possible to avoid impacts to the channels.

- **Hydrostatic Testing:** In accordance with applicable codes and regulations, the entire pipeline would undergo hydrostatic testing prior to operation by pumping water into the test sections, pressurized to design-test pressure, and maintained that pressure for a minimum amount of time to identify defects in construction. Water to be used for hydrotest would be from local water systems. Discharged water would be stored into baker tanks to be held for testing. After results of the samples are analyzed, the water may be used for dust control or used for additional testing on other pipeline segments. The Stormwater Pollution Prevention Plan (SWPPP) Plan prepared by Aera Energy would also include Best Management Practices (BMPs) in case the hydrotest is not successful initially.

- **Pigging:** Pipeline pigs are devices that are inserted into and travel throughout the length of a pipeline driven by a product flow to perform functions, such as cleaning or dewatering and provide information on the condition of the line, as well as the extent and location of any problems. After the pipeline has been hydrostatically tested and dewatered, the contractor would run several utility pigs of various types to remove as much water as possible and any remaining small debris from within the pipeline.

- **Cleanup and Restoration:** All construction material and debris would be removed and disposed of at appropriate landfills or recycled. Clean up and restoration would be ongoing throughout the Project and when an active site is completed, the area shall be restored to surface grade. In upland areas, the ROW would be regraded to its approximate pre-construction contour and stabilized or restored to pre-construction conditions, in compliance with all relevant permits. All staging areas and temporary extra workspaces would be recontoured to pre-construction conditions and would be stabilized or restored in accordance with all relevant permits. All paving repairs would be made in accordance with the current County requirements. As a final step, the route within unpaved portions of the roadway shoulder or private ROW would be marked with approximately five-foot-high pipeline markers placed in accordance with PHMSA standards.

- **Operations and Maintenance:** Maintenance of pipeline and auxiliary facilities would continue to be performed as required by state and federal requirements.

2.5.6 Field Systems Construction

The proposed Project would include the installation of a system of onsite gathering and distribution lines for various co-located services, including produced gas lines, steam distribution, source water gathering, and softened water transfer.

2.5.6.1 Intra-Field Pipelines

The field gathering and distribution system would be designed to locate pipeline corridors primarily along existing pipeline corridors on raised pipe supports to minimize external corrosion. The sequence of



general construction procedures associated with the installation of intra-field pipelines would be similar to the CO_2 pipeline construction described above and would follow the process listed below:

- Mobilization and Staging
- Surveying, Staking and Flagging
- Clearing and Grading
- Hauling and Stringing
- Pipe Placement, Welding, Inspection, and Coating
- Pipeline Installation and Testing

2.5.6.2 Intra-Field Electrical Distribution

The intra-field electrical distribution system would be constructed concurrently with injection well drilling/re-purposing and CO_2 capture facility construction. Once poles are erected, the conductor would be strung from conductor pull and tension sites at the end of the power line interconnection alignment moving from one pole to the next. Each conductor would be pulled into place at a pre-calculated sag and then tension-clamped to the end of each insulator. The sheaves and vibration dampers and accessories would be removed once installation is complete.

2.5.7 Electrical Transmission Interconnection Power Line Construction

Aera Energy would construct, operate, and maintain approximately 1.26-miles of new, 115-kV transmission line to the Aera Energy-owned substations located in the BSA. The estimated permanent disturbance of the 115 kV electrical interconnection would be 2 acres with 4 acres of temporary disturbance. To support the major construction efforts, electrical connections are anticipated be in place prior to significant field activities.

2.5.7.1 Access and Staging Areas for Electrical Transmission Interconnection

Primary access to the power line interconnection sites would be using existing access roads. Construction of the power line interconnection would be completed by the designated contractor. The new wood poles would require approximately six to eight feet of embedment. Construction would involve temporary ground disturbance around each new power pole location (approximately a 50-foot radius) as well as temporary ground disturbance associated with access to each pole location (approximately a 15-foot-wide access route). All new poles and access thereto would be located within existing oil field production areas or along a dirt road. Pole work areas would likely be located approximately every 400 feet for 115kV lines, and 200 feet for 12kV lines. Where final design allows, power pole work areas would overlap. Final design would determine final power pole locations. Temporary staging and lay down areas may also be needed for the construction of the interconnection facilities but would primarily use existing disturbed/developed areas.



2.5.7.2 Construction Methodology for Electrical Transmission Interconnection

Substations. Two new substations would be constructed near the proposed CO_2 capture facilities. Each substation would require approximately 1 acre.

Power Line Removal/Construction. The new 115 kV power lines would be supported by up to approximately 17 wooden poles.

Pole installation would consist of the following basic steps:

- Deliver new pole at pole site;
- Auger new hole using line truck attachment or hand dig if the line truck cannot access the site;
- Backfill around the pole;
- Install bottom section by line truck, crane;
- Install top section by line truck, crane; and
- Install switches where necessary. There may be several SCADA-operable or other switches at the point of interconnection and elsewhere.

Once poles are erected, conductor would be strung from conductor pull and tension sites at the end of the power line interconnection alignment. The average distance is 4,000 feet between pull and tension sites. Each conductor would be pulled into place at a pre-calculated sag and then tension-clamped to the end of each insulator. The sheaves and vibration dampers and accessories would be removed once installation is complete. Transmission Power Line construction and substation improvements are anticipated to take approximately 6 months.

2.5.8 Construction Personnel and Traffic

Equipment and personnel requirements would vary throughout the course of any given year and across the life of the Project depending on the construction activities underway. However, it is estimated that the peak construction workforce would be approximately 300 people.

Drilling rigs would operate 24 hours per day while drilling, and the proposed injection wells are expected to take approximately 14 days to complete. Drilling crews consist of six to seven contractors who would typically be on-site for 12-hour shifts, one starting at noon and the other starting at midnight.

At full build-out, the operational aspects of the Project would require a total of eight to ten personnel. During the years of peak Project operation, the Project is anticipated to generate approximately 12 average daily vehicle trips per day. Of these, two are bulk material and waste deliveries, and 10 are employee vehicle trips. Worker parking on-site would be on Project property, using designated areas such as staging areas.



2.5.9 Construction Timing

Construction of the proposed Project is anticipated to require up to three years to complete. Initial activities are expected to start in 2025 and would include the following tasks: mobilization, demolition, well abandonments, surface facility construction, pipeline construction, and well drilling. Activities in 2026 and 2027 would include well abandonments, facility construction, and pipeline construction.

2.5.10 Equipment and Personnel Requirements

Table 3 – Equipment and Personnel - Peak Estimates provides an annualized summary of anticipated equipment and personnel requirements during construction for each of the major Project components (processing facilities, field infrastructure, and utilities). Equipment and personnel requirements vary throughout the course of any given year and across the life of the Project; therefore, peak year counts and timing are provided.

Table 3. Equipment and Personnel - Peak Estimates

Activity	Peak Monthly Count	
	Personnel	Equipment
On-Site Roads	8	8
Facilities Pad Grading	15	15
Well Pad Grading	14	14
Well Drilling (Injection and Monitoring)	17	17
CO_2 Capture Facilities	96	92
Compressor Station Construction	28	20
CO_2 Main Pipeline	29	29
Distribution Pipelines	23	23
Gas Lines	20	20
Steam Lines	20	20
Water Lines	20	20
Electrical Transmission Line	12	12
Intra-Field Electrical Distribution	12	12



Activity	Peak Monthly Count	
	Personnel	Equipment
On-site Electrical Substations	18	18
Demolition	12	12

2.6 OPERATION AND MAINTENANCE

All facilities and equipment would be operated, maintained, and inspected in accordance with the applicable USEPA requirements. These regulations specify the types and frequencies of safety inspections and maintenance to be performed. Records documenting compliance with these requirements would be maintained on site and would be periodically reviewed by Aera Energy personnel to ensure compliance. In addition, safety and compliance inspections and audits of the facilities are performed on a regular basis by USEPA and other regulatory personnel.

2.6.1 Project Operations and Schedule

The proposed Project construction phase would take approximately three years. The capture of CO_2, and injection and monitoring for the Project would commence as soon as construction for the Project is completed. Project injection and monitoring wells, processing facilities, pipelines, transportation infrastructure, and maintenance involved with the Project operations is anticipated to operate for a period of approximately 20 years. The operational life of the Project would depend on the actual volume of CO_2 supplied and therefore may vary. Following the completion of CO_2 injection operations, there would be a roughly 15-year period of post-injection subsurface monitoring, plugging of injection wells, and post-closure site care. Surface monitoring in the BSA may extend for a period of up to 100 years, or as needed, to detect any CO_2 leaks, in compliance with federal and state requirements.

Aera Energy would employ direct and indirect methods to track the extent of the CO_2 plume and the presence or absence of elevated pressure during the operation period to meet USEPA requirements. Annual fluid sampling and pulsed neutron logging would be conducted at each of the monitoring wells. Pulsed neutron logs performed every three years at injection well sites would provide additional confirmation of CO_2 plume and pressure front extent. Periodic seismic surveys would also be conducted using vibroseis trucks travelling along existing roadways within the North Belridge Oil Field. The frequency of the use of vibroseis trucks would depend on the monitoring program developed in conjunction with USEPA.



3.0 METHODOLOGIES

3.1 LITERATURE REVIEW

A literature search focused on the BSA was conducted prior to field surveys in March, May, and June 2022. In addition, a query of the California Department of Fish and Wildlife (CDFW) California Natural Diversity Database (CNDDB) was conducted on September 30, 2022, and again in October 2022 and July 2023 using Geographic Information System (GIS) tools to spatially search the area encompassing the Project site and a 10-mile buffer (CNDDB October 2022). The query was conducted for the Blackwells Corner, Carneros Rocks, and Belridge USGS 7.5-Minute Series Quadrangles where the proposed Project is primarily located and the 11 surrounding quads that include: Antelope Plain, Belridge, Emigrant Hill, Las Yeguas Ranch, Lokern, Lost Hills, Lost Hills NW, McKittrick Summit, Reward, Shale Point, and West Elk Hills. Maps of special-status plant and wildlife occurrences listed in the CNDDB are shown in Appendix A, Figures A-1 and A-2.

Additional data regarding the potential for occurrence of special-status species and policies relating to these special- status species and other natural resources were gathered from the following sources:

- State and Federally Listed Endangered and Threatened Animals of California (CDFW, 2022b); Special Animals List (CDFW, 2022c);
- State and Federally Listed Endangered, Threatened, and Rare Plants of California (CDFW, 2022d);
- Inventory of Rare and Endangered Vascular Plants of California (CNPS, 2022);
- California Sensitive Natural Communities (CDFW, 2022e); and Consortium of California Herbaria (CCH, 2022).

3.2 BIOLOGICAL SURVEYS AND HABITAT ASSESSMENTS

3.2.1 Reconnaissance Wildlife and Plant Surveys

Stantec biologists conducted a habitat assessment and biological resource surveys to document the existing biological resources within the BSA over eight days, including March 15-17, May 9-12, and June 2, 2022. The reconnaissance-level surveys were performed within all habitat and terrain types present within the BSA. The primary goals of the habitat assessment and biological surveys were to identify habitat types within the BSA, assess habitats in terms of their suitability of supporting special-status wildlife or plant species, and to document the presence or absence of any special-status species and other biological resources.

Surveys were conducted throughout the BSA by experienced field biologists, with surveys being performed on foot where accessible based on terrain and vegetative cover, and by vehicle in highly developed areas with little or no vegetation. Biologists conducted the foot surveys by walking meandering transects within the Project site and within a 500-foot buffer where accessible, at an average pace of approximately 2 miles per hour (mph) (3.2 kilometers per hour [km/hr]). Biologists ensured that all habitats and topographic

conditions were encompassed during the surveys. During the surveys biologists would walk while visually scanning for wildlife, and listening for wildlife songs, calls, and other signs. Surveying was halted periodically to listen for wildlife and to identify, record, enumerate, or photograph any detected species or habitat features. Species that were present were identified and recorded through direct visual observation, sound, or their sign (e.g., scat, tracks, etc.). Species identifications conform to the most up-to-date field guides and technical literature.

Plant species and vegetation communities within the BSA were identified to the maximum extent possible during the reconnaissance surveys. The 2022 surveys were not focused on floristic surveys and were performed outside of the known flowering period for the detection of special-status species; therefore, some special-status plant species may not have been identified.

To the extent possible, surveys were conducted during the season and time of day that migratory birds were expected to be present, resident bird species were nesting and fledging, small mammals were active and detectable visually or by sign, and above-ground amphibian and reptile movement would generally be detectable. However, it should be noted that some wildlife species and/or individuals may have been difficult to detect due to their elusive nature, cryptic morphology, or nocturnal behavior. Surveys were conducted during daylight hours when temperatures were such that reptiles and other wildlife would be active.

Surveys to map potential San Joaquin kit fox (SJKF) (*Vulpes macrotis mutica*) dens were conducted by Stantec during reconnaissance surveys in March, May, and June 2022. Surveys were conducted within the proposed Project footprint and included an approximate 500-foot-buffer on either side of the pipeline where potential habitat was present and accessible. Potential dens were identified per the USFWS *Standardized Recommendations for Protection of the Endangered San Joaquin Kit Fox Prior to or During Ground Disturbance* (USFWS 2011), and mapped using GPS. The presence of SJKF signs (e.g., tracks, claw marks, scat, prey remains, and configuration of den and ramp) were also used to distinguish potential dens. Additional surveys to confirm the use of any identified potential dens are planned to be performed prior to construction.

3.2.2 Floristic Botanical Surveys

Floristic botanical surveys were conducted during daylight hours in February 22 and 23, March, 7, 8, and 9, and May 2, 3, 4, 5, 11, and 12, 2023, by Stantec biologists Ashleigh Townsend, Saoirse Kirby, Catherine Yoo, Lauren Harrison, Cassandra Cortez, Megan Wong, Julia Thompson, Ethan Martin, and Jared Pratt. The primary goals of the floristic reconnaissance survey were to identify and assess the suitability of habitat for special status plant species and to document an inventory of plant species within the BSA. The BSA was surveyed by the biologists on foot walking meandering transects throughout the Project site. Plants were identified based on professional knowledge and experience and/or by using keys, descriptions, and illustrations in the Jepson Manual: Higher Plants of California, 2nd Edition (Baldwin et al. 2012) and the Jepson Flora Project (The Jepson Herbarium 2023). Notes on plants observed were recorded, and photographs of plants and representative plant community landscapes were taken.

Surveys were conducted in accordance with current agency protocols, including the CDFW *Protocols for Surveying and Evaluating Impacts to Special Status Native Plant Populations and Natural Communities*



(CDFW 2018), the U.S. Fish and Wildlife Service (USFWS) Guidelines for Conducting and Reporting Botanical Inventories for Federally Listed, Proposed and Candidate Plants (USFWS 2000), and the CNPS Botanical Survey Guidelines (CNPS 2001).

3.2.3 Protocol Blunt-nosed Leopard Lizard Surveys

Protocol blunt-nosed leopard lizard (BNLL) (*Gambelia sila*) surveys were conducted during the adult BNLL survey season in May, June, and July 15 2023 by MESA Biological, LLC, based upon the *Approved Survey Methodology for the Blunt-nosed Leopard Lizard* (CDFW 2019). Surveys followed approved CDFW Protocol Survey Methodology guidelines regarding number and timing of surveys, time of day, temperature, weather conditions, survey crew spacing, and level of surveyor experience. The survey crew was comprised of a combination of Level I and Level II surveyors in ratios no more than three Level I to every one Level II. A Level I surveyor is defined by CDFW as a surveyor who has demonstrated the ability to distinguish BNLL from other common lizards found in the southwestern San Joaquin Valley. In addition to meeting the qualifications of a Level I surveyor, a Level II surveyor is defined as a surveyor who has participated in at least 50 BNLL surveys and has made at least one confirmed field observation of a BNLL.

The results of the adult season BNLL surveys conducted in 2023 are included the MESA Biological report presented in Appendix B.

3.2.4 Vegetation and Habitat Assessment

The primary purpose of the habitat assessment surveys was to evaluate and document the various existing conditions within the BSA and map the vegetation communities present. Habitat assessment surveys and vegetation mapping characterizes the plant communities within the BSA and determines presence or absence of sensitive plant communities and habitats, including wetland, aquatic, and riparian habitats.

Stantec biologists conducted the habitat assessment surveys to document the existing biological resources within the BSA over eight days in 2022, including March 15-17, May 9-12, and June 2, 2022. Stantec biologists walked meandering transects parallel to the proposed Project alignment throughout the BSA. Special attention was paid to areas that contained potentially suitable habitat for special-status species. Binoculars were also used to scan the landscape and aid in detection and identification of birds and other wildlife.

The results of the field mapping were incorporated into vegetation maps using geographic information systems (GIS). The total area of each plant community in acres was calculated using GIS.

The mapping and description of plant communities in the BSA were classified based on the alliance classification system described in *Preliminary Descriptions of the Terrestrial Natural Communities of California* (Holland 1986) and described in the second edition of *A Manual of California Vegetation* (Sawyer et al. 2009). Scientific names and common names are according to the second edition of *The Jepson Manual* (Baldwin et al., 2012).



Incidental wildlife species observed or expected to use the BSA were recorded by sight, calls, tracks, scat, and other signs. In addition to species observed, expected wildlife use of the BSA was determined by known habitat preferences of local species and knowledge of their relative distributions in the region.

Photo documentation of habitats within the BSA is included in Appendix C.



4.0 REGULATORY FRAMEWORK

4.1 FEDERAL REGULATIONS

4.1.1 Federal Endangered Species Act

The Federal Endangered Species Act (ESA) includes provisions that protect federally listed threatened and endangered species and their habitats from unlawful take, requiring that federal actions do not jeopardize the continued existence of a listed species or result in the destruction or adverse modification of designated critical habitat. Under the ESA, "take" is defined as "to harass, harm, pursue, hunt, shoot, wound, kill, trap, capture, or collect, or to attempt to engage in any such conduct." The ESA regulations define harm as "an act which actually kills or injures fish or wildlife." Harm is further defined to include significant habitat modification or degradation that actually kills or injures fish or wildlife by significantly impairing essential behavioral patterns, including breeding, spawning, rearing, migrating, feeding, or sheltering" (50 CFR § 17.3).

Activities that may result in "take" of listed species, and have a federal permit or funding nexus, are typically regulated by the USFWS and National Marine Fisheries Service (NMFS) through Section 7(a)(2) of the ESA. Activities that do not have a federal permit or funding nexus are regulated through Section 10(a)(1)(B) of the ESA and required a federal Incidental Take Permit (ITP) and Habitat Conservation Plan (HCP).

Critical habitat is defined in Section 3(5)(A) of the ESA as "(i) the specific areas within the geographical area occupied by the species on which are found those physical or biological features (I) essential to the conservation of the species, and (II) which may require special management considerations or protection; and (ii) specific areas outside the geographical area occupied by the species upon a determination by the Secretary of Commerce or the Secretary of the Interior (Secretary) that such areas are essential for the conservation of the species."

The effects analyses for designated critical habitat must consider the role of the critical habitat in both the continued survival and the eventual recovery (i.e., the conservation) of the species in question, consistent with the Ninth Circuit juridical opinion, Gifford Pinchot Task Force v. USFWS. The USFWS produced an updated list of candidate species December 6, 2007 (72 FR 69034). Candidate species are not afforded any legal protection under ESA; however, candidate species typically receive special attention from Federal and State agencies during the environmental review process.

4.1.2 Migratory Bird Treaty Act

The Migratory Bird Treaty Act (MBTA) of 1918 (16 U.S.C. 703-711) makes it unlawful to possess, buy, sell, purchase, barter, or "take" any migratory bird listed in Title 50 of the Code of Federal Regulations Part 10. "Take" is defined as possession or destruction of migratory birds, their nests or eggs. Disturbances that cause nest abandonment and/or loss of reproductive effort or the loss of habitats upon which these birds depend may be a violation of the MBTA. The MBTA prohibits killing, possessing, or trading in migratory



birds except in accordance with regulations prescribed by the USFWS. This act encompasses whole birds, parts of birds, and bird nests and eggs.

4.1.3 Bald and Golden Eagle Protection Act of 1940 (16 USC 668)

The Bald Eagle Protection Act of 1940 (16 U.S.C. 668, enacted by 54 Stat. 250) protects bald and golden eagles by prohibiting the taking, possession, and commerce of such birds and establishes civil penalties for violation of this Act. Take of bald and golden eagles is defined as follows: “disturb means to agitate or bother a bald or golden eagle to a degree that causes, or is likely to cause, based on the best scientific information available, (1) injury to an eagle, (2) a decrease in its productivity, by substantially interfering with normal breeding, feeding, or sheltering behavior, or (3) nest abandonment, by substantially interfering with normal breeding, feeding, or sheltering behavior’’ (72 FR 31132; 50 CFR 22.3).

The USFWS is the primary federal agency authority charged with the management of golden eagles in the United States. A permit for take of golden eagles, including take from disturbance such as loss of foraging habitat, may be required if this Project affects such resources. On November 10, 2009, the USFWS implemented new rules (74 FR 46835) governing the “take” of golden and bald eagles. The new rules were released under the existing Bald and Golden Eagle Act which has been the primary regulation protection unlisted eagle populations since 1940. All activities that may disturb or incidentally take an eagle or its nest as a result of an otherwise legal activity must be permitted by the USFWS under this act. The definition of disturb (72 FR 31132) includes interfering with normal breeding, feeding, or sheltering behavior to the degree that it causes or is likely to cause decreased productivity or nest abandonment. If a permit is required, due to the current uncertainty on the status of golden eagle populations in the western United States, it is expected permits would only be issued for safety emergencies or if conservation measures implemented in accordance with a permit would result in a reduction of ongoing take or a net take of zero.

4.1.4 Clean Water Act and Rivers and Harbors Act

Areas meeting the regulatory definition of “Waters of the U.S.” (Jurisdictional Waters) are subject to the jurisdiction of the United States Army Corps of Engineers (USACE) under provisions of Section 404 of the Clean Water Act (CWA) (1972) and Section 10 of the Rivers and Harbors Act (1899). These waters may include all waters used, or potentially used, for interstate commerce, including all waters subject to the ebb and flow of the tide, all interstate waters, all other waters (intrastate lakes, rivers, streams, mudflats, sandflats, playa lakes, natural ponds, etc.), all impoundments of waters otherwise defined as “Waters of the U.S.,” tributaries of waters otherwise defined as “Waters of the U.S.,” the territorial seas, and wetlands (termed Special Aquatic Sites) adjacent to “Waters of the U.S.” (33 CFR, Part 328, Section 328.3). Wetlands on non-agricultural lands are identified using the Army Corps of Engineers Wetlands Delineation Manual (Environmental Laboratory, 1987). The Project site falls within the South Pacific Division of the USACE and is under the jurisdiction of the Los Angeles District.

On January 18, 2023, the federal agencies published the final "Revised Definition of 'Waters of the United States” rule (2023 Rule) in the Federal Register, which became effective on March 20, 2023 (USACE and USEPA 2023). The 2023 Rule generally returns to the pre-2015 definition.

The 2023 Rule defines waters of the United States to include:



1. Traditional navigable waters, the territorial seas, and interstate waters;
2. Impoundments of other jurisdictional waters of the United States, except for those that qualify under category 5, below;
3. Tributaries to either of the above waters and tributaries that meet the "relatively permanent" standard or the "significant nexus" standard, (collectively, "jurisdictional tributaries");
4. Wetlands adjacent to traditional waters, wetlands adjacent and with a continuous surface connection to relatively permanent tributaries and impoundments, and wetlands adjacent to other jurisdictional tributaries when those wetlands meet the "significant nexus" standard; and
5. Intrastate lakes and ponds, streams, or wetlands that are not identified in categories 1–4 above that meet either the "relatively permanent" standard or the "significant nexus" standard.

The scope of category 4 (wetlands) was recently limited by the United States Supreme Court in *Sackett v. Environmental Protection Agency, et al.*, Case No. 21-454 (*Sackett*). In *Sackett*, the court held that wetlands are jurisdictional only when they are "as a practical matter indistinguishable from waters of the United States," with a "continuous surface connection" with a water of the United States "making it difficult to determine where the 'water' ends, and the 'wetland' begins."

Construction activities within jurisdictional waters are regulated by the USACE. The placement of fill into such waters must comply with permit requirements of the USACE. As a part of the permit process, the USACE works directly with the USFWS and NMFS to assess potential Project impacts on biological resources.

Section 401 of the CWA ensures that federally permitted activities comply with the federal CWA and state water quality laws. Under CWA Section 401, an applicant for a federal permit or license for any activity which may result in a discharge to federal waters must obtain Water Quality Certification (WQC) that the proposed activity will comply with state water quality standards. In California, CWA Section 401 is implemented either by the State Water Resources Control Board (SWRCB) or the applicable Regional Water Quality Control Board (RWQCB), with most WQCs issued in connection with USACE CWA Section 404 permits for dredge and fill discharges. The SWRCB or RWQCB issues a WQC via the CWA Section 401 process verifying that a proposed Project complies with water quality standards and other conditions of California law. CWA Section 401 certification typically precedes USACE CWA Section 404 permit issuance.

4.1.5 National Environmental Policy Act

The Project would require federal actions including the issuance of Class VI UIC permits from the EPA. However, the Project is Categorically Excluded from further review under the National Environmental Policy Act (NEPA); the Safe Drinking Water Act UIC program is exempt from performing an Environmental Impact Statement (EIS) under section 101(2)(C) and an alternatives analysis under section 101(2)(E) of NEPA under a functional equivalence analysis. Although the Project is exempt from NEPA, in their purview the EPA has determined the Project is an undertaking subject to Section 106 of the National Historic



Preservation Act (NHPA) of 1966, as amended and its implementing regulations (36 CFR 800), pursuant to subpart 800.3(a)).

4.2 STATE REGULATIONS

4.2.1 California Environmental Quality Act

CEQA establishes State policy to prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures. CEQA applies to discretionary actions directly undertaken, financed, or permitted by local or State lead agencies when those actions are found to have or are likely to have direct or indirect environmental impacts. Regulations for implementation are found in the State CEQA Guidelines published by the Resources Agency. These guidelines establish an overall process for the environmental evaluation of projects.

4.2.2 California Endangered Species Act

Provisions of the California Endangered Species Act (CESA) protect State-listed Threatened and Endangered species. The CDFW regulates activities that may result in "take" of individuals ("take" means "hunt, pursue, catch, capture, or kill, or attempt to hunt, pursue, catch, capture, or kill") listed under CESA. Habitat degradation or modification is not expressly included in the definition of "take" under the California Fish and Game Code. The CDFW may authorize take under the CESA via an ITP through California Fish and Game Code Section 2081(b). CDFW also maintains lists for Candidate-Endangered Species and Candidate-Threatened Species. California Candidate Species are afforded the same level of protection as listed species. Additionally, the California Fish and Game Code contains lists of vertebrate species designated as "fully protected" (California Fish & Game Code §§ 3511 [birds], 4700 [mammals], 5050 [reptiles and amphibians], 5515 [fish]). Such species may not be taken or possessed without an approved Natural Communities Conservation Plan.

In addition to Federal and State-listed species, the CDFW also has produced a list of California Species of Special Concern (SSCs) to serve as a "watch list." Species on this list are of limited distribution or the extent of their habitats has been reduced substantially, such that threat to their populations may be imminent. These SSCs may receive special attention during environmental review, but they do not have statutory protection.

4.2.3 Native Plant Protection Act (Fish & Game Code 1900-1913)

California's Native Plant Protection Act (NPPA) requires all State agencies to utilize their authority to carry out programs to conserve endangered and rare native plants. Provisions of NPPA prohibit the taking of listed plants from the wild and require notification of the CDFW at least 10 days in advance of any change in land use. This allows CDFW to salvage listed plant species that would otherwise be destroyed. The Applicant is required to conduct botanical inventories and consult with CDFW during project planning to comply with the provisions of this act and sections of CEQA that apply to rare or endangered plants.



4.2.4 California Fish and Game Code Section 1602

Section 1602 of the California Fish and Game Code requires an entity to notify CDFW before commencing an activity that will:

- Substantially divert or obstruct the natural flow, or substantially change or use any material from the bed, channel or bank of any river, stream, or lake; or
- Deposit or dispose of debris, waste or other material where it may pass into any river, stream, or lake.

If any of these activities may substantially alter its bed, channel, or bank, or adversely affect existing fish and wildlife resources, a Lake and Streambed Alteration Agreement is required. A Lake and Streambed Alteration Agreement lists the CDFW conditions of approval relative to a proposed project and serves as an agreement between an applicant and the CDFW for the performance of activities subject to Section 1602. For the purposes of this Report, potential CDFW jurisdiction is interpreted as extending from the streambed/thalweg to the outer edge of adjacent riparian vegetation (for both natural and anthropogenic drainage features) and for this BSA, is roughly equivalent to "waters of the State" as defined by the RWQCB.

4.2.5 Section 3503 & 3503.5 of the Fish and Game Code

Birds of prey are protected under the California Fish and Game Code. Sections 3503 and 3503.5 states it is "unlawful to take, possess, or destroy any birds of prey (in the order Falconiformes or Strigiformes) or to take, possess, or destroy the nest or eggs of any such bird except as otherwise provided by this Code or any regulation adopted pursuant thereto." Construction disturbance during the breeding season could result in the incidental loss of fertile eggs or nestlings or otherwise lead to nest abandonment. Disturbance that causes nest abandonment and/or loss of reproductive effort is considered "take" by the CDFW. Under Sections 3503 and 3503.5 of the California Fish and Game Code, activities that would result in the taking, possessing, or destroying of any birds-of-prey, taking or possessing of any migratory nongame bird as designated in the MBTA, or the taking, possessing, or needlessly destroying of the nest or eggs of any raptors or non-game birds protected by the MBTA, or the taking of any non-game bird pursuant to Fish and Game Code Section 3800 are prohibited.

4.2.6 Porter-Cologne Water Quality Control Act

The SWRCB and RWQCBs regulate the discharge of waste to waters of the State. All projects proposing to discharge waste that could affect waters of the State must file a waste discharge report with the appropriate regional board. The board responds to the report by issuing Waste Discharge Requirements or a waiver for that project discharge. Both of the terms "discharge of waste" and "waters of the State" are broadly defined such that discharges of waste include fill, any material resulting from human activity, or any other "discharge." Isolated waters/wetlands within California, which are no longer considered "waters of the United States" as defined by Section 404 of the CWA and limited by the *Sackett* decision, are addressed under the Porter-Cologne Act.



4.3 OTHER APPLICABLE REGULATIONS, PLANS, AND STANDARDS

4.3.1 California Native Plant Society Rare Plant Program

The mission of the California Native Plant Society (CNPS) Rare Plant Program is to develop current, accurate information on the distribution, ecology, and conservation status of California's rare and endangered plants, and to use this information to promote science-based plant conservation in California. Once a species has been identified as being of potential conservation concern, it is put through an extensive review process. Once a species has gone through the review process, information on all aspects of the species (e.g., listing status, habitat, distribution, threats, etc.) are entered into the online CNPS Inventory and given a California Rare Plant Rank (CRPR). In 2011, the CNPS officially changed the name "CNPS List" to "CRPR." The Program currently recognizes more than 1,600 plant taxa (species, subspecies and varieties) as rare or endangered in California.

Vascular plants listed as rare or endangered by the CNPS, but which might not have a designated status under State endangered species legislation, are defined by the following CRPR:

- CRPR 1A - Plants considered by the CNPS to be extinct in California
- CRPR 1B - Plants rare, threatened, or endangered in California and elsewhere
- CRPR 2 - Plants rare, threatened, or endangered in California, but more numerous elsewhere
- CRPR 3 - Plants about which we need more information – a review list
- CRPR 4 - Plants of limited distribution – a watch list

In addition to the CRPR designations above, the CNPS adds a Threat Rank as an extension added onto the CRPR and designates the level of endangerment by a 1 to 3 ranking, with 1 being the most endangered and 3 being the least endangered and are described as follows:

- 0.3 – Seriously threatened in California (high degree/immediacy of threat)
- 0.2 – Fairly threatened in California (moderate degree/immediacy of threat)
- 0.3 – Not very threatened in California (low degree/immediacy of threats or no current threats known.



5.0 EXISTING CONDITIONS

5.1 SETTING

The Project is located within the South and North Belridge oil fields south of Blackwells Corner and west of State Route 33 in Kern County, California. It is situated in Sections 21, 22, 26, 27, 28, 34, 35, and 36 of Township 27 South, Range 20 East, Sections 1, 2, and 12 of Township 28 South, Range 20 East, Sections 7, 17, 18, 20, 27, 28, 29, 32, 33, and 34 of Township 28 South, Range 21 East, and Sections 2 and 3 of Township 29 South, Range 21 East MDB&M, in the U.S. Geological Survey (USGS) Blackwells Corner, Carneros Rocks and Belridge 7.5-minute topographic quadrangles. The BSA covers the proposed project surface facilities, pipelines, and proposed injection and monitoring wells that spans approximately 13 miles and varies in width from approximately 1,000 to 1,500 feet wide. Elevation ranges from 550 to 675 feet above sea level. Surrounding land use consists of a mix of existing oil and gas development for the purposes of mineral extraction within undeveloped valley saltbush scrub habitat, and includes agricultural and grazing land.

Observations documented during the site assessment are described in Sections 4.2.1, 4.2.2, and 4.3. Additionally, evidence of use of the BSA by special-status species was documented in the field and is shown in Appendix A, Figure A-3. A photolog was also generated showing general site conditions throughout the Project site and is included in Appendix C.

5.2 VEGETATION COMMUNITIES AND LAND COVERS

As defined in the Manual of California Vegetation, 2nd Edition (MCVII), a vegetation alliance is “a category of vegetation classification which describes repeating patterns of plants across a landscape. Each alliance is defined by plant species composition and reflects the effects of local climate, soil, water, disturbance and other environmental factors” (Sawyer et al. 2009). Generally, Stantec’s mapping and description of plant communities follows the classification system described in MCVII. The MCVII is generally limited to communities that are native or naturalized within California.

Biological resources observed within the BSA during the field survey were comprised primarily of common plant species and vegetation community characteristic of the southern San Joaquin Valley. The extent and condition of vegetation communities within the BSA varied depending on the level of existing development and ongoing mineral extraction activities. Within the BSA, Stantec biologists mapped two plant communities defined by Sawyer et al. (2009) and one landcover type. These are described further in Section 5.2.1 below and depicted in Appendix A, Figure A-4. Acreages for each plant community and land cover type are provided in Table 4, below.

5.2.1 Vegetation Communities and Land Cover Types

ATRIPLEX POLYCARPA SHRUBLAND ALLIANCE (ALLSCALE SCRUB)

Allscale (*Atriplex polycarpa*) Scrub occurs primarily in the northern half of the BSA, where it has formed relatively open stands and/or is interspersed with annual grasslands described below. Patches of Allscale

Scrub also occur in southern half of the BSA but are degraded by their vicinity to intensive oil field operations. Allscale Scrub is characterized by an open to continuous canopy with a variable herbaceous layer near the ground which includes seasonal annuals and non-native grasses. Within the BSA this alliance consists primarily of allscale saltbush (*Atriplex polycarpa*) with a varied herbaceous layer that consists of *Bromus* sp. Commonly known as salt-scrub or saltbush scrub communities, these common arid-land upland communities are found in flat or hilly areas of the southern San Joaquin Valley and are typically characterized by alkaline soils and open canopy with interspersed shrubs with varying densities dependent on slope, aspect, and moisture levels. Approximately 870.28 acres of this land cover type occur within the BSA (Appendix A, Figure A-4).

RED BROME/MEDITERRANEAN GRASS GRASSLANDS HERBACEOUS SEMI-NATURAL ALLIANCE (RED BROME OR MEDITERRANEAN GRASS GRASSLANDS)

Non-native annual grasslands primarily occur toward the central section of the BSA, with an extensive stand located east of Pole Line Road. This vegetation community is also often interspersed with Allscale Scrub. Red Brome or Mediterranean Grass Grasslands consist primarily of non-native grasses from the Mediterranean region such as red brome (*Bromus madritensis* ssp. r*ubens*) and Mediterranean grass (*Schismus barbatus*). Red brome or Mediterranean Grass Grasslands are typically found in disturbed and non-disturbed habitats along roadsides, railroads, and cultivated fields. This vegetation community is highly invasive and widely distributed in the western U.S. and provides a source of fuel for wildfires. Approximately 225.49 acres of this land cover type occur within the BSA (Appendix A, Figure A-4).

DISTURBED/DEVELOPED

This classification was used to map portions of the Project site that are developed; primarily existing roadways and development as related to oil and gas operations for mineral extraction. Where vegetated, these areas are generally composed of sparse occurrences of non-native and ruderal vegetation both within and in the margins of the mapped areas. Approximately 2,179.20 acres of this land cover type occur within the BSA (Appendix A, Figure A-4).

Table 4. Vegetation Communities and Land Cover Types Occurring within the BSA and Estimated Permanent and Temporary Impacts

Vegetation Community/Land Cover Type	Acreage Within BSA	Acreage of Permanent Project Impacts[1]	Acreage of Temporary Project Impacts[2]
Disturbed/Developed	2,179.20	86.63	170.73
Allscale Shrubland	870.28	1.57	43.09
Red Brome or Mediterranean Grass Grasslands	225.49	0.86	4.74
Total	**3,274.97**	**89.06**	**218.56**

[1] Potential sources of permanent project impacts include clearing and grubbing and construction of the carbon capture facility structure, pipeline supports (assuming the pipelines and distribution piping will be above ground and elevated), and injection and monitoring wellheads. Permanently impacted areas would result in permanent structures with no revegetation/restoration.

[2] Potential sources of temporary project impacts include use of heavy equipment and worker foot-traffic along the construction corridor, access and staging, temporarily graded and grubbed areas, and future maintenance activities. Temporarily impacted areas would be revegetated/restored.

5.2.2 Common Plant Species Observed

Plants observed during the 2022 reconnaissance-level surveys and 2023 spring-time floristic surveys, were recorded. The survey resulted in the documentation of 78 species of native and non-native plants within the BSA, a list of which is provided in Table 5 below. Species scientific and common names correspond to those described in the second edition of *The Jepson Manual* (Baldwin et al., 2012).

Table 5. Plant Species Observed within the BSA

Scientific Name	Common Name
Aizoaceae	
*Mesembryanthemum nodiflorum**	slender iceplant
Amaranthaceae	
Atriplex polycarpa	cattle spinach
*Bassia scoparia**	kochia
*Chenopodium album**	common lambs quarters
Asteraceae	
Ambrosia acanthicarpa	annual bur-sage
Baccharis pilularis	coyote brush
*Centaurea melitensis**	tocalote
Centromadia sp.	tarweed
Deinandra pallida	Kern tarweed
Ericameria nauseosa	rubber rabbitbrush
Gutierrezia californica	California matchweed
Helianthus annuus	annual sunflower
Heterotheca grandiflora	telegraph weed
Isocoma acradenia var. *bracteosa*	alkali goldenbush
*Lactuca serriola**	prickly lettuce
Lasthenia californica	California goldfields
Layia glandulosa	white layia
Madia elegans	common madia
Malacothrix coulteri	snake's-head
Matricaria discoidea	pineapple weed
*Senecio vulgaris**	common groundsel
Sonchus asper ssp. *asper**	prickly sow thistle
Stephanomeria pauciflora	wire-lettuce
Boraginaceae	
Amsinckia menziesii	small-flowered fiddleneck
Amsinckia sp.	fiddleneck
Amsinckia tessellata	desert fiddleneck
Pectocarya linearis	sagebrush combseed

Scientific Name	Common Name
Phacelia ciliata	Great Valley phacelia
Plagiobothrys canescens	valley popcornflower
Brassicaceae	
*Brassica nigra**	black mustard
*Brassica tournefortii**	Saharan mustard
Descurainia pinnata	tansy mustard
*Hirschfeldia incana**	summer mustard
Lepidium nitidum	peppergrass
*Sisymbrium irio**	London rocket
*Sisymbrium orientale**	oriental mustard
Tropidocarpum gracile	slender tropidocarpum
Bryaceae	
Bryum argenteum	silvery bryum
Caryophyllaceae	
*Herniaria hirsuta**	hairy rupturewort
Spergularia sp.	sand spurry
Chenopodiaceae	
Atriplex polycarpa	allscale saltbush
*Salsola tragus**	russian thistle
Suaeda nigra	bush seepweed
Crassulaceae	
Crassula connata	pygmy-weed
Cucurbitaceae	
Cucurbita palmata	coyote melon
Euphorbiaceae	
Croton setiger	doveweed
Euphorbia ocellata	Contura Creek spurge
Euphorbia polycarpa	ribseed sandmat
Fabaceae	
Acmispon wrangeleanus	Chilean trefoil
Astragalus lentiginosus	freckled milk vetch
*Medicago polymorpha**	California burclover
Geraniaceae	
*Erodium cicutarium**	redstem filaree
*Erodium moschatum**	whitestem filaree
Lamiaceae	
*Marrubium vulgare**	white horehound

Scientific Name	Common Name
Malvaceae	
Eremalche parryi	Parry's mallow – only one flowering plant with bisexual (non-pistillate) flowers was observed; characteristics tend to be consistent with the much more common *E. parryi* ssp. *parryi* rather than *E. parryi* ssp. *kernensis*
*Malva parviflora**	cheeseweed
Onagraceae	
Camissonia contorta	plains evening primrose
Orobanchaceae	
Castilleja attenuata	narrow leaved owl's clover
Plantaginaceae	
Plantago erecta	California plantain
Plantago ovata	Desert plantain
Poaceae	
*Avena fatua**	wild oats
*Bromus diandrus**	ripgut grass
*Bromus hordeaceus**	soft-chess grass
Bromus madritensis ssp. *rubens**	red brome
Distichlis spicata	salt grass
Festuca microstachys	small fescue
Hordeum murinum ssp. *leporinum**	hare barley
Melica imperfecta	California melic
*Phalaris aquatica**	bulbous canarygrass
*Phalaris caroliniana**	Carolina canarygrass
*Polypogon monspeliensis**	annual beard grass
*Schismus barbatus**	Mediterranean grass
Polemoniaceae	
Gilia minor	little gilia
Polygonaceae	
Eriogonum angulosum	angle stem buckwheat
Pottiaceae	
Tortula muralis	wall-screw moss
Solanaceae	
Datura wrightii	Jimson weed
Tamaricaceae	
Tamarix sp.*	tamarisk
Themidaceae	
Dipterostemon capitatus ssp. *capitatus*	blue dicks

*Denotes non-native species

5.3 COMMON WILDLIFE

5.3.1 Invertebrates and Gastropods

A focused survey for insects was not conducted within the BSA during the 2022 survey effort. Conditions in the BSA provide a suite of microhabitat variations for a wide variety of terrestrial insects and other invertebrates. As in all ecological systems, invertebrates in the BSA play a crucial role in a number of biological processes. They serve as the primary or secondary food source for a variety of birds, reptiles, and mammals; they provide important pollination vectors for numerous plant species; they act as efficient components in controlling pest populations; and they support the naturally occurring maintenance of an area by consuming detritus and contributing to necessary soil nutrients. Some of the orders identified in the BSA included beetles (*Coleoptera* spp.), flies (*Diptera* spp.), grasshoppers (*Orthoptera* spp.), moths and butterflies (*Lepidoptera* spp.), wasps, bees, and ants (*Hymenoptera* spp.), and dragonflies and damselflies (*Odonata* spp.).

5.3.2 Fish

Although ephemeral drainages within the BSA are capable of conveying seasonal flows during rain events, no water was present within the BSA at the time of the 2022 survey effort. Furthermore, there are no known species of fish that occur within the BSA.

5.3.3 Amphibians

Amphibians typically require a source of standing or flowing water for an extended period (2 to 3 months) to complete their life cycle. However, some terrestrial species can survive in drier areas by remaining in moist environments or by burrowing into the soil. Downed logs, bark, and other woody material in various stages of decay (often referred to as coarse woody debris), resources which are largely absent from the BSA, can provide shelter and feeding sites for a variety of wildlife, including amphibians and reptiles. These species are highly cryptic and often difficult to detect. Amphibians all require aquatic habitat for all or part of their life cycle, which may only be present within the BSA for a short period time during and immediately after substantial rain events. Therefore, amphibians are not expected to occur within the BSA.

5.3.4 Reptiles

The number and type of reptile species that may occur at a given site is related to a number of biotic and abiotic features. These include the diversity of plant communities, substrate, soil type, climate, and presence of refugia such as rock piles, boulders, and native debris.

Weather conditions were favorable for the detection of reptiles during the 2022 surveys. Optimal conditions for reptile surveys are clear weather with temperatures between 77°F and 95°F. During the site visit, the weather was clear, with temperatures ranging between 50°F and 75°F. Although temperatures were not optimal for the detection of reptiles during the site visit, reptiles were still active and observed. Three common species were observed in the BSA at the time of the reconnaissance survey: the common side blotched lizard (*Uta stansburiana*), the western whiptail (*Aspidoscelis tigris*), and the northern pacific rattlesnake (*Crotalus oreganus*).



Many reptile species, even if present, are difficult to detect because they are cryptic and their life history characteristics (e.g., foraging, thermoregulatory behavior, fossorial nature, camouflage etc.) limit their ability to be observed during most surveys. Furthermore, many species are only active within relatively narrow thermal limits, avoiding both cold and hot conditions, and most species take refuge in microhabitats that are not directly visible to the casual observer, such as rodent burrows, in crevices, under rocks and boards, and in dense vegetation where they are protected from unsuitable environmental conditions and predators. In some cases, they are only observed when flushed from their refugia. Suitable habitat conditions for certain special-status reptiles occurs within the BSA, including the San Joaquin coachwhip (*Masticophis flagellum ruddocki*) and BNLL; both of these species were observed in the BSA during the 2023 protocol BNLL surveys.

5.3.5 Birds

Birds were identified by sight and sound and were frequently observed throughout the BSA. The most common bird species observed were common ravens (*Corvus corax*) and California quail (*Callipepla californica)*. Active common raven and mourning dove (*Zenaida macroura*) nests were observed in the BSA during reconnaissance surveys. Loggerhead shrike (*Lanius ludovicianus*), a California SSC, was observed perching on power lines and flying in the BSA during reconnaissance and protocol BNLL surveys. Swainson's hawk (*Buteo swainsoni*) is a state threatened species that was incidentally observed flying overhead during protocol BNLL surveys. California horned lark (*Eremophila alpestris actia*), prairie falcon (*Falco mexicanus*), yellow warbler (*Setophaga petechia*) are special-status bird species that were observed during protocol BNLL surveys. It is likely that many other birds use the BSA at different periods, either as wintering habitat, seasonal breeding, or as occasional migrants.

5.3.6 Mammals

Generally, the distribution of mammals on a given site is associated with the presence of factors such as access to perennial water, topographical and structural components (e.g., rock piles, vegetation) that provide cover and support a prey base, and the presence of suitable soils for fossorial mammals (e.g., sandy areas). Small mammal burrows were observed to be generally sparse within the BSA. Signs of mammal species (tracks, scat, etc.) were detected, and a number of common mammals are expected to occur within the BSA given the habitat conditions and species that are known to occur in the region. Several San Joaquin antelope squirrels (SJASs) (*Ammospermophilus nelsoni*) were observed during the 2022 reconnaissance surveys and 2023 protocol BNLL surveys. One individual kangaroo rat (*Dipodomys* sp.) was observed; however, the species was not identified. Other mammals observed include common species including the desert cottontail (*Sylvilagus audubonii*) and black-tailed jackrabbit (*Lepus californicus*). Common mammals may also include the Botta's pocket gopher (*Thomomys bottae).*

Additionally, several earthen and artificial cover sites were located within the BSA that meet the definition as a potential den for SJKF as described in the USFWS *Standardized Recommendations for Protection of the Endangered San Joaquin Kit Fox Prior to or During Ground Disturbance* (2011). While no SJKF were observed in the BSA, and none of the potential dens observed showed any obvious sign of recent SJKF activity, SJKF are known to inhabit active oil fields in the western Kern County area and monitoring of the potential dens would be required to determine current occupation status. Several potential American badgers dens were also observed and mapped.

Wildlife observed during the 2022 reconnaissance surveys and 2023 protocol BNLL surveys are included in Table 6.

Table 6. Wildlife Species Observed within the BSA

Scientific Name	Common Name	Notes
Birds		
Artemisiospiza belli	Bell's sparrow	
Bubo virginianus	great horned owl	
Buteo jamaicensis	red-tailed hawk	
Buteo swainsoni	Swainson's hawk	State Threatened Species; incidental observation reported in third party 2023 BNLL Survey
Callipepla californica	California quail	
Cathartes aura	turkey vulture	
Charadrius vociferus	killdeer	
Chordeiles acutipennis	lesser nighthawk	
Columba livia	rock dove	
Corvus brachyrhychos	American crow	*Corvus brachyrhychos*
Corvus corax	common raven	
Eremophila alpestris actia	horned lark	CDFW Watch List Species
Euphagus cyanocephalus	Brewer's blackbird	
Falco mexicanus	prairie falcon	CDFW Watch List Species
Geococcyx californianus	greater roadrunner	
Haemorhous mexicanus	house finch	
Icterus cucullatus	hooded oriole	
Lanius ludovicianus	loggerhead shrike	California Species of Special Concern
Mimus polyglottos	northern mockingbird	
Passer domesticus	house sparrow	
Passerculus sandwichensis	savannah sparrow	
Sayornis nigricans	black phoebe	
Sayornis saya	say's phoebe	
Setophaga petechia	yellow warbler	California Species of Special Concern
Sturnella neglecta	western meadowlark	
Sturnus vulgaris	European starling	
Thryomanes bewickii	Bewick's wren	
Tyrannus verticalis	western kingbird	
Tyto alba	barn owl	
Zenaida macroura	mourning dove	
Zonotrichia leucophrys	white-crowned sparrow	
Mammals		

Scientific Name	Common Name	Notes
Ammospermophilus nelsoni	San Joaquin antelope squirrel	State Threatened Species
Canis latrans	coyote	
Dipodomys sp.	kangaroo rat	
Lepus californicus	black-tailed jackrabbit	
Sylvilagus audubonii	desert cottontail	
Reptiles		
Aspidoscelis tigris	western whiptail	
Crotalus oreganus	northern Pacific rattlesnake	
Gambelia sila	blunt-nosed leopard lizard	Federal Endangered, State Endangered, CDFW Fully Protected
Masticophis flagellum ruddocki	San Joaquin coachwhip	California Species of Special Concern
Pituophis catenifer	gopher snake	
Uta stansburiana	common side-blotched lizard	

5.4 JURISDICTIONAL WATERS/WETLANDS

5.4.1 Potential Jurisdictional Features

The USACE Regulatory Program regulates activities pursuant to Section 404 of the federal Clean Water Act (CWA); the CDFW regulates activities under California Fish and Game Code Sections 1600-1607; and the RWQCB regulates activities under Section 401 of the CWA and the California Porter-Cologne Water Quality Control Act.

Potential jurisdictional aquatic features observed in the BSA include sections of Chico Martinez Creek, remnants of ephemeral streams, and various drainage ditches; these features may also be regulated as jurisdictional features by CDFW (Appendix A, Figure A-5.0-5.11). Potentially jurisdictional features are described in more detail in the attached Jurisdictional Delineation Report (see Appendix D).

5.4.2 Preliminary Jurisdictional Determination

Table 7 quantifies the potential jurisdictional waters (in acres, square feet, and linear feet) for the delineated resources within the BSA and includes footnotes summarizing the key characteristics of potential jurisdictional waters for each agency/regulatory jurisdiction based on Stantec's understanding of current regulatory guidance.

Table 7. Preliminary Jurisdictional Waters Totals in the BSA

Potential Jurisdictional Waters[1]	Acres	Square Feet	Linear Feet
U.S. Army Corps of Engineers			
N/A[2]	N/A	N/A	N/A
Total Potential USACE Jurisdiction	**N/A**	**N/A**	**N/A**

Potential Jurisdictional Waters[1]	Acres	Square Feet	Linear Feet
Regional Water Quality Control Board			
Waters of the State (Drainage Ditch between Main Camp Rd and Gas Plant 32)	0.189	8,229	411
Waters of the State (Drainage Ditch along west side of Pole Line Road and north of Tulare Road)	0.155	6,741	602
Waters of the State (Streambed of Remnant Ephemeral Stream south of Contractors Road)	1.008	43,907	1,711
Waters of the State (Streambed of Remnant Sections of Zemorra Creek south of Main Camp Road)	1.195	52,030	1,446
Chico Martinez Creek (Streambed)	6.920	301,413	6,247
Total Potential RWQCB Jurisdiction	**9.467**	**412,320**	**10,417**
California Department of Fish and Wildlife			
Drainage Ditch between Main Camp Rd and Gas Plant 32	0.189	8,229	411
Drainage Ditch along west side of Pole Line Road and north of Tulare Road	0.155	6,741	602
Streambed of Remnant Ephemeral Stream south of Contractors Road	1.008	43,907	1,711
Streambed of Remnant Sections of Zemorra Creek south of Main Camp Road	1.195	52,030.16	1,446
Streambed of Chico Martinez Creek	6.920	301,413	6,247
Total Potential CDFW Jurisdiction	**9.467**	**412,320**	**10,417**

[1] Areas of potential jurisdiction are subject to final verification and approval by the regulatory agencies (i.e., USACE, RWQCB, and CDFW).

[2] No potential federal Waters of the U.S. were delineated with the BSA due to lack of an ordinary high water mark (OHWM) and/or no evident connectivity to any other federal Waters of the U.S. recognized as a traditional navigable water.

Based upon the initial impact assumptions there would be 40,508 square feet or 0.930 acre of temporary impacts on potentially jurisdictional aquatic features within the BSA (Appendix A, Figure A-5.0). There would be no permanent impacts to potentially jurisdictional aquatic features because pipelines would be installed on pipe supports that span the creek crossings.

5.5 SOILS

Prior to conducting the field reconnaissance, historic soils data from the Natural Resources Conservation Service (NRCS) was used to determine potential soil types that may occur within the BSA, including where hydric soils may have historically occurred (Appendix A, Figure A-6). Characteristics of soils present on the site are summarized in Table 8.



Table 8. Historic Soils Occurring within the BSA

Map Unit Symbol	Map Unit Name	Description	Hydric	Acreage in BSA
174	Kimberlina fine sandy loam, 0-2% slopes	The Kimberlina series consists of very deep, well drained soils on flood plains and recent alluvial fans. These soils formed in mixed alluvium derived dominantly from igneous and/or sedimentary rock sources.	No	1,302.67
175	Kimberlina fine sandy loam, 2-5% slopes	The Kimberlina series consists of very deep, well drained soils on flood plains and recent alluvial fans. These soils formed in mixed alluvium derived dominantly from igneous and/or sedimentary rock sources.	No	232.04
176	Kimberlina fine sandy loam, 5-9% slopes	The Kimberlina series consists of very deep, well drained soils on flood plains and recent alluvial fans. These soils formed in mixed alluvium derived dominantly from igneous and/or sedimentary rock sources.	No	7.90
196	Milham sandy loam, 0 to 2 percent slopes Major Land Resource Area 17	The Milham series consists of very deep, well drained soils on alluvial fans, plains, low terraces, and fan remnants. These soils formed in mixed calcareous alluvium weathered from granitic and sedimentary rock.	No	547.25
197	Milham sandy loam, 2 to 5 percent slopes	The Milham series consists of very deep, well drained soils on alluvial fans, plains, low terraces, and fan remnants. These soils formed in mixed calcareous alluvium weathered from granitic and sedimentary rock.	No	394.53
211	Panoche clay loam, 0 to 2 percent slopes	The Panoche series consists of very deep, well drained soils on alluvial fans and flood plains. These soils formed in loamy calcareous alluvium from sedimentary rock.	No	445.81
212	Panoche clay loam, 2 to 5 percent slopes	The Panoche series consists of very deep, well drained soils on alluvial fans and flood plains. These soils formed in loamy calcareous alluvium from sedimentary rock.	No	344.78
Total				**3,274.97**

Source: NRCS, 2022

6.0 SPECIAL-STATUS BIOLOGICAL RESOURCES

The background information presented above, combined with field observations taken during the survey, was used to generate a list of special-status natural communities and special-status plant and animal taxa that either occur or may have the potential to occur within the BSA and/or adjacent habitats. For the purposes of this report, special-status taxa are defined as plants or animals that:

- Have been designated as either rare, threatened, or endangered by CDFW or the USFWS, and are protected under either the California or Federal ESAs;
- Are candidate species being considered or proposed for listing under these same acts;
- Are recognized as SSCs by the CDFW;
- Are ranked as CRPR 1, 2, 3 or 4 plant species;
- Are Fully Protected by California Fish and Game Code, Sections 3511, 4700, 5050, or 5515; or
- Are of expressed concern to resource/regulatory agencies, or local jurisdictions

6.1 SPECIAL-STATUS NATURAL COMMUNITIES

Special-status natural communities are defined by CDFW (2009) as, "...communities that are of limited distribution statewide or within a county or region and are often vulnerable to environmental effects of projects." All vegetation within the state is ranked with an "S" rank, however only those that are of special concern (S1-S3 rank) are generally evaluated under CEQA. Allscale Scrub/Shrubland is located sporadically throughout the BSA and is most common in the northern half of the BSA; this habitat type is utilized by a variety of special-status species, but it only has a state rarity rank of S4, and is not considered sensitive (CDFW 2022e).

6.2 DESIGNATED CRITICAL HABITAT

Literature review conducted prior to conducting field surveys determined that no critical habitat occurs within the BSA (USFWS 2022b). The nearest designated critical habitat units include: 1) a critical habitat unit for Buena Vista Lake ornate shrew (*Sorex ornatus relictus*) located approximately 13.8 miles east of the BSA; 2) a critical habitat unit for vernal pool fairy shrimp (*Branchinecta lynchi)* located approximately 13.8 miles southwest of the BSA; and, 3) a critical habitat unit for California tiger salamander (*Ambystoma californiense*) located approximately 18.1 miles northwest of the BSA. The BSA is also located outside of the known respective ranges of these species.

6.3 SPECIAL-STATUS PLANTS

Table 9 presents a list of special-status plants, including federally- and state-listed species and CRPR 1-4 species that are known to occur in the region surrounding the BSA (within 10 miles). A records search of the CNDDB, the CNPS Online Inventory, and the Consortium of California Herbaria (CCH) was performed for special-status plant taxa and non-protocol plant surveys within the BSA; a map of CNDDB occurrences for special-status plants within a 10-mile radius of the BSA is included in Appendix A, Figure A-1). Additionally, spring-time floristic surveys were completed by Stantec biologists in February, March, and

April 2023. Each of the taxa identified in the record searches was assessed for their potential to occur within the BSA based on the following criteria:

- **Present**: Taxa were observed within the BSA during recent botanical surveys or population has been acknowledged by CDFW, USFWS, or local experts.
- **High**: Both a documented recent record (within 10 years) exists of the taxa within the BSA or immediate vicinity (approximately 5 miles) and the environmental conditions (including soil type) associated with taxa presence occur within the BSA.
- **Moderate**: Both a documented recent record (within 10 years) exists of the taxa within the BSA or the immediate vicinity (approximately 5 miles) and the environmental conditions associated with taxa presence are marginal and/or limited within the BSA; the BSA is located within the known current distribution of the taxa and the environmental conditions (including soil type) associated with taxa presence occur within the BSA.
- **Low**: A historical record (over 10 years) exists of the taxa within the BSA or general vicinity (approximately 10 miles) and the environmental conditions (including soil type) associated with taxa presence are marginal and/or limited within the BSA.
- **Not Likely to Occur:** The environmental conditions associated with taxa presence do not occur within the BSA.

In regard to special-status plants, a single plant keyed to *Eremalche parryi* was observed west of Pole Line Road during botanical surveys in 2023 (Figure 22; Appendix C, Photo 27). The identification and potential regulatory status of this specimen is complicated by the somewhat controversial taxonomy of the Kern mallow and Parry's mallow. The debate centers around the gender, size, and color of flowers to be included in each taxon (Cypher 2002). Certain populations in the Kern/Parry's mallow complex exhibit a condition known as gynodioecy, meaning that some of the plants have only bisexual flowers and other plants in the same population have only pistillate flowers. Bisexual flowers have both male and female parts; these flowers also are known as perfect or hermaphroditic. Pistillate flowers have only female parts; these flowers also are known as male-sterile. Pistillate flowers have shorter petals than bisexual flowers in the same population. Experts agree that Kern mallow is gynodioecious. However, any gynodioecious population in the complex keys to *Eremalche parryi* ssp. in Baldwin et al. (2012), including those that species experts consider to be Parry's mallow (Cypher 2002). Other populations in the Kern/Parry's mallow complex consist only of plants with bisexual flowers; these populations key to *Eremalche parryi* ssp. *parryi* (Baldwin et al. 2012) and are indisputably Parry's mallow. Parry's mallow is generally accepted to have larger flower parts than Kern mallow; Kern mallow flowers may be either white or pale lavender, regardless of gender; Parry's mallow flowers tend to be mauve, purple, or rose-pink (Cypher 2002).

Regarding the single plant observed within the BSA, based on the subject photo and measurements (Appendix C, Photo 27), the single fully budding flower observed appeared to be purple, with petal length in excess of 8.5 mm (closer to 15 mm), calyx length in excess of 8 mm, and abruptly acuminate sepal tips – all characteristics that are more diagnostic of *E. parryi* ssp. *parryi* rather than *E. parryi* ssp. *kernensis*, per the characters/keys included in Baldwin et al. (2012) and Cypher (2002). In addition, the specimen had a bi-sexual (non-pistillate) flower. Considering this information, the specimen cannot be conclusively identified as *E. parryi* ssp. *kernensis* and is most likely the much more common *E. parryi* or *E. parryi* ssp. *parryi*. The potential for occurrence of Kern mallow within the BSA is assessed to be low.



Table 9. Known and Potential Occurrences of Special-status Plant Taxa within the BSA

Species	Status	Habitat and Distribution	Blooming Period	Potential to Occur
Allium howellii var. *howellii* Howell's onion	**4.3**	Found in valley and foothill grassland in clay or serpentinite soils between 160 and 7,220 feet (50 – 2,220 meters) in elevation	Mar-Apr	**Not Likely to Occur:** The nearest occurrence is currently unknown. Suitable habitat/soil for this species does not exist within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.
Amsinckia furcata forked fiddleneck	**4.2**	Found in cismontane woodland, and valley and foothill grasslands between 160 and 3,280 feet (50–1,000 meters) elevation	Feb-May	**Low:** The nearest occurrence is currently unknown. Suitable habitat for this species exists within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.
Androsace elongata ssp. *acuta* California androsace	**4.2**	Found in chaparral, cismontane woodland, coastal scrub, meadows and seeps, pinyon and juniper woodland, and valley and foothill grasslands, between 490 and 4,280 feet (150–1,305 meters) in elevation.	Mar-Jun	**Not Likely to Occur:** The nearest occurrence is currently unknown. Suitable habitat for this species exists within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.
Antirrhinum ovatum oval-leaved snapdragon	**4.2**	Found in chaparral, cismontane woodland, pinyon and juniper woodland, and valley and foothill grasslands in clay or gypsum and often alkaline soils between 655 and 3,280 feet (200–1,000 meters) in elevation.	May-Nov	**Not Likely to Occur:** The nearest occurrence is approximately 3.5 miles southwest of the BSA; however, this occurrence was recorded in 1962. Suitable habitat/soil for this species does not exist within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.
Astragalus hornii var. *hornii* Horn's milk-vetch	**1B.1**	Found in meadows, seeps and playas on lake margins in alkaline soils between 195 and 2,790 feet (60 – 850 meters) in elevation.	May-Oct	**Not Likely to Occur:** The nearest occurrence is currently unknown. Suitable habitat for this species does not exist within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.
Astragalus macrodon Salinas milk-vetch	**4.3**	Found in chaparral, cismontane woodlands, valley and foothill grasslands on sandstone, shale and serpentine soils, between 820 and 3,115 feet (250–950 meters) in elevation.	Apr-Jul	**Not Likely to Occur:** The nearest occurrence is currently unknown. Suitable habitat/soil for this species does not exist within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.
Atriplex cordulata var. *cordulata* heartscale	**1B.2**	Found in chenopod scrub, meadows and seeps, and valley and foothill grasslands in sandy, saline or alkaline soils below 1,835 feet (560 meters) in elevation.	Apr-Oct	**Low:** The nearest occurrence is approximately 9.9 miles east of the BSA. Suitable habitat for this species exists within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.
Atriplex cordulata var. *erecticaulis* Earlimart orache	**1B.2**	Found in valley and foothill grasslands, between 130 and 330 feet (40 – 100 meters) in elevation.	Aug-Sep (Nov)	**Not Likely to Occur:** The nearest occurrence is currently unknown. Annual grassland habitat exists within the BSA, but the elevation of the BSA is above the known elevational range for the species. Not observed in the BSA during appropriately timed floristic botanical surveys.



Species	Status	Habitat and Distribution	Blooming Period	Potential to Occur
Atriplex coronata var. *coronata* crownscale	**4.2**	Found in valley and foothill grasslands, playas, and vernal pools in alkaline soils between 455 and 1,640 feet (139 – 500 meters) in elevation.	Mar-Oct	**Low:** The nearest occurrence is currently unknown. Suitable habitat for this species exists within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.
Atriplex coronata var. *vallicola* Lost Hills crownscale	**1B.2**	Found in chenopod scrub, valley and foothill grasslands, and vernal pools in alkaline soils between 160 and 2,085 feet (50 – 635 meters) in elevation.	Apr-Sep	**Low:** The nearest recorded occurrences is approximately 4.1 miles east of the BSA from 1989, and the most recent occurrence is 8 miles east of the BSA from 2013. Suitable habitat for this species exists within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.
Atriplex flavida Carrizo Plain crownscale	**1B.3**	Found in chenopod scrub, valley and foothill grassland, and vernal pools in alkaline soils between 1,920 feet and 1,985 feet (585 – 605 meters) in elevation.	Mar-Jul	**Low:** The nearest occurrence is currently unknown. Suitable habitat for this species exists within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.
Canbya candida white pygmy-poppy	**4.2**	Found in Joshua tree woodland, Mojavean desert scrub, and pinyon and juniper woodland in granitic, gravelly, and sandy soils between 1,970 and 4,790 feet (600 – 1,460 meters) in elevation.	Mar-Jun	**Not Likely to Occur:** The nearest occurrence is currently unknown. Suitable habitat for this species does not exist within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.
Caulanthus californicus California jewelflower	**FE, SE, 1B.1**	Found in chenopod scrub, pinyon and juniper woodlands, and valley and foothill grasslands in sandy soils between 200 and 3,280 feet (61 – 1,000 meters) in elevation.	Feb-May	**Low:** The nearest recorded occurrence is approximately 1.2 miles east of the BSA from 1937; however, the most recent occurrence was recorded in 2008 and was 7.6 miles from the BSA. Suitable habitat for this species exists within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.
Caulanthus lemmonii Lemmon's jewelflower	**1B.2**	Found pinyon and juniper woodlands, and valley and foothill grasslands between 260 and 5,185 feet (80 – 1,580 meters) in elevation.	Feb-May	**Low:** The nearest recorded occurrence is approximately 8.2 miles southwest of the BSA from 2017. Suitable habitat for this species exists within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.
Cirsium crassicaule slough thistle	**1B.1**	Found in chenopod scrub, marshes and swamps, and riparian scrub between 10 and 330 feet (3 – 100 meters) in elevation.	May-Aug	**Not Likely to Occur:** The nearest recorded occurrence is approximately 9.2 miles east of the BSA from 1954; however, the most recent occurrence was recorded in 1982, 9.8 miles northeast of the BSA. Annual grassland habitat exists within the BSA, but the elevation of the BSA is above the known elevational range for the species. Not observed in the BSA during appropriately timed floristic botanical surveys.



Species	Status	Habitat and Distribution	Blooming Period	Potential to Occur
Clarkia xantiana ssp. *parviflora* Kern Canyon clarkia	**4.2**	Found in chaparral, cismontane woodland, Great Basin scrub, and valley and foothill grassland in roadside, rocky, and sandy soils and on slopes between 2,295 and 11,875 feet (700 – 3,620 meters) in elevation.	May-Jun	**Not Likely to Occur:** The nearest occurrence is currently unknown. Annual grassland habitat exists within the BSA, but the elevation of the BSA is below the known elevational range for the species. Not observed in the BSA during appropriately timed floristic botanical surveys.
Delphinium recurvatum recurved larkspur	**1B.2**	Found in chenopod scrub, cismontane woodland, and valley and foothill grasslands in alkaline soils between 5 and 2,590 feet (3 – 750 meters) in elevation.	Mar-Jun	**Low:** The nearest recorded occurrence is approximately 3.6 miles east of the BSA from 2011. Suitable habitat for this species does exist within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.
Eremalche parryi ssp. *kernensis* Kern mallow	**FE, 1B.2**	Found in in chenopod scrub, pinyon and juniper woodlands, and valley and foothill grasslands in dry, open sandy to clay soils between 225 and 4,230 feet (70 – 1,290 meters) in elevation.	(Jan, Feb) Mar-May	**Low:** A single flowering *Eremalche parryi* plant was observed during botanical surveys completed in Spring 2023 west of Pole Line Road. The specimen had bisexual (non-pistillate) flowers, and Kern mallow is acknowledged to have populations that have pistillate flowers. The flower characteristics tend to be more consistent with the much more common *E. parry*i ssp. *parryi* rather than *E. parryi* ssp. *kernensis*.
Eriastrum hooveri Hoover's eriastrum	**4.2**	Found in chenopod scrub, pinyon and juniper woodlands, and valley and foothill grasslands, sometimes in gravelly soils between 160 and 3,000 feet (50–915 meters) in elevation.	(Feb) Mar-Jul	**Moderate:** The nearest recorded occurrence is within the BSA from 1986. Suitable habitat for this species exists within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.
Eriogonum gossypinum cottony buckwheat	**4.2**	Found in chenopod scrub, and valley and foothill grasslands between 325 and 1,805 feet (100–550 meters) in elevation.	Mar-Sep	**Low:** The nearest occurrence is currently unknown. Suitable habitat for this species exists within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.
Eriogonum nudum var. *indictum* protruding buckwheat	**4.2**	Found in chaparral, chenopod scrub, and cismontane woodland in clay and serpentine soils between 490 and 4,800 feet (150 – 1,463 meters) in elevation.	(Apr) May-Oct (Dec)	**Not Likely to Occur:** The nearest occurrence is currently unknown. Suitable habitat/soil for this species does not exist within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.
Eriogonum temblorense Temblor buckwheat	**1B.2**	Found in valley and foothill grasslands in clay or sandstone soils between 990 and 3,280 feet (300 – 1,000 meters) in elevation.	(Apr) May-Sep	**Not Likely to Occur:** The nearest recorded occurrence is approximately 3.7 miles west of the BSA from 1971; however, the most recent occurrence was recorded in 2011 9 miles southeast of the BSA. Suitable habitat/soil for this species does not exist within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.

Species	Status	Habitat and Distribution	Blooming Period	Potential to Occur
Eschscholzia hypecoides San Benito poppy	**4.3**	Found in chaparral, cismontane woodland, and valley and foothill grassland in clay and serpentine soils between 655 and 4,920 feet (200 – 1500 meters) in elevation.	Mar-Jun	**Not Likely to Occur:** The nearest occurrence is currently unknown. Suitable habitat/soil for this species does not exist within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.
Eschscholzia lemmonii ssp. *kernensis* Tejon poppy	**1B.1**	Found in chenopod scrub, and valley and foothill grasslands between 520 and 3,280 feet (160 – 1000 meters) in elevation.	(Feb) Mar-May	**Low:** The nearest occurrence 9.6 miles southeast of the BSA from 2001. Suitable habitat for this species exists within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.
Eschscholzia rhombipetala diamond-petaled California poppy	**1B.1**	Found in valley and foothill grasslands in alkaline or clay soils between 0 and 3,200 feet (0 – 975 meters) in elevation.	Mar-Apr	**Low:** The nearest recorded occurrence is approximately 9.9 miles southwest of the BSA; however, this occurrence was recorded in 1986. Suitable habitat for this species exists within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.
Fritillaria agrestis stinkbells	**4.2**	Found in chaparral, cismontane woodland, pinyon and juniper woodland, and valley and foothill grasslands in clay soils, and sometimes in serpentine soils, between 30 and 5,100 feet (10–1,555 meters) in elevation.	Mar-Jun	**Not Likely to Occur:** The nearest occurrence is currently unknown. Suitable habitat/soil for this species does not exist within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.
Lasthenia chrysantha alkali-sink goldfields	**1B.1**	Found in vernal pools in alkaline soils between 0 and 655 feet (0 – 200 meters) in elevation.	Feb-Apr	**Not Likely to Occur:** The nearest recorded occurrence is approximately 8.6 miles northeast of the BSA; however, this occurrence does not have a recorded date. Suitable habitat does not exist within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.
Lasthenia ferrisiae Ferris' goldfields	**4.2**	Found in vernal pools in alkaline and clay soils between 65 and 2,295 feet (20 – 700 meters) in elevation.	Feb-May	**Not Likely to Occur:** The nearest occurrence is currently unknown. Suitable habitat for this species does not exist within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.
Lasthenia glabrata ssp. *coulteri* Coulter's goldfields	**1B.1**	Found in coastal salt marshes and swamps, playas, and vernal pools below 4,005 feet (1,220 meters) in elevation.	Feb-Jun	**Not Likely to Occur:** The nearest recorded occurrence is approximately 4.9 miles east of the BSA in 2010. Suitable habitat for this species does not exist within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.

Species	Status	Habitat and Distribution	Blooming Period	Potential to Occur
Layia heterotricha pale-yellow layia	**1B.1**	Found in cismontane woodland, coastal scrub, pinyon and juniper woodlands, and valley and foothill grasslands in alkaline or clay soils between 980 and 5,595 feet (300 – 1,705 meters) in elevation.	Mar-Jun	**Low:** The nearest recorded occurrence is approximately 5.9 miles west of the BSA from 1954; however, the most recent occurrence was recorded in 1955 8.6 miles southwest of the BSA. Suitable habitat for this species exists within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.
Layia munzii Munz's tidy-tips	**1B.2**	Found in chenopod scrub, and valley and foothill grasslands in alkaline clay soils between 490 and 2,295 feet (150 – 700 meters) in elevation.	Mar-Apr	**Not Likely to Occur:** The nearest recorded occurrence is approximately 7.5 miles north of the BSA in 1954; however, the most recent occurrence was recorded in 1988 7.9 miles northeast of the BSA. Suitable habitat/soil for this species does not exist within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.
Madia radiata showy golden madia	**1B.1**	Found in cismontane woodland and valley and foothill grasslands between 80 and 3985 feet (25 – 1215 meters) in elevation.	Mar-May	**Low:** The nearest recorded occurrence is approximately 4.3 miles east of the BSA from 1992; however, the most recent occurrence was recorded in 2008, 5.7 miles east of the BSA. Suitable habitat for this species exists within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.
Monolopia congdonii San Joaquin woollythreads	**FE, 1B.2**	Found in chenopod scrub, and valley and foothill grasslands, in sandy soils between 195 and 2,625 feet (60 – 800 meters) in elevation.	Feb-May	**Low:** The nearest recorded occurrence is approximately 0.84 miles west of the BSA from 2008. However, the most recent occurrence was from 2019, 8.2 miles northeast of the BSA. Suitable habitat for this species exists within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.
Puccinellia simplex California alkali grass	**1B.2**	Found in chenopod scrub, meadows and seeps, valley and foothill grassland, and vernal pools in sinks, alkaline soils, flats, lake margins, and mesic vernal pools between 5 and 3,050 feet (2 – 930 meters) in elevation.	Mar-May	**Low:** The nearest recorded occurrence is approximately 7.6 miles east of the BSA from 1983. Suitable habitat for this species exists within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.
Stylocline citroleum oil neststraw	**1B.1**	Found in chenopod scrub, coastal scrub, and valley and foothill grasslands in clay soils between 160 and 1,310 feet (50 – 400 meters) in elevation.	Mar-Apr	**Not Likely to Occur:** The nearest occurrence is 8.3 miles southeast of the BSA from 2011. Suitable habitat/soil for this species does not exist within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.
Trichostema ovatum San Joaquin bluecurls	**4.2**	Found in chenopod scrub and valley and foothill grassland between 215 and 1,050 feet (65 – 320 meters) in elevation.	(Apr-Jun) Jul-Oct	**Low:** The nearest occurrence is currently unknown. Suitable habitat for this species exists within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.

Species	Status	Habitat and Distribution	Blooming Period	Potential to Occur
Tropidocarpum californicum King's gold	**1B.1**	Found in chenopod scrub between 210 and 590 feet (65 - 180 meters) in elevation.	Feb-Mar	**Low:** The nearest occurrence is currently unknown. Suitable habitat for this species exists within the BSA. Not observed in the BSA during appropriately timed floristic botanical surveys.

Source: CDFW, 2022; CNPS, 2022.

* Months appearing in parenthesis listed under blooming periods above indicates and additional but uncommon blooming period for that specific species.

Status Codes

Federal Designation

FE Federally Endangered

FT Federally Threatened

State Designation

SE State Endangered

SR State Rare

California Rare Plant Rank (CRPR) Designation

1B Plants rare, threatened, or endangered in California and elsewhere.

2B Plants presumed extinct in California but more common elsewhere.

4 Plants of limited distribution – a watch list

.1 Seriously threatened in California (high degree/immediacy of threat).

.2 Fairly threatened in California (moderate degree/immediacy of threat).

.3 Not very threatened in California (low degree/immediacy of threats or no current threats known).

6.4 SPECIAL-STATUS WILDLIFE

Special-status taxa include those listed as threatened or endangered under the federal or California ESAs, taxa proposed for such listing, SSCs, and other taxa that have been identified by the USFWS, CDFW, or local jurisdictions as unique or rare and which have the potential to occur within the BSA.

The CNDDB was queried for occurrences of special-status wildlife taxa within a 10-mile radius around the BSA; a map of CNDDB occurrences for special-status wildlife within a 10-mile radius of the BSA is included in Appendix A, Figure A-2). The specific habitat requirements and the locations of known records of occurrence of each special-status wildlife species were the principal criteria used for inclusion in the list of taxa potentially occurring within the BSA. Other wildlife species added for consideration include loggerhead shrike, which is an SSC that was observed in the BSA during reconnaissance surveys, California horned lark, which is a CDFW Watch List species observed during protocol BNLL surveys, and Buena Vista Lake ornate shrew, which is a federal endangered species requested for consideration in a CDFW comment letter on the Project CEQA Notice of Preparation (NOP) (CDFW 2023a). Table 10 summarizes the special-status wildlife taxa known to occur (within 10 miles), and their potential for occurrence in the BSA. Each of the taxa identified in the database reviews/searches were assessed for its potential to occur within the BSA based on the following criteria:

Present: Taxa (or sign) were observed in the BSA or in the same watershed (aquatic taxa only) during the most recent surveys, or a population has been acknowledged by CDFW, USFWS, or local experts.

High: Habitat (including soils) for the taxa occurs on site and a known occurrence occurs within the BSA or adjacent areas (within 5 miles of the BSA) within the past 20 years; however, these taxa were not detected during the most recent surveys.

Moderate: Habitat (including soils) for the taxa occurs on site and a known regional record occurs within the database search, but not within 5 miles of the BSA or within the past 20 years; or a known occurrence occurs within 5 miles of the BSA and within the past 20 years and marginal or limited amounts of habitat occurs on site; or the taxa's range includes the geographic area and suitable habitat exists.

Low: Limited habitat for the taxa occurs on site and no known occurrences were found within the database search and the taxa's range includes the geographic area.

Not Likely to Occur: The environmental conditions associated with taxa presence do not occur within the BSA

Table 10. Known and Potential Occurrences of Special-Status Wildlife within the BSA

Species	Status	Habitat Requirements	Potential to Occur
AMPHIBIANS			
Spea hammondii western spadefoot	**SSC**	Occurs in Central valley grasslands and adjacent foothills, although some populations can be found in pine-oak woodlands of the valley foothills. Require shallow, temporary pools or steams during the breeding season. Resides in burrows most of the year.	**Low:** The nearest recorded occurrence is approximately 6 miles northeast of the BSA. Suitable upland habitat for this species is present in the BSA but there is no likely suitable breeding habitat. Not observed during reconnaissance surveys.
BIRDS			
Agelaius tricolor tricolored blackbird	**ST, SSC, BCC**	Occurs throughout the San Joaquin valley. Utilizes irrigated crops for foraging and typically nests in marshes wetlands with cattails, bulrushes, and willows as well as triticale fields.	**Not Likely to Occur (Nesting) / Moderate (Transient):** The nearest recorded occurrence is approximately 0.45 miles west of the BSA; however, the most recent occurrence was recorded over 20 years ago in 1997. This species could potentially forage in the BSA but there is no suitable nesting habitat. Not observed during reconnaissance surveys.
Athene cunicularia burrowing owl	**SSC**	Occurs in dry open grasslands, prairies, and low foothills. Highly tolerant of human activity and development including road shoulders, drainage sumps and under portable buildings.	**High (Nesting) / High (Transient):** The nearest recorded occurrence is approximately 3.89 miles northwest of the BSA. Suitable nesting and foraging habitat for this species is present in the BSA. Not observed during reconnaissance surveys.
Buteo swainsoni Swainson's hawk	**ST, BCC**	Occurs in grasslands with scattered trees, juniper-sage flats, riparian areas, savannahs, and agricultural or ranch lands with groves or lines of trees. Requires adjacent suitable foraging areas such as grasslands, or alfalfa or grain fields supporting rodent populations.	**Present (Transient):** The nearest recorded occurrence is approximately 5.17 miles northeast of the BSA. While this species could potentially forage in the BSA, there are limited potential nesting trees within a 0.5-mile radius of the BSA, and no nesting trees actually within the BSA. A single Swainson's hawk was incidentally observed flying overhead during protocol BNLL Surveys.
Charadrius montanus mountain plover	**SSC**	Occurs in grasslands, cultivated fields, and foothill valleys.	**Moderate (Nesting) / Moderate (Transient):** The nearest recorded occurrence is approximately 4.7 miles northwest of the BSA; however, the most recent occurrence was recorded over 20 years ago in 1994. Suitable nesting and foraging habitat for this species is present in the BSA. Not observed during reconnaissance surveys.
Charadrius alexandrinus nivosus western snowy plover	**FT, SSC**	Occurs year round in the San Joaquin Valley, where they breed on barren sparsely vegetated flats and along shores of alkaline and saline lakes, agricultural wastewater ponds, and salt evaporation ponds.	**Not Likely to Occur (Nesting) / Low (Transient):** The nearest recorded occurrence is 10 miles northeast of the BSA from 1978. This species could potentially forage in the BSA with low likelihood but there is no suitable nesting habitat. Not observed during reconnaissance surveys.



Species	Status	Habitat Requirements	Potential to Occur
Eremophila aplestris actia	**WL**	Occurs oastal regions, chiefly from Sonoma County to San Diego County and allso main part of San Joaquin Valley and east to foothills. Prefers hort-grass prairie, "bald" hills, mountain meadows, open coastal plains, fallow grain fields, alkali flats.	**High (Nesting) / Present (Transient):** There are no recorded occurrences within ten miles of the BSA. California horned larks were observed in the BSA during protocol BNLL surveys. Suitable nesting and foraging habitat for this species is present in the BSA.
Falco mexicanus prairie falcon	**WL**	Occurs in grasslands, savannahs, rangeland, some agricultural fields, and desert scrub. The known range is from southeastern deserts through Central Valley along the inner Coast Ranges and Sierra Nevada.	**Not Likely to Occur (Nesting) / Present (Transient):** The nearest recorded occurrence is within the BSA; this species was incidentally observed flying overhead during 2023 BNLL surveys. This species could potentially forage in the BSA but there is no suitable nesting habitat.
Gymnogyps californianus California condor	**FE**	Forages over large expanses of land including but not limited to, grasslands, foothills, coastal mountain ranges. Nests on cliff faces, large trees or manmade structures.	**Not Likely to Occur (Nesting) / Low (Transient):** There are no recorded occurrences within ten miles of the BSA. This species could potentially forage in the BSA but there is no suitable nesting habitat. Not observed during reconnaissance surveys.
Lanius ludovicianus loggerhead shrike	**SSC**	Occurs in broken woodlands, savannah, pinyon-juniper, Joshua tree, and riparian woodlands, desert oases, scrub and washes. Prefers open country for hunting, with perches for scanning, and fairly dense shrubs and brush for nesting.	**High (Nesting) / Present (Transient):** There are no recorded occurrences within ten miles of the BSA. Loggerhead shrikes were observed in the BSA during reconnaissance and protocol BNLL surveys. Suitable nesting and foraging habitat for this species is present in the BSA.
Toxostoma lecontei Le Conte's thrasher	**SSC**	Occurs in dry, sparsely vegetated deserts, grasslands, and foothills. Populations in California are known to occur in Fresno, Kern and Kings counties.	**High (Nesting) / High (Transient):** Le Conte's thrasher individuals have been recorded within the BSA; however, the occurrence was from 1948. Suitable nesting and foraging habitat for this species is present in the BSA. Not observed during reconnaissance surveys.
FISH			
Hypomesus transpacificus Delta smelt	**FT, ST**	Small fish, endemic to California that only occurs in the San Francisco Estuary. The Delta Smelt life cycle follows the four seasons—spring spawning in fresh water, summer migration/rearing in the low salinity zone, fall maturation in the low salinity zone, and winter upstream migration shortly before spawning.	**Not Likely to Occur:** The BSA is outside of the range of the species and there is no suitable aquatic habitat in the BSA. No occurrences recorded within 10 miles of the BSA. Not observed during reconnaissance surveys.
INVERTEBRATES			
Branchinecta longiantenna longhorn fairy shrimp	**FE**	Occurs in clear, freshwater vernal pools, claypan pools, or freshwater depressions in sandstone in the Central Valley and around Soda Lake in San Luis Obispo County. There are only five known locations where this species occurs.	**Not Likely to Occur:** The nearest recorded occurrence is approximately 9.2 miles west of the BSA. No vernal pools occur within the BSA so it is unlikely that this species could occur. Not observed during reconnaissance surveys.

Species	Status	Habitat Requirements	Potential to Occur
Branchinecta lynchi vernal pool fairy shrimp	**FT**	The species lives in a variety of vernal pool habitats and is currently found throughout California's Central Valley, the central coast, southern California, and southern Oregon.	**Not Likely to Occur:** No occurrences were recorded within 10 miles of the BSA. No vernal pools occur within the BSA so it is unlikely that this species could occur. Not observed during reconnaissance surveys.
Bombus crotchii Crotch bumble bee	**SCE**	Occurs from coastal California east to the Sierra-Cascade crest and south into Mexico. Food plant genera include *Antirrhinum*, *Phacelia*, *Clarkia*, *Dendromecon*, *Eschscholzia*, and *Eriogonum*.	**Moderate:** Suitable habitat is present because *Phacelia and Eriogonum* potential food plants occur within the BSA. The nearest recorded occurrence is approximately 6.7 miles southwest of the BSA from 1980; however, the most recent occurrence is from 1998, 7.5 miles southwest of the BSA. Not observed during reconnaissance surveys.
Danaus plexippus Monarch butterfly	**FC**	Winter roost sites extend along the coast from northern Mendocino to Baja California, Mexico. Roosts located in wind-protected tree groves (eucalyptus, Monterey pine, cypress), with nectar and water sources nearby. Food plant genus *Asclepias*.	**Not Likely to Occur:** No suitable habitat for food or roosting occurs within the BSA. Not observed during reconnaissance surveys.
Protodufourea zavortinki Zavortink's protodufourea bee	**SSC**	Known host plants including members of *Phacelia* and *Emmenanthe*	**Low:** Suitable habitat is present because *Phacelia* potential host plants occur within the BSA. The nearest recorded occurrence is approximately 8 miles southwest of the BSA from 1970; however, the most recent occurrence is from 1993, 8.9 miles *southeast* of the BSA. Not observed during reconnaissance surveys.
MAMMALS			
Ammospermophilus nelsoni San Joaquin antelope squirrel	**ST**	Occurs in open grasslands but prefers areas that lightly vegetated. Found in saltbush scrub lands mainly in the San Joaquin Valley.	**Present:** Suitable habitat for this species is present in the BSA. SJAS individuals were observed within the BSA during the 2022 reconnaissance surveys and 2023 protocol BNLL surveys, with all observations occurring north of Lerdo Highway and most observations concentrated toward the northern end of the BSA. SJAS was also observed in grasslands north of GP32 during 2022 protocol BNLL surveys conducted for a separate project (South Valley Biological Consulting 2022).
Antrozous pallidus pallid bat	**SSC**	Occurs in a wide variety of habitats including grasslands, shrublands, woodlands, and forests. Roosts in open, dry habitats with rocky areas including caves, crevices, trees, buildings, and mines.	**Not Likely to Occur (Roosting) / Moderate (Transient):** The nearest recorded occurrence is approximately 6 miles west of the BSA; however, this occurrence was recorded well over 20 years ago in 1948. Suitable roosting habitat for this species is not present in the BSA. Not observed during reconnaissance surveys.

Species	Status	Habitat Requirements	Potential to Occur
Dipodomys ingens giant kangaroo rat	**FE, SE**	Inhabits annual grasslands on the western side of the San Joaquin Valley, with marginal habitat in alkali scrub. Needs level terrain and sandy loam soils for burrowing.	**Low to Moderate:** The nearest recorded occurrence of giant kangaroo rat (GKR) is approximately 1 mile southeast of the BSA from 2016 at Aera Energy's Block 12 property. Relatively dense annual grasslands and saltbush scrub in the BSA may support marginal habitat for the species. Not observed during reconnaissance surveys. Small mammal trapping is proposed to determine presence/absence.
Dipodomys nitratoides brevinasus short-nosed kangaroo rat	**SSC**	Occurs in lightly vegetated grasslands in the Central San Joaquin Valley of California, primarily in areas with sandy soils conducive to burrowing. Found exclusively west of the California Aqueduct.	**Moderate:** The nearest recorded occurrence is approximately 4 miles east of the BSA from 2007. Suitable habitat for this species is present in the BSA. Not observed during reconnaissance surveys.
Dipodomys nitratoides nitratoides Tipton kangaroo rat	**FE, SE**	Occurs in lightly vegetated grasslands in the Central San Joaquin Valley of California, primarily in areas with sandy soils conducive to burrowing. Found exclusively east of the California Aqueduct.	**Not Likely to Occur:** The nearest recorded occurrence is approximately 3.5 miles east of the BSA. BSA is outside the known range of the species that occurs east of the California Aqueduct. Not observed during reconnaissance surveys.
Eumops perotis californicus western mastiff bat	**SSC**	Occurs in open, semi-arid to arid habitats, including conifer and deciduous woodlands, coastal scrub, grasslands, and chaparral. Roosts in crevices in cliff faces, high buildings, trees, and tunnels.	**Not Likely to Occur (Roosting) / Moderate (Transient):** The nearest recorded occurrence is approximately 2.6 miles east of the BSA; however, this occurrence was recorded well over 20 years ago in 1953. Suitable habitat for this species is not present in the BSA. Not observed during reconnaissance surveys.
Lasiurus cinereus hoary bat	**SSC**	May be found at any location in California, although distribution patchy in southeastern deserts. This common, solitary species winters along the coast and in southern California, breeding inland and north of the winter range. During migration, may be found at locations far from the normal range, such as the Channel Islands (Brown 1980) and the Farallon Islands (Tenaza 1966). Habitats suitable for bearing young include all woodlands and forests with medium to large-size trees and dense foliage	**Not Likely to Occur:** The nearest occurrence is 5.9 miles west of the BSA from 1947. Suitable habitat is not found within the BSA. Not observed during reconnaissance surveys.
Onychomys torridus tularensis Tulare grasshopper mouse	**SSC**	Occurs in grasslands in the Central San Joaquin Valley of California, primarily in areas with sandy soils conducive to burrowing.	**Moderate:** The nearest recorded occurrence is approximately 5.49 miles east of the BSA. Suitable habitat for this species is present in the BSA. Not observed during reconnaissance surveys.

Species	Status	Habitat Requirements	Potential to Occur
Perognathus inornatus San Joaquin pocket mouse	**SSC**	Occurs in lightly vegetated grasslands in the Central San Joaquin Valley of California, primarily in areas with sandy soils conducive to burrowing.	**Moderate:** The nearest recorded occurrence is approximately 0.7 mile south of the BSA and the most recent occurrence is from 2003, 4.5 miles southeast of the BSA. Suitable habitat for this species is present in the BSA. Not observed during reconnaissance surveys.
Sorex ornatus relictus Buena Vista Lake ornate shrew	**FE, SSC**	Occurs in marshlands and riparian areas in the Tulare Basin. Prefers moist soil. Uses stumps, logs, and litter for cover.	**Not Likely to Occur:** No occurrences were recorded within 10 miles of the BSA. No suitable marshland or riparian habitat occurs within the BSA so it is unlikely that this species could occur. Not observed during reconnaissance surveys.
Taxidea taxus American badger	**SSC**	Uncommon, permanent resident found throughout most of the state, except in the northern North Coast area. Most abundant in drier open states of most shrub, forest and herbaceous habitats, with friable soils.	**Moderate:** The nearest recorded occurrence is approximately 7.7 miles southeast from 1990. Suitable habitat exists in the BSA, and a few potential badger dens were observed in the BSA. No badgers were observed during reconnaissance surveys.
Vulpes macrotis mutica San Joaquin kit fox	**FE, ST**	Occurs in drier open stages of most shrub, forest, and herbaceous habitats. Needs a sufficient food supply, friable soils, and open, uncultivated ground. Highly tolerant of human activity and will opportunistically utilize man-made structures for cover and denning sites. Preys on burrowing rodents and discarded food-trash.	**Present:** There are two occurrences from over 20 years ago. There are multiple occurrences within 10 miles of the BSA, including a 2007 occurrence located 2.9 miles southeast of the BSA. Suitable habitat for this species is present in the BSA. Several potential SJKF dens were observed during reconnaissance surveys in 2022 and protocol BNLL surveys in 2023. No SJKF were observed during reconnaissance surveys, but the species is assumed to occur within the BSA.
REPTILES			
Anniella pulchra northern California legless lizard	**SSC**	Occurs in coastal dunes, valley-foothill, chaparral, and coastal scrub. This is a secretive species that prefers sandy or loose organic soils.	**Low:** The nearest recorded occurrence is approximately 7.8 miles southwest of the BSA from 2015. Suitable habitat for this species is present in the BSA. Not observed during reconnaissance surveys.
Anniella alexanderae Temblor legless lizard	**SCE**	Endemic to the alkali desert scrub and annual grasslands of the southwestern San Joaquin Valley, east of the Temblor mountains at 168-466m (551-1,529 ft.) elevation.	**Low:** The nearest recorded occurrence is 8.8 miles southeast of the BSA from 2017. Suitable habitat for this species is present in the BSA. Not observed during reconnaissance surveys.
Arizona elegans occidentalis California glossy snake	**SSC**	Occurs in arid scrub, rocky washes, grasslands, and chaparral. Appear to prefer microhabitats of open areas with soil loose enough for easy burrowing.	**Moderate:** The nearest recorded occurrences are approximately 5.5 and 8.5 miles southeast of the BSA from 1932 and 2015. Suitable habitat for this species is present in the BSA. Not observed during reconnaissance surveys.

Species	Status	Habitat Requirements	Potential to Occur
Emys marmorata western pond turtle	**SSC**	Occurs near permanent ponds, lakes, streams, irrigation ditches, or permanent pools along intermittent streams west of the Sierra-Cascade crest, except along the Mojave River.	**Not Likely to Occur:** The nearest recorded occurrence is approximately 4.9 and 8.9 miles east of the BSA. Suitable habitat for this species is not present in the BSA. Not observed during reconnaissance surveys.
Gambelia sila blunt-nosed leopard lizard	**FE, SE, FP**	Occurs mainly in the Carrizo Plain, Cuyama, Panoche and the San Joaquin Valleys. Typically inhabits grasslands, saltbush scrub and alkali sink scrub. Uses animal burrows for shelter.	**Present:** The nearest CNDDB occurrences are approximately 0.1 mile north and 7.2 miles southeast of the BSA from 1987 and 2020 respectively. Suitable habitat for this species is present in the BSA. Two BNLLs were observed in BNLL protocol survey Segment 4 and two BNLLs were observed in Segment 3 during the 2023 adult season protocol surveys; one adult male BNLL and one sub-adult (sex unknown) BNLL were observed in Segment 3 during the 2023 hatchling/sub-adult season protocol surveys (Appendix B; Mesa Biological 2023).
Masticophis flagellum ruddocki San Joaquin coachwhip	**SSC**	Occurs in grasslands with an understory of saltbush scrub and alkali sink scrub in areas with an abundance of small mammal burrows.	**Present:** The nearest recorded occurrences are approximately 3.1 miles southeast and 7 miles northeast of the BSA. Suitable habitat for this species is present in the BSA. A San Joaquin coachwhip was observed in the BSA during protocol BNLL surveys.
Phrynosoma blainvilli coast horned lizard	**SSC**	Occurs in valley, foothill hardwood, conifer and riparian habitats, as well as in pine-cypress, juniper and annual grassland habitats. Occurs in the Sierra Nevada foothills from Butte Co. to Kern Co. and throughout the central and southern California coast.	**Moderate:** The nearest recorded occurrence is 9.3 miles northeast of the BSA from 2008. Suitable habitat for this species is present in the BSA. Not observed during reconnaissance surveys.

Federal Rankings:
FE = Federally Endangered
FT = Federally Threatened
FC= Federal Candidate for Listing
BCC = USFWS Bird of Conservation Concern

State Rankings:
FP = Fully Protected
SE= State Endangered
ST = State Threatened
WL = CDFW Watch List
SCE = State Candidate for Listing as Endangered
SSC = Species of Special Concern

6.5 WILDLIFE CORRIDORS AND SPECIAL LINKAGES

Wildlife corridors and linkages facilitate regional animal movement and are generally centered in or around waterways, riparian corridors, flood control channels, contiguous habitat, and upland habitat. Drainages generally serve as movement corridors because wildlife can move easily through these areas, and fresh water is available. Corridors also offer wildlife unobstructed terrain for foraging and for dispersal of young individuals.

As the movements of wildlife species are more intensively studied using radio-tracking devices, there is mounting evidence that some wildlife species do not necessarily restrict their movements to some obvious landscape element, such as a riparian corridor. For example, radio-tracking and tagging studies of Coast Range newts, California red-legged frogs, southwestern pond turtles, and two-striped garter snakes found that long-distance dispersal involved radial or perpendicular movements away from a water source with little regard to the orientation of the assumed riparian "movement corridor" (Hunt, 1993; Rathbun et al., 1992; Bulger et al., 2002; Trentham, 2002; Ramirez, 2002, 2003a, 2003b). Likewise, carnivores do not necessarily use riparian corridors as movement corridors, frequently moving overland in a straight line between two points when traversing large distances (Newmark, 1995; Beier, 1993, 1995; Noss, et al., 1996; Noss et al., no date). In general, the following corridor functions can be utilized when evaluating impacts to wildlife movement corridors:

- Movement corridors are physical connections that allow wildlife to move between patches of suitable habitat. Simberloff et al. (1992) and Beier and Loe (1992) correctly state that, for most species, we do not know what corridor traits (length, width, adjacent land use, etc.) are required for a corridor to be useful. But, as Beier and Loe (1992) also note, the critical features of a movement corridor may not be its physical traits but rather how well a particular piece of land fulfills several functions, including allowing dispersal, plant propagation, genetic interchange, and recolonization following local extirpation.
- Dispersal corridors are relatively narrow, linear landscape features embedded in a dissimilar matrix that links two or more areas of suitable habitat that would otherwise be fragmented and isolated from one another by rugged terrain, changes in vegetation, or human-altered environments. Corridors of habitat are essential to the local and regional population dynamics of a species because they provide physical links for genetic exchange and allow animals to access alternative territories as dictated by fluctuating population densities.
- Habitat linkages are broader connections between two or more habitat areas. This term is commonly used as a synonym for a wildlife corridor (Meffe and Carroll, 1997). Habitat linkages may themselves serve as source areas for food, water, and cover, particularly for small- and medium-size animals.
- Travel routes are usually landscape features, such as ridgelines, drainages, canyons, or riparian corridors within larger natural habitat areas that are used frequently by animals to facilitate movement and provide access to water, food, cover, den sites, or other necessary resources. A travel route is generally preferred by a species because it provides the least amount of topographic resistance in moving from one area to another yet still provides adequate food, water, or cover (Meffe and Carroll, 1997).



- Wildlife crossings are small, narrow areas of limited extent that allow wildlife to bypass an obstacle or barrier. Crossings typically are manmade and include culverts, underpasses, drainage pipes, bridges, and tunnels to provide access past roads, highways, pipelines, or other physical obstacles. Wildlife crossings often represent choke points" along a movement corridor because useable habitat is physically constricted at the crossing by human-induced changes to the surrounding areas (Meffe and Carroll, 1997).

6.5.1 Wildlife Movement in the Project Site

Wildlife likely use both the natural and developed portions of the BSA on a regular basis during normal foraging, migration, nesting, and denning activities. There are no known, widespread, wildlife corridor studies that include the BSA. The CDFW maintains GIS data for "Missing Linkages" (i.e., wildlife corridors) derived from the California Essential Habitat Connectivity Project, which is the best available information on important areas needed for maintaining connectivity between large blocks of land for wildlife corridor purposes (CDFW 2023b). Essential Connectivity Areas are intended to be a broad scale representation of areas that provide essential connectivity. The BSA does not fall within an Essential Connectivity Area; the nearest Essential Connectivity Area is the Temblor Range approximately 5 to 10 miles west of the Belridge Oil Fields (CDFW 2023).



7.0 IMPACT ASSESSMENT FOR SPECIAL-STATUS SPECIES AND SENSITIVE HABITATS

Construction of the proposed Project could impact various special-status wildlife species and their habitat. The construction of the CCS facility, pipelines and supports, injection and monitoring wells, and associated infrastructure would require clearing/grubbing, grading, excavation, and other land disturbance impacts. Potential sources of temporary project impacts include use of heavy equipment and worker foot-traffic along the construction corridor, access and staging, temporarily graded and grubbed areas, and future maintenance activities.

7.1 DIRECT EFFECTS

Construction activities would most likely be most adverse to ground dwelling or fossorial animals (i.e., animals that live in nests, dens, burrows, or substrate below ground). Animals such as foraging and nesting Crotch bumble bee, reptiles, small mammals, burrowing owl, SJAS, and American badger have the potential to be injured or killed while above ground or while occupying dens/burrows from heavy equipment used during construction activities, including during new pipeline construction, well drilling, utility line construction, trenching, excavation of foundations for Project features, construction of utility line towers, and construction of other Project facilities. Impacts could include crushing of individuals and crushing or collapse of burrows by construction vehicles and during construction work. Such animals could also fall into excavated areas (e.g., pipeline trenching, bore pits) and become trapped, which could result in mortality or injury. Additionally, if left unimpeded, individuals that could move through the work areas and across access roads could be at risk of injury or mortality from foot and vehicle traffic. Direct effects on wildlife, including injury or mortality, may could also result from regrading dirt roads with heavy equipment, and maintaining paved roads with paving equipment if wildlife were to enter construction areas or be near where this work is being carried out.

Construction activities could also directly impact ground nesting birds or birds that nest in shrubs. Clearing/grubbing could directly impact active bird nests if these activities are conducted during the nesting season, resulting in potential damage or destruction to nests, eggs, and/or young.

Direct effects on special-status wildlife could also result from increased equipment and human presence, including construction related disturbance and ground vibration during excavation, trenching, pipeline installation, and related activities. Construction noise, disturbance, and ground vibration could cause collapse of burrows and may deter wildlife from inhabiting or foraging in areas near construction activities. Therefore, foraging and other above-ground behaviors could be disrupted, and exposure to predators and competition with other animals for resources could result from displacement behavior as wildlife migrate to other areas without construction disturbance.

Direct effects on special-status wildlife could result from the loss of suitable habitat in the BSA. With the large size of the BSA and expected scarcity of special-status species in the BSA, it is not possible to quantify direct impacts on special-status species. Because most of the areas where Project construction would occur are already impacted and developed with oil and gas extraction infrastructure, the potential



for direct impacts on special-status species, including from loss of burrows and other suitable habitat in the BSA, is expected to be low. Additionally, direct impacts from construction are expected to be mainly temporary, and would cease after construction within affected areas has been completed. Due to the relatively small size and primarily temporary nature of impacts expected on suitable habitat in the BSA, the Project is not anticipated to substantially reduce the overall availability of habitat for special-status wildlife species.

No direct effect/impacts on special-status plants are anticipated because no special-status plants were confirmed to occur within the BSA as a result of appropriately timed floristic botanical surveys.

7.2 INDIRECT EFFECTS

Project construction activities would temporarily reduce vegetation in areas where vegetation trimming or removal is needed, and may temporarily increase airborne dust that may settle on vegetation surrounding construction areas within the BSA. The dust from construction activity may temporarily degrade the overall quality of the local vegetation communities in the BSA. Additionally, heavy equipment working in the BSA may disrupt or compact soils in localized areas and make some habitat less suitable for digging burrows by mammals for a period of time. Certain biotic crusts and other developed soil profiles may be affected by construction activities and would potentially reduce soil viability for special status plants and animals. These indirect effects may diminish the suitability of habitat near construction areas for special-status wildlife for a period of time following construction while vegetation regenerates, rainstorms remove dust from vegetation, and burrows are re-established. Noise disturbance could also have the potential to alter the foraging and/or dispersal/migration behaviors of species such as SJAS and nesting behaviors of various bird species. However, these indirect impacts would be temporary and localized, and are not expected to translate into adverse effects on special-status wildlife because most locations within the Project site and beyond would not be subjected to these indirect effects.

7.3 CUMULATIVE EFFECTS

Potential cumulative effects must be considered in context of the intensive oilfield operations that have been ongoing in the region for decades. The BSA consists mostly of existing disturbed oil and gas infrastructure interspersed with impacted Allscale Scrub shrubland, and Red Brome or Mediterranean Grass grasslands within roughly the southern half of the Project site, with more natural stands of Allscale Scrub and grasslands within roughly the northern half of the BSA. Although the size of the Project footprint is relatively large, the estimated permanent and temporary impacts are small. Potential impacts to special-status species would be mitigated with a suite of comprehensive measures, and impacts to habitats and jurisdictional waters would also be offset with restoration and/or compensatory mitigation. As a result, no substantial cumulative effects are anticipated.



8.0 AVOIDANCE, MINIMIZATION, AND MITIGATION MEASURES

8.1 AVOIDANCE AND MINIMIZATION MEASURES

The avoidance and minimization measures below pertain to Project activities in the BSA. Through the Project design features and application of the general and species-specific avoidance and minimization measures outlined below, Aera Energy will avoid and minimize potential impacts on federally listed species and minimize loss and degradation of federally listed species habitat in the BSA to the greatest extent practicable. Agency-approved biologist(s) will also be identified prior to start of construction, and will be responsible for monitoring Project activities to ensure compliance with avoidance and minimization measures; agency-approved biologists may require approvals from USFWS, CDFW, and/or Kern County. The agency-approved biologist(s) will have the authority to immediately stop any activity not complying with avoidance and minimization measures or other conditions prescribed by future Project permits (e.g., USFWS Biological Opinion [BO], State ITP). The agency-approved biologist(s) will be knowledgeable and experienced in the biology and natural history of the covered federally listed species and experienced with implementing the measures required in the BO. At least 30 days prior to the start of ground-disturbing activities, Aera Energy will submit biologist qualifications to the applicable agencies for approval. Qualifications will include the necessary experience and/or permits for handling of special-status species (if authorized), excavating burrows or dens, and monitoring construction activities.

8.1.1 Best Management Practices

The BMPs below have been incorporated into the implementation of Project activities to avoid and minimize effects on special-status species and their habitat in the BSA. These BMPs will be implemented at all times.

BMP-1: Aera Energy will initiate a trash abatement program before starting Project activities and will continue the program for the duration of the Project. Aera Energy will ensure that trash and food items are contained in animal-proof containers and removed at least once a week to avoid attracting opportunistic predators such as ravens, coyotes, and feral dogs.

BMP-2: Upon completion of Project activities at each work area, Aera Energy will remove from and properly dispose of all temporary fill and construction refuse.

BMP-3: Aera Energy will implement dust control measures during Project activities to facilitate visibility for monitoring of special-status by the agency-approved biologist. Aera Energy will keep the amount of water used to the minimum amount needed and will not allow water to form puddles.

BMP-4: Aera Energy will prohibit use of erosion control materials potentially harmful to special-status species, such as monofilament netting or similar material, in potential special-status species habitat.



BMP-5: Before starting construction activities, Aera Energy will clearly delineate the boundaries of the construction area with fencing, stakes, or flags and will restrict all Project activities to within these areas. Aera Energy will maintain all fencing, stakes, and flags until the completion of construction activities in that area.

BMP-6: Aera Energy will immediately stop and arrange for repair and cleanup of any fuel or hazardous waste leaks or spills at the time of occurrence, or as soon as it is safe to do so. Aera Energy will ensure the proper storage and handling of hazardous materials during Project activities and properly contain and dispose of any unused or leftover hazardous products off site.

BMP-7: Aera Energy will keep oil out of trenches and other excavations. In the event that oil, produced water, or drilling mud containing oil are accidentally conveyed to an excavated area, Aera Energy will implement measures to preclude BNLL, GKR, and SJKF access to the excavated area until oil and oil residues have been removed and no longer pose exposure risk to wildlife. Measures will include installation of temporary netting or covering to preclude species access.

BMP-8: Aera Energy will ensure that any application of herbicide is done by a licensed applicator in accordance with label specifications and all applicable federal, state, local laws and regulations.

BMP-9: Aera Energy will prohibit the use of rodenticides in the BSA.

BMP-10: Aera Energy will ensure that all equipment fueling and equipment maintenance occur at least 100 feet from special-status species dens, burrows, or precincts. Sufficient spill containment and cleanup equipment will be present at all fueling locations.

BMP-11: In temporary disturbance areas, Aera Energy will conserve, stock-pile, and re-spread topsoil.

BMP-12: If the proposed Project could impact jurisdictional waters, construction activities in jurisdictional waters would occur only during dry conditions.

8.1.2 General Avoidance and Minimization Measures

The avoidance and minimization measures below will be implemented whenever Project activities occur.

GEN-1: An agency-approved biologist will be onsite during all ground-disturbing Project activities that may result in take of special-status species or adverse impacts to their habitat.

GEN-2: Aera Energy will clearly delineate work exclusion zones for habitat of special-status species that will be avoided during Project activities within the BSA. Aera Energy will maintain all signs, stakes, flags, and/or rope or cord, and fencing until the completion of Project activities in each area.

GEN-3: Project-related personnel will access the BSA using existing routes and will not cross natural areas outside of or in route to the BSA. Aera Energy will restrict Project -related vehicle traffic to established roads, staging, and parking areas. Aera Energy will ensure that vehicle speeds do not exceed 15 mph to avoid special-status species on or traversing roads. Aera Energy will flag all dirt access roads in the field and vehicle operation will be limited to these designated ingress and egress routes.



GEN-4: Aera Energy will conduct an education program for all persons employed or otherwise working in the BSA before performing any work that includes information about the biology and general behavior of special-status species, and the need and requirement to properly implement the BMPs and avoidance and minimization measures.

GEN-5: Aera Energy will confine all ground- or vegetation-disturbing construction activities to daylight hours (sunrise to sunset). Well drilling activities will occur 24-hours per day.

GEN-6: Aera Energy will not allow vehicles to park within 50 feet of known special-status species dens, burrows, or precincts.

GEN-7: Workers will inspect for wildlife under vehicles and equipment every time the vehicles and equipment are moved. If wildlife is present, the worker will wait for the wildlife to move unimpeded to a safe location or for the agency-approved biologist to determine if the animal may be safely moved.

GEN-8: The agency-approved biologist will inspect all open holes and trenches within the Project footprint at the beginning, middle, and end of each day for trapped wildlife. Aera Energy will provide escape ramps at all excavated, steep-walled holes or trenches and the agency-approved biologist will oversee the covering of all of the excavations at the close of each working day.

GEN-9: All pipes, hoses, conduits, culverts, or similar materials stockpiled or installed in the Project footprint will be capped or otherwise enclosed at the ends to prevent entry by special-status species and other wildlife. The agency-approved biologist will inspect all such materials for special-status wildlife before they are moved, buried or capped.

GEN-10: Workers will inform the agency-approved biologist if a special-status species is seen within or near the Project footprint. All work in the vicinity of a special-status species will cease until the animal is moved by the agency-approved biologist or it moves from the area of its own accord.

GEN-11: The agency-approved biologist will perform pre-construction surveys for presence of special-status species no more than 14 days prior to construction activities in order to delineate work exclusion zones and mark small-mammal burrows within 50 feet of the ground disturbance area.

GEN-12: Prior to construction within the ground disturbance area, Aera Energy will hand-remove large shrubs identified by the agency-approved biologist to encourage special-status species to move out of the area. Aera Energy will also install temporary exclusion fencing around the ground disturbance areas to exclude special-status species from the construction site. The temporary exclusion fencing would be installed in a sequential manner that corresponds to the progression of construction activities. For example, temporary exclusion fencing will not be installed simultaneously at all work locations and will be removed immediately upon completion of Project construction activities at each work area to minimize habitat fragmentation caused by fencing. Aera Energy will submit a fencing plan to the applicable agencies for approval prior to new construction occurring as part of the Project that will specify the type of temporary fence to be used, installation procedure, specific area fenced, and fencing maintenance procedures. If an animal is found trapped inside the temporary fencing, all work will cease and the agency-approved biologist will open the fence to allow the animal leave the fenced area on its own accord.



GEN-13: The agency-approved biologist will accompany the exclusion fence construction crew to ensure that special-status species are not killed or injured during fence installation. The temporary exclusion fencing will be installed to avoid special-status species burrows when feasible and supported sufficiently to maintain its integrity under all conditions such as wind and heavy rain for the duration of the construction activities in that work area. The agency-approved biologist will check the temporary exclusion fence at least once weekly to identify necessary maintenance or repairs.

GEN-14: After completion of live trapping described below under Species-Specific Avoidance Measures, any burrows that could be used by BNLL, GKR, SJAS, or SJKF present within the fenced ground disturbance area or burrows that are likely to be connected to burrows within the fenced area, as determined by the agency-approved biologist, will be fully excavated by hand by the agency-approved biologist or by an individual under the direct supervision of the agency-approved biologist. The agency-approved biologist will determine if burrows outside of the fenced area are likely to be connected to burrows within the fenced area, based on several factors, including:

- Proximity of burrows outside the fencing to those within fencing;
- Burrow size and orientation; and
- Soil hardness/compaction (indicator of the depth of the burrows).

The agency-approved biologist may also use a scope to help make this determination.

GEN-15: If a BNLL, GKR, SJAS, or SJAS is injured as a result of Project-related activities during construction, operations and maintenance, or well plugging and abandonment, the agency-approved biologist will immediately take it to a USFWS- and/or CDFW-approved wildlife rehabilitation or veterinary facility, and USFWS and/or CDFW will be notified immediately.

GEN-16: To the greatest extent feasible, vehicles left overnight will not be located within 50 feet of small mammal burrows.

GEN-17: Aera Energy will limit nighttime activity to essential personnel only, including emergency response or security personnel, to ensure that vehicle traffic necessary during nighttime hours will minimize effects on GKR and SJAS.

GEN-18: Aera Energy will minimize new disturbance and habitat fragmentation by consolidating infrastructure and confining all Project-related parking, storage, laydown, and temporary equipment storage areas to previously disturbed areas to the greatest extent practicable.

GEN-19: Prior to construction, Aera Energy shall coordinate with USFWS and USEPA to obtain a federal BO for federally listed species that could be affected by the Project.

GEN-20: Prior to construction, Aera Energy shall coordinate with CDFW to obtain a State ITP or CESA consistency determination for state listed species that could be affected by the Project.



8.1.3 Species-Specific Avoidance and Minimization Measures

The following avoidance and minimization measures are proposed for special-status species that have either been observed within the BSA, assessed as having the potential to occur within the BSA, or are otherwise assessed as having the potential to be impacted by the proposed Project.

8.1.3.1 Crotch Bumble Bee (CBB)

CBB-1: If Crotch bumble bee becomes state listed or remains a candidate species under the California ESA, at least one year prior to construction a qualified biologist shall conduct a survey within the Project footprint and a 100-foot buffer zone following the CDFW *Survey Considerations for California Endangered Species Act (CESA) Candidate Bumble Bee Species* (CDFW 2023). The Crotch bumble bee survey effort shall include at minimum:

- A detailed habitat assessment;
- A survey proposal submitted to and approved by CDFW;
- Appropriately-timed foraging and nesting bumble bee surveys;
- Per the CDFW guidance (2023c), Aera Energy shall notify CDFW for further coordination as required to avoid or mitigate impacts and to determine if a State ITP will be required.

CBB-2: At minimum, a 50-foot avoidance buffer shall be maintained surrounding foraging Crotch bumble bees and active Crotch bumble bee nests unless CDFW agrees to a reduced buffer.

8.1.3.2 Burrowing Owl (BUOW)

BUOW-1: At least one year prior to construction, a qualified biologist shall conduct a protocol survey within the Project footprint and a 150-meter (approximately 500 ft.) buffer zone following the California Burrowing Owl Consortium *Burrowing Owl Survey Protocol and Mitigation Guideline*s (Burrowing Owl Consortium 1993). The burrowing owl protocol survey effort shall include:

- Phase I: Habitat Assessment;
- Phase II: Burrow Survey;
- Phase III: Burrowing Owl Surveys, Census, and Mapping; and
- Phase IV: Resource Summary and Written Report

BUOW-2: Prior to construction and no more than 14 days prior to ground-disturbing activities, a qualified biologist shall conduct preconstruction surveys of all areas with suitable habitat that will be permanently or temporarily impacted, plus a 200-meter buffer in areas subject to legal access, to locate active breeding or wintering burrowing owl burrows. The survey methodology shall be consistent with the take avoidance survey methods outlined in the CDFW *Staff Report on Burrowing Owl Mitigation* (CDFW 2012). Because burrowing owl may re-colonize a site after only a few days, time lapses between Project



activities may trigger subsequent surveys, including, but not limited to, a final survey conducted within 24 hours prior to ground disturbance to identify any additional burrowing owl or burrows necessitating avoidance, minimization, or mitigation measures. The need for additional surveys will be at the final discretion of the qualified biologist. If burrowing owl absence is reverified, Project activities can proceed providing acceptance by CDFW of the survey results.

If burrowing owl are detected on-site during preconstruction surveys or during construction, no ground-disturbing activities within a minimum 200-meter avoidance buffer shall occur around occupied burrows during the breeding season (February 1 to August 31), unless authorized by CDFW. During the non-breeding season (September 1 to January 31), no ground-disturbing activities within a minimum 50-meter avoidance buffer shall occur around occupied burrows, unless authorized by CDFW.

If burrow avoidance is infeasible during the non-breeding season or during the breeding season where resident owls have not yet begun egg laying or incubation, or where the juveniles are foraging independently and capable of independent survival, the applicant shall coordinate with CDFW to develop a Burrowing Owl Exclusion and Mitigation Plan. The Burrowing Owl Exclusion and Mitigation Plan strategy may include, but is not limited to, the following:

- Passive exclusion of BUOW from burrows within the Project site using one-way doors.
- Excavation of potential BUOW burrows that are confirmed to be empty of BUOW adults and/or young.
- Creation of artificial BUOW burrows to offset the loss of known occupied BUOW burrows.
- Acquisition of BUOW conservation lands and/or bank credits.

8.1.3.3 Swainson's Hawk (SWHA)

SWHA-1: At least one year prior to construction, a qualified biologist shall conduct a protocol survey within the Project footprint and a 0.5 mile buffer zone following the Swainson's Hawk Advisory Committee *Recommended Timing and Methodology for Swainson's Hawk Nesting Surveys in California's Central Valley* (Swainson's Hawk Advisory Committee 2000). The Swainson's hawk protocol survey effort shall include:

- Phase I: Pre-breeding Season Nest Surveys (recommended optional); Schedule: one all day survey conducted from January to March;
- Phase II: Nesting Territory and Courtship Surveys; Schedule: three surveys conducted from sunrise to 10:00AM and/or 16:00PM to sunset; surveys conducted from March 20 to April 5;
- Phase III: Nesting Activity Surveys; Schedule: three surveys conducted from sunrise to noon and/or 16:30PM to sunset; surveys conducted from April 5 to April 20;
- Phase IV: Egg-laying and Incubation Monitoring (monitoring known nest sites only, if required); Schedule: monitoring conducted as needed per biologist discretion from April 21 to June 10.

- Phase V: Fledging and Post-fledging Monitoring (if required); Schedule: three monitoring days conducted from sunrise to noon and/or 16:00PM to sunset; monitoring conducted from June 10 to July 30.

SWHA-2: If active Swainson's hawk nest(s) are identified during protocol surveys, Aera Energy shall coordinate with CDFW to develop appropriate avoidance buffers and to determine if a State ITP for Swainson's hawk is required.

SWHA-3: At minimum, a 500-foot avoidance buffer shall be maintained surrounding active Swainson's hawk nests unless CDFW agrees to a reduced buffer.

8.1.3.4 California Horned Lark, Loggerhead Shrike, LeConte's Thrasher, and Other Nesting Birds (NB)

The following avoidance and minimization measures will be implemented to protect special-status bird species that have been observed in the BSA as well as the numerous bird species protected under the MBTA and California Fish and Game Code.

NB-1: If feasible, clearing and grubbing shall be scheduled to occur in the fall and winter (between September 16 and January 31), outside of the typical nesting season. If any construction activities are proposed to occur during the typical nesting season (February 1 to September 15), a nesting bird survey in areas of suitable nesting habitat as determined by a qualified biologist shall be conducted no more than 14 days prior to construction to determine presence/absence of nesting birds. A Nesting Bird Survey Report documenting the results of nesting bird surveys shall be submitted to the involved regulatory agencies for review/approval prior to construction.

NB-2: If an active bird nest is observed during preconstruction surveys or during construction, at a minimum, a 500-foot avoidance buffer surrounding the nest shall implemented for nesting raptors and a 250-foot avoidance buffer shall be implemented for other nesting bird species. Nest avoidance buffers may be reduced if monitoring determines nesting birds are acclimated to construction disturbance and under the discretion of a qualified biologist.

NB-3: Nests, eggs, or young of birds covered by the MBTA, California Fish and Game Code, or any other regulatory laws shall not be moved or disturbed until a qualified biologist has determined that the nest has become inactive or young have fledged and become independent of the nest,

8.1.3.5 Blunt-nosed Leopard lizard (BNLL)

Aera Energy proposes to utilize the measures below to avoid and minimize impacts on BNLL during Project activities. The proposal to use these measures shall be submitted to CDFW for review/approval prior to construction. USFWS/CDFW will be notified if the avoidance and minimization measures vary from what is described in this BRTR.

BNLL-1: Protocol-level surveys will be conducted by agency-approved Project biologist(s) in suitable habitat within the Project footprint one year prior to the start of construction following the CDFW *Approved Survey Methodology for the Blunt-Nosed Leopard Lizard* (CDFW 2019).



BNLL-2: The agency-approved biologist will conduct visual preconstruction surveys within the Project footprint in areas of potential BNLL habitat no more than 30 days prior to ground disturbing activities associated with each construction phase. The USFWS-approved biologist will conduct daily surveys prior to construction activities to ensure BNLLs are not within the Project footprint. Reports for each survey will be submitted to USFWS/CDFW within 30 days of completion.

BNLL-3. During the BNLL active season (April 15 through October 15), in areas where BNLL or BNLL signs are present, the following measures will be implemented:

a. Following the preconstruction survey for BNLL within the Project footprint, if active burrows or egg clutch sites are identified within the Project footprint, the USFWS-approved biologist will establish, maintain, and monitor 50-foot buffers around active burrows and egg clutch sites. The 50-foot buffers will be established around the active burrow and clutch sites in a manner that allows for a connection between the burrow site and the suitable natural habitat adjacent to the footprint so that BNLL may leave the Project footprint after the young have hatched. Project activities within the 50-foot buffers, including vegetation clearing and grubbing (as described below), will be prohibited until the eggs have hatched and BNLL have been allowed to leave the Project footprint, as determined by the USFWS-approved biologist.

b. Following the preconstruction survey for BNLL within the Project footprint, if no active burrows or egg clutch sites are identified within the Project footprint, the USFWS-approved biologist will supervise vegetation clearing and grubbing activities with hand tools. Cleared vegetation will be cut to 4 inches above the ground level, and all trimmings will be removed from the Project footprint. A follow-up preconstruction survey will be conducted in the vegetation-free work area to look for BNLL or their sign. Any BNLL observed during the follow-up survey will be allowed to leave the work site on their own accord. Immediately after the follow-up preconstruction survey of the vegetation-free work area, the Project footprint will be delineated with high-visibility fencing and "a non-gaping, nonclimbing barrier using a rigid and non-climbable material" wildlife exclusion fence. The vegetation-free work area within the wildlife exclusion fence will be maintained and monitored daily by the USFWS-approved biologist or USFWS-approved biological monitor.

c. The Contractor will conduct ground-disturbing activities when air temperatures are between 75- and 95°F. The temperature range corresponds to the period when this species is active and can avoid danger.

BNLL-4: During the non-active season (October 16 through April 14), suitable BNLL burrows identified during protocol-level and preconstruction surveys will be avoided by the Contractor. A 50-foot no-work buffer will be established around burrows to prevent impacts until the active season, when BNLL will be able to leave the vegetation-free work area on their own accord. The no-work buffer will be established by routing the high-visibility fencing and wildlife exclusion fence around the suitable burrow sites in a manner that allows for a connection between the burrow site and the suitable natural habitat adjacent to the footprint so that BNLL can leave the Project footprint during the active season. If construction activities are required during this period, the appropriate measures will be established through consultation with the USFWS and CDFW.



BNLL-5: If BNLL are observed at any time during protocol-level surveys, preconstruction surveys, or the construction period, USFWS and CDFW will be contacted. Appropriate measures to avoid take of the species will be established through consultation with the USFWS and CDFW.

BNLL-6: Non-disturbance exclusion zones will be established along the Project footprint in potentially suitable areas (alkali desert scrub, annual grassland, barren, valley foothill riparian); fencing will be composed of a combination of both high-visibility fencing and wildlife exclusion fencing.

BNLL-7: Non-disturbance exclusion zones will be maintained and monitored by the USFWS-approved biological monitor(s) to avoid the possibility for take of BNLL, their burrows/nests, or the species' habitat outside of the Project footprint.

To clarify terminology in the above measures, it is acknowledged that “active burrows” and “egg clutch sites” are difficult to identify. Thus, burrows will be considered potentially “active” or potentially “egg clutch sites” when a BNLL has been observed on-site. If no BNLL are observed, all burrows will be considered inactive. To clarify the timing of after “the eggs have hatched,” active burrows will be considered active until after the juvenile season (August 15–September 30; CDFW 2019) is over.

In addition to the above measures for BNLL, the following additional general measures will be followed during construction activities occurring within the BNLL protocol survey Segments 3 and 4 (see Appendix B) where BNLL have been observed during protocol surveys:

* Measures to be implemented prior to and during initial clear and grub.

** Measures to be implemented until potentially suitable areas for BNLL are cleared of burrows and vegetation.

*** Measures to be implemented at all times.

BNLL-8: In addition to an environmental training program, site specific BNLL training will be provided to construction personnel prior to and during clear/grub activities. Training will not be required post clear/grub. Construction personnel will be provided a BNLL site-specific avoidance measures handout for reference; the BNLL handout will be available to crews in the field during tailgate meetings.

BNLL-9: During periods that are optimal for BNLL activity (approximately April 15 through October 15), an additional USFWS-approved BNLL biologist/monitor will be present full time during all ground disturbing activities and mobilizations per work area.**

a. The qualified biologists will conduct visual surveys for BNLL and check the work area(s) and access route(s) to determine presence or absence of BNLL.**

b. If the USFWS-approved biologist determines that further investigation is required to rule out potentially active burrows, a scope may be used to examine burrows for egg clutches.

BNLL-10: If BNLL are observed within the exclusionary fencing during construction, a 250 foot avoidance buffer will be erected on the north and south side of the buffer while the eastern and/or western edges of the fencing will be dis-assembled and lain on the ground to allow the BNLL to leave on its own volition.



Once the BNLL is observed leaving the work area the fencing will be installed back to its previous condition and the 250-foot buffer removed. If the BNLL does not leave the work area of its own volition within 24 hours, USFWS/CDFW will be consulted for further guidance.***

BNLL-11: Offsite locations where BNLL have been observed or are likely to occur will be clearly marked, when possible, to prevent workers from driving off the road and to prevent inadvertent destruction of burrows.***

BNLL-12: A speed limit of 5 mph will be posted and observed within work areas in BNLL protocol survey Segments 3 and 4 (refer to Appendix B) until approved otherwise by the USFWS-approved biologist.**

BNLL-13: Construction and Project related vehicles will be escorted by a USFWS-approved biologist/monitor, within predetermined ingress/egress routes.**

BNLL-14: A USFWS-approved biologist will survey areas of suitable habitat 24 hours prior to ground disturbance in order to determine if any significant changes have occurred since last surveyed.*

BNLL-15: Prior to ground disturbing activities (burrow excavations and/or construction activities), enhanced surveys, in addition to protocol surveys, will take place for 5 days in areas that contain open land cover (such as dirt roads and barren open spots) where BNLL had not been previously detected but are adjacent to recent observations. These surveys will be conducted in addition to protocol surveys. Enhanced surveys will consist of two surveyors walking adjacent transects to provide 100 percent visual coverage within each segment. Enhanced surveys will take place under the optimal temperature described by CDFW (2019) and will be completed by September 30 of the relevant year. Additionally, should the USFWS-approved biologist assess any burrow or area of potentially housing BNLL, the biologist may surveil the area continuously for additional time each day to ensure no BNLL are present.

8.1.3.6 Temblor Legless Lizard (TLL)

TLL-1: If Temblor legless lizard becomes state listed or remains a candidate species under the California ESA, at least one year prior to construction a qualified biologist shall conduct a survey within the Project footprint. The Temblor legless lizard survey effort shall include at minimum:

- A detailed habitat assessment;
- A survey proposal submitted to and approved by CDFW;
- Aera Energy shall notify CDFW for further coordination to avoid or mitigate impacts and to determine if a State ITP will be required for Temblor legless lizard.

TLL-2: At minimum, a 30-foot avoidance buffer shall be maintained surrounding unearthed Temblor legless lizards unless CDFW agrees to a reduced buffer.

8.1.3.7 Northern California Legless Lizard, California Glossy Snake, San Joaquin Coachwhip, Coast Horned Lizard, and Other Reptiles (OR)

OR-1: After installation of exclusion fencing, a qualified biologist shall conduct visual preconstruction surveys within the Project footprint in areas of suitable habitat no more than 30 days prior to ground disturbing activities. If any northern California legless lizard, California gloss snake, San Joaquin coachwhip, coast horned lizard, or other reptiles are observed within exclusion fencing, they will be relocated to suitable habitat outside of the exclusion fencing by a qualified biologist.

OR-2: At minimum, a 50-foot avoidance buffer shall be maintained surrounding northern California legless lizard, California gloss snake, San Joaquin coachwhip, coast horned lizard, or other special-status reptile species unless CDFW agrees to a reduced buffer.

8.1.3.8 Giant Kangaroo Rat (GKR)

Aera Energy will utilize the measures below to avoid and minimize impacts on GKR during Project activities. USFWS/CDFW will be notified if the avoidance and minimization measures, including GKR trapping and relocation, vary from what is described in this BRTR. USFWS/CDFW will approve any measures not described herein prior to implementation.

GKR-1: A qualified biologist with required federal and state permits will conduct small mammal trapping in suitable habitat within the BSA to determine presence/absence of GKR. Trapping efforts shall follow the USFWS *Survey Protocol for Determining Presence of San Joaquin Kangaroo Rats* (USFWS 2013). A survey proposal shall be submitted for review and approval by USFWS/CDFW. Survey results shall be submitted to USFWS/CDFW to determine if a federal BO and state ITP will be required for GKR.

GKR-2: No more than 14 days prior to construction, the USFWS-approved biologist will conduct surveys to identify all potential burrows used by GKR within the disturbance areas and within 50 feet of areas where ground disturbance will occur.

GKR-3: The agency-approved biologist will establish a buffer of at least 50 feet around potential GKR burrows to avoid impacts on burrows. The buffer area will be delineated prior to construction activities and marked with brightly colored markers that will be visible to workers as well as signs, stakes, flags, and/or rope or cord.

GKR-4: Aera Energy will leave undisturbed any GKR food stores (e.g., haystacks, seed caches, or other stockpiled forage). If avoidance is not feasible, the USFWS-approved biologist will implement measures to keep the food stores intact, including temporarily relocating the food stores and covering seeds with plywood to allow temporary vehicle or on-foot access.

GKR-5: GKR burrows within the fenced disturbance area will be live trapped prior to surface disturbance or vegetation grubbing activities within that specific temporary exclusion fencing area and relocated (see **GKR-7**). Aera Energy's live-trapping and relocation procedures will adhere to a relocation plan for GKR and SJAS approved by USFWS/CDFW prior to ground disturbance occurring. Aera Energy would target fall (September-November) or early spring (March-April) if kangaroo rats do not show signs of being reproductively active or tending young (lactating) for trapping and relocation to maximize the potential for



relocation success (Tennant et al. 2013). The trapping period will continue for at least 5 consecutive trap nights, within each project segment. If presence is determined within a specific project segment area, then trapping within the segment will cease. Traps will be set at dusk and checked and closed at dawn. Traps may be checked more often if weather conditions (i.e., abnormally high or low nighttime temperatures, inclement weather, etc.) warrant, as determined by the USFWS-approved biologist. If predicted nighttime temperatures drop below 50°F, then traps may be checked more frequently, and synthetic batting or additional insulating material may be placed in traps to reduce the effects of colder temperatures on trapped animals. Trapping will cease if captured animals are found to be lethargic or otherwise exhibiting signs of a decrease in body temperature. If a lactating female is captured, it will be released until it is no longer lactating. Trapped animals will be held temporarily in large plastic buckets with a layer of sandy soil and sections of cardboard tube in a sheltered and secure location prior to their release. GKRs will be released within 48 hours of their capture, unless it is determined by the USFWS-approved biologist that holding them for a longer period will increase the potential for relocation success. No animals will be held for more than 7 days. Following completion of trapping, the area will be searched for evidence of continued presence of GKRs. If evidence indicates a GKR remains within the enclosure but is avoiding the traps, then that animal will be removed by carefully excavating the occupied precinct with hand tools (see **GKR-7**).

GKR-6: After completion of live trapping, burrows would be fully excavated by hand per **GEN-14**. Any GKRs encountered will be allowed to escape out of harm's way into adjacent habitat (if present) or, at the discretion of the USFWS-approved biologist, will be collected and relocated (see **GKR-7**).

GKR-7: Trapped or collected GKRs will be relocated within the BSA at least 50 feet from ground disturbance areas. Aera Energy's live-trapping and relocation procedures will adhere to a relocation plan for GKR approved by USFWS/CDFW prior to ground disturbance occurring. The USFWS-approved biologist will conduct reconnaissance surveys of a potential release site to determine suitability. Preference will be given to unoccupied or low-occupancy release locations with ample burrows that consist of alluvial and loamy soils, soils with a sandy or gravelly texture, or fine-grained soils with sparsely distributed shrubs that also provide ample refugia. Sites with suitable habitat and lacking burrows can also be suitable if artificial burrows are used (as described below). The USFWS-approved biologist will evaluate suitability, based on habitat characteristics, burrow density, signs of GKR presence (scat, clippings, auditory cues, etc.), small mammal trapping, and the size of the relocation site. Aera Energy would use soft-release methods. Artificial burrows and temporary enclosure fencing will be used to reduce risk of predation or mortality resulting from disoriented animals fleeing the release site.

Artificial burrow designs will be based on best available science currently accepted by USFWS/CDFW. Generally, artificial burrows will be constructed using cardboard or similar material tubes (approximately 3 to 4 inches wide, and 48 to 60 inches in length) that are sloped from opposite directions to a central chamber set approximately 12 to 18 inches below the ground. Artificial burrows will be constructed in similar arrangement as the native burrows from which the GKRs were relocated. Enclosures would also be based on best available science currently accepted by USFWS/CDFW. Generally, enclosures will be constructed with 48-inch-tall wire mesh fencing or similar material supported by metal fence posts, with mesh openings small enough to prevent GKRs from prematurely leaving the release site or becoming entangled. The enclosure will be circular, with a 12- to 15-foot diameter around the artificial burrow. The

bottom 8 inches of the fence material will be buried below ground level to deter predators and GKRs from excavating passages under the fence. The top of the enclosure will be covered with polyvinyl chloride (PVC) hardware, cloth, or similar material to deter avian predators from landing inside the enclosure. Enclosure fencing will be in place for 7 days after the relocation, and supplemental food (a seed mix consisting of 75 percent white proso millet and 25 percent oat) will be provided for 7 days. Only the USFWS-approved biologist is authorized to capture, handle, and relocate GKRs.

GKR-8: Any sick or injured GKR encountered will be collected by the USFWS-approved biologist and taken to a wildlife rehabilitation center of veterinary facility for injured animals.

8.1.3.9 Short-nosed Kangaroo Rat, Tulare Grasshopper Mouse, San Joaquin Pocket Mouse, and Other Small Mammals (SM)

The following avoidance and minimization measures will be implemented to protect special-status small mammal species that have potential to occur in the BSA.

SM-1: Presence/absence of short-nosed kangaroo rat, Tulare grasshopper mouse, San Joaquin pocket mouse, and other small mammals shall be documented during GKR trapping proposed in **GKR-1**.

SM-2: If live-trapping and/or excavation of burrows is authorized by USFWS/CDFW for the purpose of relocation of GKR, any short-nosed kangaroo rat, Tulare grasshopper mouse, San Joaquin pocket mouse, and other small mammals discovered during implementation of **GKR-5**, **GKR-6**, and **GKR-7** will be likewise relocated.

SM-3: During construction, any short-nosed kangaroo rat, Tulare grasshopper mouse, San Joaquin pocket mouse, or other small mammals incidentally unearthed during construction activities or entrapped in work areas by exclusion fencing shall either be:

- Captured and relocated outside of the exclusion fencing by a qualified biologist; or
- Released through a temporary opening in the exclusion fencing, with the exclusion fencing to be repaired to restore fence integrity immediately after release of the animal(s).

8.1.3.10 San Joaquin Antelope Squirrel (SJAS)

Aera Energy will utilize the measures below to avoid and minimize impacts on SJASs during Project activities. CDFW will be notified if the avoidance and minimization measures, including SJAS trapping and relocation, vary from what is described in this application. CDFW will approve any measures not described herein prior to implementation.

SJAS-1: No more than 14 days prior to construction, the CDFW-approved biologist will conduct surveys to identify all potential burrows used by SJAS within the disturbance areas and within 50 feet of areas where ground disturbance will occur.

SJAS-2: The CDFW-approved biologist will establish a buffer of at least 50 feet around potential SJAS burrows to avoid impacts on burrows. The buffer area will be delineated prior to construction activities and



marked with brightly colored markers that will be visible to workers as well as signs, stakes, flags, and/or rope or cord.

SJAS-3: Any potential SJAS burrows detected by the CDFW-approved biologist within the temporary exclusion fencing installed after preconstruction surveys (see **GEN-12**) that cannot be avoided will be live trapped prior to surface disturbance or vegetation grubbing activities within that specific temporary exclusion fencing area and relocated (see **SJAS-5**). Aera Energy's live-trapping and relocation procedures will adhere to a relocation plan for GKR and SJAS approved by CDFW prior to ground disturbance occurring. The CDFW-approved biologist and biological monitor, or a supervised trapping crew, will conduct live trapping over at least five consecutive days. If possible, trapping and the relocation of SJAS will avoid the breeding/mating season (January to May) in order to avoid disrupting family units. Ideally, this will take place during late summer and early fall. However, if trapping/relocation activities cannot be delayed until after the breeding season and a lactating female is captured, it will be released until it is no longer lactating.

SJAS-4: After completion of live trapping, burrows would be fully excavated by hand per **GEN-14**. Any SJAS encountered during the excavation will be allowed to escape to adjacent natural habitat (if present) or, at the discretion of the CDFW-approved biologist, collected and relocated (see **SJAS-5**).

SJAS-5: Trapped or collected SJASs would be relocated to an area of suitable habitat in the BSA, at least 50 feet from any disturbance areas. Aera Energy's live-trapping and relocation procedures will adhere to a relocation plan for GKR and SJAS approved by CDFW prior to ground disturbance occurring. The CDFW-approved biologist will conduct reconnaissance surveys of a potential release site to determine suitability. Preference will be given to unoccupied or low-occupancy release locations with ample burrows that consist of alluvial and loamy soils, soils with a sandy or gravelly texture, or fine-grained soils with sparsely distributed shrubs that also provide ample refugia. Sites with suitable habitat and lacking burrows can also be suitable, if artificial burrows are used (as described below). The CDFW-approved biologist will evaluate suitability, based on habitat characteristics, burrow density, signs of SJAS presence (scat and auditory cues), and the size of the relocation site. The CDFW-approved biologist may also complete camera surveys or small-mammal trapping if visual signs are not adequate for judging the level of site occupancy. If the CDFW-approved biologist determines that there does not appear to be a sufficient number of natural existing burrows that could be used by the relocated SJAS at the release site (a minimum of one burrow per individual released will be the target), artificial burrows will be constructed. SJAS will be hard released.

Artificial burrows would consist of two cardboard tubes (e.g., cardboard mailing or storage tubes), minimum of 3 inches in diameter, that slope from opposite directions to a central chamber situated 15 to 20 inches below the ground surface. The central chamber would consist of corrugated cardboard or other biodegradable material that would form the walls of an approximately 2-foot-square excavation. The walls of the chamber would be secured with plywood to prevent the chamber from being crushed when backfilling the trench. The chamber would be provisioned with a food cache of seeds (~ 5 pounds, a mix of 75 percent proso white millet and 25 percent oat groats, or similar mixture), along with a few sheets of paper towels. Artificial burrows would be spaced a minimum of 60 feet apart to account for the typical home range of SJAS. However, in order to preserve the configurations of neighbors, the spatial



relationship of neighbor groups from the capture site will be maintained at the release site, to the extent possible, by replicating the spatial relationship of burrows from the capture site at the release site to the extent feasible.

SJAS-6: Only the CDFW-approved biologist is authorized to capture, handle, and relocate SJAS. Each captured SJAS will be placed into a separate container, such as a 5-gallon bucket or other similar container, filled with at least 6 inches of sand and fitted with a lid. The lid shall be made of wire screen, or other similar material; air holes may be drilled into a solid lid. In order to minimize the amount of time individuals are held within the containers, the captured individuals will be taken to the preidentified release site immediately following each day of the 5-day trapping effort.

SJAS-7: Any sick or injured SJAS encountered will be collected by the CDFW-approved biologist and taken to a rehabilitation center or veterinary facility for injured animals.

8.1.3.11 San Joaquin Kit Fox (SJKF)

The following measures will be deployed during Project activities to avoid or minimize adverse effects on SJKF as well as avoid injury or mortality.

SJKF-1: If a potential SJKF den is discovered or a SJKF is found in an "atypical" den (e.g., a pipe or culvert), Aera Energy will establish a minimum 50-foot buffer around the den. If a "known" den (one that shows evidence of current use or was used in the past) is discovered, Aera Energy will establish a minimum buffer of at least 100 feet around the den. If a "natal" den (den in which SJKF young are reared, typically with two or more openings) is discovered, a buffer of at least 200 feet will be established around the den. Natal dens with pups present will have a buffer of at least 500 feet. If these buffers cannot be completely avoided, the USFWS-approved biologist will notify USFWS/CDFW.

SJKF-2: Potential and known dens that cannot be avoided by the minimum buffer distances described above may be destroyed only after the USFWS-approved biologist has determined that SJKF is not currently present after 4 consecutive nights of monitoring. Dens must be destroyed immediately after the fourth night of monitoring if no activity is documented. Den destruction would include the following measures:

- Dens would be carefully hand excavated under the direct supervision of the USFWS-approved biologist. The den would then be filled with dirt and compacted to prevent reentry and use of the den during the construction period. If a SJKF is discovered during excavation, the excavation will cease immediately, and monitoring of the den, as described above, will be resumed. Completing the excavation and the destruction of the den will resume when, in the judgment of the USFWS-approved biologist, it can be verified that the SJKF has left the partially destroyed den.

- Natal dens will not be excavated until 1) the pups and adults have vacated the den and 2) concurrence to proceed with the excavation has been received from USFWS/CDFW. If a SJKF does not vacate a den within a reasonable timeframe, USFWS and CDFW will be consulted to obtain written guidance (via email) prior to proceeding with the den destruction.



SJKF-3: Potential dens lacking signs of occupancy that are at least 50 feet from work or disturbance areas will remain intact and will not be altered or blocked from use.

SJKF-4: Aera Energy will replace each known and natal SJKF den that cannot be avoided and will be destroyed by Project activities as follows:

- Aera Energy will install one artificial SJKF den for each known den and three artificial dens for each natal den to be collapsed due to unavoidable disturbance. Aera Energy will install artificial dens within 300 feet of the collapsed den, or as close as deemed safe from oil and gas operations, prior to excavation of the known or natal den. Artificial natal dens will be multi-chambered and have multiple entrances. If more than 10 suitable SJKF dens are located within a 300-foot radius of the collapsed den, Aera Energy will locate the replacement dens within 400 feet of the collapsed den. The artificial den(s) will be completed before excavation of known and natal SJKF dens can occur to compensate for the loss of important shelter for protection, reproduction, and escape from predators.
    - The following criteria will be considered when selecting an artificial SJKF den location within the BSA:
        - Artificial dens should be as close as possible to the destroyed or disturbed SJKF den,
        - The location should have a high likelihood of SJKF visitation,
        - Den entrances should be oriented to avoid flooding and direct sun exposure, and
        - The den complex should have a reduced likelihood of future disturbance, including development, regular maintenance, and human tampering.
    - Construction of dens will follow the guidance available in best available science, including that provided in the USFWS *Standardized Recommendations for Protection of the San Joaquin Fox Prior to or During Ground Disturbance* (USFWS 2011) and *Urban Roads and the Endangered San Joaquin Kit Fox* (Bjurlin et al. 2005), as well as the related descriptions and discussion provided in Harrison et al. (2011) and Cypher et al. (2012). Generally, artificial dens will meet the following specifications:
        - Subterranean dens will consist of at least two entrance tunnels measuring approximately 3.3 feet in length and roughly 8 inches in diameter, and will be oriented to avoid flooding.
        - Material will be PVC, high-density polyethylene pipe or similar material.
        - Subterranean chambers will be at least 20 inches in diameter and 15 inches tall, and the floor of the chamber will be at least 3.3 feet below ground to provide



thermal insulation. Additionally, subterranean chambers will be box-or dome-shaped, with an earthen floor to allow foxes to enlarge the den over time.

- Dens will be constructed to exclude larger predators such as red foxes, bobcats, and coyotes.
- Natal dens will be constructed to include multiple entrances with multiple chambers.

8.1.3.12 American Badger

AB-1: No less than 14 days and no more than 30 days prior to any construction activities, a preconstruction survey shall be conducted by a qualified biologist for American badger. The status of all potential American badger dens shall be determined and mapped.

AB-2: At minimum, a 50-foot avoidance buffer shall be maintained surrounding active American badger dens unless CDFW agrees to a reduced buffer.

8.1.4 Mitigation Compliance

It is estimated the proposed Project would result in the following impacts to habitats and jurisdictional waters:

- Allscale Shrubland: 1.61 acres permanent impacts; 43.06 acres temporary impacts;
- Red Brome or Mediterranean Grass Grasslands: 0.86 acre permanent impacts; 4.74 acres temporary impacts; and
- RWQCB Waters of the State/CDFW Jurisdictional Areas: 0.012 acre permanent impacts; up to 1.144 acre temporary impacts.

The following compensatory mitigation measures will be implemented to offset impacts to habitats and jurisdictional waters:

MIT-1: Post-construction, Aera Energy shall restore temporarily impacted Allscale Shrubland and Red Brome or Mediterranean Grass Grasslands. A qualified habitat restoration specialist shall prepare a Habitat Mitigation and Monitoring Plan (HMMP) that outlines the following at minimum:

- Mitigation work plan, including species palette, planting and irrigation schedule, hydroseeding, and erosion control;
- Maintenance plan/schedule;
- Success criteria;
- Monitoring methods;



- Monitoring and reporting schedule; and
- Provisions for long-term and adaptive management.

MIT-2: For permanent impacts to Allscale Scrubland and Red Brome or Mediterranean Grass Grasslands habitat, Aera Energy shall either:

- Purchase conservation bank credits at a minimum 2:1 replacement ratio; or
- Obtain suitable mitigation lands to preserve Allscale Scrub shrubland habitat at a minimum 2:1 replacement ratio:
    - All land that is protected for the purpose of mitigation will be placed under a permanent conservation easement and managed in perpetuity;
    - Mitigation lands shall be monitored, with a monitoring and reporting schedule to be negotiated with the involved regulatory agencies (e.g., CDFW).

MIT-3: Prior to construction, Aera Energy shall coordinate with SWRCB/RWQCB and CDFW and obtain a Waste Discharge Requirement permit and/or Lake and Streambed Alteration Agreement if required.

MIT-4: Post-construction, Aera Energy shall restore temporarily impacted jurisdictional waters to pre-construction grades and conditions, including bed grooming and smoothing, bank restoration, and/or temporary erosion and sedimentation controls, where necessary. Restoration of temporary impacts shall follow any provisions included in the Waste Discharge Requirement permit and/or Lake and Streambed Alteration Agreement, if applicable.

MIT-5: For permanent impacts to confirmed jurisdictional waters, Aera Energy shall either:

- Purchase mitigation bank credits at a minimum 2:1 replacement ratio; or
- Post-construction, conduct enhancement of jurisdictional features in which permanent impacts occur; enhancement of jurisdictional waters shall be monitored, with a monitoring and reporting schedule to be negotiated with the involved regulatory agencies (e.g., SWRCB/RWQCB, CDFW).



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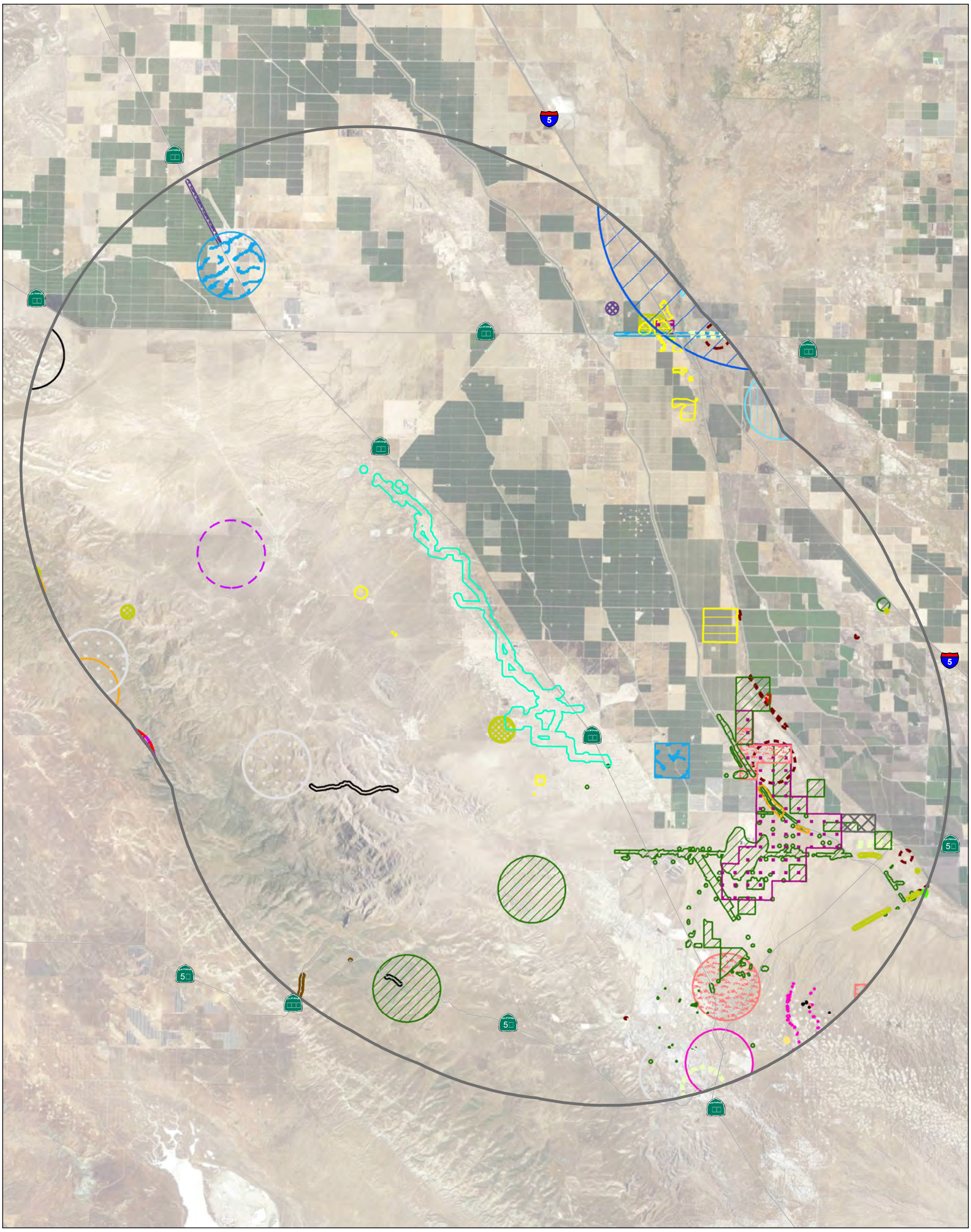
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Appendix A FIGURES





10 Mile CNDDB Results

Plants

Terrestrial Communities

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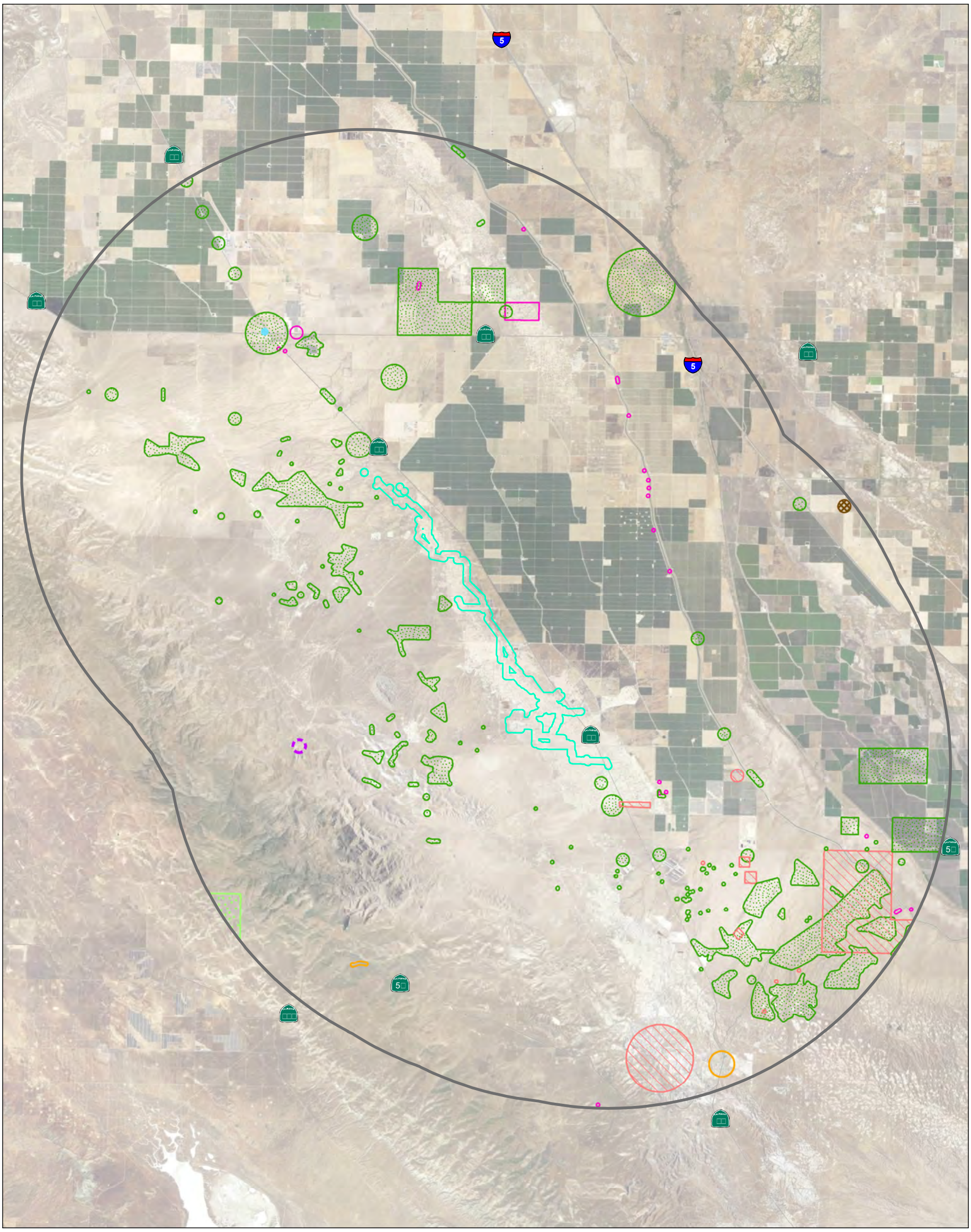
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10 Mile CNDDB Results - Plants and Terrestrial Communities



10 Mile CNDDB Results

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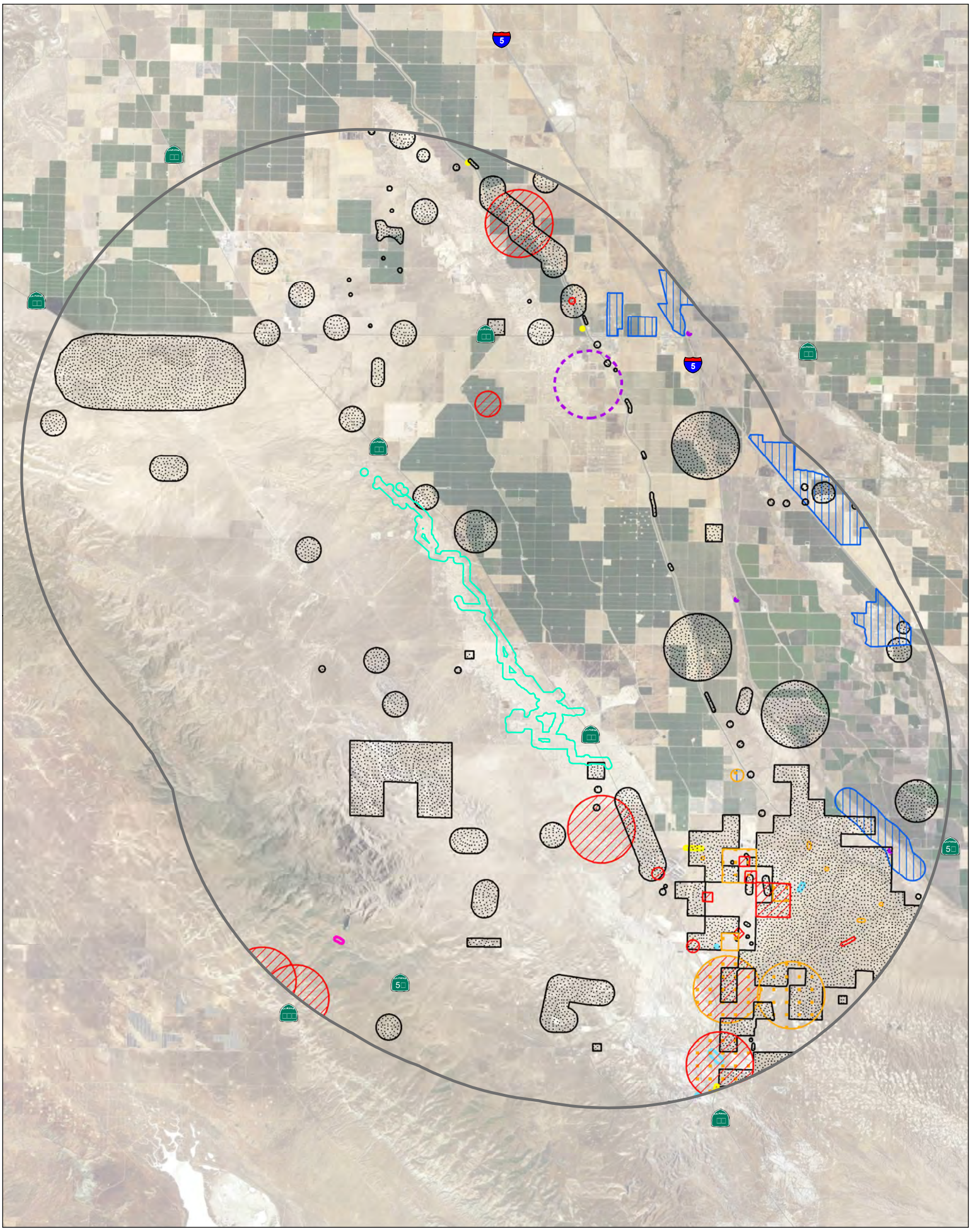
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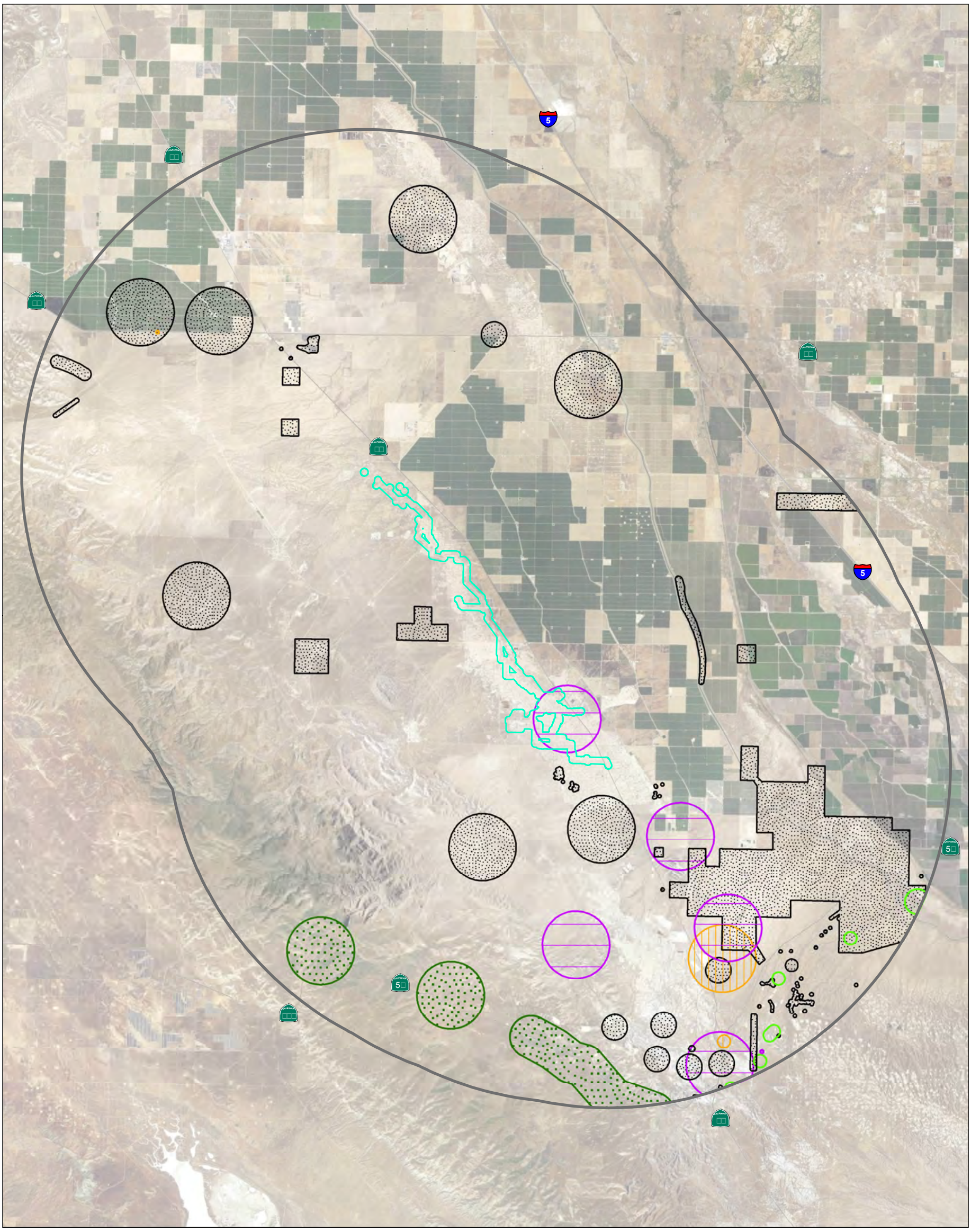
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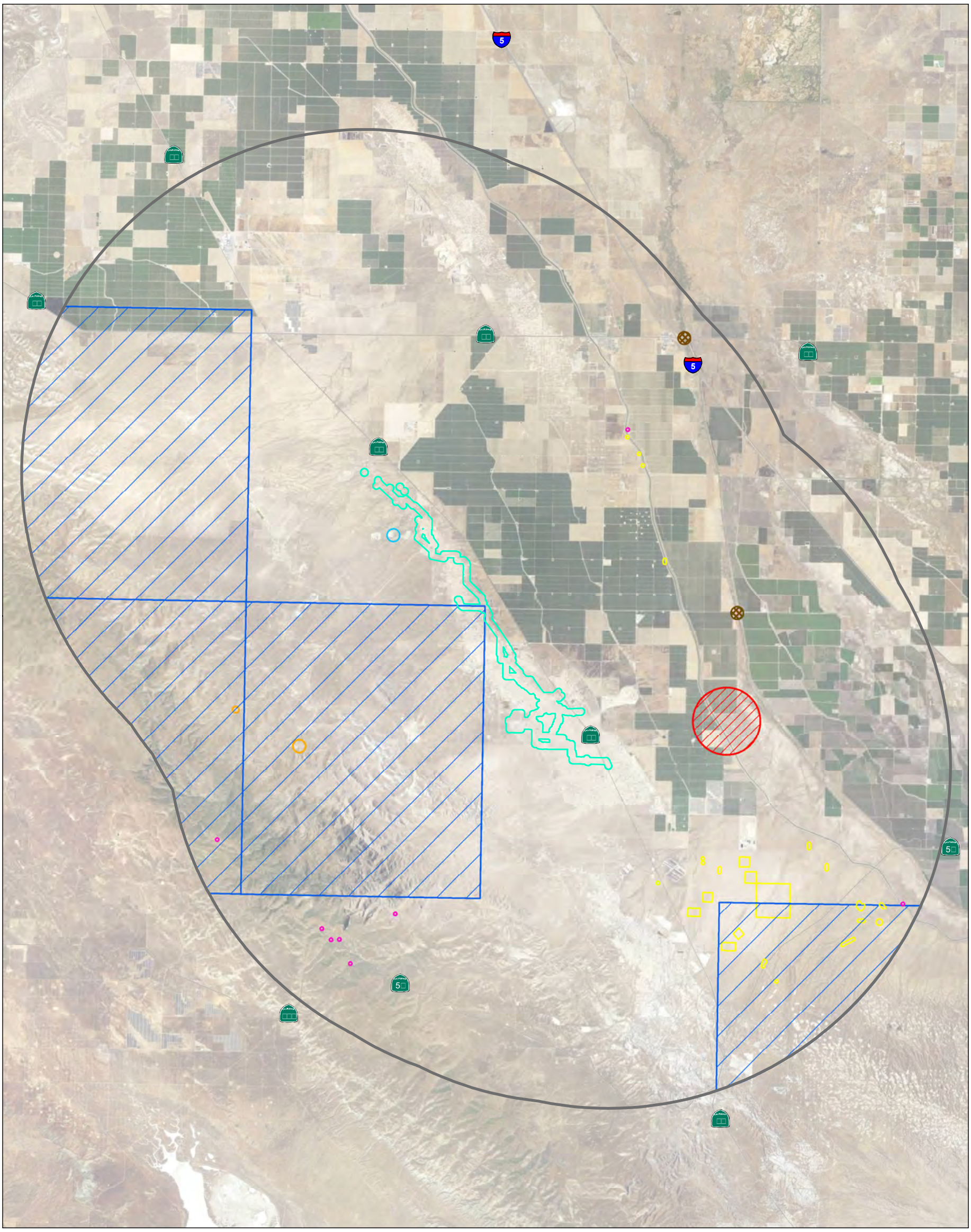
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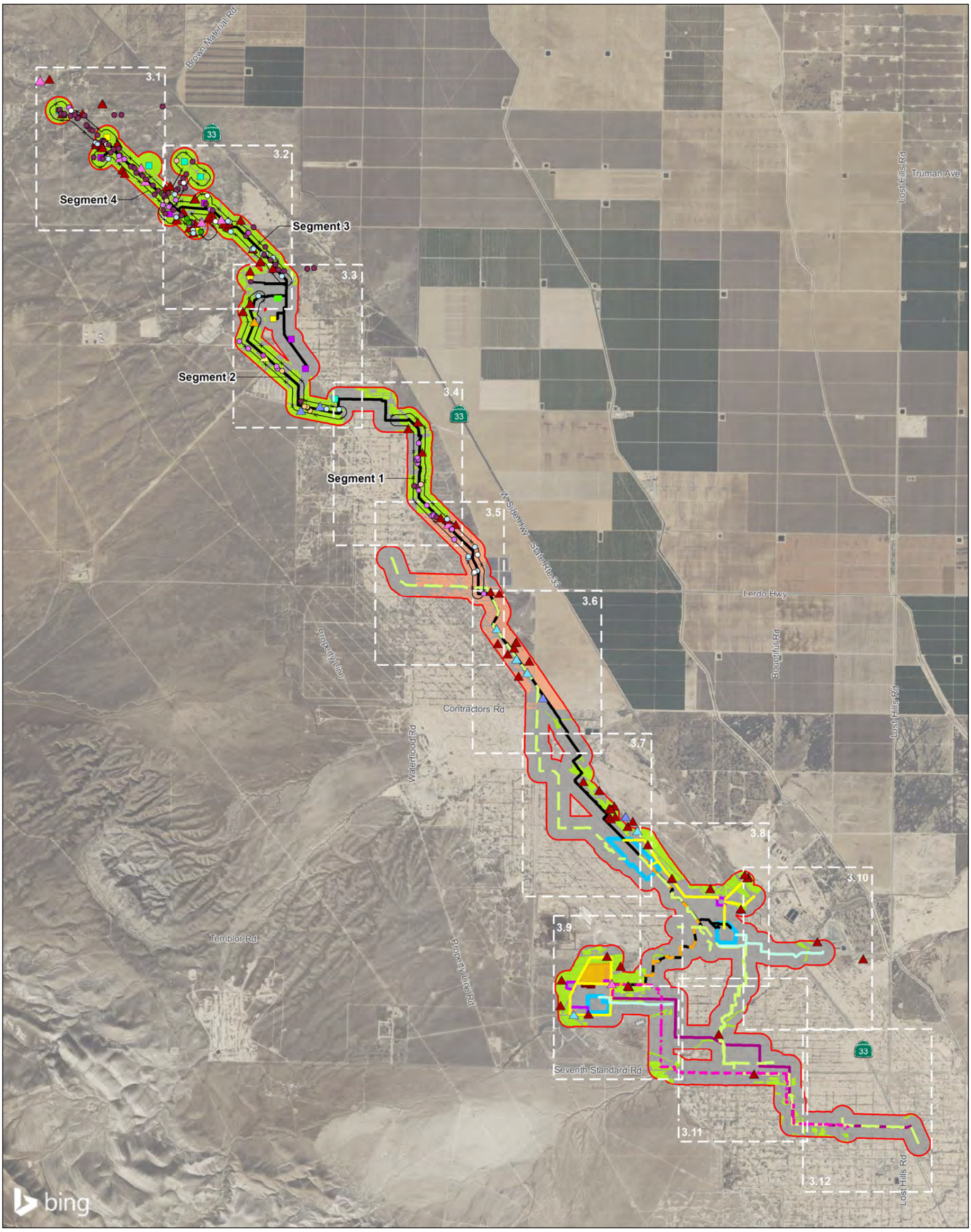
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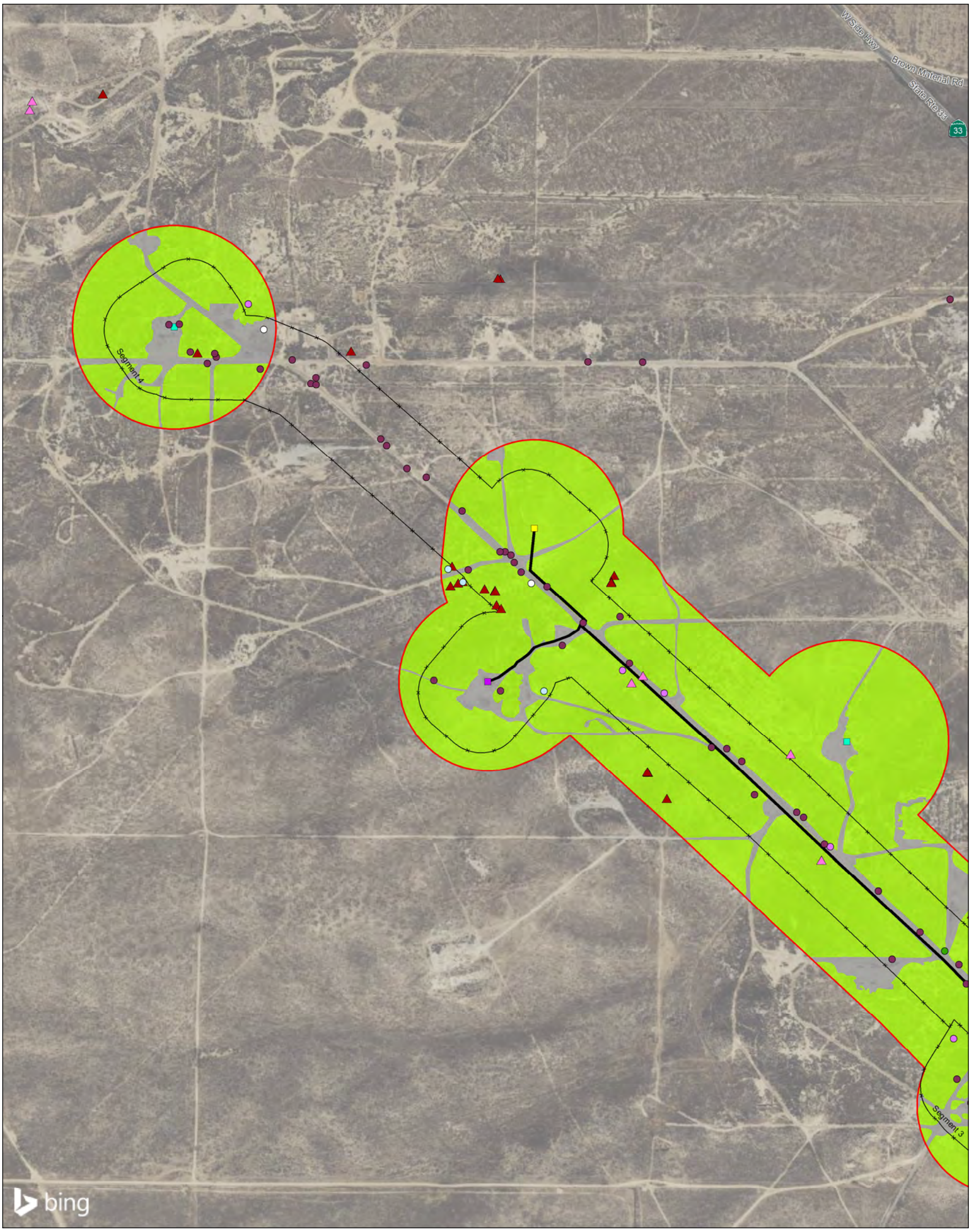
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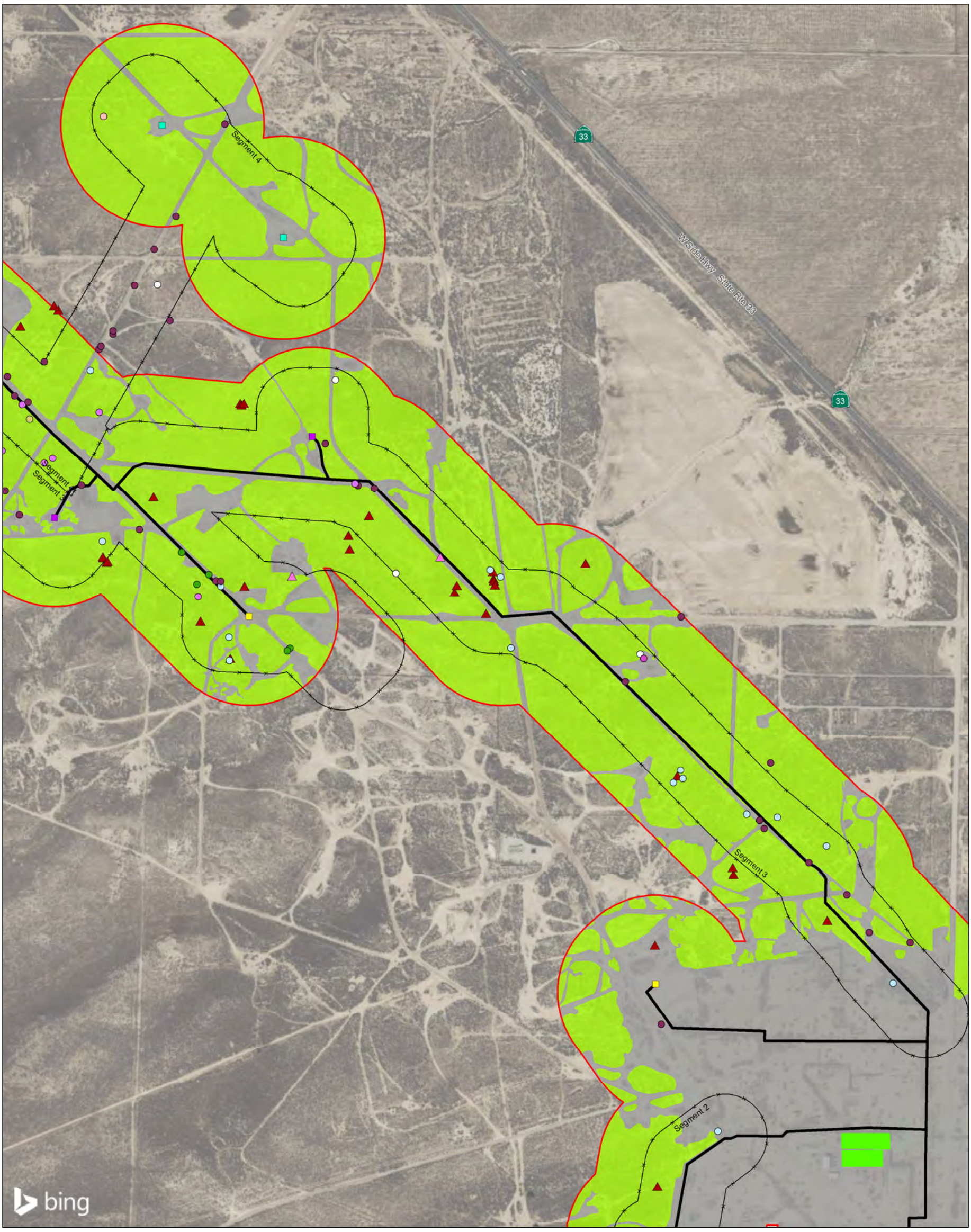
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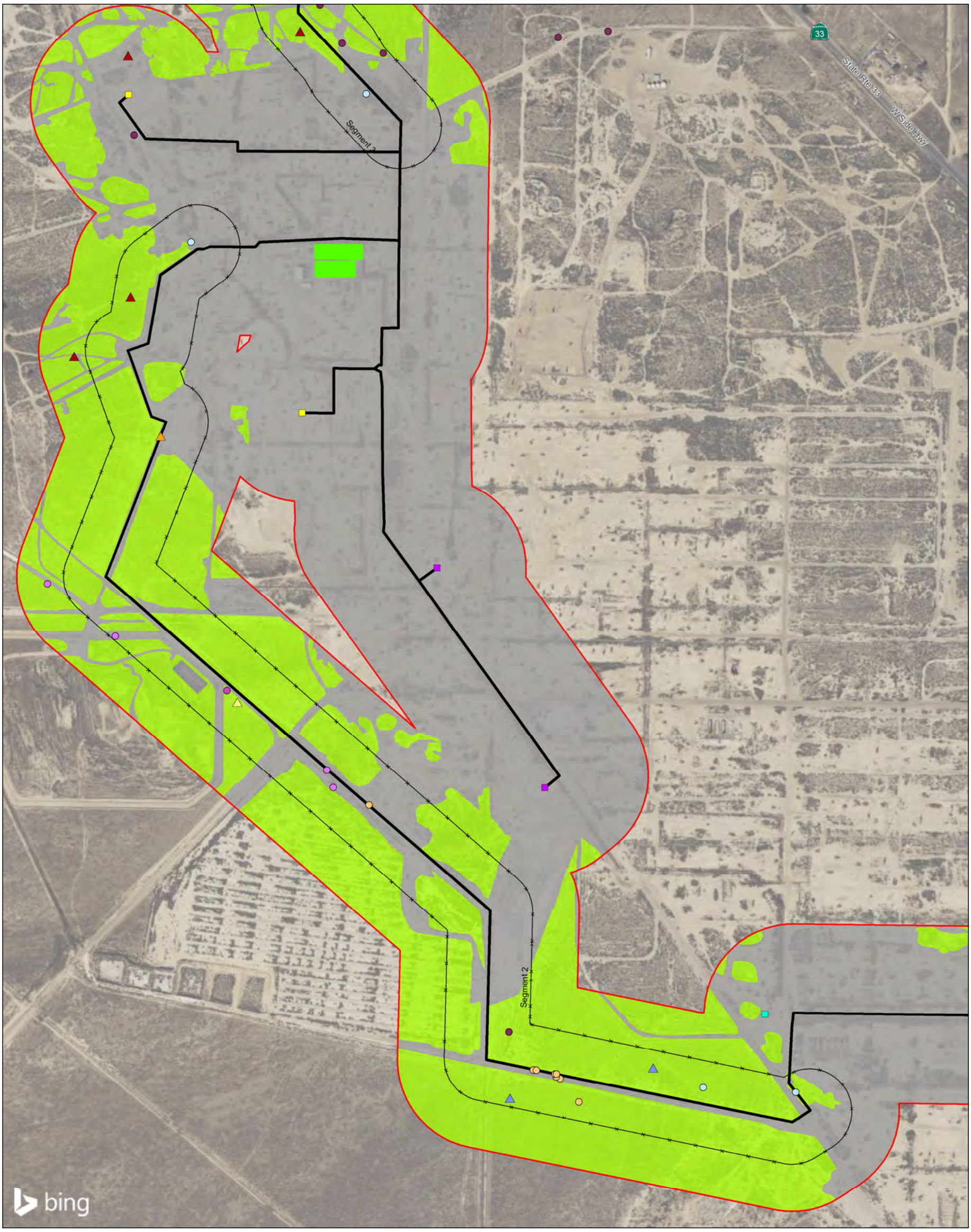
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Figure No.
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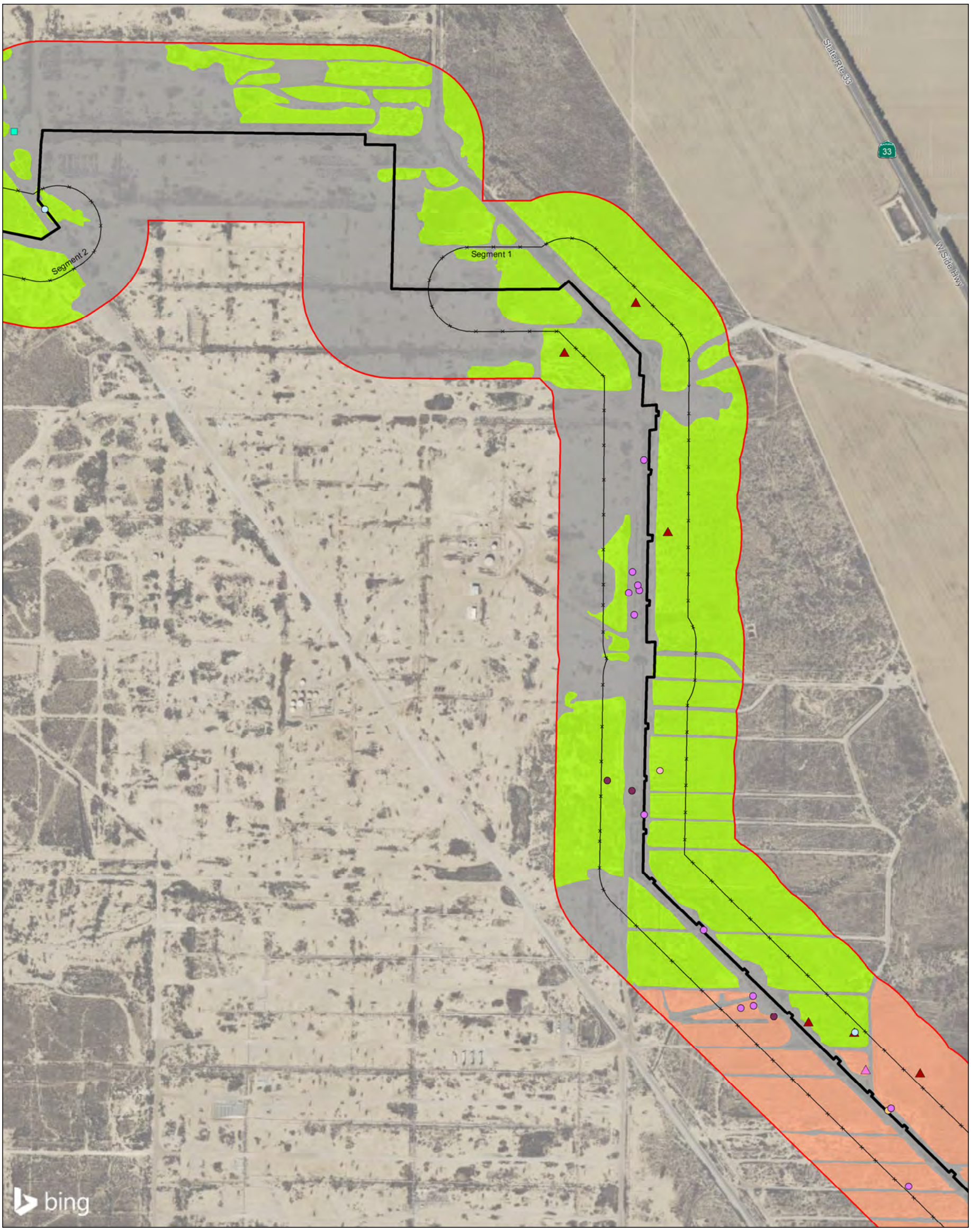
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Project Boundary
Project Mesa Monitoring Area
Project Buffer

Vegetation Communities and Land Cover Types

Developed/Developed Landscaped
Open Water/Irrigation Canal
Riparian Woodland/Scrub

Stantec 2022/2023 Biological Data

Special Status Plant Observation
Special Status Wildlife Observation

Mesa Monitoring Area

Mesa 2023 Biological Data

Special Status Plant Observation
Special Status Wildlife Observation
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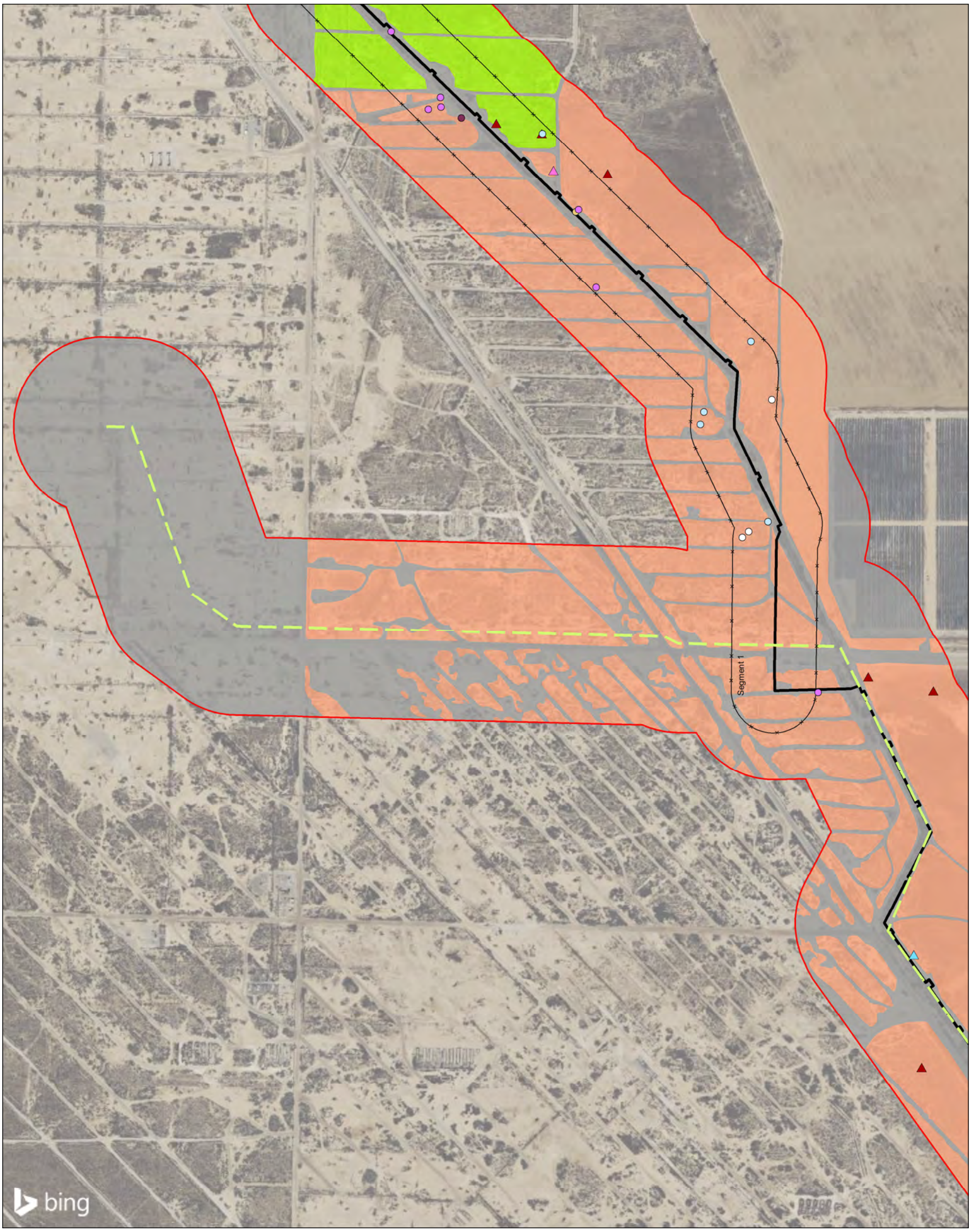
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Vegetation Communities and Land Cover Types

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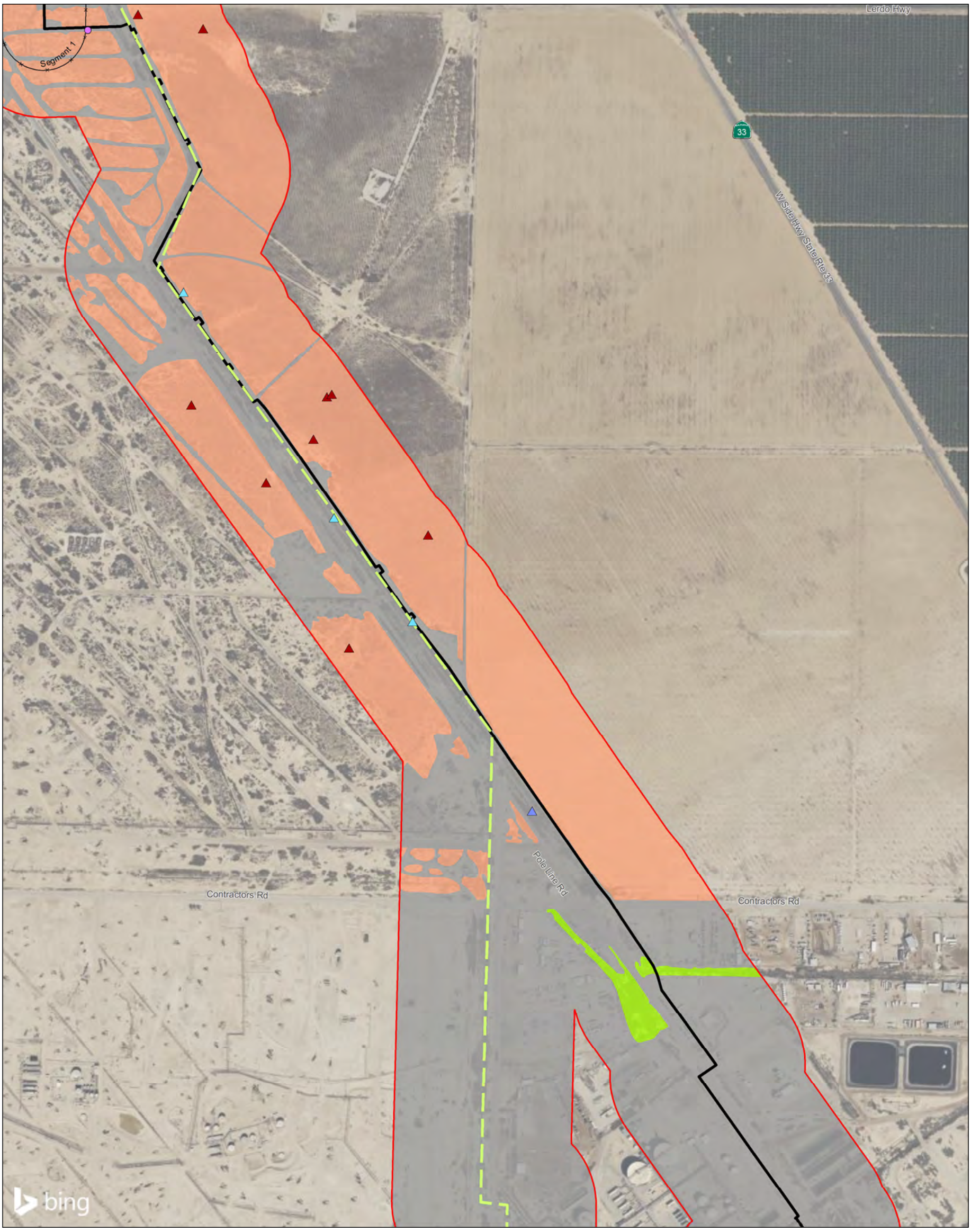
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Title
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Vegetation Communities and Land Cover Types

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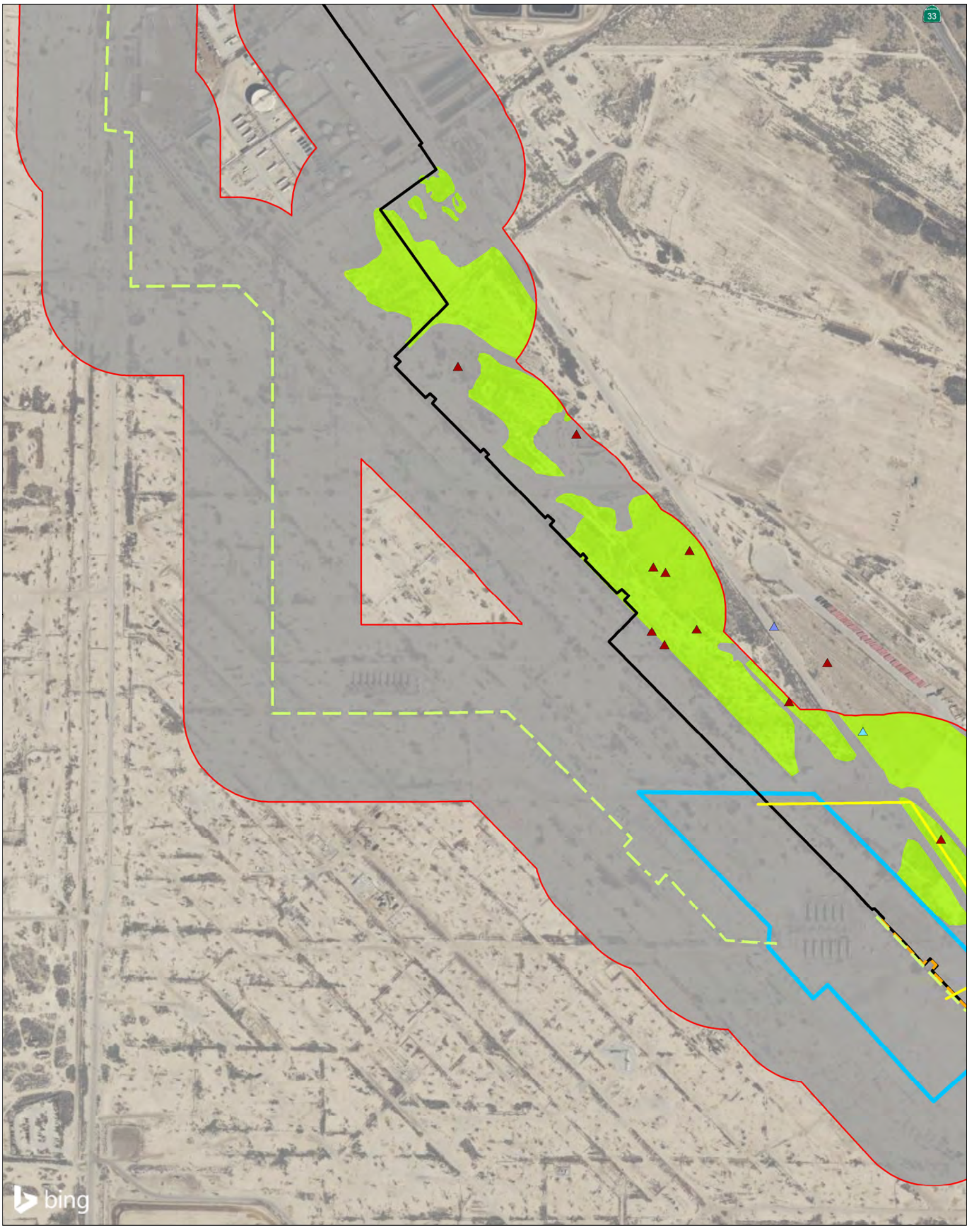
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Vegetation Communities and Land Cover Types

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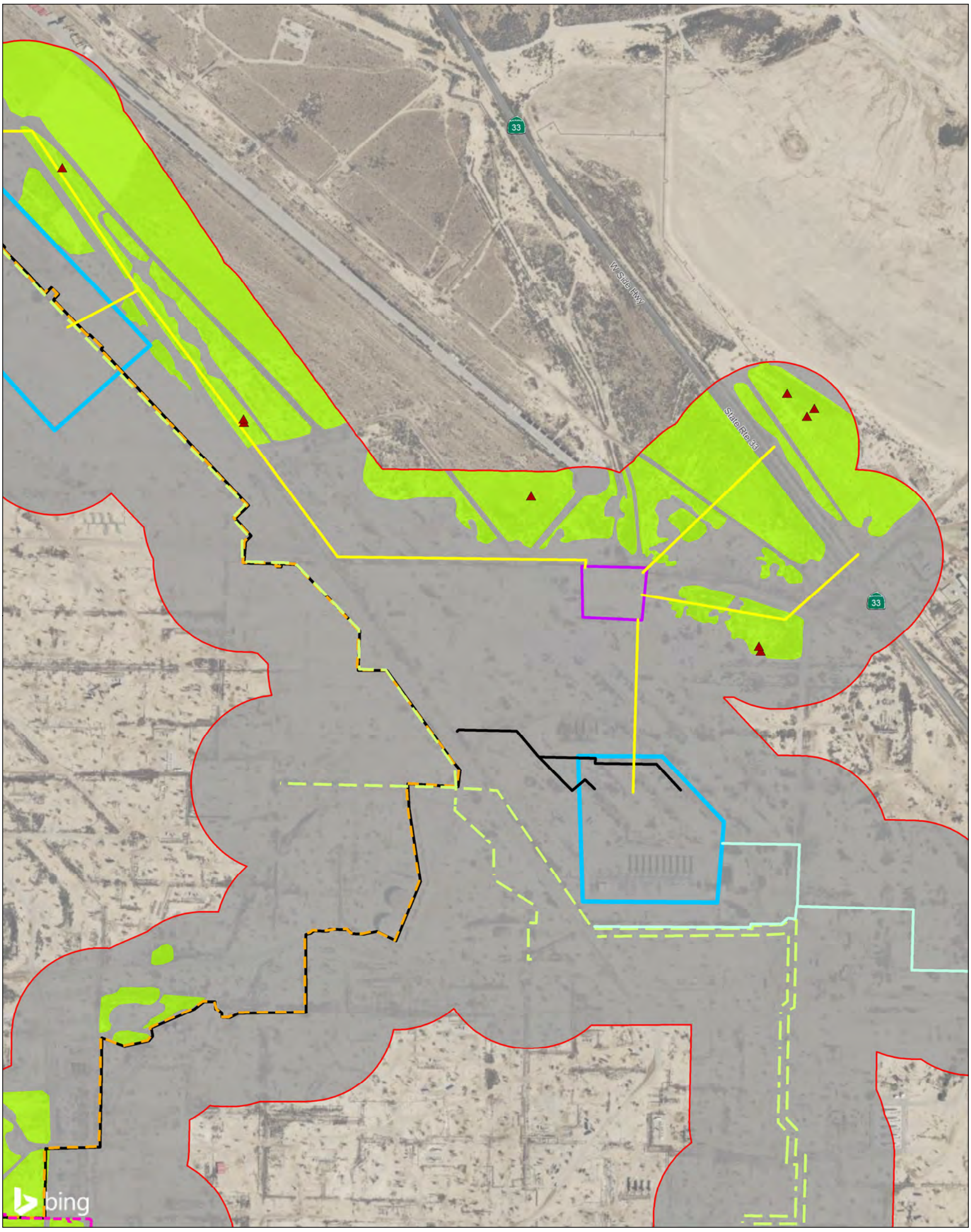
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Vegetation Communities and Land Cover Types

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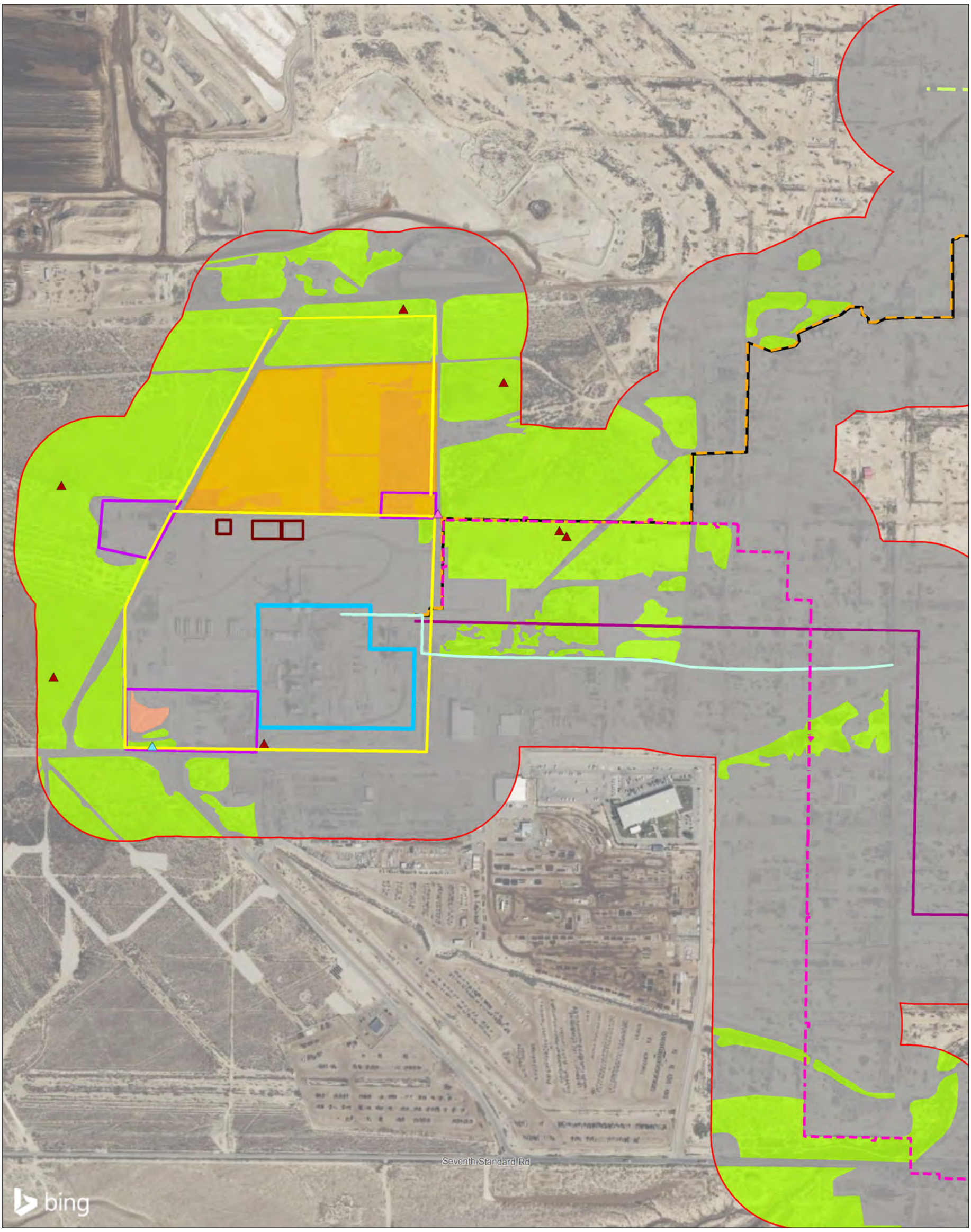
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Title

Special Status Species Evidence

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Vegetation Communities and Land Cover Types

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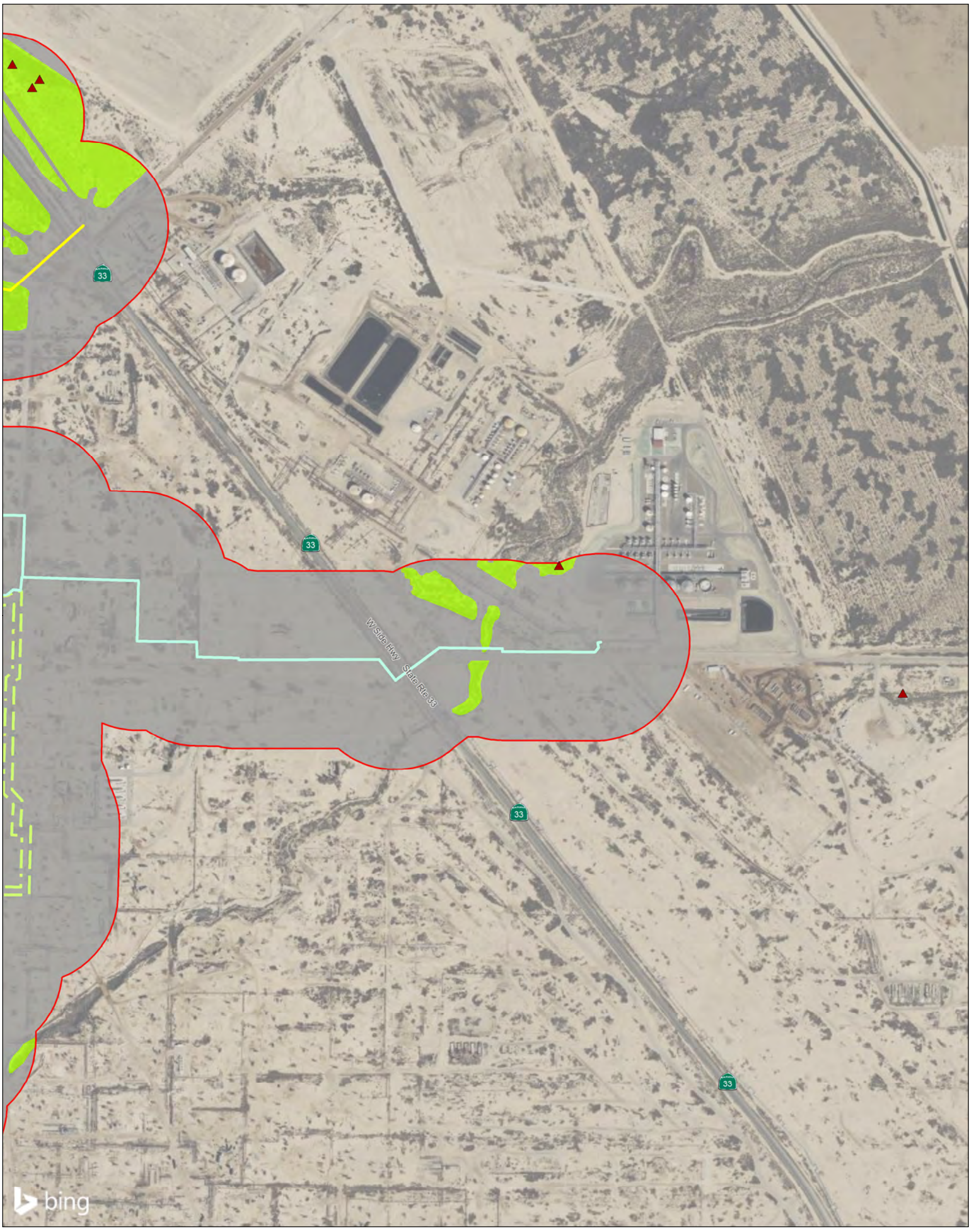
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Vegetation Communities and Land Cover Types

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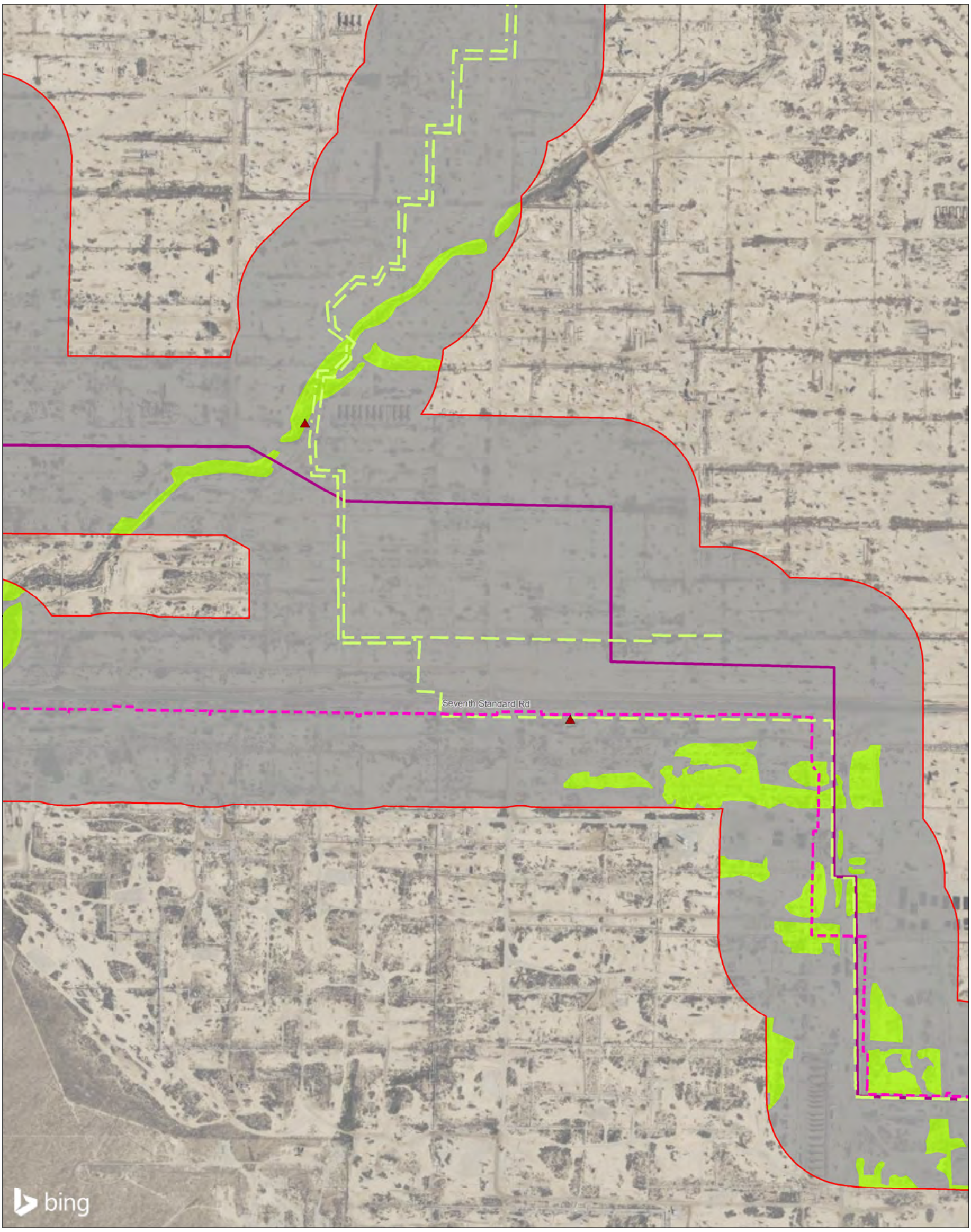
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Title
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Vegetation Communities and Land Cover Types

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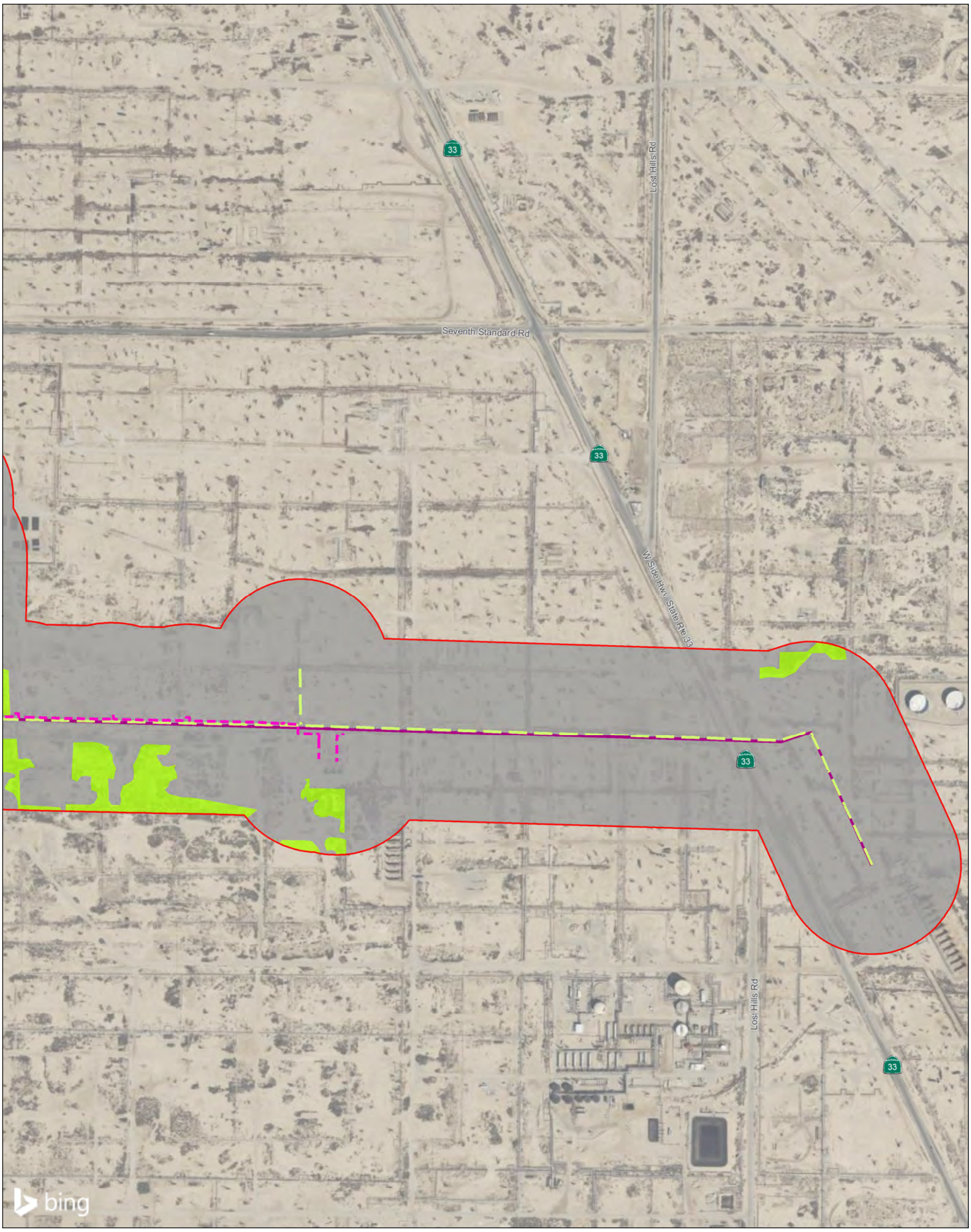
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Figure No.
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Vegetation Communities and Land Cover Types

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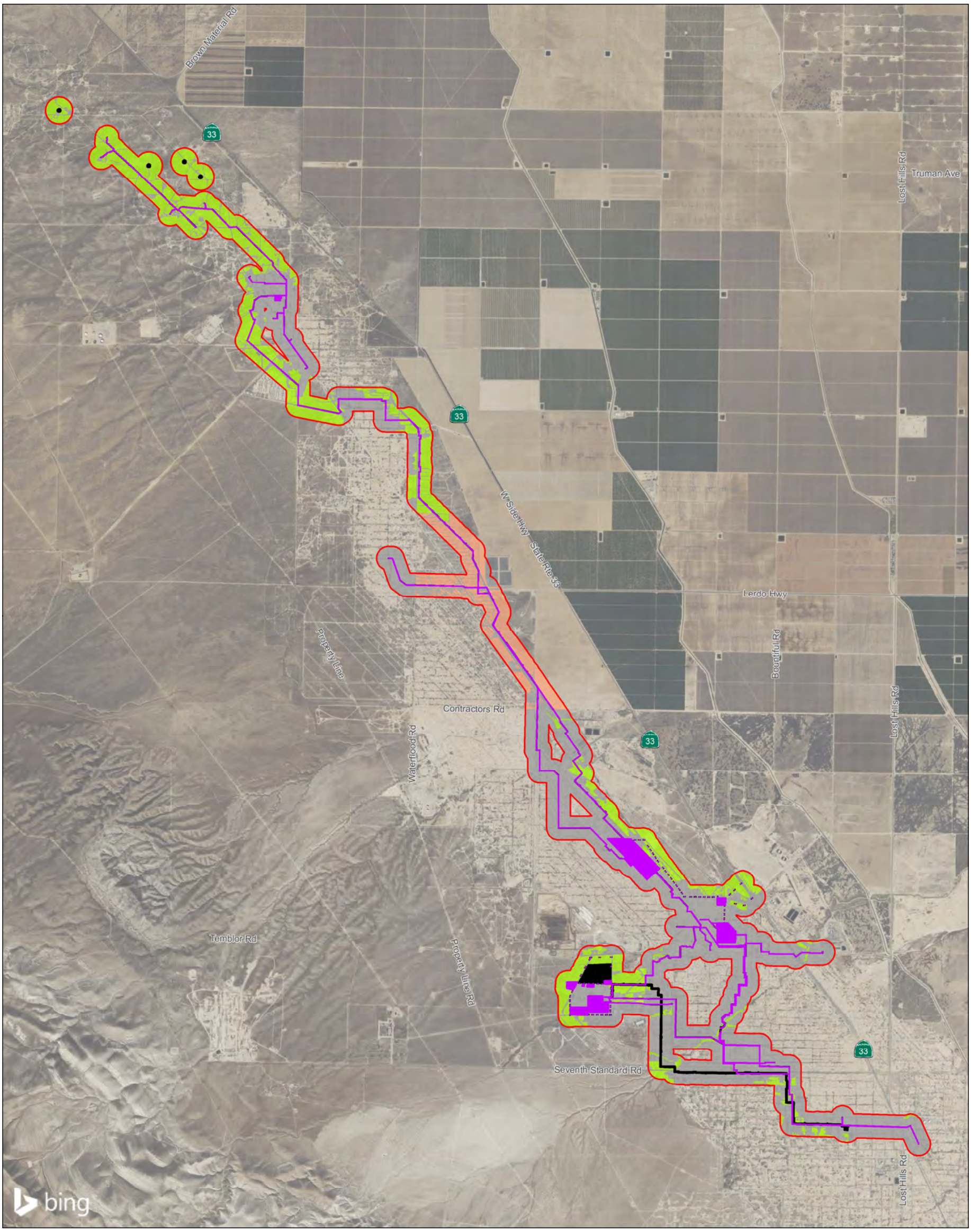
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Vegetation Communities and Land Cover Types

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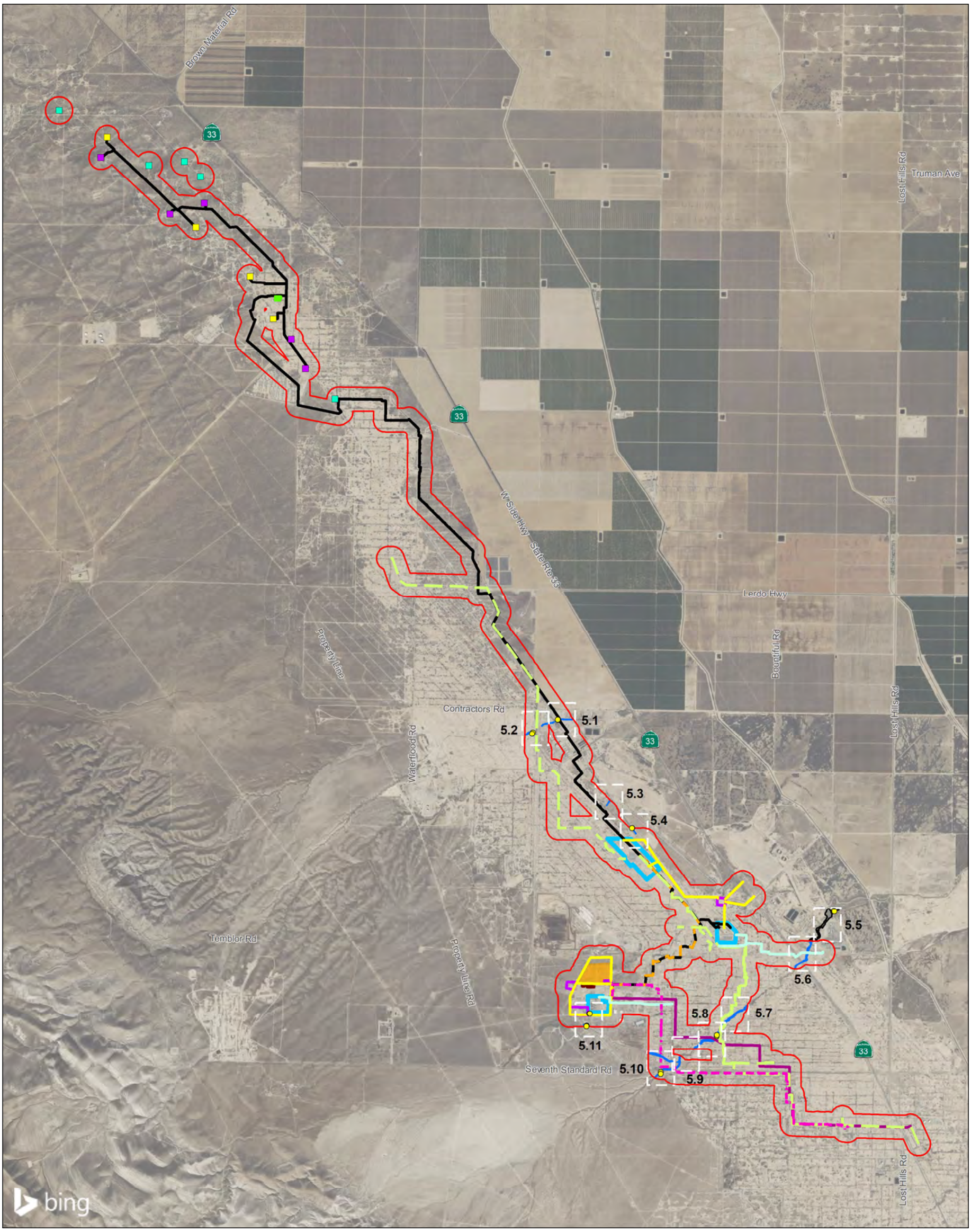
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Vegetation Communities and Land Cover Types

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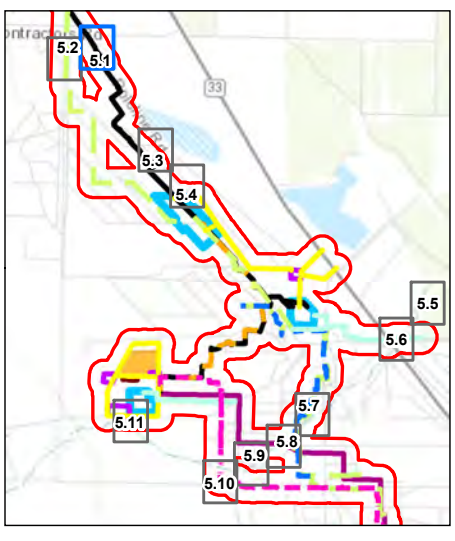
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Figure No.

A - 5.1

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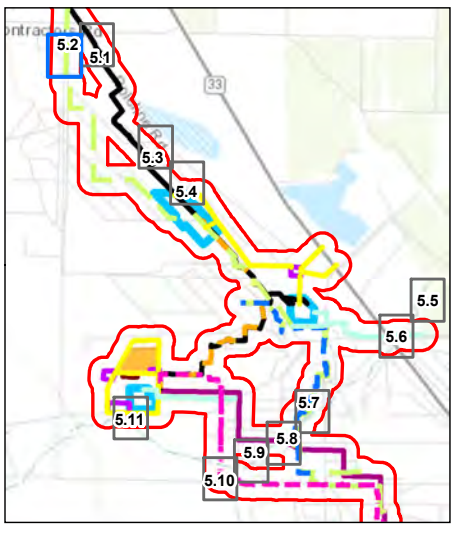
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Figure A - 5.1



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A - 5.2

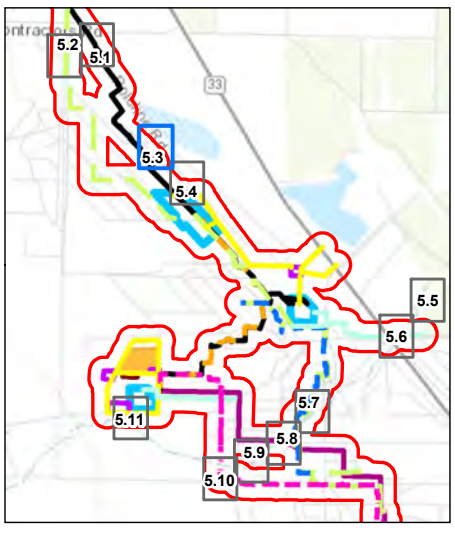
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Figure No.

A - 5.3

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Potential Jurisdictional Waters

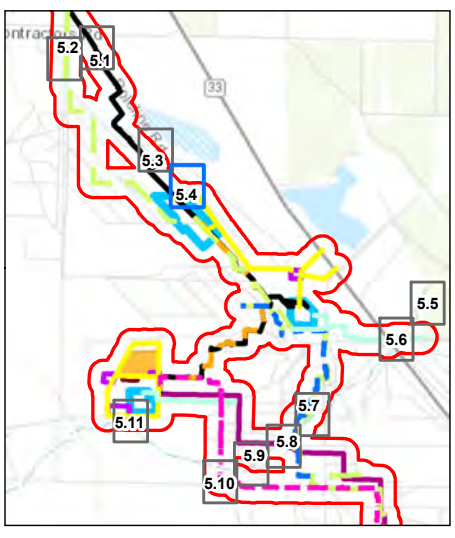
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Figure No.

A - 5.4

Title

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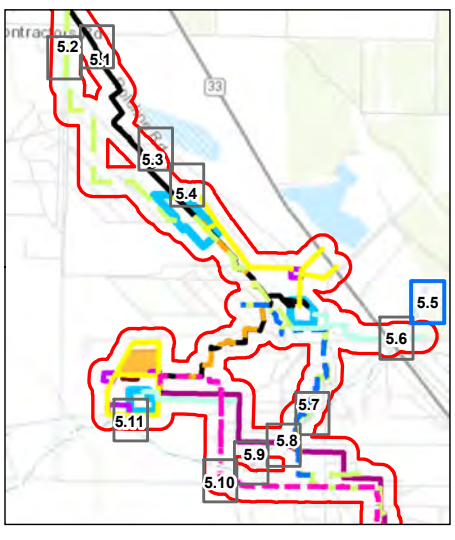
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Figure No.

A - 5.5

Title

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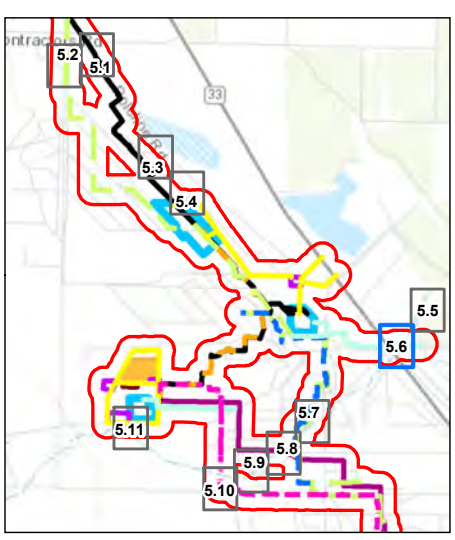
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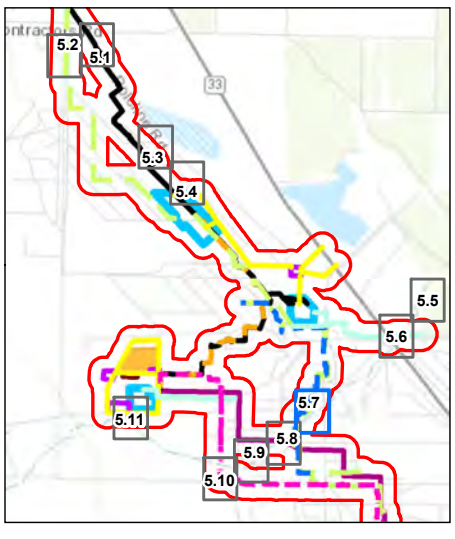
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Pipeline Proposed to Span Drainage

Pipeline Proposed to Span Drainage

Chico Martinez Creek

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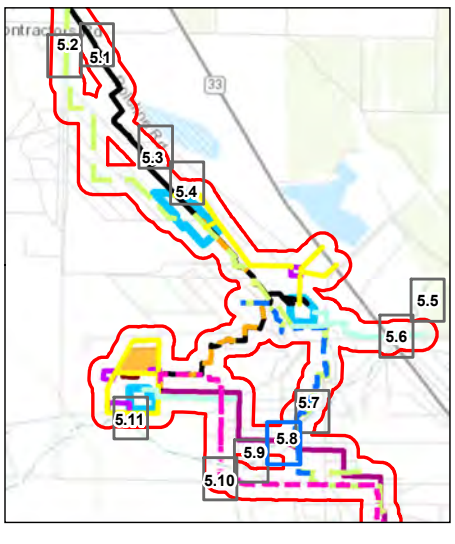
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Figure A - 5.7

Figure A - 5.9

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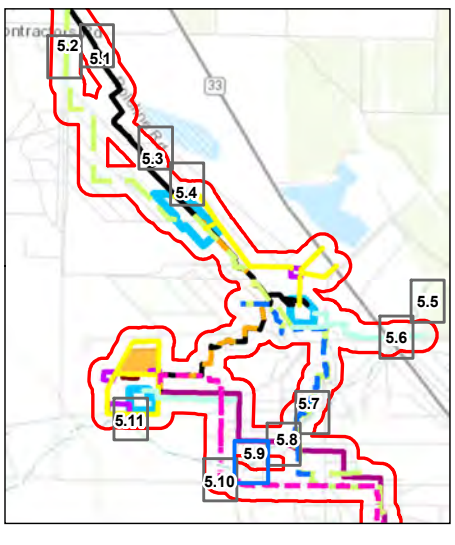
Title

Potential Jurisdictional Waters

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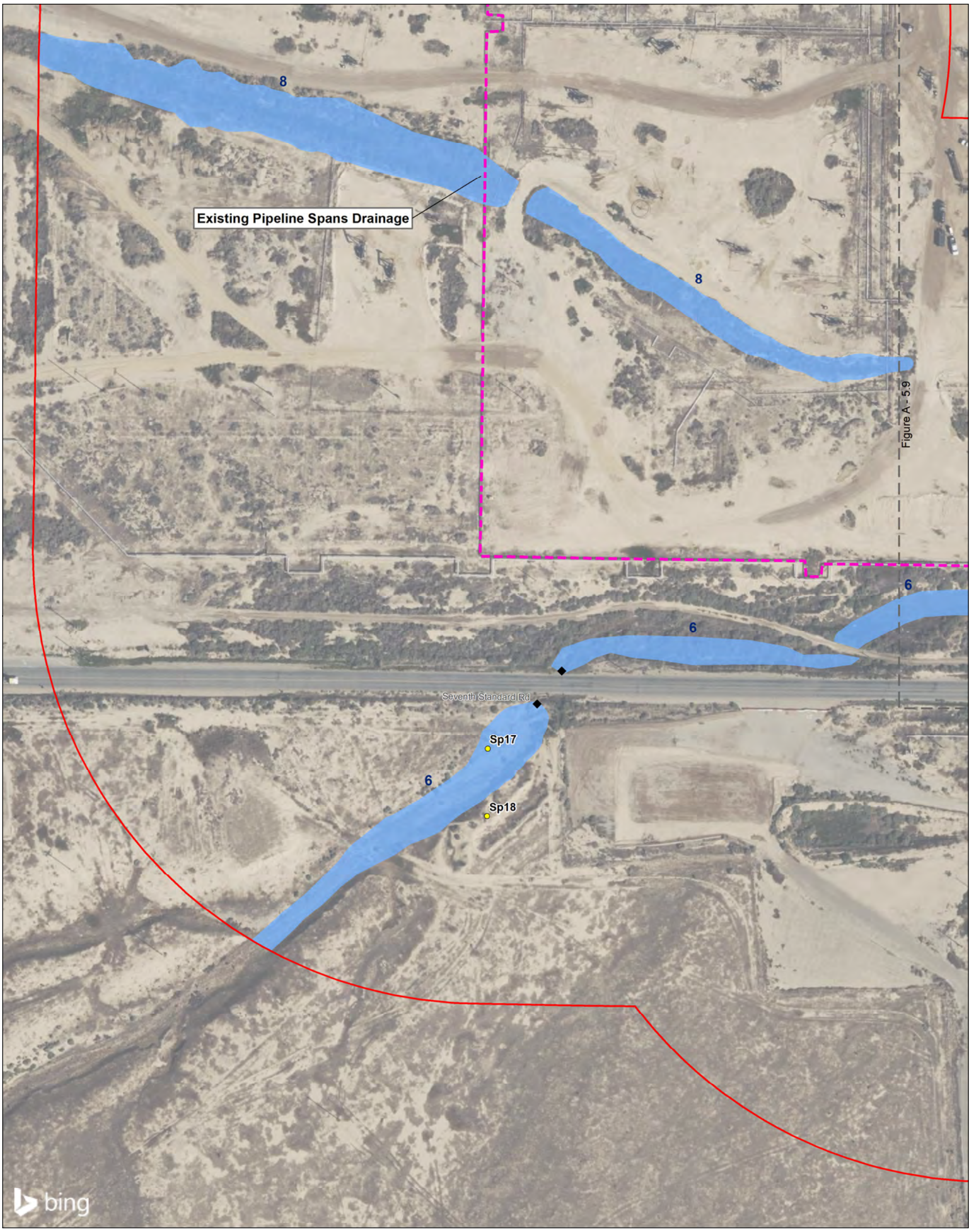
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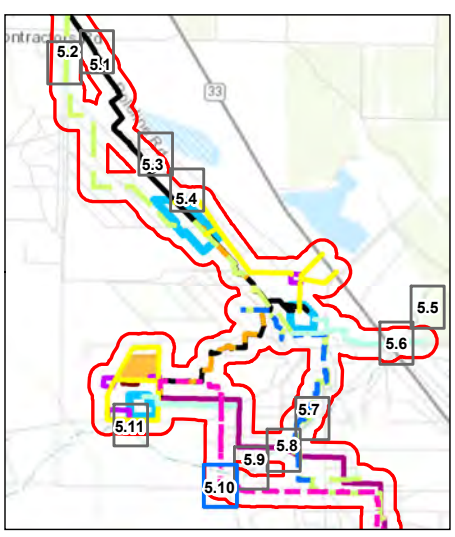
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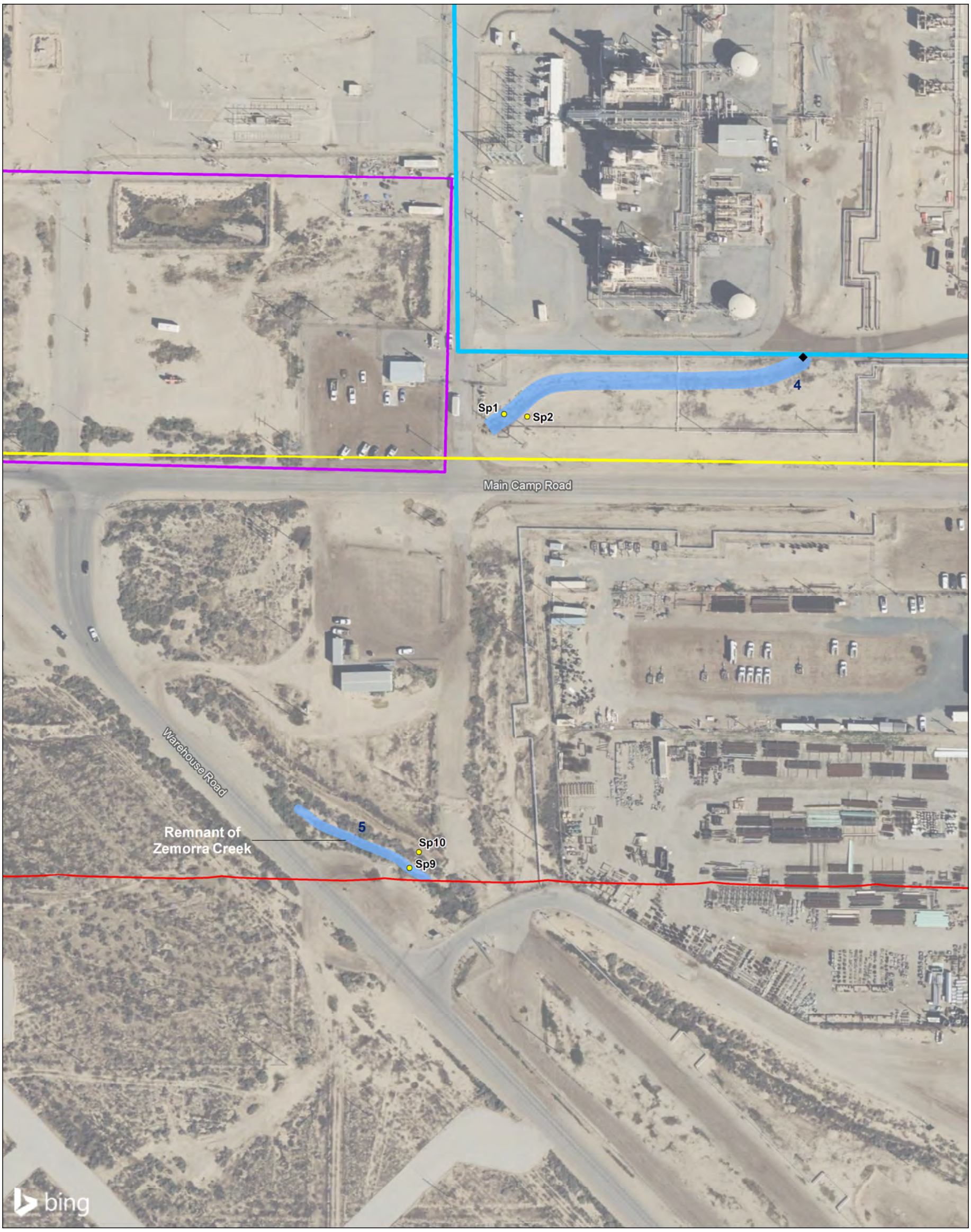
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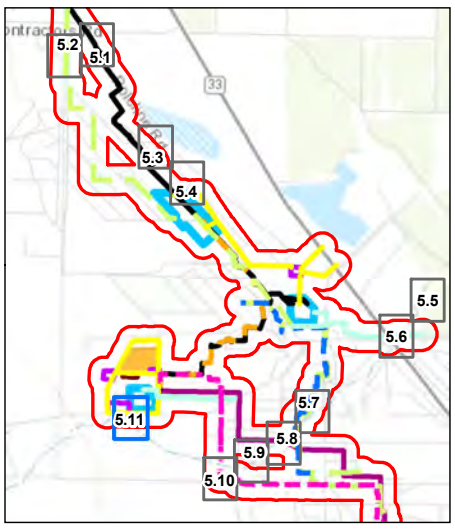
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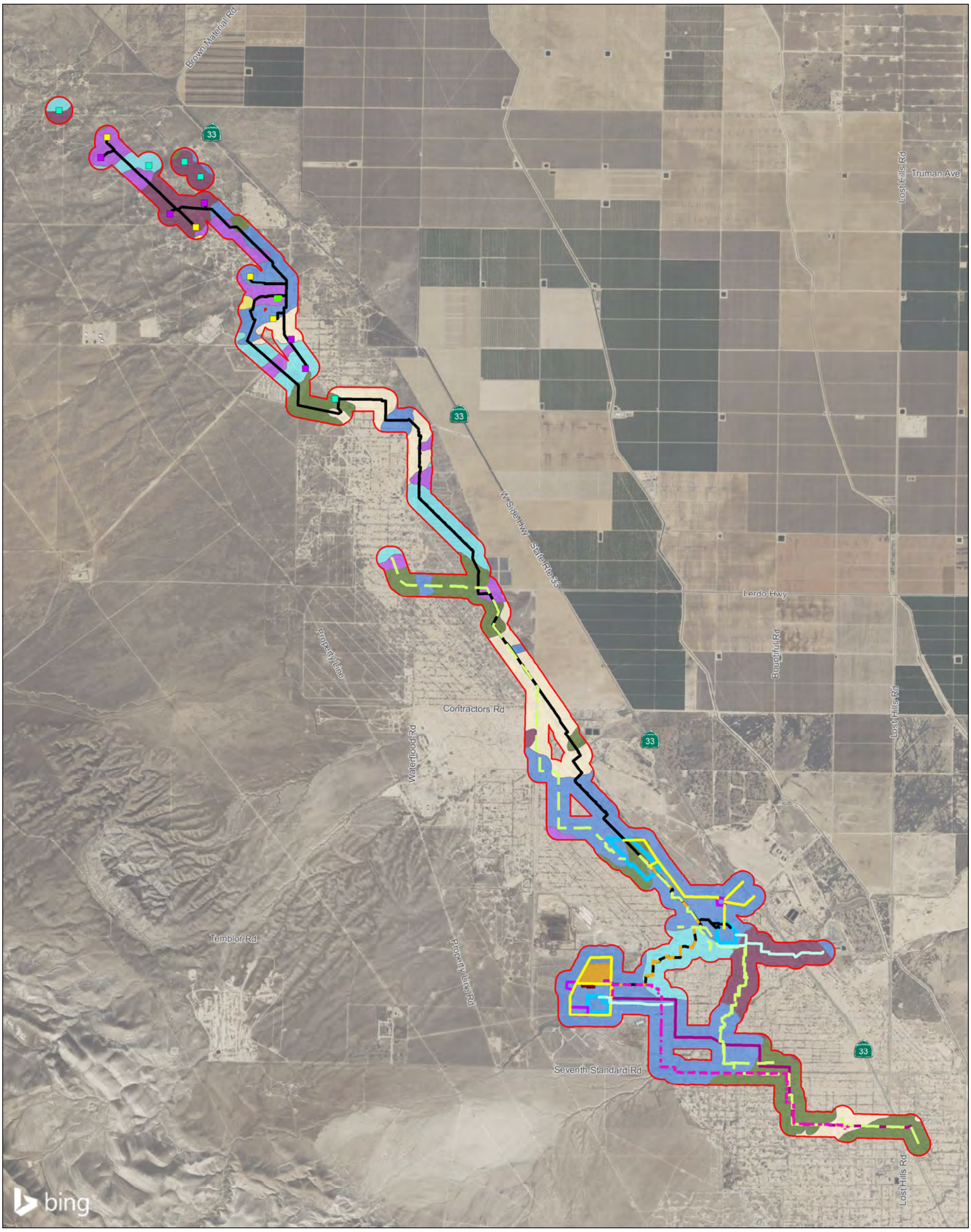
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Figure No.

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Appendix B 2023 BLUNT-NOSED LEOPARD LIZARD SURVEYS, BELRIDGE OIL FIELDS, KERN COUNTY, CALIFORNIA



PROTOCOL-LEVEL BLUNT-NOSED LEOPARD LIZARD SURVEY REPORT

AERA ENERGY LLC - CARBON FRONTIER

Prepared by: MESA Biological LLC

Prepared for: Nina Casterline – Environmental Advisor - Aera Energy LLC

Date: October 12, 2023

SECTION 1.0 - PROPERTY DETAILS AND LOCATION

1.1 Project Details

Client:	Aera Energy LLC	**Project Name:**	CarbonFrontier
Project Contact 1:	Nina Casterline	**Project Contact 2:**	Beau Gentry

Brief Project Description:

Aera has applied to the Kern County Planning and Natural Resources Department to request approval of a Zone Change and Conditional Use Permit (CUP) and will obtain any other required approvals for the construction and operation for the proposed Project in the South and North Belridge oil fields. The proposed Project would capture carbon dioxide (CO_2) from existing produced-gas streams (pre-combustion) and emissions from existing stationary sources (post-combustion) and transport the CO_2 by pipeline from South Belridge to the North Belridge Oil Field for permanent sequestration via CO_2 injection wells into a designated underground sequestration zone, known as the 64 Zone, at depths of approximately 8,500 feet below ground surface. It is anticipated that the proposed Project would capture approximately 30 million metric tons of CO_2 throughout its estimated 20-year lifetime.

The proposed Project includes re-purposing five existing oil wells and drilling four new wells for CO_2 injection. A new 6- to 12-inch pipeline would be constructed to deliver CO_2 from the capture facilities to the proposed injection wells. The pipelines would be primarily installed aboveground, except where the pipeline would cross main access roads (below ground) within the oil field properties. Distribution piping, each approximately 4- to 8-inches in size, would extend from the main pipeline to the proposed injection wells. The distribution pipelines would also be primarily aboveground on pipe supports, except where the pipelines cross main access roads (below ground) within the oil field.

1.2 Public Land Survey System (PLSS) / CalGEM Oilfield and Land Ownership

Section, Township, Range, Meridian:

Segment 1:	**Segment 2:**	**Segment 3:**	**Segment 4:**
Sec 18, T28S, R21E	Sec 1, T28S, R20E	Sec 35, T27S, R20E	Sec 26, T27S, R20E
Sec 7, T28S, R21E	Sec 2, T28S, R20E	Sec 26, T27S, R20E	Sec 27, T27S, R20E
Sec 6, T28S, R21E	Sec 35, T27S, R20E	Sec 27, T27S, R20E	Sec 28, T27S, R20E
Sec 1, T28S, R20E			Sec 21, T27S, R20E

CalGEM Field Name: North Belridge	**Surface Owner:** Aera Energy LLC

1.3 Description of Survey Focus Areas

Total Acres Segment 1:	Total Acres Segment 2:	Total Acres Segment 3:	Total Acres Segment 4:
92.905 acres	89.386 acres	108.088 acres	135.894 acres

Total Acres Surveyed: 426.273 acres

Description of Focus Areas:

After receiving project data and preliminary survey focus areas from Aera Energy LLC (Aera), MESA Biological LLC (MESA) prepared a scope of work to conduct protocol level blunt-nosed leopard lizard surveys covering approximately 7.15 linear miles of pipeline. This included 8 well locations that will each require a drilling pad of approximately 280ft x 145ft. After evaluating Aera's project data and the requirements of the California Department of Fish and Wildlife (CDFW) survey protocol, MESA determined the proposed scope and preliminary survey coverage areas were too large to adequately cover while still meeting the requirement of survey protocol. MESA's analysis determined that the project could meet the requirements of protocol if broken into 4 relatively equal segments. It is important to note, there were areas that were inaccessible due to fences, surface expressions/ground fissures, and an asbestos contaminated disposal site. Prior to initiating surveys, Aera concluded that it was unsafe to conduct the survey within the vicinity of these surface expressions and disposal site. A small portion of the project area was not included as it was an active agricultural field.

SECTION 2.0 - METHODOLOGIES AND DATA COLLECTION

2.1 Survey Methodologies

Description of Methodologies:

On April 25th, 2023, Aera provided MESA with a KMZ file that represented the proposed survey coverage area that included pre-determined segments of the project that were considered to contain habitat suitable for the blunt nosed leopard lizard. A visual assessment of shrub density and measurements of vegetation densities were recorded at various points throughout the four survey focus areas to help determine appropriate transect spacings. CDFW protocol states "BNLL are often difficult to detect, particularly in areas where shrubs are fairly numerous (>30% cover) and/or the herbaceous vegetation is dense and tall (>30 cm). In such conditions, no greater than 10-meter-wide transects should be walked at a slow pace. In areas with few shrubs and shorter herbaceous vegetation (<10 cm), transects as wide as 20 meters are acceptable". Throughout the survey focus areas, only a few random clusters of vegetation in each segment contained shrub cover that exceeded 30% cover. Most of the segments contained a sporadic and sparse cover of *Atriplex* that did not exceed the 30% threshold. Vegetation height was also estimated at several points throughout the segments and although there were a few small patchy areas containing pockets of *Amsinkia* sp. and other herbaceous vegetation that exceeded 10 cm, most of the focus areas did not exceed this threshold. A sizeable amount of previously disturbed land comprised of roadways, well pads and other oil production infrastructure also occurred throughout the project areas. After analyzing these factors, MESA concluded that 20 meter transects would satisfy the protocol requirements for visual coverage and would provide the researcher with suitable opportunity to detect presence of blunt-nosed leopard lizards.

Prior to initiating surveys, MESA estimated that a total of 4 surveyors would be necessary to adequately cover each of the 4 segments using 20 meters transect spacing. However, after the first few surveys, it was determined that the number of surveyors could be reduced to 3 surveyors. The first few survey days provided an opportunity for biologists to evaluate coverage suitability determining that the roadways that were centered in each segment still afforded 3 surveyors opportunity to achieved 100% visual survey coverage. For the remainder of the surveys, MESA utilized 3 to 4 surveyors to conduct each day of surveys. Using the pre-determined survey focus area boundaries, 20 meter transect lines were created electronically in ESRI's ArcGIS and uploaded to ESRI's FieldMaps. Transects uploaded to FieldMaps were electronically referenced by each surveyor during surveys to support consistently accurate coverages. Prior to conducted each survey, a crew lead was assigned to each crew. This crew lead was a level II surveyor and was responsible for all safety related requirements and data collection described in Section 2.2. Surveys were conducted in a north/south direction where feasible; however, portions of all segments required alternate survey directions.

The survey was completed in accordance with all protocol requirements listed in the 2019 California Department of Fish and Wildlife's Approved Survey Methodology for the Blunt-Nosed Leopard Lizard.

2.2 Data Collection Procedures

The crew lead for each survey day was responsible for recording all start/end times, temperatures and weather conditions using ESRI's Survey123. The crew lead was also tasked with recording common lizard counts and all incidentally observed wildlife species gathered by the crew at the end of each transect. During the survey, tracks of all surveyors were recorded using FieldMaps and overlayed onto an aerial image to help ensure adequate coverage within the survey boundary. FieldMaps was also used to record the location of all incidental special-status species observed. All incidentally observed dens potentially suitable for San Joaquin kit fox were recorded along with active or inactive stick nests. At the end of each survey day, the crew lead would utilize the raw data collected in Survey123 and compile a formal data form using the MESA formatted document. All compiled data forms are provided in **Attachment B – MESA Biological LLC Data Forms**. Upon completion of the final survey day, MESA mapped all occurrences of BNLL and other incidentally observed sensitive resources to prepare **Attachment A – Survey Focus Areas and Special-Status Species Observations Maps**.

2.3 Survey Dates Protocol Survey Requirements

All survey dates and other requirements of the protocol survey have been summarized in **Attachment C – Protocol Blunt-Nosed Leopard Lizard Summary Results Table**. One summary table for each of the 4 survey segments has been provided.

2.4 List of Surveyor Levels

A list of all surveyor's names and levels can be found in Attachment C - Protocol Blunt-Nosed Leopard Lizard Survey Results Summary Table.

SECTION 3.0 HABITAT IDENTIFIED

3.1 Habitat Communities Present in Survey Focus Areas

All four of the survey segments contain largely undisturbed lands primarily consisting of Saltbush Scrub or as referred to in A Manual of California Vegetation (Sawyer, J.O., T. Keeler-Wolf, and J. M. Evens. 2009), *Atriplex polycarpa* shrubland alliance (Allscale Scrub). Mixed within this community are areas that contain current and historical oil producing infrastructure. This infrastructure largely consists of oil pumping units, pipelines, header or manifold facilities, tank settings, electrical power poles and electrical substation facilities. Surrounding a large majority of the oil production equipment are lands used to access these facilities. Roadways, well pads and maintenance corridors containing hard compacted soils that are void of vegetation occur in and around this oil production infrastructure.

3.2 General Habitat Characteristics, Land Uses and Survey Limitations

The vegetation community that best describes each of the four segments can be described as Allscale scrub. This community contains a mixture of weedy or ruderal type vegetation. Much of the weedy vegetation is associated with oil producing infrastructure that occurs at varying levels throughout the four segments.

Segment 1: contains more disturbed lands from oil production than the other 3 segments. Almost the entirety of this survey focus area parallels an existing pipeline corridor. The Segment 1 transects have been centered on the existing corridor and Allscale scrub is the dominant vegetation community. Much of this scrub habitat is mixed with pockets of weedy or ruderal plants that have taken over areas that have been previously disturbed by oil production. A significant amount of the weedy vegetation occurs along road edges or perimeters of well pads and other infrastructure (see **Photograph 1**) In this segment, two areas were omitted from transect survey coverage. One small area near the southern end of the segment was not included as it was an agricultural field (see **Photograph 2**). Another section near the north end of the segment was not covered by transect surveys as there where several areas that contained surface expressions or ground fissures that posed a safety risk (see **Photograph 3**). Segment 1 boundary and the omitted areas are shown in **Attachment A – Figure 1.1**.

Segment 2: comparable to Segment 1, transects have been centered primarily on an existing pipeline corridor. Some of Segment 2 occurs within a land farm that was historically used to dispose of drill cuttings. This land farm has been left dormant for a long enough to allow for regeneration of Allscale scrub (see **Photograph 4**). Two portions of Segment 2 were inaccessible. One area located at the south end of the segment was surrounded by a barbed wire fence, no access points to enter this area could be found nearby (see **Photograph 5**). Another area near the mid-point of the segment was inaccessible as there was a chain link fence that prohibited access (see **Photograph 6**). The topography in the southern end of this segment is relatively flat. The Segment 2 boundary and the omitted fenced off areas are shown in **Attachment A – Figure 1.2**.

Segment 3: occurs within relatively unimpacted Allscale scrub. Although some oil production infrastructure exists, a higher density occurs to the south in Segments 1 and 2. The topography contains more rolling undulations than Segment 1 and 2. The location of Segment 3 can be seen in **Attachment A – Figure 1.3**. Much of this segment also parallels an existing pipeline corridor with dirt access road.

Segment 4: occurs within relatively unimpacted Allscale scrub. Much of the oil producing infrastructure occurs to the south of Segment 4. Of all segments, Segment 4 contains more hilly terrain that other southern segments. The topography can be best described as very gentle rolling hills or undulations. The location of Segment 4 can be seen in **Attachment A – Figure 1.4**.

SECTION 4.0 - SITE PHOTOGRAPHS

4.1 Photographic Site Conditions

	
Photograph 1 – Segment 1: was taken facing south overlooking the pipe corridor that currently runs parallel with the proposed CO_2 pipeline route. Photo illustrates Allscale scrub mixed with weedy plants in an area that accommodates some existing oil producing infrastructure.	**Photograph 2 – Segment 1:** was taken facing north on the east side of the proposed CO_2 pipeline corridor. The photograph illustrates the agricultural field that was excluded from the survey.
	
Photograph 3 – Segment 1: shows the road closure barriers used by Aera to restrict access to the northern portion of Segment 1. Several surface expressions or ground fissures were identified in this area and were deemed a safety hazard.	**Photograph 4 – Segment 2:** was taken near the mid-point of Segment 2 facing south. Photograph shows the existing corridor that will accommodate the proposed CO_2 pipeline. Also, the old drill cutting land farm occurs to the west (right side of the corridor) now contains a relatively dense cover of *Atriplex* sp.
	
Photograph 5 – Segment 2: illustrates a barbed wire fence that surrounds a small area within Segment 2 that was excluded from the survey area.	**Photograph 6 – Segment 2:** illustrates a chain link fence that surrounds a lined pit within the Segment 2 survey area. This area contained asbestos and was inaccessible.

	
Photograph 7 – Segment 3: was taken near the mid-point of Segment 3 facing north overlooking the existing corridor that will accommodate the proposed CO_2 pipeline. Corridor is surrounded by relatively intact Allscale scrub.	**Photograph 8 – Segment 4:** was taken facing north overlooking the proposed CO_2 pipeline corridor in Segment 4
	
Photograph 9: Photograph shows the sub-adult blunt-nosed leopard lizard found in Segment 3.	**Photograph 10:** Photograph shows one of the adult blunt-nosed leopard lizards observed during protocol surveys.

SECTION 5.0 - SPECIAL-STATUS AND COMMON SPECIES IDENTIFIED

5.1 Blunt-Nosed Leopard Lizard Observations

Date (month/day/year)	Location Description (Segment Number)	Sex (male/female)	Life Stage (adult/sub-adult/hatchling)	Coordinates (Decimal degrees)
06/09/23	Segment 4	female	adult	35.546400°, -119.799638°
06/15/23	Segment 3	unknown	adult	35.543039°, -119.795407°
06/30/23	Segment 3	unknown	adult	35.541822°, -119.793807°
06/30/23	Segment 3	unknown	adult	35.541867°, -119.793773°
09/20/23	Segment 3	male	adult	35.543394°, -119.795956°
09/20/23	Segment 3	unknown	sub-adult	35.542878°, -119.795594°

5.2 Other Incidentally Observed Special-Status Species

Common Name	*Scientific Name*	Status:
San Joaquin antelope squirrel	(*Ammospermophilus nelsoni*)	California Threatened
Loggerhead shrike	(*Lanius ludovinicanus*)	California Species of Special Concern
California horned lark	(*Eremophila alpestris actia*)	California Watch List
San Joaquin coachwhip	(*Masticophis flagellum ruddocki*)	California Species of Special Concern
San Joaquin kit fox (scat)	(*Vulpes macrotis mutica*)	USFWS Endangered; California Threatened
Prairie falcon	(*Falco mexicanus*)	California Watch List

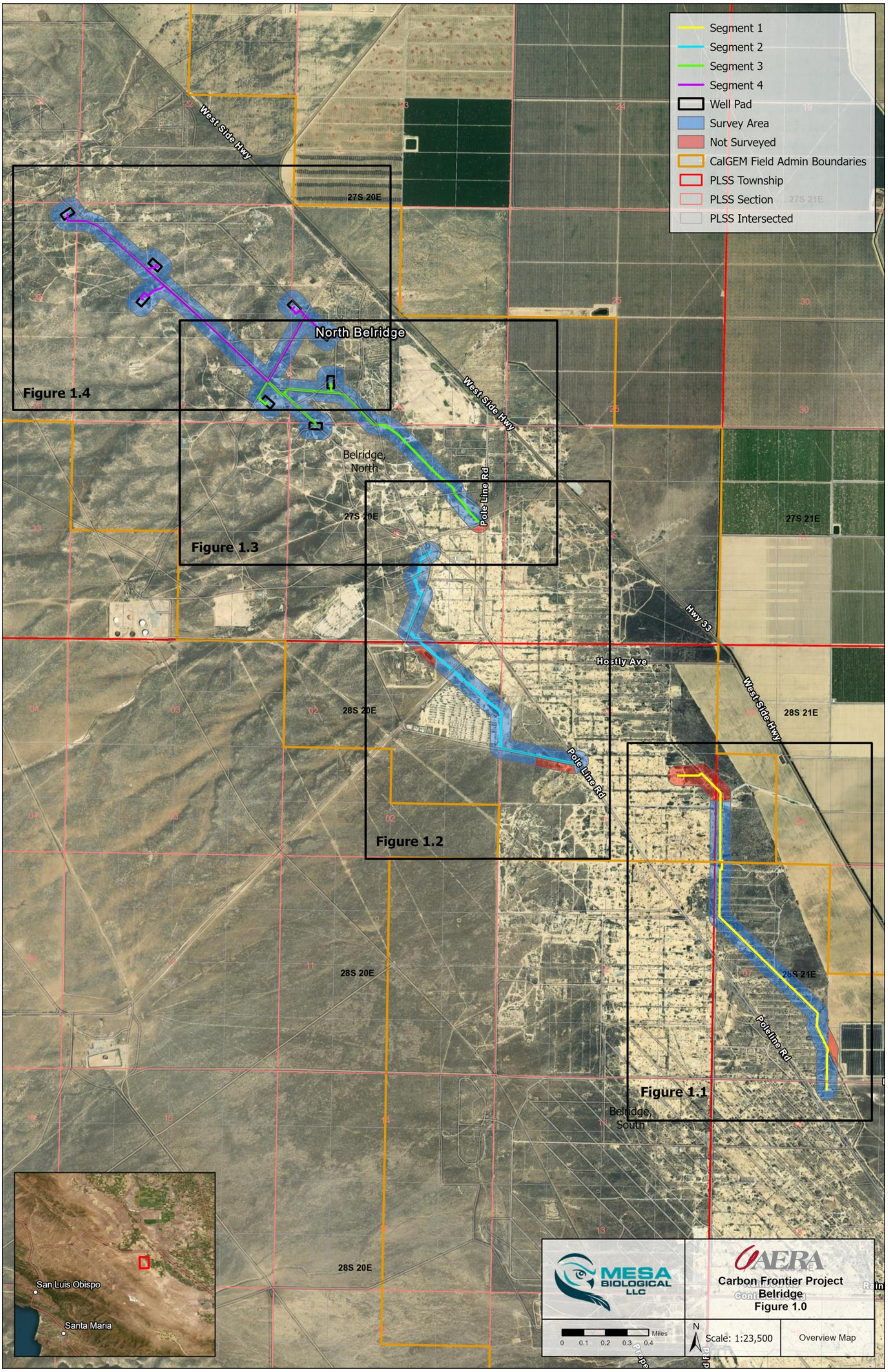
Swainson's hawk	(*Buteo swainsoni*)	California Threatened

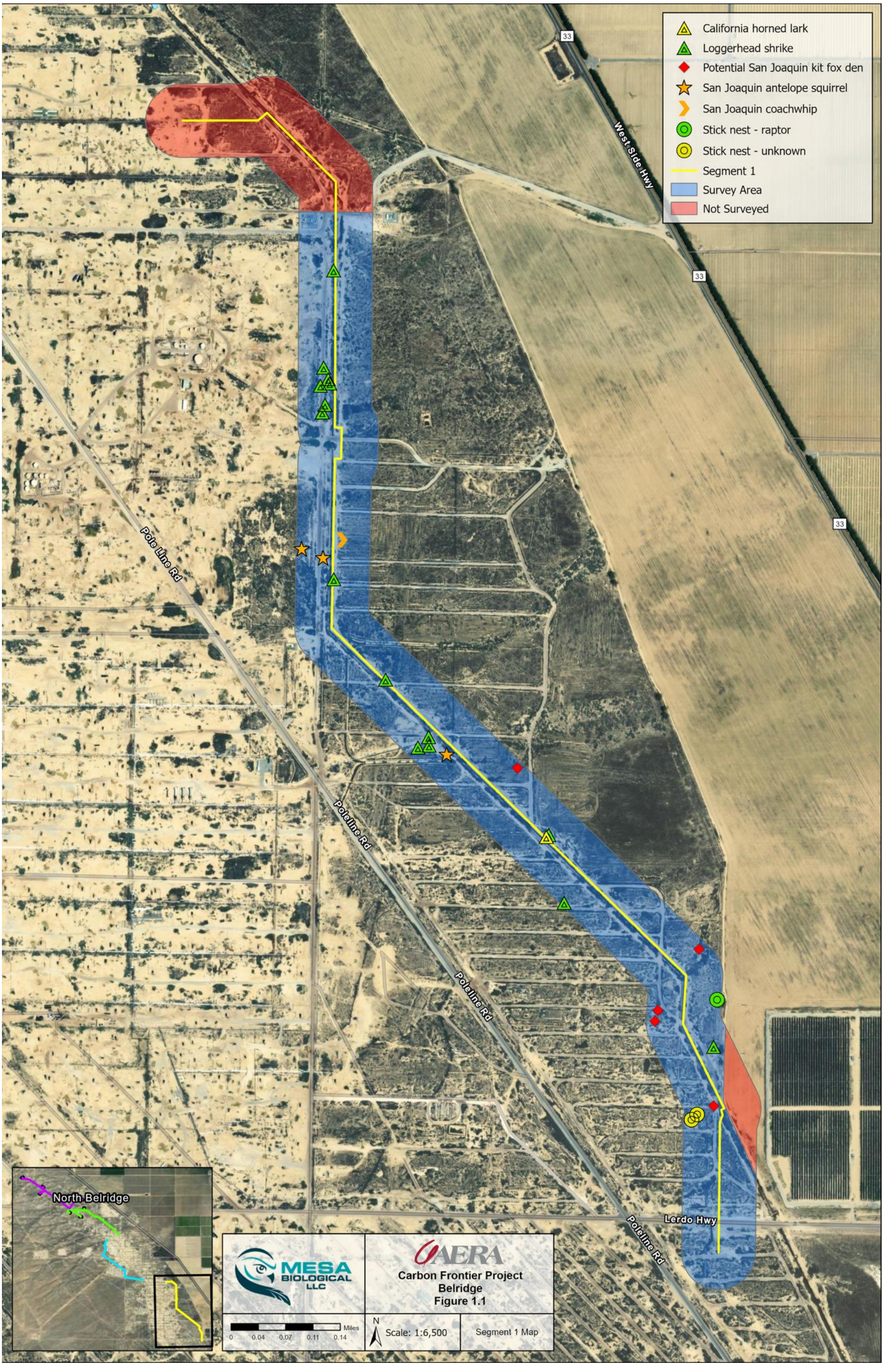
Additional Comments:
Several stick nests were incidentally observed during the survey. The location of each nest is shown in **Attachment A – Figures 1.1 to 1.4**. Scat indicative of San Joaquin kit fox was observed on the proposed Segment 3 CO_2 pipeline corridor. No CNDDB RareFind Field Form was submitted for this observation of kit fox sign. The location can be found in **Attachment A – Figure 1.3**. According to the 2011 United States Fish and Wildlife Service (USFWS) Standardized Recommendations for the Protection of the San Joaquin Kit Fox Prior to or During Ground Disturbance multiple dens that would be considered "potential dens" were incidentally found and recorded during the survey. One prairie falcon and one Swainson's hawk was observed soaring overhead. No CNDDB RareFind Field Form submittals were uploaded to the database as these two species did not appear to have an affiliation with the project site.

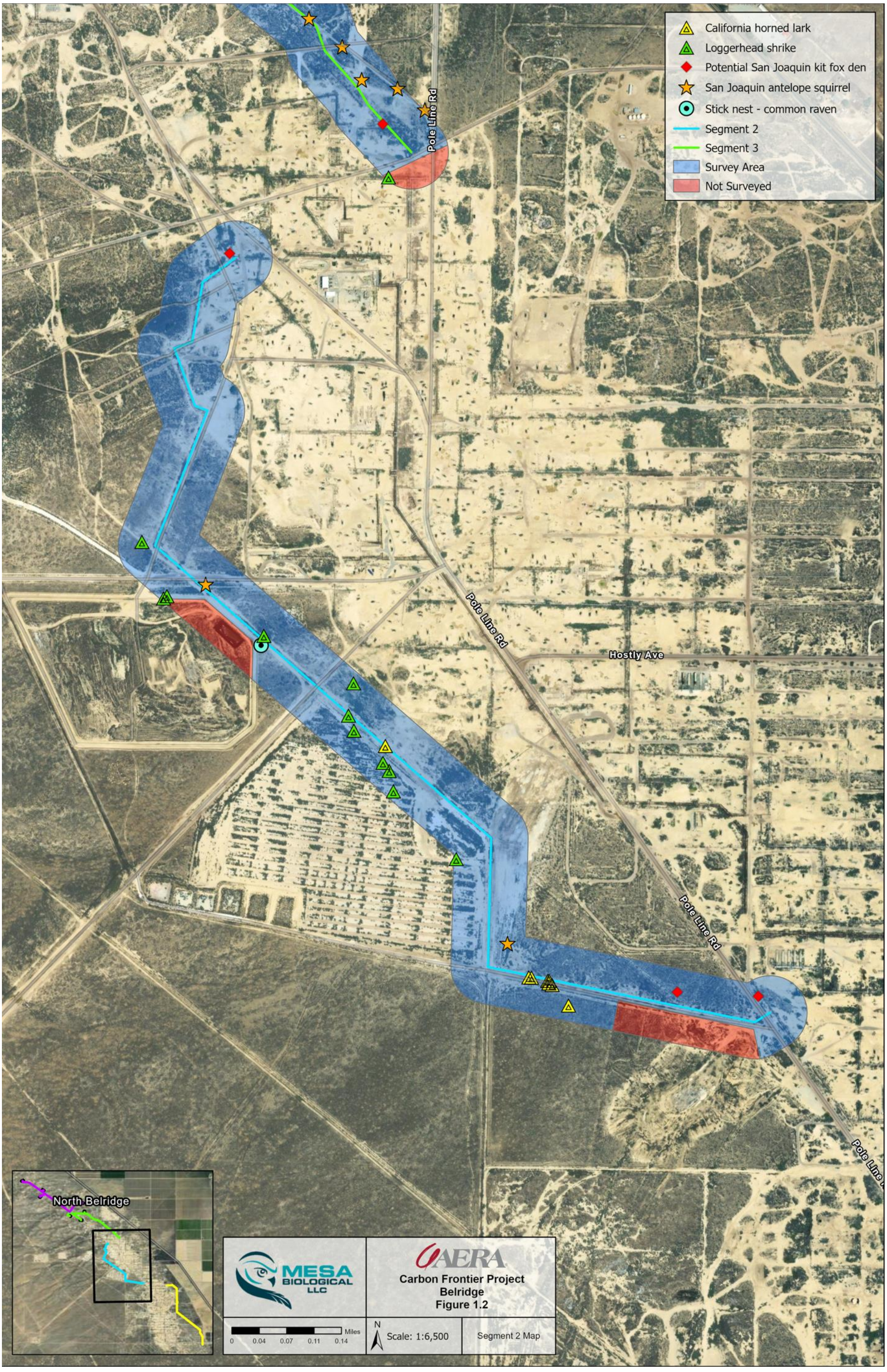
6.0 List of Common Species Observed During Surveys

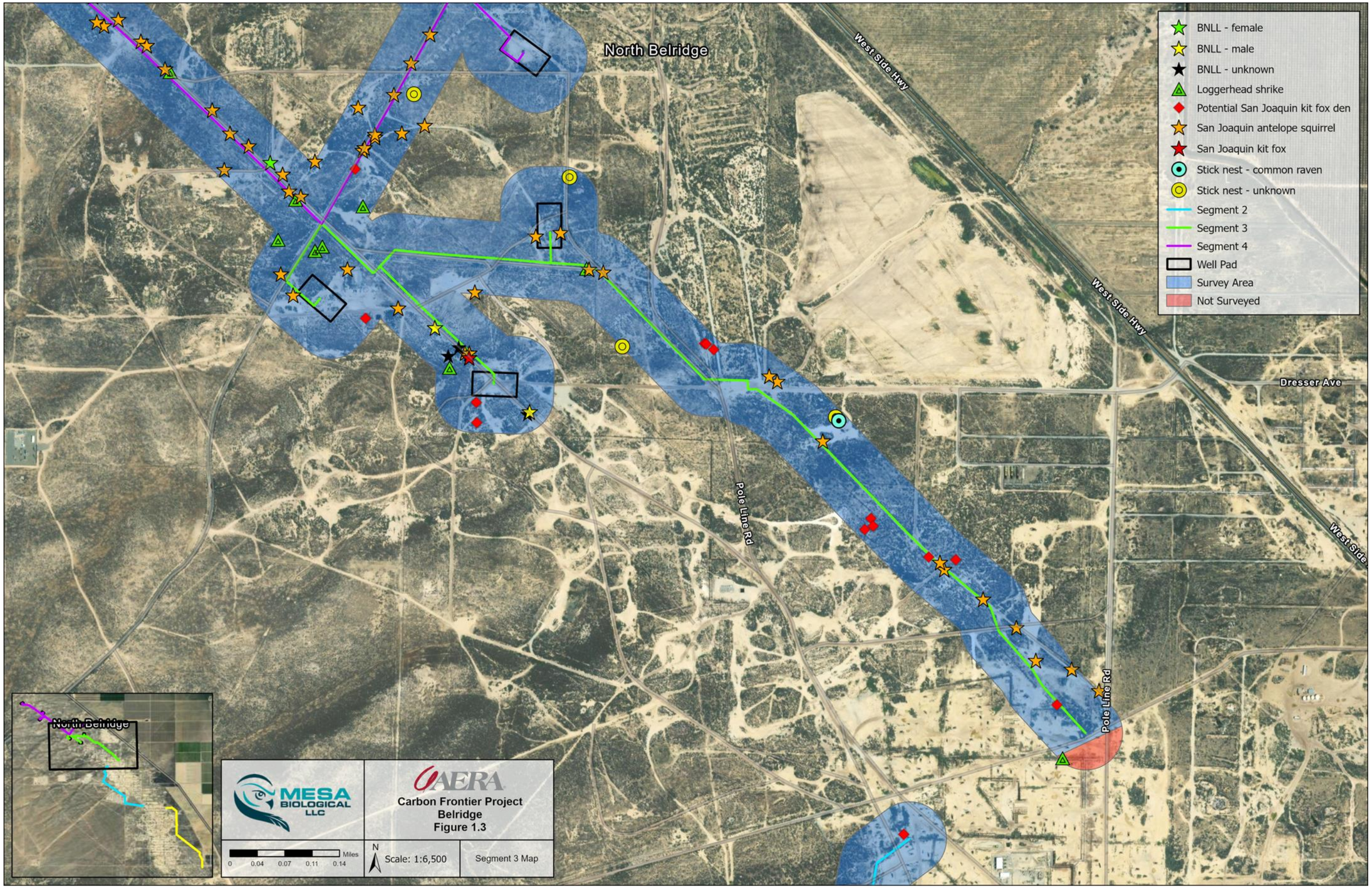
Common Name:	Scientific Name:
northern mockingbird	*Mimus polyglottos*
lesser nighthawk	*Chordeiles acutipennis*
common raven	*Corvus corax*
mourning dove	*Zenaida macroura*
Brewer's blackbird	*Euphagus cyanocephalus*
desert cottontail	*Sylvilagus audubonii*
red-tailed hawk	*Buteo jamaicensis*
western meadowlark	*Sturnella neglecta*
western kingbird	*Tyrannus verticalis*
California quail	*Callipepla californica*
hooded oriole	*Icerus cucullatus*
black-tailed jackrabbit	*Lepus californicus*
great horned owl	*Bubo virginianus*
barn owl	*Tyto alba*
gopher snake	*Pituophis catenifer*
European starling	*Sturnus vulgaris*
killdeer	*Charadrius vociferus*
kangaroo rat	*Dipodomys sp.*
greater roadrunner	*Geococcyx californianus*
yellow warbler	*Setophaga petechia*
black phoebe	*Sayornis nigricans*
Savannah sparrow	*Passerculus sandwichensis*
western pacific rattlesnake	*Crotalus oreganus*
American crow	*Corvus brachyrhynchos*

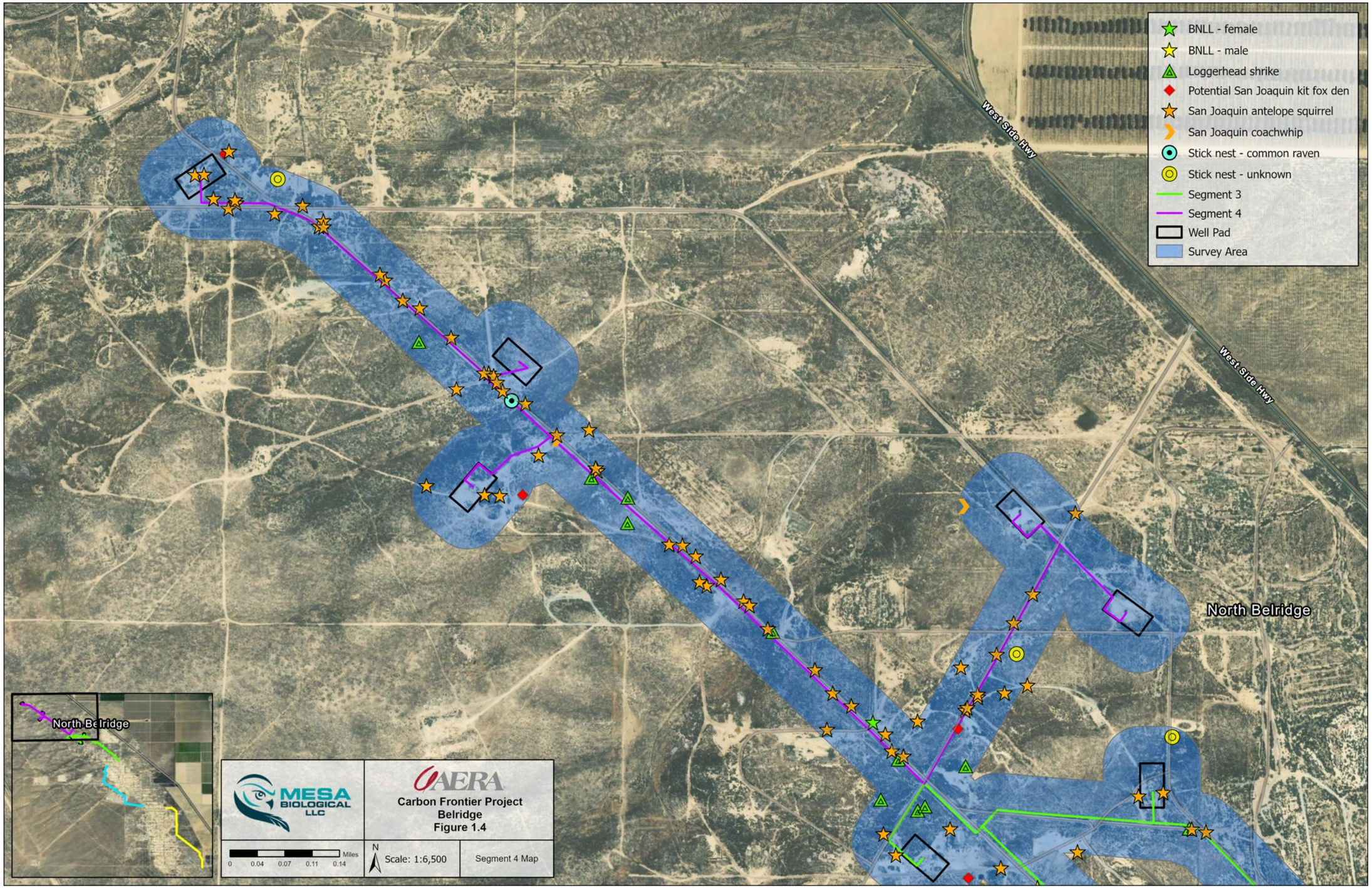
Attachment A: Survey Focus Areas and Special-Status Species Observations


Segment 1
Segment 2
Segment 3
Segment 4
Well Pad
Survey Area
Not Surveyed
CalGEM Field Admin Boundaries
PLSS Township
PLSS Section
PLSS Intersected
West Side Hwy
27S 20E
27S 21E
North Belridge
Figure 1.4
Belridge, North
Pole Line Rd
Figure 1.3
Hwy 33
Hostly Ave
28S 20E
28S 21E
Figure 1.2
Poleline Rd
Figure 1.1
Belridge, South
San Luis Obispo
Santa Maria
MESA BIOLOGICAL LLC
AERA
Carbon Frontier Project
Belridge
Figure 1.0
Miles
0 0.1 0.2 0.3 0.4
N
Scale: 1:23,500
Overview Map


California horned lark
Loggerhead shrike
Potential San Joaquin kit fox den
San Joaquin antelope squirrel
San Joaquin coachwhip
Stick nest - raptor
Stick nest - unknown
Segment 1
Survey Area
Not Surveyed
West Side Hwy
33
Pole Line Rd
Poleline Rd
Lerdo Hwy
North Belridge
MESA BIOLOGICAL LLC
AERA
Carbon Frontier Project
Belridge
Figure 1.1
Miles
0 0.04 0.07 0.11 0.14
N
Scale: 1:6,500
Segment 1 Map


California horned lark
Loggerhead shrike
Potential San Joaquin kit fox den
San Joaquin antelope squirrel
Stick nest - common raven
Segment 2
Segment 3
Survey Area
Not Surveyed
Pole Line Rd
Hostly Ave
North Belridge
MESA BIOLOGICAL LLC
AERA
Carbon Frontier Project
Belridge
Figure 1.2
Miles
0 0.04 0.07 0.11 0.14
N
Scale: 1:6,500
Segment 2 Map


North Belridge
West Side Hwy
West Side Hwy
Dresser Ave
Pole Line Rd
Pole Line Rd
West Side
BNLL - female
BNLL - male
BNLL - unknown
Loggerhead shrike
Potential San Joaquin kit fox den
San Joaquin antelope squirrel
San Joaquin kit fox
Stick nest - common raven
Stick nest - unknown
Segment 2
Segment 3
Segment 4
Well Pad
Survey Area
Not Surveyed
North Belridge
MESA BIOLOGICAL LLC
AERA
Carbon Frontier Project
Belridge
Figure 1.3
Miles
0 0.04 0.07 0.11 0.14
N
Scale: 1:6,500
Segment 3 Map


BNLL - female
BNLL - male
Loggerhead shrike
Potential San Joaquin kit fox den
San Joaquin antelope squirrel
San Joaquin coachwhip
Stick nest - common raven
Stick nest - unknown
Segment 3
Segment 4
Well Pad
Survey Area
West Side Hwy
West Side Hwy
North Belridge
North Belridge
MESA BIOLOGICAL LLC
AERA
Carbon Frontier Project
Belridge
Figure 1.4
Miles
0 0.04 0.07 0.11 0.14
N
Scale: 1:6,500
Segment 4 Map

Attachment B: Mesa Biological LLC Data Forms
Segments 1, 2, 3 and 4

Mesa Biological LLC Data Forms Segment 1

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 1 – Aera Energy LLC Carbon Frontier - Survey Day 1

Survey Information

Survey Date:	Client:	Location:	Project:
May 15, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 1

Surveyors

Name:	Surveyor Qualifications:
Paul Rosebush	Level II
Samantha Medellin	Level II
Karla Lopez	Level II
Rory Miller	Level II

Start/End Times and Recorded Weather Conditions

Start Time:	8:56am	**End Time:**	11:35am
Start Temperature (°F):	81.6°F	**End Temperature (°F):**	91.0°F
Start Cloud Cover:	2%	**End Cloud Cover:**	2%
Wind Speed:	1.0mph	**Wind Speed:**	3.0mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	79
California Whiptail Lizard (*Aspidoscelis tigris munda*):	6
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
San Joaquin antelope squirrel	*Ammospermophilus nelsoni*	CT
Loggerhead shrike	*Lanius ludovicianus*	SSC
California horned lark	*Eremophila alpestris actia*	WL

CT: California Threatened; SSC: California Species of Special Concern; WL: California Watch List

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
northern mockingbird	*Mimus polyglottos*	red-tailed hawk	*Buteo jamaicensis*
Lesser nighthawk	*Chordeiles acutipennis*	western meadowlark	*Sturnella neglecta*
common raven	*Corvus corax*	western kingbird	*Tyrannus verticalis*
mourning dove	*Zenaida macroura*	California quail	*Callipepla californica*
Brewer's blackbird	*Euphagus cyanocephalus*	Bell's sparrow	*Artemisiospiza belli*
desert cottontail	*Sylvilagus audubonii*	black-tailed jackrabbit	*Lepus californicus*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 1 – Aera Energy LLC Carbon Frontier - Survey Day 2

Survey Information

Survey Date:	Client:	Location:	Project:
June 6, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 1

Surveyors

Name:	Surveyor Qualifications:
Jeffrank Solorzano	Level II
Paul Rosebush	Level II
Rory Miller	Level II
Jaden Drake	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	10:25am	**End Time:**	12:45pm
Start Temperature (°F):	78.6°F	**End Temperature (°F):**	82.9°F
Start Cloud Cover:	75%	**End Cloud Cover:**	50%
Wind Speed:	1.8mph	**Wind Speed:**	2.9mph
Weather Summary:	Sunny skies, partial clouds		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	N/A

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	96
California Whiptail Lizard (*Aspidoscelis tigris munda*):	8
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
None identified	--	--

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
northern mockingbird	*Mimus polyglottos*	red-tailed hawk	*Buteo jamaicensis*
Lesser nighthawk	*Chordeiles acutipennis*	western meadowlark	*Sturnella neglecta*
common raven	*Corvus corax*	western kingbird	*Tyrannus verticalis*
mourning dove	*Zenaida macroura*	California quail	*Callipepla californica*
killdeer	*Charadrius vociferus*	hooded oriole	*Icerus cucullatus*
desert cottontail	*Sylvilagus audubonii*	black-tailed jackrabbit	*Lepus californicus*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 1 – Aera Energy LLC Carbon Frontier - Survey Day 3

Survey Information

Survey Date:	Client:	Location:	Project:
June 12, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 1

Surveyors

Name:	Surveyor Qualifications:
Jeffrank Solorzano	Level II
Karla Lopez	Level II
Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	10:10am	**End Time:**	12:01pm
Start Temperature (ºF):	78.0°F	**End Temperature (ºF):**	88.9°F
Start Cloud Cover:	10%	**End Cloud Cover:**	10%
Wind Speed:	2.2mph	**Wind Speed:**	2.8mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	N/A

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	83
California Whiptail Lizard (*Aspidoscelis tigris munda*):	16
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
California horned lark	*Eremophila alpestris actia*	WL
Loggerhead shrike	*Lanius ludovicianus*	SSC

SSC: California Species of Special Concern: WL: California Watch List

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
northern mockingbird	*Mimus polyglottos*	red-tailed hawk	*Buteo jamaicensis*
common raven	*Corvus corax*	western meadowlark	*Sturnella neglecta*
mourning dove	*Zenaida macroura*	western kingbird	*Tyrannus verticalis*
house finch	*Haemorhous mexicanus*	California quail	*Callipepla californica*
black-tailed jackrabbit	*Lepus californicus*	Barn owl	*Tyto alba*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 1 – Aera Energy LLC Carbon Frontier - Survey Day 4

Survey Information

Survey Date:	Client:	Location:	Project:
June 13, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 1

Surveyors

Name:	Surveyor Qualifications:
Samantha Medellin	Level II
Rory Miller	Level II
Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	9:04am	**End Time:**	11:01am
Start Temperature (ºF):	77.4°F	**End Temperature (ºF):**	84.1°F
Start Cloud Cover:	2%	**End Cloud Cover:**	2%
Wind Speed:	3.7mph	**Wind Speed:**	4.0mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	N/A

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	60
California Whiptail Lizard (*Aspidoscelis tigris munda*):	8
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
Loggerhead shrike	*Lanius ludovicianus*	SSC
San Joaquin coachwhip	*Masticophis flagellum ruddocki*	SSC

SSC: California Species of Special Concern

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
northern mockingbird	*Mimus polyglottos*	western kingbird	*Tyrannus verticalis*
common raven	*Corvus corax*	California quail	*Callipepla californica*
mourning dove	*Zenaida macroura*	Barn owl	*Tyto alba*
black-tailed jackrabbit	*Lepus californicus*	house finch	*Haemorhous mexicanus*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 1 – Aera Energy LLC Carbon Frontier - Survey Day 5

Survey Information

Survey Date:	Client:	Location:	Project:
June 14, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 1

Surveyors

Name:	Surveyor Qualifications:
Jeffrank Solorzano	Level II
Rory Miller	Level II
Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	8:40am	**End Time:**	10:30am
Start Temperature (ºF):	78.6°F	**End Temperature (ºF):**	82.6°F
Start Cloud Cover:	10%	**End Cloud Cover:**	10%
Wind Speed:	0.9mph	**Wind Speed:**	3.3mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	N/A

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	74
California Whiptail Lizard (*Aspidoscelis tigris munda*):	12
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
Loggerhead shrike	*Lanius ludovicianus*	SSC
SSC: California Species of Special Concern		

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
northern mockingbird	*Mimus polyglottos*	western kingbird	*Tyrannus verticalis*
common raven	*Corvus corax*	California quail	*Callipepla californica*
mourning dove	*Zenaida macroura*	Barn owl	*Tyto alba*
black-tailed jackrabbit	*Lepus californicus*	house finch	*Haemorhous mexicanus*
red-tailed hawk	*Buteo jamaicensis*		

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 1 – Aera Energy LLC Carbon Frontier - Survey Day 6

Survey Information

Survey Date:	Client:	Location:	Project:
June 15, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 1

Surveyors

Name:	Surveyor Qualifications:
Samantha Medellin	Level II
Rory Miller	Level II
Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	8:39am	**End Time:**	10:53am
Start Temperature (°F):	77.8°F	**End Temperature (°F):**	88.7°F
Start Cloud Cover:	2%	**End Cloud Cover:**	2%
Wind Speed:	4.1mph	**Wind Speed:**	4.3mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	N/A

Other Lizard Species Observations

Side Blotched Lizard (*Uta stansburiana*):	33
California Whiptail Lizard (*Aspidoscelis tigris munda*):	1
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
None observed	--	--

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
northern mockingbird	*Mimus polyglottos*	western kingbird	*Tyrannus verticalis*
common raven	*Corvus corax*	California quail	*Callipepla californica*
mourning dove	*Zenaida macroura*	gopher snake	*Pituophis catenifer*
black-tailed jackrabbit	*Lepus californicus*	house finch	*Haemorhous mexicanus*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 1 – Aera Energy LLC Carbon Frontier - Survey Day 7

Survey Information

Survey Date:	Client:	Location:	Project:
June 27, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 1

Surveyors

Name:	Surveyor Qualifications:
Karla Lopez	Level II
Rory Miller	Level II
Jaden Drake	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	9:24am	**End Time:**	10:58am
Start Temperature (°F):	80.1°F	**End Temperature (°F):**	86.8°F
Start Cloud Cover:	5%	**End Cloud Cover:**	5%
Wind Speed:	1.6mph	**Wind Speed:**	2.7mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex (male/female)	Life Stage (adult/sub-adult/hatchling)	Coordinates (Latitude/Longitude)	Notes:
0	N/A	N/A	N/A

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	85
California Whiptail Lizard (*Aspidoscelis tigris munda*):	9
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
Loggerhead shrike	*Lanius ludovicianus*	SSC
San Joaquin antelope squirrel	*Ammospermophilus nelsoni*	CT

CT: California Threatened; SSC: California Species of Special Concern

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
northern mockingbird	*Mimus polyglottos*	western kingbird	*Tyrannus verticalis*
common raven	*Corvus corax*	California quail	*Callipepla californica*
mourning dove	*Zenaida macroura*	European starling	*Sturnis vulgaris*
black-tailed jackrabbit	*Lepus californicus*	house finch	*Haemorhous mexicanus*
red-tailed hawk	*Buteo jamaicensis*		

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 1 – Aera Energy LLC Carbon Frontier - Survey Day 8

Survey Information

Survey Date:	Client:	Location:	Project:
June 28, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 1

Surveyors

Name:	Surveyor Qualifications:
Samantha Medellin	Level II
Rory Miller	Level II
Rodney Aguirre	Level II

Start/End Times and Recorded Weather Conditions

Start Time:	9:00am	**End Time:**	11:10am
Start Temperature (ºF):	80.2°F	**End Temperature (ºF):**	83.2°F
Start Cloud Cover:	5%	**End Cloud Cover:**	5%
Wind Speed:	2.7mph	**Wind Speed:**	5.4mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	N/A

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	58
California Whiptail Lizard (*Aspidoscelis tigris munda*):	4
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
Loggerhead shrike	*Lanius ludovicianus*	SSC
SSC: California Species of Special Concern		

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
northern mockingbird	*Mimus polyglottos*	western kingbird	*Tyrannus verticalis*
common raven	*Corvus corax*	California quail	*Callipepla californica*
mourning dove	*Zenaida macroura*	western meadowlark	*Sturnella neglecta*
black-tailed jackrabbit	*Lepus californicus*	house finch	*Haemorhous mexicanus*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 1 – Aera Energy LLC Carbon Frontier - Survey Day 9

Survey Information

Survey Date:	Client:	Location:	Project:
June 29, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 1

Surveyors

Name:	Surveyor Qualifications:
Dorothy Tran	Level II
Rodney Aguirre	Level II
Jaden Drake	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	8:24am	**End Time:**	10:40am
Start Temperature (°F):	79.6°F	**End Temperature (°F):**	92.3°F
Start Cloud Cover:	0%	**End Cloud Cover:**	0%
Wind Speed:	1.2mph	**Wind Speed:**	2.5mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	N/A

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	64
California Whiptail Lizard (*Aspidoscelis tigris munda*):	4
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
Loggerhead shrike	*Lanius ludovicianus*	SSC
SSC: California Species of Special Concern		

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
northern mockingbird	*Mimus polyglottos*	western kingbird	*Tyrannus verticalis*
common raven	*Corvus corax*	California quail	*Callipepla californica*
mourning dove	*Zenaida macroura*		

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 1 – Aera Energy LLC Carbon Frontier - Survey Day 10

Survey Information

Survey Date:	Client:	Location:	Project:
July 8, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 1

Surveyors

Name:	Surveyor Qualifications:
Paul Rosebush	Level II
Rodney Aguirre	Level II
Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	9:12am	**End Time:**	11:18am
Start Temperature (°F):	77.8°F	**End Temperature (°F):**	83.2°F
Start Cloud Cover:	0%	**End Cloud Cover:**	0%
Wind Speed:	4.0mph	**Wind Speed:**	3.8mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	N/A

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	68
California Whiptail Lizard (*Aspidoscelis tigris munda*):	6
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
Loggerhead shrike	*Lanius ludovicianus*	SSC
SSC: California Species of Special Concern		

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
black-tailed jackrabbit	*Lepus californicus*	western kingbird	*Tyrannus verticalis*
common raven	*Corvus corax*	California quail	*Callipepla californica*
mourning dove	*Zenaida macroura*		

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 1 – Aera Energy LLC Carbon Frontier - Survey Day 11

Survey Information

Survey Date:	Client:	Location:	Project:
July 10, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 1

Surveyors

Name:	Surveyor Qualifications:
Samantha Medellin	Level II
Rodney Aguirre	Level II
Jaden Drake	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	9:40am	**End Time:**	11:28am
Start Temperature (°F):	77.5°F	**End Temperature (°F):**	85.0°F
Start Cloud Cover:	2%	**End Cloud Cover:**	2%
Wind Speed:	5.0mph	**Wind Speed:**	4.0mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	N/A

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	74
California Whiptail Lizard (*Aspidoscelis tigris munda*):	5
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
Loggerhead shrike	*Lanius ludovicianus*	SSC
SSC: California Species of Special Concern		

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
black-tailed jackrabbit	*Lepus californicus*	western kingbird	*Tyrannus verticalis*
common raven	*Corvus corax*	California quail	*Callipepla californica*
mourning dove	*Zenaida macroura*		

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 1 – Aera Energy LLC Carbon Frontier - Survey Day 12

Survey Information

Survey Date:	Client:	Location:	Project:
July 11, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 1

Surveyors

Name:	Surveyor Qualifications:
Jeffrank Solorzano	Level II
Rodney Aguirre	Level II
Jaden Drake	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	9:00am	**End Time:**	10:50am
Start Temperature (°F):	83.4°F	**End Temperature (°F):**	90.1°F
Start Cloud Cover:	0%	**End Cloud Cover:**	0%
Wind Speed:	2.3mph	**Wind Speed:**	3.1mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	N/A

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	94
California Whiptail Lizard (*Aspidoscelis tigris munda*):	7
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
None identified	--	--

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
black-tailed jackrabbit	*Lepus californicus*	western kingbird	*Tyrannus verticalis*
common raven	*Corvus corax*	house finch	*Haemorphous mexicanus*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 1 - Aera Energy LLC Carbon Frontier - Survey Day 13

Survey Information

Survey Date	Client	Location	Project
Aug 22, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 1

Surveyors

Name:	Surveyor Qualifications:
Josue Leyva	Level I
Rodney Aguirre	Level II
Sam Medellin	Level II

Start/End Times and Recorded Weather Conditions

Start Time:	9:30am	**End Time:**	11:12am
Start Temperature (ºF):	77.6°F	**End Temperature (ºF):**	80.4°F
Start Cloud Cover:	5%	**End Cloud Cover**	5%
Wind Speed:	6.0mph	**Wind Speed:**	2.7mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex (male/female)	Life Stage (adult/sub-adult/hatchling)	Coordinates (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	122
California Whiptail Lizard (*Aspidoscelis tigris munda*):	3
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
Loggerhead shrike	*Lanius ludovicianus*	SSC
CT: California Threatened; SSC Species of Special Concern		

Incidental Common Species Observations:

Common Name	Scientific Name:	Common Name	Scientific Name:
Black-tailed jackrabbit	*Lepus californicus*	great horned owl	*Bubo virginianus*
california quail	*Callipepla californica*	lesser nighthawk	*Chordeiles acutipennis*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 1 - Aera Energy LLC Carbon Frontier - Survey Day 14

Survey Information

Survey Date	Client	Location	Project
Aug 23, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 1

Surveyors

Name:	Surveyor Qualifications:
Josue Leyva	Level I
Rodney Aguirre	Level II
Samantha Medellin	Level II

Start/End Times and Recorded Weather Conditions

Start Time:	8:52am	**End Time:**	10:55am
Start Temperature (°F):	79.8°F	**End Temperature (°F):**	85.7°F
Start Cloud Cover:	5%	**End Cloud Cover**	5%
Wind Speed:	6.4mph	**Wind Speed:**	2.9mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex (male/female)	**Life Stage** (adult/sub-adult/hatchling)	**Coordinates** (Latitude/Longitude)	**Notes:**
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	180
California Whiptail Lizard (*Aspidoscelis tigris munda*):	3
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
Loggerhead shrike	*Lanius ludovicianus*	SSC
SSC Species of Special Concern		

Incidental Common Species Observations:

Common Name	Scientific Name:	Common Name	Scientific Name:
black-tailed jackrabbit	*Lepus californicus*	lesser nighthawk	*Chordeiles acutipennis*
california quail	*Callipepla californica*		

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 1 – Aera Energy LLC Carbon Frontier - Survey Day 15

Survey Information

Survey Date:	Client:	Location:	Project:
Sept 19, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 1

Surveyors

Name:	Surveyor Qualifications:
Dorothy Tran	Level II
Samantha Medellin	Level II
Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	10:33am	**End Time:**	12:17pm
Start Temperature (°F):	79.1°F	**End Temperature (°F):**	83.2°F
Start Cloud Cover:	50%	**End Cloud Cover:**	0%
Wind Speed:	0.8mph	**Wind Speed:**	1.3mph
Weather Summary:	Sunny skies, partly cloudy		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	163
California Whiptail Lizard (*Aspidoscelis tigris munda*):	1
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
None found	--	--

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
common raven	*Corvus corax*	western meadowlark	*Sturnella neglecta*
mourning dove	*Zenaida macroura*	California quail	*Callipepla californica*
prairie falcon	*Falco mexicanus*	black-tailed jackrabbit	*Lepus californicus*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 1 – Aera Energy LLC Carbon Frontier - Survey Day 16

Survey Information

Survey Date:	Client:	Location:	Project:
Sept 25, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 1

Surveyors

Name:	Surveyor Qualifications:
Dorothy Tran	Level II
Jeffrank Solarzano	Level II
Rory Miller	Level II
Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	10:33am	**End Time:**	12:02pm
Start Temperature (°F):	78.6°F	**End Temperature (°F):**	86.2°F
Start Cloud Cover:	15%	**End Cloud Cover:**	0%
Wind Speed:	1.3mph	**Wind Speed:**	2.1mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	185
California Whiptail Lizard (*Aspidoscelis tigris munda*):	5
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
None found		

CT: California Threatened; SSC: California Species of Special Concern

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
black-tailed jackrabbit	*Lepus californicus*	Bell's sparrow	*Artemisiospiza belli*
mourning dove	*Zenaida macroura*	great horned owl	*Bubo virginianus*
common raven	*Corvus corax*		

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 1 – Aera Energy LLC Carbon Frontier - Survey Day 17

Survey Information

Survey Date:	Client:	Location:	Project:
Sept 29, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 1

Surveyors

Name:	Surveyor Qualifications:
Dorothy Tran	Level II
Jeffrank Solarzano	Level II
Rory Miller	Level II

Start/End Times and Recorded Weather Conditions

Start Time:	10:59am	**End Time:**	12:27pm
Start Temperature (ºF):	80.2°F	**End Temperature (ºF):**	83.5°F
Start Cloud Cover:	0%	**End Cloud Cover:**	0%
Wind Speed:	3.0mph	**Wind Speed:**	3.0mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	124
California Whiptail Lizard (*Aspidoscelis tigris munda*):	7
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
None found	--	--

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
black-tailed jackrabbit	*Lepus californicus*	Bell's sparrow	*Artemisiospiza belli*
mourning dove	*Zenaida macroura*	great horned owl	*Bubo virginianus*
common raven	*Corvus corax*		

Mesa Biological LLC Data Forms Segment 2

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 2 – Aera Energy LLC Carbon Frontier - Survey Day 1

Survey Information

Survey Date:	Client:	Location:	Project:
May 22, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 2

Surveyors

Name:	Surveyor Qualifications:
Karla Lopez	Level II
Rory Miller	Level II
Dorothy Tran	Level II
Rodney Aguirre	Level II

Start/End Times and Recorded Weather Conditions

Start Time:	9:10am	**End Time:**	11:18am
Start Temperature (°F):	80.1°F	**End Temperature (°F):**	90.2°F
Start Cloud Cover:	5%	**End Cloud Cover:**	5%
Wind Speed:	1.8mph	**Wind Speed:**	2.2mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	36
California Whiptail Lizard (*Aspidoscelis tigris munda*):	21
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
California horned lark	*Eremophila alpestris actia*	WL
WL: California Watch List		

Incidental Common Species Observations:

Common Name:	Scientific Name:	Common Name:	Scientific Name:
European starling	*Sturnus vulgaris*	house finch	*Haemorhous mexicanus*
lesser nighthawk	*Chordeiles acutipennis*	western meadowlark	*Sturnella neglecta*
common raven	*Corvus corax*	western kingbird	*Tyrannus verticalis*
mourning dove	*Zenaida macroura*	California quail	*Callipepla californica*
black-tailed jackrabbit	*Lepus californicus*	Bell's sparrow	*Artemisiospiza belli*
desert cottontail	*Sylvilagus audubonii*		

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 2 – Aera Energy LLC Carbon Frontier - Survey Day 2

Survey Information

Survey Date:	Client:	Location:	Project:
May 23, 2023	Aera Energy LLC	North Belridge, Kern County, Ca	Carbon Frontier Segment 2

Surveyors

Name:	Surveyor Qualifications:
Karla Lopez	Level II
Jeffrank Solorzano	Level II
Rory Miller	Level II
Rodney Aguirre	Level II

Start/End Times and Recorded Weather Conditions

Start Time:	8:20am	**End Time:**	11:11am
Start Temperature (°F):	83.3°F	**End Temperature (°F):**	88.1°F
Start Cloud Cover:	5%	**End Cloud Cover:**	5%
Wind Speed:	1.6mph	**Wind Speed:**	2.7mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	81
California Whiptail Lizard (*Aspidoscelis tigris munda*):	42
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
California horned lark	*Eremophila alpestris actia*	WL
WL: California Watch List		

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
European starling	*Sturnus vulgaris*	house finch	*Haemorhous mexicanus*
lesser nighthawk	*Chordeiles acutipennis*	western meadowlark	*Sturnella neglecta*
common raven	*Corvus corax*	western kingbird	*Tyrannus verticalis*
mourning dove	*Zenaida macroura*	California quail	*Callipepla californica*
black-tailed jackrabbit	*Lepus californicus*	Bell's sparrow	*Artemisiospiza belli*
desert cottontail	*Sylvilagus audubonii*		

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 2 – Aera Energy LLC Carbon Frontier - Survey Day 3

Survey Information

Survey Date:	Client:	Location:	Project:
May 24, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 2

Surveyors

Name:	Surveyor Qualifications:
Karla Lopez	Level II
Rory Miller	Level II
Dorothy Tran	Level II
Rodney Aguirre	Level II

Start/End Times and Recorded Weather Conditions

Start Time:	10:30am	**End Time:**	12:58pm
Start Temperature (°F):	77.2°F	**End Temperature (°F):**	87.2°F
Start Cloud Cover:	5%	**End Cloud Cover:**	5%
Wind Speed:	2.8mph	**Wind Speed:**	3.8mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	46
California Whiptail Lizard (*Aspidoscelis tigris munda*):	21
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
California horned lark	*Eremophila alpestris actia*	WL
WL: California Watch List		

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
European starling	*Sturnus vulgaris*	house finch	*Haemorhous mexicanus*
Lesser nighthawk	*Chordeiles acutipennis*	western meadowlark	*Sturnella neglecta*
common raven	*Corvus corax*	western kingbird	*Tyrannus verticalis*
mourning dove	*Zenaida macroura*	California quail	*Callipepla californica*
black-tailed jackrabbit	*Lepus californicus*	Bell's sparrow	*Artemisiospiza belli*
desert cottontail	*Sylvilagus audubonii*		

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 2 – Aera Energy LLC Carbon Frontier - Survey Day 4

Survey Information

Survey Date:	Client:	Location:	Project:
May 25, 2023	Aera Energy LLC	North Belridge, Kern County, Ca	Carbon Frontier Segment 2

Surveyors

Name:	Surveyor Qualifications:
Karla Lopez	Level II
Rory Miller	Level II
Rodney Aguirre	Level II
Jaden Drake	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	10:56am	**End Time:**	12:55pm
Start Temperature (°F):	77.9°F	**End Temperature (°F):**	86.5°F
Start Cloud Cover:	5%	**End Cloud Cover:**	5%
Wind Speed:	2.7mph	**Wind Speed:**	3.3mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	40
California Whiptail Lizard (*Aspidoscelis tigris munda*):	10
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
California horned lark	*Eremophila alpestris actia*	WL
WL: California Watch List		

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
European starling	*Sturnus vulgaris*	California quail	*Callipepla californica*
Lesser nighthawk	*Chordeiles acutipennis*	western meadowlark	*Sturnella neglecta*
common raven	*Corvus corax*	black-tailed jackrabbit	*Lepus californicus*
mourning dove	*Zenaida macroura*	Bell's sparrow	*Artemisiospiza belli*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 2 – Aera Energy LLC Carbon Frontier - Survey Day 5

Survey Information

Survey Date:	Client:	Location:	Project:
June 8, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 2

Surveyors

Name:	Surveyor Qualifications:
Karla Lopez	Level II
Jeffrank Solorzano	Level II
Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	10:05am	**End Time:**	12:25pm
Start Temperature (ºF):	78.1°F	**End Temperature (ºF):**	85.9°F
Start Cloud Cover:	20%	**End Cloud Cover:**	35%
Wind Speed:	2.9mph	**Wind Speed:**	6.4mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	64
California Whiptail Lizard (*Aspidoscelis tigris munda*):	33
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
California horned lark	*Eremophila alpestris actia*	WL
loggerhead shrike	*(Lanius ludovicianus)*	SSC

SSC: California Species of Special Concern; WL: California Watch List

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
European starling	*Sturnus vulgaris*	California quail	*Callipepla californica*
kangaroo rat	*Dipodomys sp*	western meadowlark	*Sturnella neglecta*
common raven	*Corvus corax*	greater roadrunner	*Geococcyx californianus*
mourning dove	*Zenaida macroura*	yellow warbler	*Setophaga petechia*
black-tailed jackrabbit	*Lepus californicus*		

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 2 – Aera Energy LLC Carbon Frontier - Survey Day 6

Survey Information

Survey Date:	Client:	Location:	Project:
June 9, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 2

Surveyors

Name:	Surveyor Qualifications:
Sam Medellin	Level II
Dorothy Tran	Level II
Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	9:51am	**End Time:**	12:23pm
Start Temperature (ºF):	77.8°F	**End Temperature (ºF):**	85.3°F
Start Cloud Cover:	2%	**End Cloud Cover:**	2%
Wind Speed:	2.7mph	**Wind Speed:**	3.9mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	39
California Whiptail Lizard (*Aspidoscelis tigris munda*):	26
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
California horned lark	*Eremophila alpestris actia*	WL
San Joaquin antelope squirrel	*Ammospermophilus nelsoni*	CT
loggerhead shrike	*Lanius ludovicianus*	SSC

CT: California Threatened; SSC: California Species of Special Concern; WL: California Watch List

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
desert cottontail	*Sylvilagus audubonii*	deer mouse	*Peromyscus maniculatus*
Bell's sparrow	*Artemisiospiza belli*	western meadowlark	*Sturnella neglecta*
common raven	*Corvus corax*	black-tailed jackrabbit	*Lepus californicus*
mourning dove	*Zenaida macroura*	California quail	*Callipepla californica*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 2 – Aera Energy LLC Carbon Frontier - Survey Day 7

Survey Information

Survey Date:	Client:	Location:	Project:
June 10, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 2

Surveyors

Name:	Surveyor Qualifications:
Karla Lopez	Level II
Jeffrank Solorzano	Level II
Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	9:40am	**End Time:**	11:23am
Start Temperature (°F):	77.4°F	**End Temperature (°F):**	87.1°F
Start Cloud Cover:	75%	**End Cloud Cover:**	40%
Wind Speed:	1.9mph	**Wind Speed:**	2.3mph
Weather Summary:	Sunny skies, partly cloudy		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	83
California Whiptail Lizard (*Aspidoscelis tigris munda*):	25
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
California horned lark	*Eremophila alpestris actia*	WL
loggerhead shrike	*(Lanius ludovicianus)*	SSC

WL: California Watch List

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
California quail	*Callipepla californica*	mourning dove	*Zenaida macroura*
western meadowlark	*Sturnella neglecta*	black-tailed jackrabbit	*Lepus californicus*
common raven	*Corvus corax*	greater roadrunner	*Geococcyx californianus*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 2 – Aera Energy LLC Carbon Frontier - Survey Day 8

Survey Information

Survey Date:	Client:	Location:	Project:
June 16, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 2

Surveyors

Name:	Surveyor Qualifications:
Dorothy Tran	Level II
Karla Lopez	Level II
Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	8:49am	**End Time:**	10:55am
Start Temperature (°F):	81.5°F	**End Temperature (°F):**	89.1°F
Start Cloud Cover:	1%	**End Cloud Cover:**	1%
Wind Speed:	2.3mph	**Wind Speed:**	3.3mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side Blotched Lizard (*Uta stansburiana*):	60
California Whiptail Lizard (*Aspidoscelis tigris munda*):	32
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
loggerhead shrike	*Lanius ludovicianus*	SSC
SSC: California Species of Special Concern		

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
California quail	*Callipepla californica*	gopher snake	*Pituophis catenifur*
Bell's sparrow	*Artemisiospiza belli*	western meadowlark	*Sturnella neglecta*
common raven	*Corvus corax*	great horned owl	*Bubo virginianus*
mourning dove	*Zenaida macroura*	desert cottontail	*Sylvilagus audubonii*
black-tailed jackrabbit	*Lepus californicus*		

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 2 – Aera Energy LLC Carbon Frontier - Survey Day 9

Survey Information

Survey Date:	Client:	Location:	Project:
June 26, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 2

Surveyors

Name:	Surveyor Qualifications:
Dorothy Tran	Level II
Rory Miller	Level II
Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	9:03am	End Time:	10:59am
Start Temperature (ºF):	79.0°F	End Temperature (ºF):	85.9°F
Start Cloud Cover:	0%	End Cloud Cover:	1%
Wind Speed:	1.5mph	Wind Speed:	1.4mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	44
California Whiptail Lizard (*Aspidoscelis tigris munda*):	30
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
California horned lark	*Eremophila alpestris actia*	WL
loggerhead shrike	*Lanius ludovicianus*	SSC

SSC: California Species of Special Concern; WL: California Watch List

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
California quail	*Callipepla californica*	mourning dove	*Zenaida macroura*
kangaroo rat	*Dipodomys sp*	western meadowlark	*Sturnella neglecta*
common raven	*Corvus corax*	western kingbird	*Tyrannus verticalis*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 2 – Aera Energy LLC Carbon Frontier - Survey Day 10

Survey Information

Survey Date:	Client:	Location:	Project:
July 6, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 2

Surveyors

Name:	Surveyor Qualifications:
Karla Lopez	Level II
Jeffrank Solorzano	Level II
Jaden Drake	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	9:40am	**End Time:**	11:25am
Start Temperature (°F):	81.7°F	**End Temperature (°F):**	88.4°F
Start Cloud Cover:	0%	**End Cloud Cover:**	0%
Wind Speed:	3.2mph	**Wind Speed:**	1.7mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	40
California Whiptail Lizard (*Aspidoscelis tigris munda*):	29
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
None found	--	--

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
California quail	*Callipepla californica*	mourning dove	*Zenaida macroura*
black-tailed jackrabbit	*Lepus californicus*	western meadowlark	*Sturnella neglecta*
common raven	*Corvus corax*		

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 2 – Aera Energy LLC Carbon Frontier - Survey Day 11

Survey Information

Survey Date:	Client:	Location:	Project:
July 7, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 2

Surveyors

Name:	Surveyor Qualifications:
Jeffrank Solorzano	Level II
Dorothy Tran	Level II
Jaden Drake	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	9:45am	**End Time:**	11:35am
Start Temperature (ºF):	81.6°F	**End Temperature (ºF):**	88.7°F
Start Cloud Cover:	0%	**End Cloud Cover:**	0%
Wind Speed:	3.1mph	**Wind Speed:**	2.3mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	40
California Whiptail Lizard (*Aspidoscelis tigris munda*):	18
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
None found	--	--

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
California quail	*Callipepla californica*	mourning dove	*Zenaida macroura*
common raven	*Corvus corax*	western meadowlark	*Sturnella neglecta*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 2 – Aera Energy LLC Carbon Frontier - Survey Day 12

Survey Information

Survey Date:	Client:	Location:	Project:
July 8, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 2

Surveyors

Name:	Surveyor Qualifications:
Jeffrank Solorzano	Level II
Karla Lopez	Level II
Sam Medellin	Level II

Start/End Times and Recorded Weather Conditions

Start Time:	10:10am	**End Time:**	11:45am
Start Temperature (ºF):	82.0°F	**End Temperature (ºF):**	87.8°F
Start Cloud Cover:	0%	**End Cloud Cover:**	0%
Wind Speed:	1.6mph	**Wind Speed:**	3.1mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	39
California Whiptail Lizard (*Aspidoscelis tigris munda*):	16
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
None found	--	--

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
California quail	*Callipepla californica*	western meadowlark	*Sturnella neglecta*
common raven	*Corvus corax*	lesser nighthawk	*Chordeiles acutipennis*
mourning dove	*Zenaida macroura*	western kingbird	*Tyrannus verticalis*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 2 – Aera Energy LLC Carbon Frontier - Survey Day 13

Survey Information

Survey Date:	Client:	Location:	Project:
Aug 15, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 2

Surveyors

Name:	Surveyor Qualifications:
Jeffrank Solorzano	Level II
Jaden Drake	Level I
Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	8:00am	**End Time:**	9:45am
Start Temperature (ºF):	85.1°F	**End Temperature (ºF):**	94.1°F
Start Cloud Cover:	5%	**End Cloud Cover:**	5%
Wind Speed:	2.1mph	**Wind Speed:**	3.7mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side Blotched Lizard (*Uta stansburiana*):	75
California Whiptail Lizard (*Aspidoscelis tigris munda*):	11
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
None found	--	--

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
California quail	*Callipepla californica*	western meadowlark	*Sturnella neglecta*
common raven	*Corvus corax*	black-tailed jackrabbit	*Lepus californicus*
western kingbird	*Tyrannus verticalis*		

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 2- Aera Energy LLC Carbon Frontier- Survey Day 14

Survey Information

Survey Date	Client	Location	Project
Aug 16, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 2

Surveyors

Name:	Surveyor Qualifications:
Jaden Drake	Level I
Josue Leyva	Level I
Jeffrank Solorzano	Level II

Start/End Times and Recorded Weather Conditions

Start Time:	8:00am	**End Time:**	9:45am
Start Temperature (°F):	87.1°F	**End Temperature (°F):**	94.9°F
Start Cloud Cover:	30%	**End Cloud Cover**	40%
Wind Speed:	1.2mph	**Wind Speed:**	1.7mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex (male/female)	**Life Stage** (adult/sub-adult/hatchling)	**Coordinates** (Latitude/Longitude)	**Notes:**
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	102
California Whiptail Lizard (*Aspidoscelis tigris munda*):	11
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
San Joaquin antelope squirrel	*Ammospermophilus nelsoni*	CT
Loggerhead shrike	*Lanius ludoovicianus*	SSC

CT: California Threatened; SSC Species of Special Concern

Incidental Common Species Observations:

Common Name	Scientific Name:	Common Name	Scientific Name:
greater roadrunner	*Geococcyx californianus*	western kingbird	*Tyrannus verticalis*
California quail	*Callipepla californica*	lesser nighthawk	*Chordeiles acutipennis*
common raven	*Corvus corax*	house finch	*Haemorhous mexicanus*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 2- Aera Energy LLC Carbon Frontier- Survey Day 15

Survey Information

Survey Date	Client	Location	Project
Sept 13, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 2

Surveyors

Name:	Surveyor Qualifications:
Jeffrank Solorzano	Level II
Rory Miller	Level II
Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	8:47am	**End Time:**	10:35am
Start Temperature (°F):	78.0°F	**End Temperature (°F):**	85.1°F
Start Cloud Cover:	1%	**End Cloud Cover**	1%
Wind Speed:	3.0mph	**Wind Speed:**	3.3mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex (male/female)	**Life Stage** (adult/sub-adult/hatchling)	**Coordinates** (Latitude/Longitude)	**Notes:**
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	151
California Whiptail Lizard (*Aspidoscelis tigris munda*):	13
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
Loggerhead shrike	*Lanius ludoovicianus*	SSC
SSC Species of Special Concern		

Incidental Common Species Observations:

Common Name	Scientific Name:	Common Name	Scientific Name:
kangaroo rat	*Dipodomys sp*	western meadowlark	*Sturnella neglecta*
California quail	*Callipepla californica*	black-tailed jackrabbit	*Lepus californicus*
common raven	*Corvus corax*	mourning dove	*Zenaida macroura*
desert cottonail	*Sylvilagus audubonii*		

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 2 – Aera Energy LLC Carbon Frontier - Survey Day 16

Survey Information

Survey Date	Client	Location	Project
Sept 21, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment #

Surveyors

Name:	Surveyor Qualifications:
Dorothy Tran	Level II
Samantha Medellin	Level II
Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	9:58am	**End Time:**	11:46am
Start Temperature (ºF):	78.7°F	**End Temperature (ºF):**	84.2°F
Start Cloud Cover:	0%	**End Cloud Cover**	15%
Wind Speed:	4.0mph	**Wind Speed:**	2.7mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex (male/female)	Life Stage (adult/sub-adult/hatchling)	Coordinates (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	174
California Whiptail Lizard (*Aspidoscelis tigris munda*):	13
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
None found	--	--

Incidental Common Species Observations:

Common Name	Scientific Name:	Common Name	Scientific Name:
mourning dove	*Zenaida macroura*	black-tailed jackrabbit	Lepus californicus
Bell's sparrow	*Artemisiospiza belli*	California quail	*Callipepla californica*
western meadowlark	Sturnella neglecta		

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 2 – Aera Energy LLC Carbon Frontier - Survey Day 17

Survey Information

Survey Date	Client	Location	Project
Sept 27, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 2

Surveyors

Name:	Surveyor Qualifications:
Jeffrank Solorzano	Level II
Dorothy Tran	Level II
Rory Miller	Level II
Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	10:15am	**End Time:**	11:50am
Start Temperature (°F):	77.0°F	**End Temperature (°F):**	81.4°F
Start Cloud Cover:	5%	**End Cloud Cover**	5%
Wind Speed:	2.3mph	**Wind Speed:**	2.7mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex (male/female)	Life Stage (adult/sub-adult/hatchling)	Coordinates (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	204
California Whiptail Lizard (*Aspidoscelis tigris munda*):	14
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
None found	--	--

Incidental Common Species Observations:

Common Name	Scientific Name:	Common Name	Scientific Name:
mourning dove	*Zenaida macroura*	black-tailed jackrabbit	Lepus californicus
common raven	*Corvus corax*	house finch	*Haemorhous mexicanus*

Mesa Biological LLC Data Forms Segment 3

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 3 – Aera Energy LLC Carbon Frontier - Survey Day 1

Survey Information

Survey Date:	Client:	Location:	Project:
May 17, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 3

Surveyors

Name:	Surveyor Qualifications:
Samantha Medellin	Level II
Karla Lopez	Level II
Rory Miller	Level II
Paul Rosebush	Level II

Start/End Times and Recorded Weather Conditions

Start Time:	8:45am	**End Time:**	11:55am
Start Temperature (°F):	80.2°F	**End Temperature (°F):**	94.7°F
Start Cloud Cover:	2%	**End Cloud Cover:**	2%
Wind Speed:	3.7mph	**Wind Speed:**	5.2mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	84
California Whiptail Lizard (*Aspidoscelis tigris munda*):	57
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
loggerhead shrike	*Lanius ludovicianus*	SSC
San Joaquin antelope squirrel	*Ammospermophilus nelsoni*	CT

CT: California Threatened; SSC: California Species of Special Concern

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
California quail	*Callipepla californica*	house finch	*Haemorhous mexicanus*
Lesser nighthawk	*Chordeiles acutipennis*	western meadowlark	*Sturnella neglecta*
common raven	*Corvus corax*	black-tailed jackrabbit	*Lepus californicus*
mourning dove	*Zenaida macroura*	black phoebe	*Sayornis nigricans*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 3 – Aera Energy LLC Carbon Frontier - Survey Day 2

Survey Information

Survey Date:	Client:	Location:	Project:
May 19, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 3

Surveyors

Name:	Surveyor Qualifications:
Samantha Medellin	Level II
Karla Lopez	Level II
Rory Miller	Level II
Rodney Aguirre	Level II

Start/End Times and Recorded Weather Conditions

Start Time:	8:20am	**End Time:**	11:40am
Start Temperature (°F):	81.1°F	**End Temperature (°F):**	91.4°F
Start Cloud Cover:	2%	**End Cloud Cover:**	2%
Wind Speed:	3.7mph	**Wind Speed:**	3.0mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	111
California Whiptail Lizard (*Aspidoscelis tigris munda*):	46
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
None found	--	--

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
California quail	*Callipepla californica*	western meadowlark	*Sturnella neglecta*
Bell's sparrow	*Artermisiospiza belli*	black-tailed jackrabbit	*Lepus californicus*
common raven	*Corvus corax*	desert cottontail	*Sylvilagus audubonii*
mourning dove	*Zenaida macroura*		

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 3 – Aera Energy LLC Carbon Frontier - Survey Day 3

Survey Information

Survey Date:	Client:	Location:	Project:
June 12, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 3

Surveyors

Name:	Surveyor Qualifications:
Paul Rosebush	Level II
Rodney Aguirre	Level II
Rory Miller	Level II
Jaden Drake	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	9:45am	**End Time:**	12:24pm
Start Temperature (°F):	77.9°F	**End Temperature (°F):**	86.5°F
Start Cloud Cover:	0%	**End Cloud Cover:**	0%
Wind Speed:	2.9mph	**Wind Speed:**	3.4mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	102
California Whiptail Lizard (*Aspidoscelis tigris munda*):	56
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
San Joaquin antelope squirrel	*Ammospermophilus nelsoni*	CT
CT: California Threatened		

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
California quail	*Callipepla californica*	mourning dove	*Zenaida macroura*
western meadowlark	*Sturnella neglecta*	black-tailed jackrabbit	*Lepus californicus*
common raven	*Corvus corax*		

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 3 – Aera Energy LLC Carbon Frontier - Survey Day 4

Survey Information

Survey Date:	Client:	Location:	Project:
June 13, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 3

Surveyors

Name:	Surveyor Qualifications:
Jeffrank Solorzano	Level II
Paul Rosebush	Level II
Rodney Aguirre	Level II
Jaden Drake	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	8:40am	**End Time:**	11:15am
Start Temperature (ºF):	78.4°F	**End Temperature (ºF):**	86.8°F
Start Cloud Cover:	0%	**End Cloud Cover:**	10%
Wind Speed:	2.4mph	**Wind Speed:**	1.9mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	170
California Whiptail Lizard (*Aspidoscelis tigris munda*):	111
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
San Joaquin antelope squirrel	*Ammospermophilus nelsoni*	CT
CT: California Threatened		

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
California quail	*Callipepla californica*	mourning dove	*Zenaida macroura*
western meadowlark	*Sturnella neglecta*	black-tailed jackrabbit	*Lepus californicus*
common raven	*Corvus corax*		

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 3 – Aera Energy LLC Carbon Frontier - Survey Day 5

Survey Information

Survey Date:	Client:	Location:	Project:
June 14, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 3

Surveyors

Name:	Surveyor Qualifications:
Samantha Medellin	Level II
Rodney Aguirre	Level II
Paul Rosebush	Level II
Jaden Drake	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	8:24am	**End Time:**	11:17am
Start Temperature (°F):	78.9°F	**End Temperature (°F):**	90.2°F
Start Cloud Cover:	2%	**End Cloud Cover:**	2%
Wind Speed:	4.3mph	**Wind Speed:**	4.3mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	129
California Whiptail Lizard (*Aspidoscelis tigris munda*):	81
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
loggerhead shrike	*Lanius ludovicianus*	SSC
SSC: California Species of Special Concern		

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
California quail	*Callipepla californica*	Brewer's blackbird	*Euphagus cyanocephalus*
northern mockingbird	*Mimus polyglottos*	western meadowlark	*Sturnella neglecta*
common raven	*Corvus corax*	black-tailed jackrabbit	*Lepus californicus*
mourning dove	*Zenaida macroura*	black phoebe	*Sayornis nigricans*

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Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 3 – Aera Energy LLC Carbon Frontier - Survey Day 6

Survey Information

Survey Date:	Client:	Location:	Project:
June 15, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 3

Surveyors

Name:	Surveyor Qualifications:
Jeffrank Solorzano	Level II
Paul Rosebush	Level II
Rodney Aguirre	Level II
Jaden Drake	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	9:05am	**End Time:**	11:25am
Start Temperature (ºF):	78.6°F	**End Temperature (ºF):**	87.0°F
Start Cloud Cover:	0%	**End Cloud Cover:**	0%
Wind Speed:	3.9mph	**Wind Speed:**	4.3mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
Unknown	adult	35.543039°, -119.795407°	On road intersected by ephemeral stream

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	99
California Whiptail Lizard (*Aspidoscelis tigris munda*):	55
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
San Joaquin antelope squirrel	*Ammospermophilus nelsoni*	CT
CT: California Threatened		

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
California quail	*Callipepla californica*	lesser nighthawk	*Chordeiles acutipennis*
western meadowlark	*Sturnella neglecta*	black-tailed jackrabbit	*Lepus californicus*
common raven	*Corvus corax*	northern mockingbird	*Mimus polyglottos*
mourning dove	*Zenaida macroura*		

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 3 – Aera Energy LLC Carbon Frontier - Survey Day 7

Survey Information

Survey Date:	Client:	Location:	Project:
June 23, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 3

Surveyors

Name:	Surveyor Qualifications:
Samantha Medellin	Level II
Karla Lopez	Level II
Rodney Aguirre	Level II

Start/End Times and Recorded Weather Conditions

Start Time:	9:31am	**End Time:**	12:24pm
Start Temperature (°F):	79.9°F	**End Temperature (°F):**	80.1°F
Start Cloud Cover:	2%	**End Cloud Cover:**	2%
Wind Speed:	1.6mph	**Wind Speed:**	2.7mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	95
California Whiptail Lizard (*Aspidoscelis tigris munda*):	70
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
San Joaquin antelope squirrel	*Ammospermophilus nelsoni*	CT
loggerhead shrike	*Lanius ludovicianus*	SSC

CT: California Threatened; SSC: California Species of Special Concern

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
California quail	*Callipepla californica*	mourning dove	*Zenaida macroura*
lesser nighthawk	*Chordeiles acutipennis*	black-tailed jackrabbit	*Lepus californicus*
common raven	*Corvus corax*	northern mockingbird	*Mimus polyglottos*

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Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 3 – Aera Energy LLC Carbon Frontier - Survey Day 8

Survey Information

Survey Date:	Client:	Location:	Project:
June 26, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 3

Surveyors

Name:	Surveyor Qualifications:
Samantha Medellin	Level II
Rodney Aguirre	Level II
Jaden Drake	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	8:45am	**End Time:**	11:20am
Start Temperature (°F):	77.1°F	**End Temperature (°F):**	80.7°F
Start Cloud Cover:	2%	**End Cloud Cover:**	2%
Wind Speed:	3.0mph	**Wind Speed:**	4.1mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	82
California Whiptail Lizard (*Aspidoscelis tigris munda*):	59
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
San Joaquin antelope squirrel	*Ammospermophilus nelsoni*	CT
loggerhead shrike	*Lanius ludovicianus*	SSC

CT: California Threatened; SSC: California Species of Special Concern

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
western kingbird	*Tyrannus verticalis*	mourning dove	*Zenaida macroura*
house finch	*Haemorhous mexicanus*	black-tailed jackrabbit	*Lepus californicus*
common raven	*Corvus corax*		

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 3 – Aera Energy LLC Carbon Frontier - Survey Day 9

Survey Information

Survey Date:	Client:	Location:	Project:
June 30, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 3

Surveyors

Name:	Surveyor Qualifications:
Jeffrank Solorzano	Level II
Dorothy Tran	Level II
Jaden Drake	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	8:00am	**End Time:**	10:05am
Start Temperature (ºF):	85.6°F	**End Temperature (ºF):**	94.1°F
Start Cloud Cover:	0%	**End Cloud Cover:**	0%
Wind Speed:	2.7mph	**Wind Speed:**	5.7mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
Unknown	adult	35.541849°, -119.793807°	pair of BNLL found together on edge of dirt road.
Male	adult	35.541867°, -119.793773°	

Other Lizard Species Observations

Side-blotched lizard (*Uta stansburiana*):	82
California Whiptail Lizard (*Aspidoscelis tigris munda*):	64
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
San Joaquin antelope squirrel	*Ammospermophilus nelsoni*	CT
CT: California Threatened		

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
California quail	*Callipepla californica*	common raven	*Corvus corax*
black-tailed jackrabbit	*Lepus californicus*	mourning dove	*Zenaida macroura*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 3 – Aera Energy LLC Carbon Frontier - Survey Day 10

Survey Information

Survey Date:	Client:	Location:	Project:
July 5, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 3

Surveyors

Name:	Surveyor Qualifications:

Paul Rosebush	Level II
Rodney Aguirre	Level II
Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	8:17am	**End Time:**	11:10am
Start Temperature (°F):	80.1°F	**End Temperature (°F):**	88.9°F
Start Cloud Cover:	0%	**End Cloud Cover:**	0%
Wind Speed:	1.6mph	**Wind Speed:**	3.8mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	**Life Stage:** (adult/sub-adult/hatchling)	**Coordinates:** (Latitude/Longitude)	**Notes:**
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	113
California Whiptail Lizard (*Aspidoscelis tigris munda*):	48
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	**Scientific Name:**	**Status:**
San Joaquin antelope squirrel	*Ammospermophilus nelsoni*	CT
CT: California Threatened		

Incidental Common Species Observations

Common Name:	**Scientific Name:**	**Common Name:**	**Scientific Name:**
western kingbird	*Tyrannus verticalis*	American crow	*Corvus brachyrhynchos*
black phoebe	*Sayornis nigricans*	California quail	*Callipepla californica*
common raven	*Corvus corax*	black-tailed jackrabbit	*Lepus californicus*
mourning dove	*Zenaida macroura*	desert cottontail	*Sylvilagus audubonii*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 3 – Aera Energy LLC Carbon Frontier - Survey Day 11

Survey Information

Survey Date:	**Client:**	**Location:**	**Project:**
July 6, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 3

Surveyors

Name:	**Surveyor Qualifications:**
Paul Rosebush	Level II
Rodney Aguirre	Level II

Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	9:49am	**End Time:**	12:17pm
Start Temperature (°F):	81.8°F	**End Temperature (°F):**	92.8°F
Start Cloud Cover:	0%	**End Cloud Cover:**	0%
Wind Speed:	3.6mph	**Wind Speed:**	3.7mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	**Life Stage:** (adult/sub-adult/hatchling)	**Coordinates:** (Latitude/Longitude)	**Notes:**
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	92
California Whiptail Lizard (*Aspidoscelis tigris munda*):	35
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	**Scientific Name:**	**Status:**
San Joaquin antelope squirrel	*Ammospermophilus nelsoni*	CT
loggerhead shrike	*Lanius ludovicianus*	SSC
CT: California Threatened; SSC: California Species of Special Concern		

Incidental Common Species Observations

Common Name:	**Scientific Name:**	**Common Name:**	**Scientific Name:**
western kingbird	*Tyrannus verticalis*	mourning dove	*Zenaida macroura*
black phoebe	*Sayornis nigricans*	black-tailed jackrabbit	*Lepus californicus*
common raven	*Corvus corax*	desert cottontail	*Sylvilagus audubonii*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 3 – Aera Energy LLC Carbon Frontier - Survey Day 12

Survey Information

Survey Date:	**Client:**	**Location:**	**Project:**
July 7, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 3

Surveyors

Name:	**Surveyor Qualifications:**
Paul Rosebush	Level II
Rodney Aguirre	Level II
Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	9:31am	**End Time:**	12:10pm
Start Temperature (ºF):	78.9°F	**End Temperature (ºF):**	86.7°F
Start Cloud Cover:	0%	**End Cloud Cover:**	0%
Wind Speed:	4.8mph	**Wind Speed:**	6.2mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	**Life Stage:** (adult/sub-adult/hatchling)	**Coordinates:** (Latitude/Longitude)	**Notes:**
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	65
California Whiptail Lizard (*Aspidoscelis tigris munda*):	37
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	**Scientific Name:**	**Status:**
San Joaquin antelope squirrel	*Ammospermophilus nelsoni*	CT
loggerhead shrike	*Lanius ludovicianus*	SSC
CT: California Threatened; SSC: California Species of Special Concern		

Incidental Common Species Observations

Common Name:	**Scientific Name:**	**Common Name:**	**Scientific Name:**
western kingbird	*Tyrannus verticalis*	mourning dove	*Zenaida macroura*
black phoebe	*Sayornis nigricans*	black-tailed jackrabbit	*Lepus californicus*
common raven	*Corvus corax*	desert cottontail	*Sylvilagus audubonii*

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Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 3 – Aera Energy LLC Carbon Frontier - Survey Day 13

Survey Information

Survey Date:	**Client:**	**Location:**	**Project:**
Aug 23, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 3

Surveyors

Name:	**Surveyor Qualifications:**
Karla Lopez	Level II
Rory Miller	Level II
Jaden Drake	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	08:30am	**End Time:**	10:47am

Start Temperature (°F):	81.1°F	**End Temperature (°F):**	88.8°F
Start Cloud Cover:	1%	**End Cloud Cover:**	1%
Wind Speed:	2.8mph	**Wind Speed:**	4.9mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	**Life Stage:** (adult/sub-adult/hatchling)	**Coordinates:** (Latitude/Longitude)	**Notes:**
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	319
California Whiptail Lizard (*Aspidoscelis tigris munda*):	59
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	**Scientific Name:**	**Status:**
None found	--	--

Incidental Common Species Observations

Common Name:	**Scientific Name:**	**Common Name:**	**Scientific Name:**
western kingbird	*Tyrannus verticalis*	mourning dove	*Zenaida macroura*
red-tailed hawk	*Buteo jamaicensis*	black-tailed jackrabbit	*Lepus californicus*
common raven	*Corvus corax*	Savannah sparrow	*Passerculus sandwichensis*
house finch	*Haemorhous mexicanus*		

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 3 Aera Energy LLC – Carbon Frontier - Survey Day 14

Survey Information

Survey Date:	**Client:**	**Location:**	**Project:**
Aug 25, 2023	AERA Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 3

Surveyors

Name:	**Surveyor Qualifications:**
Jaden Drake	Level I
Rory Miller	Level II
Karla Lopez	Level II

Start/End Times and Recorded Weather Conditions

Start Time:	8:30am	**End Time:**	10:20am
Start Temperature (°F):	77.3°F	**End Temperature (°F):**	87.7°F
Start Cloud Cover:	1%	**End Cloud Cover:**	1%
Wind Speed:	2.1mph	**Wind Speed:**	3.8mph
Weather Summary:	Sunny skies, smoke		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	332
California Whiptail Lizard (*Aspidoscelis tigris munda*):	49
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
Loggerhead shrike	*Lanius ludovicianus*	SSC
San Joaquin antelope squirrel	*Ammospermophilus nelsoni*	CT
CT: California Threatened; SSC: Species of Special Concern		

Incidental Common Species Observations:

Common Name:	Scientific Name:	Common Name:	Scientific Name:
black-tailed jackrabbit	*Lepus californicus*	mourning dove	*Zenaida macroura*
California quail	*Callipepla californica*	red-tailed hawk	*Buteo jamaicensis*
western kingbird	*Tyrannus verticalis*	Savannah sparrow	*Passerculus sandiwchensis*
house finch	*Haemorhous mexicanus*	common raven	*Corvux corax*
European starling	*Sturnus vulgaris*		

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 3 Aera Energy LLC – Carbon Frontier - Survey Day 15

Survey Information

Survey Date:	Client:	Location:	Project:
Sept 14, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 3

Surveyors

Name:	Surveyor Qualifications:
Jeffrank Solorzano	Level II
Rory Miller	Level II
Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	8:55am	**End Time:**	11:05am
Start Temperature (°F):	78.9°F	**End Temperature (°F):**	88.1°F
Start Cloud Cover:	1%	**End Cloud Cover:**	1%
Wind Speed:	2.0mph	**Wind Speed:**	2.3mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	251
California Whiptail Lizard (*Aspidoscelis tigris munda*):	31
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
San Joaquin antelope squirrel	*Ammospermophilus nelsoni*	CT
CT: California Threatened		

Incidental Common Species Observations:

Common Name:	Scientific Name:	Common Name:	Scientific Name:
black-tailed jackrabbit	*Lepus californicus*	mourning dove	*Zenaida macroura*
California quail	*Callipepla californica*	western meadowlark	*Sturnella neglecta*
house finch	*Haemorhous mexicanus*	common raven	*Corvux corax*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 3 – Aera Energy LLC Carbon Frontier - Survey Day 16

Survey Information

Survey Date	Client	Location	Project
Sept 20, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 3

Surveyors

Name:	Surveyor Qualifications:
Dorothy Tran	Level II
Rory Miller	Level II
Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	8:53am	**End Time:**	11:36am
Start Temperature (ºF):	78.7°F	**End Temperature (ºF):**	86.4°F
Start Cloud Cover:	0%	**End Cloud Cover**	1%
Wind Speed:	0.8mph	**Wind Speed:**	1.3mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex (male/female)	**Life Stage** (adult/sub-adult/hatchling)	**Coordinates** (Latitude/Longitude)	**Notes:**
1 Male	Adult	35.543394°, -119.795956°	Adult BNLL, orange color on hind legs found at the base of a bush
1 Unknown	Hatchling	35.542938°, -119.795594°	Hatchling found standing on pipeline

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	323
California Whiptail Lizard (*Aspidoscelis tigris munda*):	38
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
None found	--	--

Incidental Common Species Observations:

Common Name	Scientific Name:	Common Name	Scientific Name:
common raven	*Corvus corax*	western meadowlark	*Sturnella neglecta*
desert cottontail	Sylvilagus audubonii	mourning dove	*Zenaida macroura*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 3 – Aera Energy LLC Carbon Frontier - Survey Day 17

Survey Information

Survey Date	Client	Location	Project
Sept 28, 23	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 3

Surveyors

Name:	Surveyor Qualifications:
Dorothy Tran	Level II
Jeffrank Solarzano	Level II
Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	10:35am	**End Time:**	12:35pm
Start Temperature (ºF):	78.5°F	**End Temperature (ºF):**	85.6°F
Start Cloud Cover:	0%	**End Cloud Cover**	0%
Wind Speed:	0.8mph	**Wind Speed:**	2.0mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex (male/female)	Life Stage (adult/sub-adult/hatchling)	Coordinates (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	263
California Whiptail Lizard (*Aspidoscelis tigris munda*):	31
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
None found	--	--

Incidental Common Species Observations:

Common Name	Scientific Name:	Common Name	Scientific Name:
common raven	*Corvus corax*	Bell's sparrow	*Artemisiospiza belli*
western meadowlark	*Sturnella neglecta*	black-tailed jackrabbit	*Lepus californicus*
mourning dove	*Zenaida macroura*		

Mesa Biological LLC Data Forms Segment 4

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 4 – Aera Energy LLC Carbon Frontier - Survey Day 1

Survey Information

Survey Date:	Client:	Location:	Project:
June 8, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 4

Surveyors

Name:	Surveyor Qualifications:
Paul Rosebush	Level II
Rory Miller	Level II
Jaden Drake	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	9:32am	**End Time:**	12:53pm
Start Temperature (°F):	78.5°F	**End Temperature (°F):**	84.5°F
Start Cloud Cover:	5%	**End Cloud Cover:**	15%
Wind Speed:	3.2mph	**Wind Speed:**	1.8mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	104
California Whiptail Lizard (*Aspidoscelis tigris munda*):	63
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
loggerhead shrike	*Lanius ludovicianus*	SSC
San Joaquin antelope squirrel	*Ammospermophilus nelsoni*	CT

CT: California Threatened; SSC: California Species of Special Concern

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
Bell's sparrow	*Artemisiospiza belli*	northern mockingbird	*Mimus polyglottos*
Lesser nighthawk	*Chordeiles acutipennis*	western meadowlark	*Sturnella neglecta*
common raven	*Corvus corax*	black-tailed jackrabbit	*Lepus californicus*
mourning dove	*Zenaida macroura*	western kingbird	*Tyrannus verticalis*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 4 – Aera Energy LLC Carbon Frontier - Survey Day 2

Survey Information

Survey Date:	Client:	Location:	Project:
June 9, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 4

Surveyors

Name:	Surveyor Qualifications:
Paul Rosebush	Level II
Rodney Aguirre	Level II
Jaden Drake	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	9:27am	**End Time:**	12:33pm
Start Temperature (ºF):	77.7°F	**End Temperature (ºF):**	89.6°F
Start Cloud Cover:	0%	**End Cloud Cover:**	10%
Wind Speed:	1.2mph	**Wind Speed:**	2.1mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
Female	adult	35.546535°, -119.799638°	Female BNLL observed on road edge with distinct breeding colors.

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	114
California Whiptail Lizard (*Aspidoscelis tigris munda*):	58
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
loggerhead shrike	*Lanius ludovicianus*	SSC
San Joaquin antelope squirrel	*Ammospermophilus nelsoni*	CT

CT: California Threatened; SSC: Species of Special Concern

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
Bell's sparrow	*Artemisiospiza belli*	northern mockingbird	*Mimus polyglottos*
lesser nighthawk	*Chordeiles acutipennis*	black-tailed jackrabbit	*Lepus californicus*
common raven	*Corvus corax*	western meadowlark	*Sturnella neglecta*
mourning dove	*Zenaida macroura*		

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 4 – Aera Energy LLC Carbon Frontier - Survey Day 3

Survey Information

Survey Date:	Client:	Location:	Project:
June 10, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 4

Surveyors

Name:	Surveyor Qualifications:
Paul Rosebush	Level II
Samantha Medellin	Level II
Rodney Aguirre	Level II
Jaden Drake	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	9:27am	**End Time:**	12:55pm
Start Temperature (ºF):	80.6°F	**End Temperature (ºF):**	87.7°F
Start Cloud Cover:	60%	**End Cloud Cover:**	10%
Wind Speed:	3.4mph	**Wind Speed:**	4.0mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	135
California Whiptail Lizard (*Aspidoscelis tigris munda*):	114
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
San Joaquin antelope squirrel	*Ammospermophilus nelsoni*	CT
CT: California Threatened		

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
northern mockingbird	*Mimus polyglottos*	mourning dove	*Zenaida macroura*
lesser nighthawk	*Chordeiles acutipennis*	black-tailed jackrabbit	*Lepus californicus*
common raven	*Corvus corax*	western meadowlark	*Sturnella neglecta*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 4 – Aera Energy LLC Carbon Frontier - Survey Day 4

Survey Information

Survey Date:	Client:	Location:	Project:
June 11, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 4

Surveyors

Name:	Surveyor Qualifications:
Paul Rosebush	Level II
Dorothy Tran	Level II
Rodney Aguirre	Level II
Jaden Drake	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	9:00am	**End Time:**	11:40am
Start Temperature (°F):	77.2°F	**End Temperature (°F):**	86.3°F
Start Cloud Cover:	5%	**End Cloud Cover:**	5%
Wind Speed:	8.6mph	**Wind Speed:**	4.0mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	96
California Whiptail Lizard (*Aspidoscelis tigris munda*):	45
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
San Joaquin coachwhip	*Coluber flagellum ruddocki*	SSC
San Joaquin antelope squirrel	*Ammospermophilus nelsoni*	CT

CT: California Threatened; SSC: California Species of Special Concern

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
northern mockingbird	*Mimus polyglottos*	mourning dove	*Zenaida macroura*
Lesser nighthawk	*Chordeiles acutipennis*	black-tailed jackrabbit	*Lepus californicus*
common raven	*Corvus corax*	western meadowlark	*Sturnella neglecta*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 4 – Aera Energy LLC Carbon Frontier - Survey Day 5

Survey Information

Survey Date:	Client:	Location:	Project:
June 16, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 4

Surveyors

Name:	Surveyor Qualifications:
Paul Rosebush	Level II
Rory Miller	Level II
Rodney Aguirre	Level II
Jaden Drake	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	8:32am	**End Time:**	11:25am
Start Temperature (°F):	82.2°F	**End Temperature (°F):**	89.5°F
Start Cloud Cover:	5%	**End Cloud Cover:**	0%
Wind Speed:	1.5mph	**Wind Speed:**	3.5mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side Blotched Lizard (*Uta stansburiana*):	96
California Whiptail Lizard (*Aspidoscelis tigris munda*):	56
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
San Joaquin coachwhip	*Coluber flagellum ruddocki*	SSC
SSC: California Species of Special Concern		

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
northern mockingbird	*Mimus polyglottos*	cottontail jackrabbit	*Sylviagus audubonii*
Lesser nighthawk	*Chordeiles acutipennis*	black-tailed jackrabbit	*Lepus californicus*
common raven	*Corvus corax*	western meadowlark	*Sturnella neglecta*
mourning dove	*Zenaida macroura*		

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 4 – Aera Energy LLC Carbon Frontier - Survey Day 6

Survey Information

Survey Date:	Client:	Location:	Project:
June 23, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 4

Surveyors

Name:	Surveyor Qualifications:
Paul Rosebush	Level II
Jeffrank Solorzano	Level II
Jaden Drake	Level I
Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	10:00am	**End Time:**	12:40pm
Start Temperature (ºF):	77.4°F	**End Temperature (ºF):**	82.9°F
Start Cloud Cover:	0%	**End Cloud Cover:**	0%
Wind Speed:	5.6mph	**Wind Speed:**	6.1mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	142
California Whiptail Lizard (*Aspidoscelis tigris munda*):	131
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
San Joaquin antelope squirrel	*Ammospermophilus nelsoni*	CT
CT: California Threatened; SSC: California Species of Special Concern		

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
northern mockingbird	*Mimus polyglottos*	mourning dove	*Zenaida macroura*
cottontail jackrabbit	*Sylviagus audubonii*	black-tailed jackrabbit	*Lepus californicus*
common raven	*Corvus corax*	western meadowlark	*Sturnella neglecta*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 4 – Aera Energy LLC Carbon Frontier - Survey Day 7

Survey Information

Survey Date:	Client:	Location:	Project:
June 29, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 4

Surveyors

Name:	Surveyor Qualifications:
Paul Rosebush	Level II
Samantha Medellin	Level II
Rory Miller	Level II
Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	8:45am	**End Time:**	11:30am
Start Temperature (°F):	81.9°F	**End Temperature (°F):**	95.3°F
Start Cloud Cover:	2%	**End Cloud Cover:**	2%
Wind Speed:	3.9mph	**Wind Speed:**	4.8mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	105
California Whiptail Lizard (*Aspidoscelis tigris munda*):	72
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
San Joaquin antelope squirrel	*Ammospermophilus nelsoni*	CT
loggerhead shrike	*Lanius ludovicianus*	SSC

CT: California Threatened; SSC: California Species of Special Concern

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
northern mockingbird	*Mimus polyglottos*	house finch	*Haemorhous mexicanus*
cottontail jackrabbit	*Sylviagus audubonii*	California quail	*Callipepla californica*
common raven	*Corvus corax*	black-tailed jackrabbit	*Lepus californicus*
mourning dove	*Zenaida macroura*	western meadowlark	*Sturnella neglecta*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 4 – Aera Energy LLC Carbon Frontier - Survey Day 8

Survey Information

Survey Date:	Client:	Location:	Project:
July 5, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 4

Surveyors

Name:	Surveyor Qualifications:
Jeffrank Solorzano	Level II
Dorothy Tran	Level II
Rory Miller	Level II
Jaden Drake	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	8:00am	**End Time:**	10:45am
Start Temperature (°F):	77.5°F	**End Temperature (°F):**	90.6°F
Start Cloud Cover:	0%	**End Cloud Cover:**	0%
Wind Speed:	1.3mph	**Wind Speed:**	2.7mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	156
California Whiptail Lizard (*Aspidoscelis tigris munda*):	105
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
San Joaquin antelope squirrel	*Ammospermophilus nelsoni*	CT
CT: California Threatened		

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
northern mockingbird	*Mimus polyglottos*	mourning dove	*Zenaida macroura*
western meadowlark	*Sturnella neglecta*	black-tailed jackrabbit	*Lepus californicus*
common raven	*Corvus corax*		

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 4 – Aera Energy LLC Carbon Frontier - Survey Day 9

Survey Information

Survey Date:	Client:	Location:	Project:
July 10, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 4

Surveyors

Name:	Surveyor Qualifications:
Rory Miller	Level II
Paul Rosebush	Level II
Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	9:00am	**End Time:**	11:30am
Start Temperature (°F):	77.5°F	**End Temperature (°F):**	88.7°F
Start Cloud Cover:	1%	**End Cloud Cover:**	0%
Wind Speed:	3.2mph	**Wind Speed:**	3.6mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	94
California Whiptail Lizard (*Aspidoscelis tigris munda*):	40
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
San Joaquin antelope squirrel	*Ammospermophilus nelsoni*	CT
CT: California Threatened		

Incidental Common Species Observations

Common Name	Scientific Name:	Common Name	Scientific Name:
northern mockingbird	*Mimus polyglottos*	mourning dove	*Zenaida macroura*
western meadowlark	*Sturnella neglecta*	black-tailed jackrabbit	*Lepus californicus*
common raven	*Corvus corax*	northern pacific rattlesnake	*Corualus oreganus*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 4 – Aera Energy LLC Carbon Frontier - Survey Day 10

Survey Information

Survey Date:	Client:	Location:	Project:
July 11, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 4

Surveyors

Name:	Surveyor Qualifications:
Rory Miller	Level II
Paul Rosebush	Level II
Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	9:01am	**End Time:**	11:45am
Start Temperature (ºF):	79.6°F	**End Temperature (ºF):**	93.8°F
Start Cloud Cover:	0%	**End Cloud Cover:**	0%
Wind Speed:	2.2mph	**Wind Speed:**	6.0mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex (male/female)	Life Stage (adult/sub-adult/hatchling)	Coordinates (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	83
California Whiptail Lizard (*Aspidoscelis tigris munda*):	36
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
San Joaquin antelope squirrel	*Ammospermophilus nelsoni*	CT
CT: California Threatened		

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
northern mockingbird	*Mimus polyglottos*	mourning dove	*Zenaida macroura*
western meadowlark	*Sturnella neglecta*	black-tailed jackrabbit	*Lepus californicus*
common raven	*Corvus corax*	Lesser nighthawk	*Chordeiles acutipennis*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 4 – Aera Energy LLC Carbon Frontier - Survey Day 11

Survey Information

Survey Date:	Client:	Location:	Project:
July 12, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 4

Surveyors

Name:	Surveyor Qualifications:
Rory Miller	Level II
Rodney Aguirre	Level II
Jaden Drake	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	8:45am	**End Time:**	11:04am
Start Temperature (°F):	89.0°F	**End Temperature (°F):**	96.0°F
Start Cloud Cover:	1%	**End Cloud Cover:**	1%
Wind Speed:	1.7mph	**Wind Speed:**	1.6mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	88
California Whiptail Lizard (*Aspidoscelis tigris munda*):	60
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
None found.	--	--

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
red-tailed hawk	*Buteo jamaicensis*	black-tailed jackrabbit	*Lepus californicus*
western meadowlark	*Sturnella neglecta*	western kingbird	*Tyrannus verticalis*
common raven	*Corvus corax*	mourning dove	*Zenaida macroura*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 4 – Aera Energy LLC Carbon Frontier - Survey Day 12

Survey Information

Survey Date:	Client:	Location:	Project:
July 13, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 4

Surveyors

Name:	Surveyor Qualifications:
Rodney Aguirre	Level II
Josue Leyva	Level I
Jaden Drake	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	8:45am	**End Time:**	12:30pm
Start Temperature (ºF):	89.4°F	**End Temperature (ºF):**	95.8°F
Start Cloud Cover:	5%	**End Cloud Cover:**	3%
Wind Speed:	3.4mph	**Wind Speed:**	2.0mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex: (male/female)	Life Stage: (adult/sub-adult/hatchling)	Coordinates: (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	89
California Whiptail Lizard (*Aspidoscelis tigris munda*):	63
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
San Joaquin antelope squirrel	*Ammospermophilus nelsoni*	CT
San Joaquin coachwhip	*Masticophis flagellum*	SSC
CT: California Threatened; SSC: California Species of Special Concern		

Incidental Common Species Observations

Common Name:	Scientific Name:	Common Name:	Scientific Name:
northern mockingbird	*Mimus polyglottos*	western meadowlark	*Sturnella neglecta*
common raven	*Corvus corax*	western kingbird	*Tyrannus verticalis*
mourning dove	*Zenaida macroura*	house finch	*Haemorhous mexicanus*
black-tailed jackrabbit	*Lepus californicus*		

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 4 Aera Energy LLC – Carbon Frontier - Survey Day 13

Survey Information

Survey Date	Client	Location	Project
Aug 24, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 4

Surveyors

Name:	Surveyor Qualifications:
Josue Leyva	Level I
Jaden Drake	Level I
Rodney Aguirre	Level II
Samantha Medellin	Level II

Start/End Times and Recorded Weather Conditions

Start Time:	8:30am	**End Time:**	10:40am
Start Temperature (°F):	83.9°F	**End Temperature (°F):**	93.7°F
Start Cloud Cover:	2%	**End Cloud Cover**	10%
Wind Speed:	1.0mph	**Wind Speed:**	4.7mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex (male/female)	Life Stage (adult/sub-adult/hatchling)	Coordinates (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	242
California Whiptail Lizard (*Aspidoscelis tigris munda*):	72
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
Loggerhead shrike	*Lanius ludovicianus*	SSC
SSC: Species of Special Concern		

Incidental Common Species Observations:

Common Name	Scientific Name:	Common Name	Scientific Name:
black-tailed jackrabbit	*Lepus californicus*	lesser nighthawk	*Chordeiles acutipennis*
California quail	*Callipepla californica*	mourning dove	*Zenaida macroura*
red-tailed hawk	*Buteo jamaicensis*	northern mockingbird	*Mimus polyglottos*
western meadowlark	*Sturnella neglecta*		

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 4 Aera Energy LLC – Carbon Frontier - Survey Day 14

Survey Information

Survey Date	Client	Location	Project
Aug 25, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 4

Surveyors

Name:	Surveyor Qualifications:
Samantha Medellin	Level II
Rodney Aguirre	Level II
Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	8:25am	**End Time:**	10:46am
Start Temperature (°F):	77.0°F	**End Temperature (°F):**	90.2°F
Start Cloud Cover:	2%	**End Cloud Cover**	2%
Wind Speed:	0.2mph	**Wind Speed:**	2.0mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex (male/female)	**Life Stage** (adult/sub-adult/hatchling)	**Coordinates** (Latitude/Longitude)	**Notes:**
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	194
California Whiptail Lizard (*Aspidoscelis tigris munda*):	24
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
None	--	--

Incidental Common Species Observations:

Common Name	Scientific Name:	Common Name	Scientific Name:
black-tailed jackrabbit	*Lepus californicus*	northern mockingbird	*Mimus polyglottos*
common raven	*Corvus corax*	mourning dove	*Zenaida macroura*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 4 Aera Energy LLC – Carbon Frontier - Survey Day 15

Survey Information

Survey Date	Client	Location	Project
Sept 15, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 4

Surveyors

Name:	Surveyor Qualifications:
Dorothy Tran	Level II
Rory Miller	Level II
Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	8:46am	**End Time:**	11:56am
Start Temperature (°F):	81.4°F	**End Temperature (°F):**	91.2°F
Start Cloud Cover:	1%	**End Cloud Cover**	0%
Wind Speed:	2.1mph	**Wind Speed:**	1.9mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex (male/female)	**Life Stage** (adult/sub-adult/hatchling)	**Coordinates** (Latitude/Longitude)	**Notes:**
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	321
California Whiptail Lizard (*Aspidoscelis tigris munda*):	65
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
None	--	--

Incidental Common Species Observations:

Common Name	Scientific Name:	Common Name	Scientific Name:
black-tailed jackrabbit	*Lepus californicus*	western meadowlark	*Sturnella neglecta*
common raven	*Corvus corax*	mourning dove	*Zenaida macroura*
Bell's sparrow	*Artemisiospiza belli*	kangaroo rat	*Dipodomys s.p.*

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 4 Aera Energy LLC – Carbon Frontier - Survey Day 16

Survey Information

Survey Date	Client	Location	Project
Sept 18, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 4

Surveyors

Name:	Surveyor Qualifications:
Samantha Medellin	Level II
Rory Miller	Level II
Dorothy Tran	Level II
Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	10:46am	**End Time:**	1:42pm
Start Temperature (°F):	81.2°F	**End Temperature (°F):**	92.1°F
Start Cloud Cover:	20%	**End Cloud Cover**	2%
Wind Speed:	4.0mph	**Wind Speed:**	3.0mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex (male/female)	Life Stage (adult/sub-adult/hatchling)	Coordinates (Latitude/Longitude)	Notes:
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	362
California Whiptail Lizard (*Aspidoscelis tigris munda*):	59
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
San Joaquin antelope squirrel	*Ammospermophilus nelsoni*	CT

Incidental Common Species Observations:

Common Name	Scientific Name:	Common Name	Scientific Name:
black-tailed jackrabbit	*Lepus californicus*	red-tailed hawk	*Buteo jamaicensis*
common raven	*Corvus corax*	mourning dove	*Zenaida macroura*
Bell's sparrow	*Artemisiospiza belli*	California quail	*Callipepla californica*
western meadowlark	*Sturnella neglecta*		

Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Datasheet

Segment 4 Aera Energy LLC – Carbon Frontier - Survey Day 17

Survey Information

Survey Date	Client	Location	Project
Sept 26, 2023	Aera Energy LLC	North Belridge, Kern County, CA	Carbon Frontier Segment 4

Surveyors

Name:	Surveyor Qualifications:
Jeffrank Solorzano	Level II
Dorothy Tran	Level II
Josue Leyva	Level I

Start/End Times and Recorded Weather Conditions

Start Time:	10:30am	**End Time:**	1:20pm
Start Temperature (ºF):	77.5°F	**End Temperature (ºF):**	83.4°F
Start Cloud Cover:	5%	**End Cloud Cover**	5%
Wind Speed:	2.9mph	**Wind Speed:**	4.7mph
Weather Summary:	Sunny skies		

Recorded Blunt-Nosed Leopard Lizard Observations and Location

Sex (male/female)	**Life Stage** (adult/sub-adult/hatchling)	**Coordinates** (Latitude/Longitude)	**Notes:**
0	N/A	N/A	No BNLL identified

Other Lizard Species Observations

Side-Blotched Lizard (*Uta stansburiana*):	306
California Whiptail Lizard (*Aspidoscelis tigris munda*):	45
Blainsville Horned Lizard (*Phrynosoma blainvillii*):	0

Other Special-Status Species Observed

Common Name:	Scientific Name:	Status:
San Joaquin antelope squirrel	*Ammospermophilus nelsoni*	CT
CT: California Threatened		

Incidental Common Species Observations:

Common Name	Scientific Name:	Common Name	Scientific Name:
black-tailed jackrabbit	*Lepus californicus*	house finch	*Haemorhous mexicanus*
common raven	*Corvus corax*	western meadowlark	*Sturnella neglecta*
mourning dove	*Zenaida macroura*		

Attachment C: Protocol Blunt-Nosed Leopard Lizard Survey Results Summary Table

Protocol-Level Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Results Summary Table

Segment 1 - Aera Energy LLC Carbon Frontier Project

Survey Day	Survey Date	BNLL Surveyors (**bold indicates Level II Surveyor**)	Survey Timeframes		Air Temperatures (˚F)		Cloud Cover (%)		Wind Speed (mph)		Other Lizard Species			Recorded Blunt-nosed Leopard Lizard (BNLL) (*Gambelia sila*)			
			Start Time	End Time	Start Temp	End Temp	Start Cloud Cover	End Cloud Cover	Start Speed	End Speed	Side-Blotched Lizard (*Uta stansburiana*)	California Whiptail Lizard (*Aspidoscelis tigris munda*)	Blainsville Horned Lizard (*Phrynosoma blainvillii*)	Male	Female	Unknown	Hatchling/Sub-Adult
Adult Surveys																	
1	5/15/23	**Samantha Medellin**, **Paul Rosebush**, **Karla Lopez**, **Rory Miller**	8:56 AM	11:35 AM	81.6	91.0	2%	2%	1.0	3.0	79	6	0	0	0	0	0
2	6/6/23	**Jeffrank Solarzano**, **Paul Rosebush**, **Rory Miller,** Jaden Drake	10:25 AM	12:45 PM	78.6	82.9	75%	50%	1.8	2.9	96	8	0	0	0	0	0
3	6/12/23	**Jeffrank Solarzano**, **Karla Lopez**, Josue Leyva	10:10 AM	12:01 PM	78.0	88.9	10%	10%	2.2	2.8	83	16	0	0	0	0	0
4	6/13/23	**Samantha Medellin**, **Rory Miller**, Josue Leyva	9:04 AM	11:01 AM	77.4	84.1	2%	2%	3.7	4.0	60	8	0	0	0	0	0
5	6/14/23	**Jeffrank Solarzano**, **Rory Miller**, Josue Leyva	8:40 AM	10:30 AM	78.6	82.6	10%	10%	0.9	3.3	74	12	0	0	0	0	0
6	6/15/23	**Samantha Medellin**, **Rory Miller,** Josue Leyva	8:39 AM	10:53 AM	77.8	88.7	2%	2%	4.1	4.3	33	1	0	0	0	0	0
7	6/27/23	**Karla Lopez, Rory Miller**, Jaden Drake	9:24 AM	10:58 AM	80.1	86.8	5%	5%	1.6	2.7	85	9	0	0	0	0	0
8	6/28/23	**Samantha Medellin**, **Rodney Aguirre**, **Rory Miller**	9:00 AM	11:10 AM	80.2	83.2	5%	5%	2.7	5.4	58	4	0	0	0	0	0
9	6/29/23	**Dorothy Tran**, **Rodney Aguirre**, Jaden Drake	8:24 AM	10:40 AM	79.6	92.3	0%	0%	1.2	2.5	64	4	0	0	0	0	0
10	7/8/23	**Paul Rosebush, Rodney Aguirre**, Josue Leyva	9:12 AM	11:18 AM	77.8	83.2	0%	0%	4.0	3.8	68	6	0	0	0	0	0
11	7/10/23	**Samantha Medellin**, **Rodney Aguirre**, Jaden Drake	9:40 AM	11:28 AM	77.5	85.0	2%	2%	5.0	4.0	74	5	0	0	0	0	0
12	7/11/23	**Jeffrank Solarzano**, **Rodney Aguirre**, Jaden Drake	9:00 AM	10:50 AM	83.4	90.1	0%	0%	2.3	3.1	94	7	0	0	0	0	0
Hatchling / Sub-Adult Surveys																	
1	8/22/23	**Samantha Medellin, Rodney Aguirre**, Josue Leyva	9:30 AM	11:12 AM	77.6	80.4	5%	5%	6.0	2.7	122	3	0	0	0	0	0
2	8/23/23	**Samantha Medellin, Rodney Aguirre,** Josue Leyva	8:52 AM	10:55 AM	79.8	85.7	5%	5%	6.4	2.9	180	3	0	0	0	0	0
3	9/19/23	**Samantha Medellin, Dorothy Tran**, Josue Leyva	10:33 AM	12:17 AM	79.1	83.2	50%	0%	0.8	1.3	163	1	0	0	0	0	0
4	9/25/23	**Jeffrank Solorzano, Dorothy Tran, Rory Miller,** Josue Leyva	10:33 AM	12:02 AM	78.6	86.2	15%	0%	1.3	2.1	185	5	0	0	0	0	0
5	9/29/23	**Jeffrank Solorzano, Dorothy Tran, Rory Miller**	10:59 AM	12:27 AM	80.2	83.5	0%	0%	3.0	3.0	124	7	0	0	0	0	0

California Department of Fish and Wildlife Protocol Survey Requirements:
1) Four consecutive survey days occurred from June 12th through June 15th.
2) No more than eight days occurred within a 30-day period.
3) No more than five survey days occurred within any seven day period.

Protocol-Level Blunt-Nosed Leopard Lizard (*Gambelia sila)* Survey Results Summary Table

Segment 2 - Aera Energy LLC Carbon Frontier Project

Survey Day	Survey Date	BNLL Surveyors (**bold indicates Level II Surveyor**)	Survey Timeframes		Air Temperatures (°F)		Cloud Cover (%)		Wind Speed (mph)		Other Lizard Species			Recorded Blunt-nosed Leopard Lizard (BNLL) (*Gambelia sila)*			
			Start Time	End Time	Start Temp	End Temp	Start Cloud Cover	End Cloud Cover	Start Speed	End Speed	Side-Blotched Lizard (*Uta stansburiana*)	California Whiptail Lizard (*Aspidoscelis tigris munda*)	Blainsville Horned Lizard (*Phrynosoma blainvillii*)	Male	Female	Unknown	Hatchling/Sub-Adult
Adult Surveys																	
1	5/22/23	**Karla Lopez, Dorothy Tran, Rory Miller, Rodney Aguirre**	9:10 AM	11:18 AM	80.1	90.2	5%	5%	1.8	2.2	36	21	0	0	0	0	0
2	5/23/23	**Karla Lopez, Jeffrank Solorzano, Rory Miller, Rodney Aguirre**	8:20 AM	11:11 AM	83.3	88.1	5%	5%	1.6	2.7	81	42	0	0	0	0	0
3	5/24/23	**Dorothy Tran, Karla Lopez, Rory Miller, Rodney Aguirre**	10:30 AM	12:58 PM	77.2	87.2	5%	5%	2.8	3.8	46	21	0	0	0	0	0
4	5/25/23	**Karla Lopez, Rory Miller, Rodney Aguirre**, Jaden Drake	10:56 AM	12:55 PM	77.9	86.5	5%	5%	2.7	3.3	40	10	0	0	0	0	0
5	6/8/23	**Jeffrank Solorzano, Karla Lopez**, Josue Leyva	10:05 AM	12:25 PM	78.1	85.9	20%	35%	2.9	6.4	64	33	0	0	0	0	0
6	6/9/23	**Sam Medellin, Dorothy Tran**, Josue Leyva	9:51 AM	12:23 PM	77.8	85.3	2%	2%	2.7	3.9	39	26	0	0	0	0	0
7	6/10/23	**Jeffrank Solorzano, Karla Lopez**, Josue Leyva	9:40 AM	11:23 AM	77.4	87.1	75%	40%	1.9	2.3	83	25	0	0	0	0	0
8	6/16/23	**Dorothy Tran, Karla Lopez**, Josue Leyva	8:49 AM	10:55 AM	81.5	89.1	1%	1%	2.3	3.3	60	32	0	0	0	0	0
9	6/26/23	**Dorothy Tran, Rory Miller**, Josue Leyva	9:03 AM	10:59 AM	79.0	85.9	0%	1%	1.5	1.4	44	30	0	0	0	0	0
10	7/6/23	**Jeffrank Solorzano, Karla Lopez**, Jaden Drake	9:40 AM	11:25 AM	81.7	88.4	0%	0%	3.2	1.7	40	29	0	0	0	0	0
11	7/7/23	**Jeffrank Solorzano, Dorothy Tran**, Jaden Drake	9:45 AM	11:35 AM	81.6	88.7	0%	0%	3.1	2.3	40	18	0	0	0	0	0
12	7/8/23	**Jeffrank Solorzano, Karla Lopez, Sam Medellin**	10:10 AM	11:45 AM	82.0	87.8	0%	0%	1.6	3.1	39	16	0	0	0	0	0
Hatchling / Sub-Adult Surveys																	
13	8/15/23	**Jeffrank Solorzano,** Jaden Drake, Josue Leyva	8:00 AM	9:45 AM	85.1	94.1	5%	5%	2.1	3.7	75	11	0	0	0	0	0
14	8/16/23	**Jeffrank Solorzano,** Jaden Drake, Josue Leyva	8:00 AM	9:45 AM	87.1	94.9	30%	40%	1.2	1.7	102	11	0	0	0	0	0
15	9/13/23	**Jeffrank Solorzano, Rory Miller**, Josue Leyva	8:47 AM	10:35 AM	78.0	85.1	1%	1%	3.0	3.3	151	13	0	0	0	0	0
16	9/21/23	**Dorothy Tran, Samantha Medellin**, Josue Leyva	9:58 AM	11:46 AM	78.7	84.2	0%	15%	4.0	2.7	174	13	0	0	0	0	0
17	9/27/23	**Jeffrank Solorzano, Dorothy Tran, Rory Miller,** Josue Leyva	10:15 AM	11:50 AM	77.0	81.4	5%	5%	2.3	2.7	204	14	0	0	0	0	0

California Department of Fish and Wildlife Protocol Survey Requirements:
1) Four consecutive survey days occurred from May 22th through May 25th..
2) No more than eight days occurred within a 30-day period.
3) No more than five survey days occurred within any seven day period.

Protocol-Level Blunt-Nosed Leopard Lizard (*Gambelia sila)* Survey Results Summary Table

Segment 3 - Aera Energy LLC Carbon Frontier Project

Survey Day	Survey Date	BNLL Surveyors (**bold indicates Level II Surveyor**)	Survey Timeframes		Air Temperatures (˚F)		Cloud Cover (%)		Wind Speed (mph)		Other Lizard Species			Recorded Blunt-nosed Leopard Lizard (BNLL) (*Gambelia sila)*			
			Start Time	End Time	Start Temp	End Temp	Start Cloud Cover	End Cloud Cover	Start Speed	End Speed	Side-Blotched Lizard (*Uta stansburiana*)	California Whiptail Lizard (*Aspidoscelis tigris munda*)	Blainsville Horned Lizard (*Phrynosoma blainvillii*)	Male	Female	Unknown	Hatchling/Sub-Adult
Adult Surveys																	
1	5/17/23	**Samantha Medellin**, **Karla Lopez**, **Rory Miller**, **Paul Rosebush**	8:45 AM	11:55 AM	80.2	94.7	2%	2%	3.7	5.2	84	57	0	0	0	0	0
2	5/19/23	**Karla Lopez**, **Rodney Aguirre**, **Rory Miller**, **Samantha Medellin**	8:20 AM	11:40 AM	81.1	91.4	2%	2%	3.7	3.0	111	46	0	0	0	0	0
3	6/12/23	**Paul Rosebush**, **Rory Miller**, **Rodney Aguirre**, Jaden Drake	9:45 AM	12:24 PM	77.9	86.5	0%	0%	2.9	3.4	102	56	0	0	0	0	0
4	6/13/23	**Jeffrank Solorzano**, **Paul Rosebush**, **Rodney Aguirre**, Jaden Drake	8:40 AM	11:15 AM	78.4	86.8	0%	10%	2.4	1.9	170	111	0	0	0	0	0
5	6/14/23	**Samantha Medellin**, **Rodney Aguirre**, **Paul Rosebush**, Jaden Drake	8:24 AM	11:17 AM	78.9	90.2	2%	2%	4.3	4.3	129	81	0	0	0	0	0
6	6/15/23	**Jeffrank Solorzano**, **Paul Rosebush**, **Rodney Aguirre**, Jaden Drake	9:05 AM	11:25 AM	78.6	87.0	0%	0%	3.9	4.3	99	55	0	0	0	1	0
7	6/23/23	**Samantha Medellin**, **Karla Lopez**, **Rodney Aguirre**	9:31 AM	12:24 PM	79.9	80.1	2%	2%	1.6	2.7	95	70	0	0	0	0	0
8	6/26/23	**Samantha Medellin**, **Rodney Aguirre**, Jaden Drake	8:45 AM	11:20 AM	77.1	80.7	2%	2%	3.0	4.1	82	59	0	0	0	0	0
9	6/30/23	**Jeffrank Solorzano**, **Dorothy Tran**, Jaden Drake	8:00 AM	10:05 AM	85.6	94.1	0%	0%	2.7	5.7	82	64	0	2	0	0	0
10	7/5/23	**Paul Rosebush**, **Rodney Aguirre**, Josue Leyva	8:17 AM	11:10 AM	80.1	88.9	0%	0%	1.6	3.8	113	48	0	0	0	0	0
11	7/6/23	**Paul Rosebush**, **Rodney Aguirre**, Josue Leyva	9:49 AM	12:17 PM	81.8	92.8	0%	0%	3.6	3.7	92	35	0	0	0	0	0
12	7/7/23	**Paul Rosebush**, **Rodney Aguirre**, Josue Leyva	9:31 AM	12:10 PM	78.9	86.7	0%	0%	4.8	6.2	65	37	0	0	0	0	0
Hatchling / Sub-Adult Surveys																	
13	8/23/23	**Karla Lopez, Rory Miller,** Jaden Drake	8:30 AM	10:47 AM	81.1	88.8	1%	1%	2.8	4.9	319	59	0	0	0	0	0
14	8/25/23	**Karla Lopez, Rory Miller,** Jaden Drake	8:30 AM	10:20 AM	77.3	87.7	1%	1%	2.1	3.8	332	49	0	0	0	0	0
15	9/14/23	**Jeffrank Solorzano, Rory Miller,** Josue Leyva	8:55 AM	11:05 AM	78.9	88.1	1%	1%	2.0	2.3	251	31	0	0	0	0	0
16	9/20/23	**Dorothy Tran, Rory Miller,** Josue Leyva	8:53 AM	11:36 AM	78.7	86.4	0%	1%%	0.8	1.3	323	38	0	1	0	0	1
17	9/28/23	**Dorothy Tran, Jeffrank Solorzano,** Josue Leyva	10:35 AM	12:35 PM	78.5	85.6	0%	0%	0.8	0.0	263	31	0	0	0	0	0

California Department of Fish and Wildlife Protocol Survey Requirements:
1) Four consecutive survey days occurred from June 12th through June 15th.
2) No more than eight days occurred within a 30-day period.
3) No more than five survey days occurred within any seven day period.

Protocol-Level Blunt-Nosed Leopard Lizard (*Gambelia sila*) Survey Results Summary Table

Segment 4 - Aera Energy LLC Carbon Frontier Project

Survey Day	Survey Date	BNLL Surveyors (**bold indicates Level II Surveyor**)	Survey Timeframes		Air Temperatures (˚F)		Cloud Cover (%)		Wind Speed (mph)		Other Lizard Species			Recorded Blunt-nosed Leopard Lizard (BNLL) (*Gambelia sila*)			
			Start Time	End Time	Start Temp	End Temp	Start Cloud Cover	End Cloud Cover	Start Speed	End Speed	Side-Blotched Lizard (*Uta stansburiana*)	California Whiptail Lizard (*Aspidoscelis tigris munda*)	Blainsville Horned Lizard (*Phrynosoma blainvillii*)	Male	Female	Unknown	Hatchling/Sub-Adult
Adult Surveys																	
1	6/8/23	**Paul Rosebush**, **Rory Miller**, **Rodney Aguirre**, Jaden Drake	9:32 AM	12:53 PM	78.5	84.5	5%	15%	3.2	1.8	104	63	0	0	0	0	0
2	6/9/23	**Paul Rosebush**, **Rodney Aguirre**, **Jaden Drake**	9:27 AM	12:33 PM	77.7	89.6	0%	10%	1.2	2.1	114	58	0	0	1	0	0
3	6/10/23	**Paul Rosebush**, **Rodney Aguirre**, **Sam Medellin**, Jaden Drake	9:27 AM	12:55 PM	80.6	87.7	60%	10%	3.4	4.0	135	114	0	0	0	0	0
4	6/11/23	**Paul Rosebush**, **Rodney Aguirre**, **Dorothy Tran**, Jaden Drake	9:00 AM	11:40 AM	77.2	86.3	5%	5%	8.6	4.0	96	45	0	0	0	0	0
5	6/16/23	**Paul Rosebush**, **Rory Miller**, **Rodney Aguirre**, Jaden Drake	8:32 AM	11:25 AM	82.2	89.5	5%	0%	1.5	3.5	96	56	0	0	0	0	0
6	6/23/23	**Paul Rosebush**, **Jeffrank Solorzano**, Jaden Drake, Josue Leyva	10:00 AM	12:40 PM	77.4	82.9	0%	0%	5.6	6.1	142	131	0	0	0	0	0
7	6/29/23	**Paul Rosebush**, **Rory Miller**, **Sam Medellin**, Josue Leyva	8:45 AM	11:30 AM	81.9	95.3	2%	2%	3.9	4.8	105	72	0	0	0	0	0
8	7/5/23	**Jeffrank Solorzano**, **Dorothy Tran**, **Rory Miller**, Jaden Drake	8:00 AM	10:45 AM	77.5	90.6	0%	0%	1.3	2.7	156	105	0	0	0	0	0
9	7/10/23	**Paul Rosebush**, **Rory Miller**, Josue Leyva	9:00 AM	11:30 AM	77.5	88.7	1%	0%	3.2	3.6	94	40	0	0	0	0	0
10	7/11/23	**Paul Rosebush**, **Rory Miller**, Josue Leyva	9:01 AM	11:45 AM	79.6	93.8	0%	0%	2.2	6.0	83	36	0	0	0	0	0
11	7/12/23	**Rodney Aguirre**, **Rory Miller**, Jaden Drake	8:45 AM	11:04 AM	89.0	98.0	1%	1%	1.7	1.6	88	60	0	0	0	0	0
12	7/13/23	**Rodney Aguirre**, Jaden Drake, Josue Leyva	8:45 AM	12:30 PM	89.4	95.8	5%	3%	3.4	2.0	89	63	0	0	0	0	0
Hatchling / Sub-Adult Surveys																	
13	8/24/23	**Samantha Medellin**, **Rodnery Aguirre**, Jaden Drake, Josue Leyva	8:30 AM	10:40 AM	83.9	93.7	2%	10%	1.0	4.7	242	72	0	0	0	0	0
14	8/25/23	**Samantha Medellin**, **Rodney Aguirre**, Josue Leyva	8:25 AM	10:46 AM	77.0	90.2	2%	2%	0.2	2.0	194	24	0	0	0	0	0
15	9/15/23	**Dorothy Tran**, **Rory Miller**, Josue Leyva	8:46 AM	11:65 AM	81.4	91.2	1%	0%	2.1	1.9	321	65	0	0	0	0	0
16	9/18/23	**Samantha Medellin**, **Rory Miller**, **Dorothy Tran**, Josue Leyva	10:46 AM	1:42 PM	81.2	91.2	20%	2%	4.0	3.0	362	59	0	0	0	0	0
17	9/26/23	**Jeffrank Solorzano**, **Dorothy Tran**, Josue Leyva	10:30 AM	1:20 AM	77.5	83.4	5%	5%	2.9	4.7	306	45	0	0	0	0	0

California Department of Fish and Wildlife Protocol Survey Requirements:
1) Four consecutive survey days occurred from July 10th through July 13th.
2) No more than eight days occurred within a 30-day period.
3) No more than five survey days occurred within any seven day period.

Attachment D: California Natural Diversity Database Reporting Forms

CNDDB Online Field Survey Form Report

California Natural Diversity Database
Department of Fish and Wildlife
1416 9th Street, Suite 1266
Sacramento, CA 95814
Fax: 916.324.0475
cnddb@wildlife.ca.gov
www.dfg.ca.gov/biogeodata/cnddb/

This data has been reported to the CNDDB, but may not have been evaluated by the CNDDB staff

Source code ROS23F0001
Quad code 3511957
Occ. no.
EO index no.
Map index no.

Scientific name: *Gambelia sila*

Common name: blunt-nosed leopard lizard

Date of field work (mm-dd-yyyy): 09-29-2023

Comment about field work date(s): Began May 15th 2023 ending Sept 29th 2023

OBSERVER INFORMATION

Observer: Paul D. Rosebush

Affiliation: MESA Biological LLC on behalf of Aera Energy LLC

Address: 8847 Hickory Hills Ave , Bakersfield, CA 93312

Email: paul@mesabio.com

Phone: (661) 203-2409

Other observers: Jeffrank Solorzano, Dorothy Tran, Rory Miller

DETERMINATION

Keyed in:

Compared w/ specimen at:

Compared w/ image in:

By another person: Paul Rosebush, Jeffrank Solorzano, Rory Miller, Dorothy Tran

Other:

Identification explanation: A total of six individuals were observed by 4 surveyors during transects surveys. Surveyors were able to photograph 4 of 6 individuals.

Identification confidence: Very confident

Species found: Yes **If not found, why not?**

Level of survey effort: Protocol level blunt-nosed leopard lizard walking transect surveys.

Total number of individuals: 6

Collection? No **Collection number:**

Museum/Herbarium:

ANIMAL INFORMATION

How was the detection made? Seen

Number detected in each age class:

adults	juveniles	larvae	egg mass	unknown
5	1			

Age class comment: 5 adult individuals and 1 juvenile observed

Site use description: Very low density of oil field infrastructure. Some evidence of historical sheep grazing.

What was the observed behavior? All six individuals were observed along the edges of a dirt access road. Normal foraging behavior was noted.

Describe any evidence of reproduction: One of the six individuals was a hatchling. One female was observed with distinct breeding colors.

SITE INFORMATION

Habitat description: Generalized habitat is Allscale scrub surrounding light oil field infrastructure.

Slope: Less than 5% slope.

Aspect:

Land owner/manager: Property is owned by an oil production company.

Site condition + population viability: Good

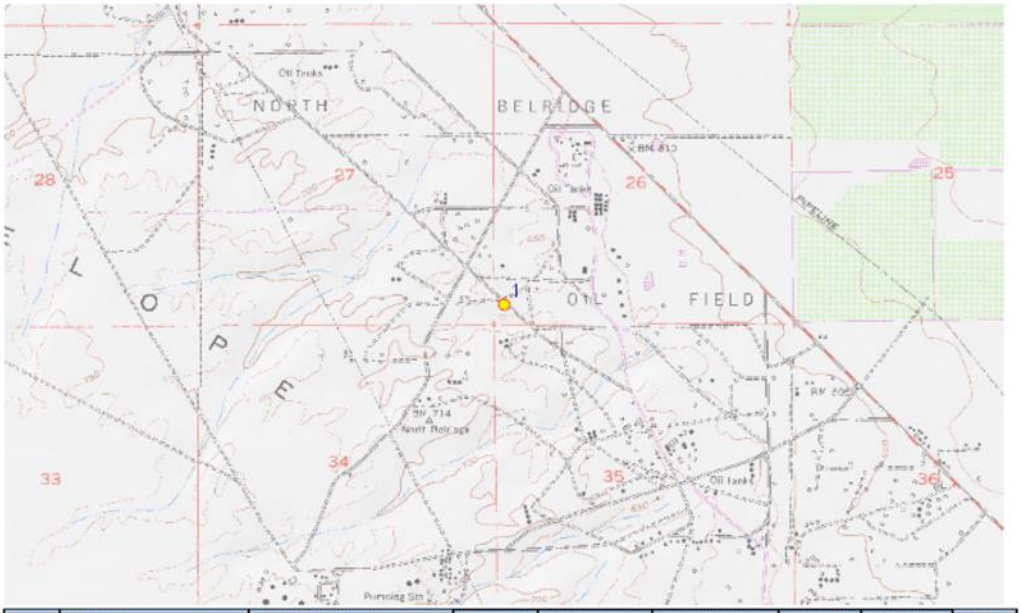
Immediate & surrounding land use: Primary use is oil extraction, some evidence of sheep grazing was noted. Lands to the east of the existing oil field are comprised of active agriculture. Lands to the west of the existing oil field are comprised of grazed grasslands.

Visible disturbances: Evidence of light oil infrastructure in the form of oil wells, access roads, pipelines and electrical infrastructure. Some evidence of historical sheep grazing was identified.

Threats: Oil production.

General comments:

MAP INFORMATION



ID	County	24K Quadrangle	Elev. (ft)	Latitude NAD83	Longitude NAD83	UTM E NAD83	UTM N NAD83	UTM Zone
	Kern	Blackwells Corner	662	35.54354	-119.79614	246513	3936920	11

ID	Public Land Survey	Feature Comment
1	M T27S R20E 26	6 individuals found within a 1,200ft radius

The mapped feature is accurate within: 500 m

Source of mapped feature: CNDDB online field survey tool

Mapping notes:

Location/directions comments: Approximately 1 mile to the west of State Highway 33 with North Belridge oil field.

CNDDB Online Field Survey Form Report

California Natural Diversity Database
Department of Fish and Wildlife
1416 9th Street, Suite 1266
Sacramento, CA 95814
Fax: 916.324.0475
cnddb@wildlife.ca.gov
www.dfg.ca.gov/biogeodata/cnddb/

This data has been reported to the CNDDB, but may not have been evaluated by the CNDDB staff

Source code ROS23F0004
Quad code 3511957
Occ. no.
EO index no.
Map index no.

Scientific name: *Eremophila alpestris actia*

Common name: California horned lark

Date of field work (mm-dd-yyyy): 09-29-2023

Comment about field work date(s): ~8 incidental observations of California horned lark during protocol level BNLL surveys

OBSERVER INFORMATION

Observer: Paul D. Rosebush

Affiliation: MESA Biological LLC

Address: 8847 Hickory Hills Ave , Bakersfield, CA 93312

Email: paul@mesabio.com

Phone: (661) 203-2409

Other observers: Karla Lopez, Jeffrank Solorzano, Dorothy Tran, Rodney Aguirre, Rory Miller, Samantha Medellin

DETERMINATION

Keyed in:

Compared w/ specimen at:

Compared w/ image in:

By another person:

Other: Physical identification of approx. 8 California horned larks made during protocol level BNLL surveys.

Identification explanation: ~8 positive observations of California horned lark

Identification confidence: Very confident

Species found: Yes **If not found, why not?**

Level of survey effort: Incidental observations of California horned larks made during protocol level survey for blunt-nosed leopard lizard.

Total number of individuals: ~8

Collection? No **Collection number:**

Museum/Herbarium:

ANIMAL INFORMATION

How was the detection made? Seen

Number detected in each age class:

adults	juveniles	larvae	egg mass	unknown
8				

Age class comment:

Bird site use:

☐ Nesting ☐ Rookery ☐ Nesting colony ☐ Burrow site ☐ Lek

☐ Non-breeding (over-wintering) ☐ Communal roost ☑ Other

Site use description: possible nesting habitat. No nests or nesting behaviors displayed.

What was the observed behavior? routine foraging

Describe any evidence of reproduction: None

SITE INFORMATION

Habitat description: Generalized habitat: Allscale scrub mixed with pockets of oil producing infrastructure.

Slope: less than 5% Land owner/manager: Oil production company

Aspect:

Site condition + population viability: Good

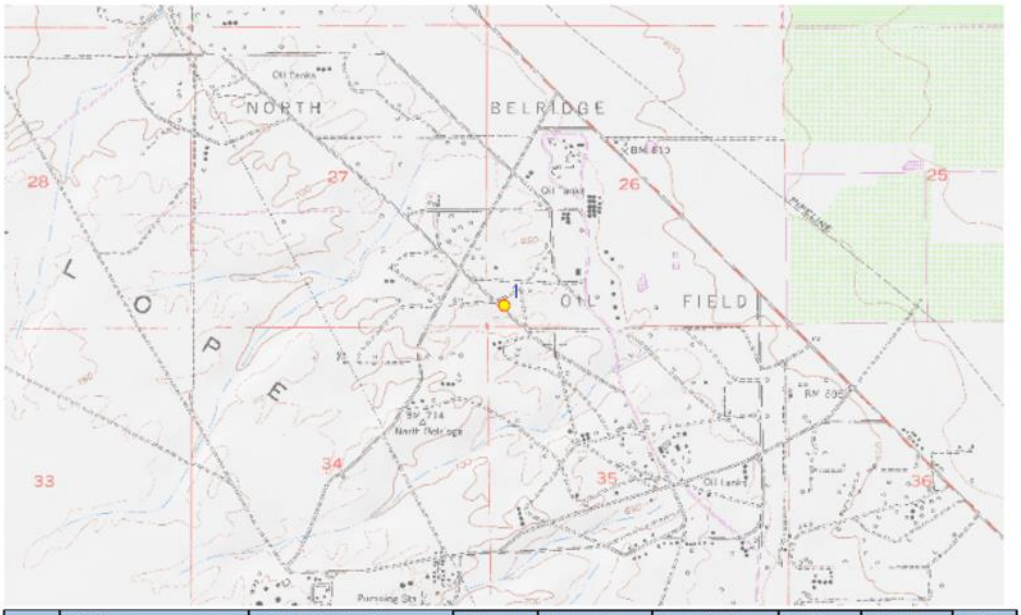
Immediate & surrounding land use: Immediate land use is oil production surrounded by active agriculture to the east and open grazed grasslands to the north and west. High density oil infrastructure occurs to the south.

Visible disturbances: Some disturbances from oil production have occurred

Threats: Oil production

General comments:

MAP INFORMATION



ID	County	24K Quadrangle	Elev. (ft)	Latitude NAD83	Longitude NAD83	UTM E NAD83	UTM N NAD83	UTM Zone
	Kern	Blackwells Corner	659	35.54359	-119.79573	246550	3936925	11
	Public Land Survey	**Feature Comment**						
1	M T27S R20E 26	~8 observations made during protocol BNLL						

The mapped feature is accurate within: 100 m

Source of mapped feature: CNDDB Online Field Tool

Mapping notes: The point supplied represents a center point for 8 individuals. See attachment for pipeline routing.

Location/directions comments: Survey area was located approximately 1 mile west of State Highway 33.

Attachment(s): PIPELINE ROUTING.kmz

CNDDB Online Field Survey Form Report

California Natural Diversity Database
Department of Fish and Wildlife
1416 9th Street, Suite 1266
Sacramento, CA 95814
Fax: 916.324.0475
cnddb@wildlife.ca.gov
www.dfg.ca.gov/biogeodata/cnddb/

This data has been reported to the CNDDB, but may not have been evaluated by the CNDDB staff

Source code ROS23F0003
Quad code 3511957
Occ. no.
EO index no.
Map index no.

Scientific name: *Lanius ludovicianus*

Common name: loggerhead shrike

Date of field work (mm-dd-yyyy): 09-29-2023

Comment about field work date(s): May 15th to September 29th, 2023

OBSERVER INFORMATION

Observer: Paul D. Rosebush

Affiliation: MESA Biological LLC

Address: 8847 Hickory Hills Ave , Bakersfield, CA 93312

Email: paul@mesabio.com

Phone: (661) 203-2409

Other observers: Jeffrank Solorzano, Dorothy Tran, Karla Lopez, Samantha Medellin, Rodney Aguirre, Rory Miller

DETERMINATION

Keyed in:

Compared w/ specimen at:

Compared w/ image in:

By another person: Paul Rosebush, Jeffrank Solorzano, Samantha Medellin, Dorothy Tran, Rodney Aguirre, Karla Lopez

Other: Physical identification of over 35 incidental observations of loggerhead shrike made during protocol level BNLL surveys.

Identification explanation: Over 35 individual observations of loggerhead shrike made during protocol level blunt-nosed leopard lizard surveys.

Identification confidence: Very confident

Species found: Yes **If not found, why not?**

Level of survey effort: Incidental observations of loggerhead shrike made during protocol level blunt-nosed leopard lizard surveys.

Total number of individuals: 35 observations

Collection? No **Collection number:**

Museum/Herbarium:

ANIMAL INFORMATION

How was the detection made? Seen

Number detected in each age class:

adults	juveniles	larvae	egg mass	unknown
35				

Age class comment: all adults observed

Bird site use:

☑ Nesting ☐ Rookery ☐ Nesting colony ☐ Burrow site ☐ Lek

☐ Non-breeding (over-wintering) ☐ Communal roost ☐ Other

Site use description: Multiple loggerhead shrikes were observed perched on power lines and on other oil production infrastructure.

What was the observed behavior? Mostly foraging, some displayed nesting behaviors.

Describe any evidence of reproduction: Some nesting behavior was noted.

SITE INFORMATION

Habitat description: Generalized habitat: Allscale scrub mixed with pockets of oil producing infrastructure

Slope: les than 5% Land owner/manager: Oil production company

Aspect:

Site condition + population viability: Good

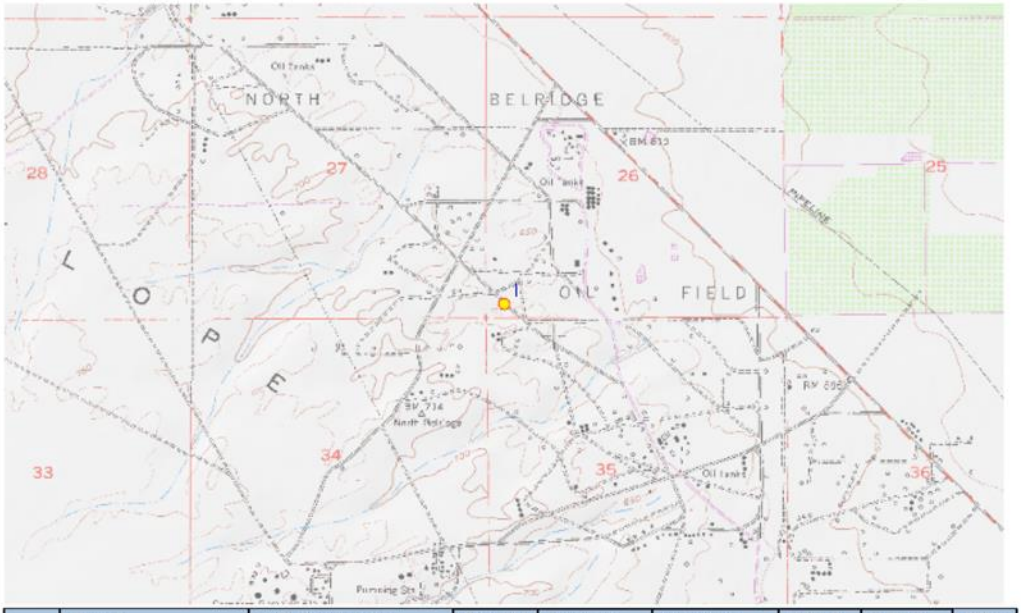
Immediate & surrounding land use: Immediate land use is oil production surrounded by active agriculture to the east and open grazed grasslands to the north and west. High density oil infrastructure occurs to the south.

Visible disturbances: Some disturbances from oil production have occurred

Threats: Oil production

General comments:

MAP INFORMATION



ID	County	24K Quadrangle	Elev. (ft)	Latitude NAD83	Longitude NAD83	UTM E NAD83	UTM N NAD83	UTM Zone
	Kern	Blackwells Corner	655	35.54324	-119.79567	246555	3936886	11
1	**Public Land Survey**	**Feature Comment**						
	M T27S R20E 26	over 35 observations during BNLL surveys						

The mapped feature is accurate within: 100 m

Source of mapped feature: CNDDB Online Field Tool

Mapping notes: The point supplied represents a center point for over 35 individuals. See attachment for pipeline routing.

Location/directions comments: Survey area was located approximately 1 mile west of State Highway 33.

Attachment(s): PIPELINE ROUTING.kmz

CNDDB Online Field Survey Form Report

California Natural Diversity Database
Department of Fish and Wildlife
1416 9th Street, Suite 1266
Sacramento, CA 95814
Fax: 916.324.0475
cnddb@wildlife.ca.gov
www.dfg.ca.gov/biogeodata/cnddb/

This data has been reported to the CNDDB, but may not have been evaluated by the CNDDB staff

Source code ROS23F0002
Quad code 3511957
Occ. no.
EO index no.
Map index no.

Scientific name: *Ammospermophilus nelsoni*

Common name: Nelson's (=San Joaquin) antelope squirrel

Date of field work (mm-dd-yyyy): 09-29-2023

Comment about field work date(s): May 15th to September 29th

OBSERVER INFORMATION

Observer: Paul D. Rosebush

Affiliation: MESA Biological LLC

Address: 8847 Hickory Hills Ave , Bakersfield, CA 93312

Email: paul@mesabio.com

Phone: (661) 203-2409

Other observers: Karla Lopez, Jeffrank Solorzano, Dorothy Tran, Rodney Aguirre, Rory Miller

DETERMINATION

Keyed in:

Compared w/ specimen at:

Compared w/ image in:

By another person: Paul Rosebush, Jeffrank Solorzano, Dorothy Tran, Karla Lopez, Rodney Aguirre, Rory Miller

Other: Physical identification of over 40 incidental observations of San Joaquin antelope squirrel made during protocol level BNLL surveys

Identification explanation: Over 40 positive observations of San Joaquin antelope squirrel.

Identification confidence: Very confident

Species found: Yes **If not found, why not?**

Level of survey effort: Incidental observations of San Joaquin antelope squirrel made during protocol level survey for blunt-nosed leopard lizard.

Total number of individuals: Over 40 individuals

Collection? No **Collection number:**

Museum/Herbarium:

ANIMAL INFORMATION

How was the detection made? Seen

Number detected in each age class:

adults	juveniles	larvae	egg mass	unknown
~40				

Age class comment:

Site use description: Survey areas was within an active oil field producing field.

What was the observed behavior? The majority of individuals were observed to be foraging on the existing dirt roadways that parallels this planned pipeline.

Describe any evidence of reproduction: None

SITE INFORMATION

Habitat description: Generalized habitat: Allscale scrub mixed with pockets of oil producing infrastructure.

Slope: Less that 5% Land owner/manager: Oil production company

Aspect:

Site condition + population viability: Good

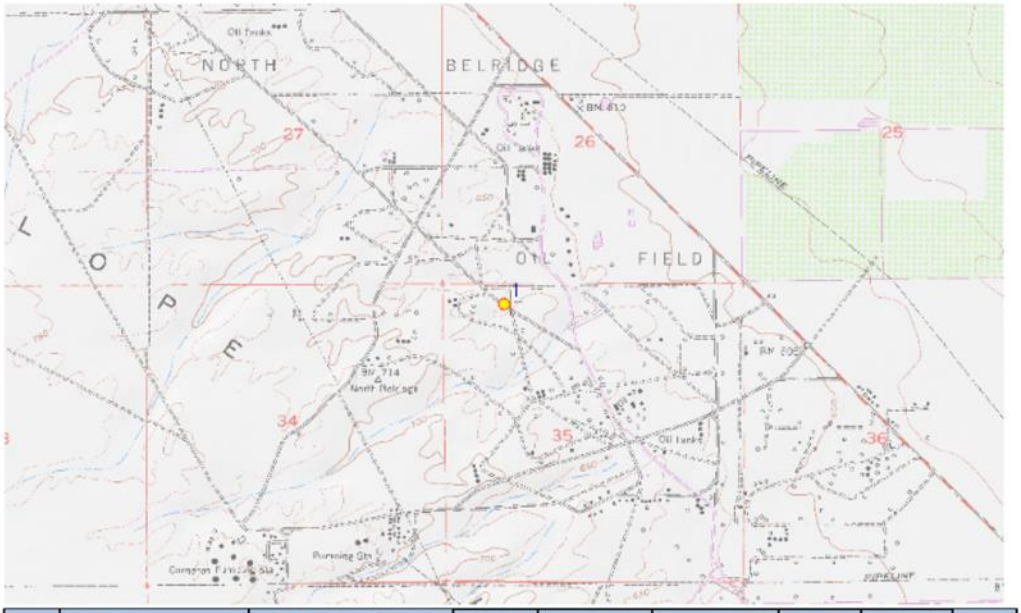
Immediate & surrounding land use: Immediate land use is oil production surrounded by active agriculture to the east and open grazed grasslands to the north and west. High density oil infrastructure occurs to the south.

Visible disturbances: Some disturbances from oil production have occurred.

Threats: Oil production

General comments:

MAP INFORMATION



ID	County	24K Quadrangle	Elev. (ft)	Latitude NAD83	Longitude NAD83	UTM E NAD83	UTM N NAD83	UTM Zone
	Kern	Blackwells Corner	653	35.54156	-119.79305	246787	3936693	11
1	**Public Land Survey**	**Feature Comment**						
	M T27S R20E 35							

The mapped feature is accurate within: 100 m

Source of mapped feature: CNDDB Online Field Tool

Mapping notes: The point supplied represents a center point for over 40 individuals. See attachment for pipeline routing.

Location/directions comments: Survey area was located approximately 1 mile west of State Highway 33.

Attachment(s): PIPELINE ROUTING.kmz, Over 40 individual observations observed within 250ft of the attached pipeline routing.

CNDDB Online Field Survey Form Report

California Natural Diversity Database
Department of Fish and Wildlife
1416 9th Street, Suite 1266
Sacramento, CA 95814
Fax: 916.324.0475
cnddb@wildlife.ca.gov
www.dfg.ca.gov/biogeodata/cnddb/

This data has been reported to the CNDDB, but may not have been evaluated by the CNDDB staff

Source code ROS23F0005
Quad code 3511957
Occ. no.
EO index no.
Map index no.

Scientific name: *Masticophis flagellum ruddocki*

Common name: San Joaquin coachwhip

Date of field work (mm-dd-yyyy): 09-29-2023

Comment about field work date(s): 3 individuals over the project area were incidentally observed during protocol level BNLL surveys.

OBSERVER INFORMATION

Observer: Paul D. Rosebush

Affiliation: MESA Biological LLC

Address: 8847 Hickory Hills Ave , Bakersfield, CA 93312

Email: paul@mesabio.com

Phone: (661) 203-2409

Other observers:

DETERMINATION

Keyed in:

Compared w/ specimen at:

Compared w/ image in:

By another person:

Other: 3 incidental observations of San Joaquin antelope squirrel made during protocol level BNLL surveys

Identification explanation: visual observations during focused BNLL surveys.

Identification confidence: Very confident

Species found: Yes **If not found, why not?**

Level of survey effort: Incidental observations of San Joaquin coachwhip made during protocol level survey for blunt-nosed leopard lizard.

Total number of individuals: 3

Collection? No **Collection number:**

Museum/Herbarium:

ANIMAL INFORMATION

How was the detection made? Seen

Number detected in each age class:

adults	juveniles	larvae	egg mass	unknown
3				

Age class comment: unknown

Submitted: 10/09/2023 ROS23F0005 Page 1 of 2

Site use description:

What was the observed behavior? routine behavior

Describe any evidence of reproduction: N/A

SITE INFORMATION

Habitat description: Generalized habitat: Allscale scrub mixed with pockets of oil producing infrastructure.

Slope: less than 5% Land owner/manager: oil production company

Aspect:

Site condition + population viability: Good

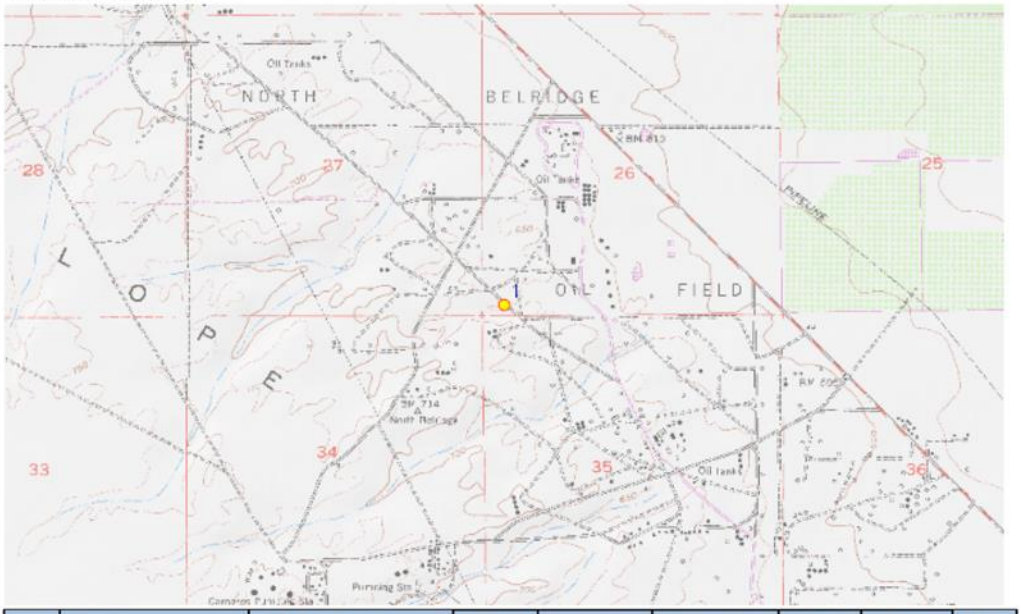
Immediate & surrounding land use: Immediate land use is oil production surrounded by active agriculture to the east and open grazed grasslands to the north and west. High density oil infrastructure occurs to the south.

Visible disturbances: Some disturbances from oil production have occurred.

Threats: Oil production

General comments:

MAP INFORMATION



ID	County	24K Quadrangle	Elev. (ft)	Latitude NAD83	Longitude NAD83	UTM E NAD83	UTM N NAD83	UTM Zone
	Kern	Blackwells Corner	652	35.54305	-119.79544	246575	3936864	11
	Public Land Survey	**Feature Comment**						
1	M T27S R20E 26	3 individual observations throughout project						

The mapped feature is accurate within: 100 m

Source of mapped feature: CNDDB Online Field Tool

Mapping notes: The point supplied represents a center point for 3 individuals. See attachment for pipeline routing covered.

Location/directions comments: Survey area was located approximately 1 mile west of State Highway 33.

Attachment(s): PIPELINE ROUTING.kmz

Submitted: 10/09/2023 ROS23F0005 Page 2 of 2

Appendix C PHOTO DOCUMENTATION

Client:	**Aera Energy LLC**	**Project: Carbon Frontier Project**
Site Location:	**Belridge Oil Fields, Kern County, California**	

Photograph ID: 1 **Photo Location:** North Belridge Oil Field 35.56°W; 119.81°N **Direction:** Southwest **Survey Date:** 6/7/2023 **Comments:** View of Allscale Scrub and interspersed Red Brome/Mediterranean Grass grassland habitat in North Belridge Oil Field.	
Photograph ID: 2 **Photo Location:** North Belridge Oil Field 35.55°W; 119.81°N **Direction:** Southeast **Survey Date:** 6/7/2023 **Comments:** View of access road near proposed monitoring well site and adjacent Allscale Scrub habitat.	

Client:	**Aera Energy LLC**	**Project: Carbon Frontier Project**
Site Location:	**Belridge Oil Fields, Kern County, California**	

Photograph ID: 3 **Photo Location:** North Belridge Oil Field 35.55°W; 119.80°N **Direction:** Southeast **Survey Date:** 5/26/2023 **Comments:** View near proposed monitoring well site in north Belridge Oil Field.	
Photograph ID: 4 **Photo Location:** North Belridge Oil Field 35.55°W; 119.80°N **Direction:** Northeast **Survey Date:** 5/26/2023 **Comments:** View of Allscale Scrub and weedy species in North Belridge Oil Field.	

Client:	**Aera Energy LLC**	**Project: Carbon Frontier Project**
Site Location:	**Belridge Oil Fields, Kern County, California**	

Photograph ID: 5 **Photo Location:** North Belridge Oil Field 35.55°W; 119.79°N **Direction:** North **Survey Date:** 5/26/2023 **Comments:** View of Red Brome/Mediterranean Grass grassland habitat in North Belridge Oil Field.	
Photograph ID: 6 **Photo Location:** North Belridge Oil Field 35.55°W; 119.79°N **Direction:** East **Survey Date:** 5/26/2023 **Comments:** View of Allscale Scrub mixed with Red Brome and Mediterranean Grass grassland, and disturbed land in North Belridge Oil Field.	

Client:	**Aera Energy LLC**	**Project: Carbon Frontier Project**
Site Location:	**Belridge Oil Fields, Kern County, California**	

Photograph ID: 7 **Photo Location:** North Belridge Oil Field 35.54°W; 119.80°N **Direction:** East **Survey Date:** 6/7/2023 **Comments:** View of proposed CO_2 Pipeline route in North Belridge Oil Field. Note existing pipelines.	
Photograph ID: 8 **Photo Location:** North Belridge Oil Field 35.54°W; 119.79°N **Direction:** Southeast **Survey Date:** 5/26/2023 **Comments:** View of well pad and pipeline along proposed CO_2 Pipeline Route in North Belridge Oil Field.	

Client:	**Aera Energy LLC**	**Project: Carbon Frontier Project**
Site Location:	**Belridge Oil Fields, Kern County, California**	

Photograph ID: 9 **Photo Location:** Central Belridge Oil Field 35.53°W; 119.78°N **Direction:** West **Survey Date:** 5/26/2023 **Comments:** Belridge Oil Field in central portion of Action Area near site of proposed CO_2 Injection Well, with disturbed land and Allscale Scrub Habitat in the foreground.	
Photograph ID: 10 **Photo Location:** Central Belridge Oil Field 35.53°W; 119.78°N **Direction:** South **Survey Date:** 5/26/2023 **Comments:** Belridge Oil Field in central portion of Action Area near site of proposed CO_2 Injection Well, with disturbed land in the foreground and Allscale Scrub Habitat in the background.	

Client:	**Aera Energy LLC**	**Project: Carbon Frontier Project**
Site Location:	**Belridge Oil Fields, Kern County, California**	

Photograph ID: 11 **Photo Location:** Central Belridge Oil Field 35.52°W; 119.78°N **Direction:** East **Survey Date:** 6/7/2023 **Comments:** View of existing pipeline and access road along proposed CO_2 Pipeline Route in central portion of Action Area.	
Photograph ID: 12 **Photo Location:** Central Belridge Oil Field 35.52°W; 119.77°N **Direction:** North **Survey Date:** 6/7/2023 **Comments:** View of existing pipeline and access road along proposed CO_2 Pipeline Route in central portion of Action Area.	

Client:	**Aera Energy LLC**	**Project: Carbon Frontier Project**
Site Location:	**Belridge Oil Fields, Kern County, California**	

Photograph ID: 13 **Photo Location:** Central Belridge Oil Field 35.52°W; 119.76°N **Direction:** South **Survey Date:** 6/7/2023 **Comments:** View of proposed CO_2 Pipeline Route and access road in central portion of Action Area.	
Photograph ID: 14 **Photo Location:** Central Belridge Oil Field 35.52°W; 119.76°N **Direction:** South **Survey Date:** 6/7/2023 **Comments:** View of Allscale Scrub habitat and interspersed non-native mustard in central portion of Action Area.	

Client:	**Aera Energy LLC**	**Project: Carbon Frontier Project**
Site Location:	**Belridge Oil Fields, Kern County, California**	

Photograph ID: 15 **Photo Location:** Central Belridge Oil Field 35.51°W; 119.76°N **Direction:** Southeast **Survey Date:** 6/7/2023 **Comments:** View of proposed CO_2 Pipeline Route and access road in central portion of Action Area.	
Photograph ID: 16 **Photo Location:** Central Belridge Oil Field 35.50°W; 119.75°N **Direction:** South **Survey Date:** 6/7/2023 **Comments:** View of existing pipelines along proposed CO_2 Pipeline Route and access road in central portion of Action Area.	

Client:	**Aera Energy LLC**	**Project: Carbon Frontier Project**
Site Location:	**Belridge Oil Fields, Kern County, California**	

Photograph ID: 17 **Photo Location:** Central Belridge Oil Field 35.50°W; 119.76°N **Direction:** Southeast **Survey Date:** 5/26/2023 **Comments:** View of existing pipelines and oil platforms along proposed Steam Pipeline Route in central portion of Action Area.	
Photograph ID: 18 **Photo Location:** Central Belridge Oil Field 35.50°W; 119.76°N **Direction:** East **Survey Date:** 5/26/2023 **Comments:** View of existing pipelines and oil platforms along Lerdo Highway in central portion of Action Area. Proposed Steam Pipeline Route is adjacent to existing silver pipelines on left	

Client:	**Aera Energy LLC**	**Project: Carbon Frontier Project**
Site Location:	**Belridge Oil Fields, Kern County, California**	

Photograph ID: 19 **Photo Location:** Central Belridge Oil Field 35.49°W; 119.75°N **Direction:** Southeast **Survey Date:** 6/7/2023 **Comments:** View of Poleline Road on right and existing pipelines on left. Proposed Steam Pipeline and CO_2 Pipeline Route is adjacent to existing brown pipelines on left.	
Photograph ID: 20 **Photo Location:** Central Belridge Oil Field 35.49°W; 119.74°N **Direction:** Northeast **Survey Date:** 5/26/2023 **Comments:** View of Allscale Scrub habitat and existing steam pipelines in central portion of Action Area.	

Client:	**Aera Energy LLC**	**Project: Carbon Frontier Project**
Site Location:	**Belridge Oil Fields, Kern County, California**	

Photograph ID: 21 **Photo Location:** South Belridge Oil Field 35.48°W; 119.74°N **Direction:** East **Survey Date:** 5/26/2023 **Comments:** View of existing pipelines and Aera facilities along proposed steam pipeline route in southern portion of Action Area.	
Photograph ID: 22 **Photo Location:** South Belridge Oil Field 35.48°W; 119.74°N **Direction:** South **Survey Date:** 5/26/2023 **Comments:** View of existing pipelines and Aera oil facilities along proposed steam pipeline route in southern portion of Action Area.	

Client:	**Aera Energy LLC**	**Project: Carbon Frontier Project**
Site Location:	**Belridge Oil Fields, Kern County, California**	

Photograph ID: 23 **Photo Location:** South Belridge Oil Field 35.47°W; 119.74°N **Direction:** Southeast **Survey Date:** 5/26/2023 **Comments:** View of existing Aera oil facilities, pipelines, and disturbed habitat along proposed steam pipeline route in southern portion of Action Area.	
Photograph ID: 24 **Photo Location:** South Belridge Oil Field 35.47°W; 119.74°N **Direction:** West **Survey Date:** 5/26/2023 **Comments:** View of existing Aera oil facilities, pipelines, and disturbed habitat facing proposed steam pipeline route in southern portion of Action Area. Note level of disturbance to southern portion of Action Area.	

Client:	**Aera Energy LLC**	**Project: Carbon Frontier Project**
Site Location:	**Belridge Oil Fields, Kern County, California**	

Photograph ID: 25 **Photo Location:** South Belridge Oil Field 35.47°W; 119.73°N **Direction:** West **Survey Date:** 5/26/2023 **Comments:** View of existing Aera oil facilities, pipelines, and disturbed habitat along proposed steam pipeline route in southern portion of Action Area. Note level of disturbance to southern portion of Action Area.	
Photograph ID: 26 **Photo Location:** South Belridge Oil Field 35.44°W; 119.72°N **Direction:** Northeast **Survey Date:** 6/13/2023 **Comments:** View of Chico Martinez Creek in southern portion of Action Area with Aera oil facilities in the background.	

Client:	**Aera Energy LLC**	**Project: Carbon Frontier Project**
Site Location:	**Belridge Oil Fields, Kern County, California**	

Photograph ID: 27 **Photo Location:** North Belridge Oil Field 35.53°W; 119.78°N **Direction:** Toward ground **Survey Date:** 3/7/2023 **Comments:** *Eremalche parryi* individual observed during floristic botanical survey. Only one flowering plant with bisexual (non-pistillate) flowers was observed; characteristics tend to be consistent with the much more common *E. parryi* ssp. *parryi* rather than Kern mallow (*E. parryi* ssp. *kernensis*).	
Photograph ID: 28 **Photo Location:** South Belridge Oil Field 35.49°W; 119.75°N **Direction:** Southeast **Survey Date:** 6/7/2023 **Comments:** View of annual grassland habitat east of Pole Line Road in area that had multiple potential kit fox dens.	

Client:	**Aera Energy LLC**	**Project: Carbon Frontier Project**
Site Location:	**Belridge Oil Fields, Kern County, California**	

Photograph ID: 29 **Photo Location:** South Belridge Oil Field 35.45°W; 119.69°N **Direction:** Toward ground **Survey Date:** 7/20/2022 **Comments:** Uncapped pipe within the BSA that could serve as a potential atypical kit fox den.	
Photograph ID: 30 **Photo Location:** South Belridge Oil Field 35.46°W; 119.71°N **Direction:** Southeast **Survey Date:** 7/20/2022 **Comments:** Potential kit fox den observed and mapped east of Pole Line Road.	

Appendix D AQUATIC RESOURCE DELINEATION REPORT



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3.0□REGULATORY BACKGROUND

3.1□CLEAN WATER ACT SECTION 404

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3.3□CALIFORNIA FISH AND GAME CODE SECTION 1602

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4.0□ METHODS

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4.1□DESKTOP REVIEW

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4.3□JURISDICTIONAL ASSESSMENT

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5.0□ RESULTS AND DISCUSSION

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5.1.2□Remnants of Ephemeral Streams

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5.3□PRELIMINARY JURISDICTIONAL DETERMINATION

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6.0□ SUMMARY AND CONCLUSIONS

6.1□FEDERAL WETLANDS/OTHER WATERS

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6.4□CONCLUSION

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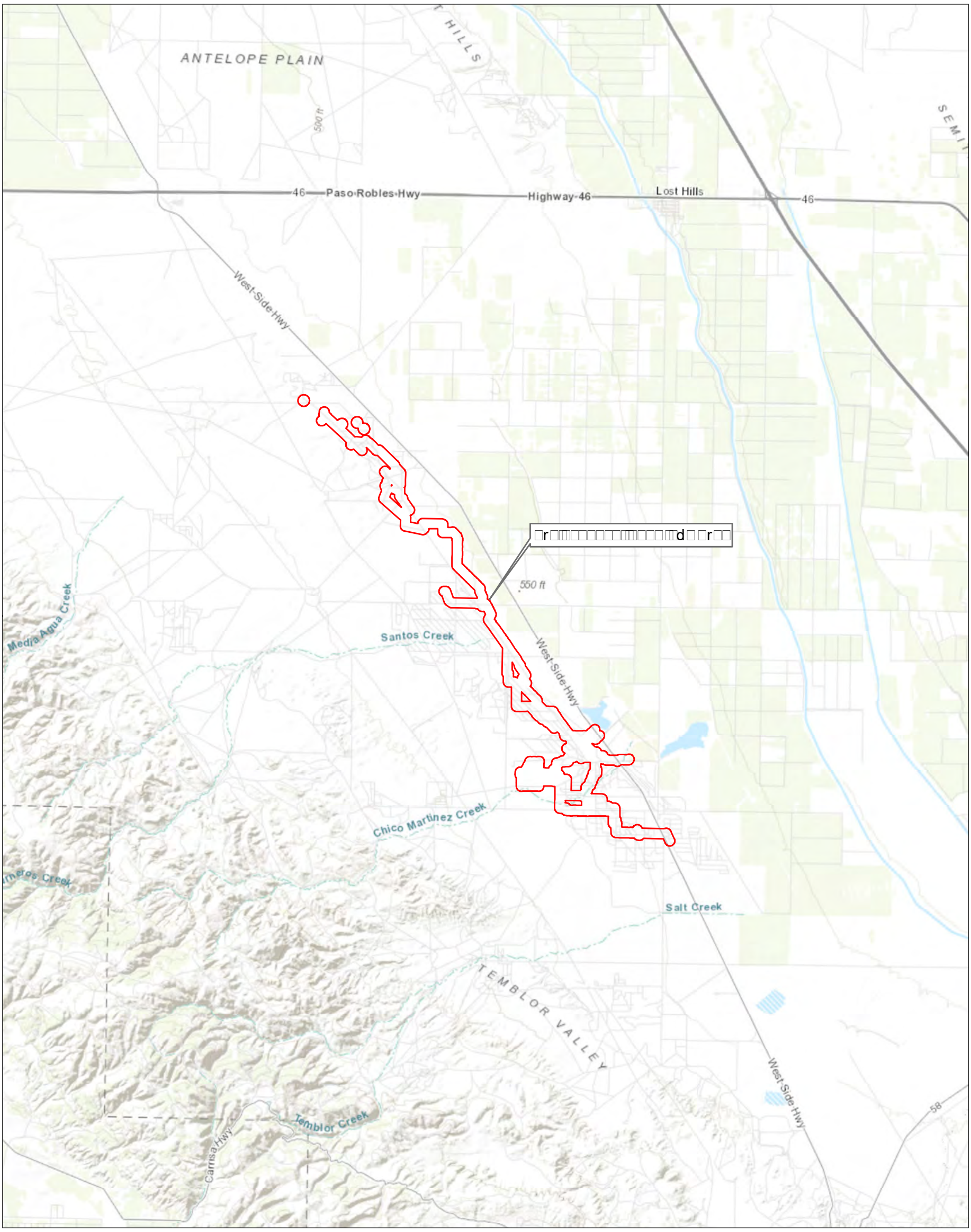
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Appendix A□ FIGURES





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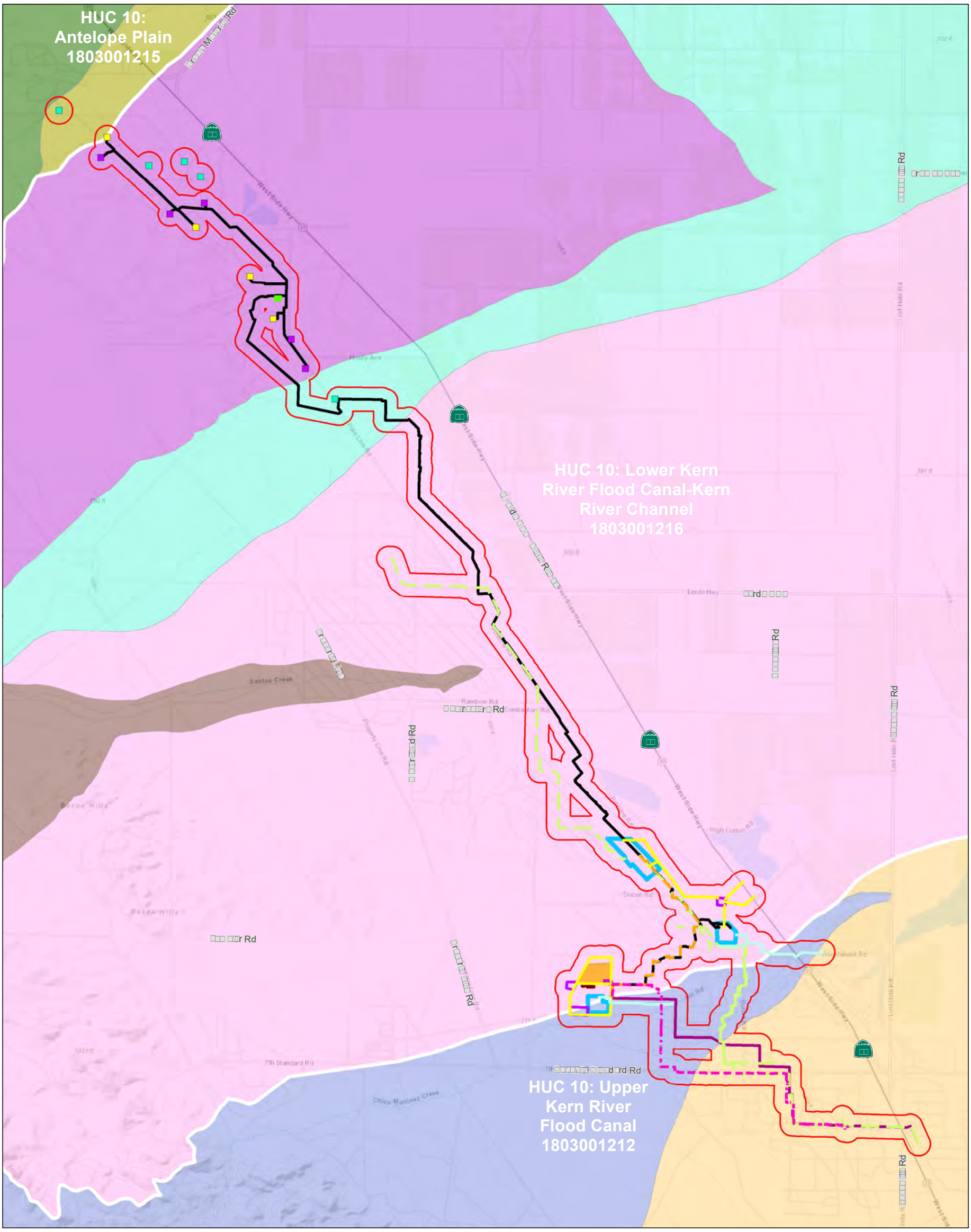
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Figure No.
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Project Location / Study Area

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Watershed Boundary Dataset: Hydrologic Unit 12

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Project Location

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Figure No.

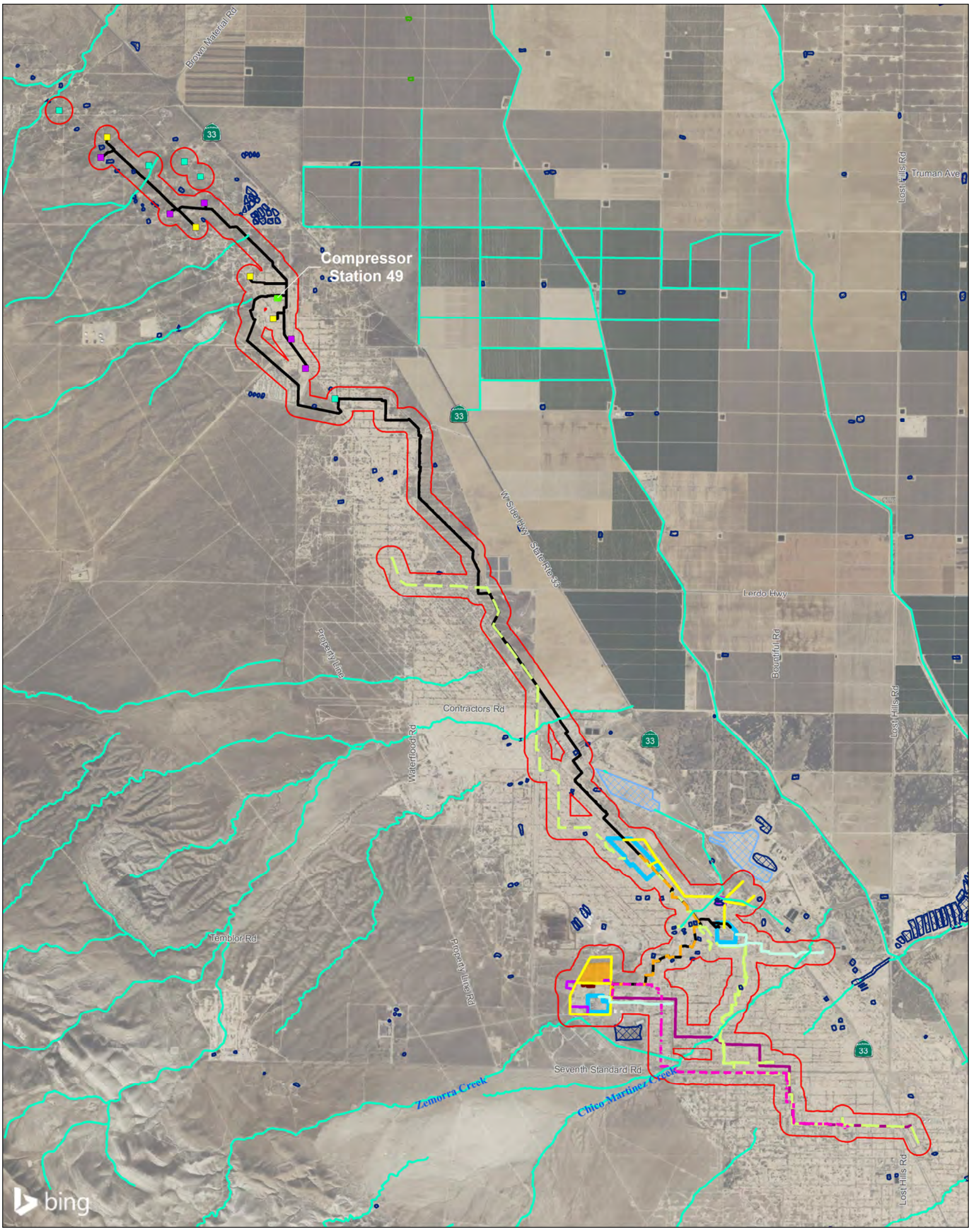
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Title

Hydrologic Unit Codes

Notes

1.
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- Project Boundary
- Proposed Compressor Station
- Proposed Meter Station
- Proposed Main Line
- Proposed Distribution Line
- Proposed Main Line Boring
- Proposed Access Road
- Proposed Temporary Access Road
- Proposed Temporary Laydown Area
- Proposed Temporary Staging Area
- Proposed Temporary Pipe Yard
- Proposed Temporary Construction Area
- Proposed Temporary Boring Area
- Proposed Temporary Pull Back Area
- Proposed Temporary Hydrostatic Test Water Discharge Area

NWI Wetlands

- Freshwater Emergent Wetland
- Freshwater Pond
- Lake
- Riverine

0 5 Miles

1 inch represents 5 miles

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Figure No.

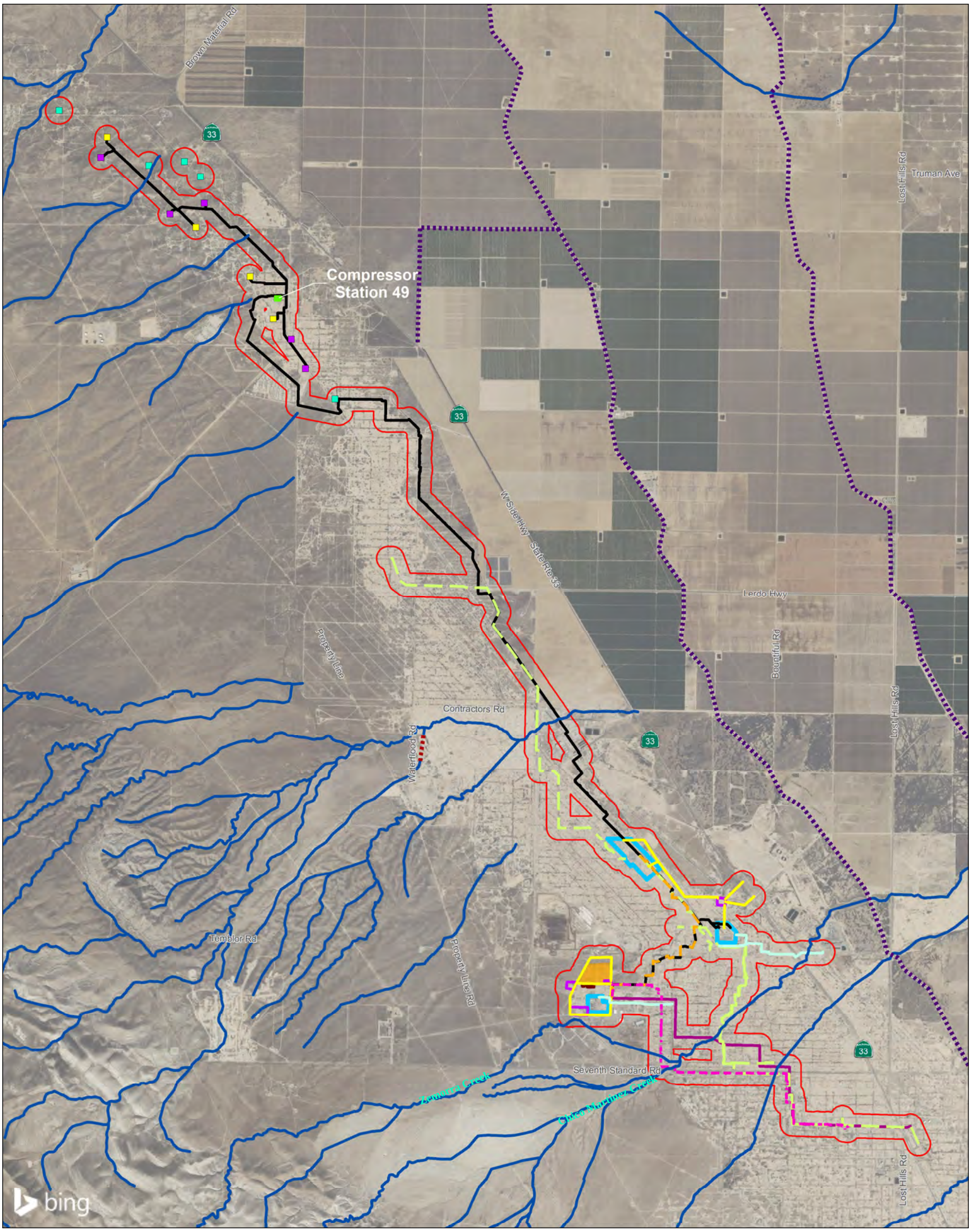
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Title

National Wetlands Inventory (NWI)

Notes

1. Proposed Distribution Line Boring
2. Proposed Distribution Line
3. Proposed Main Line



NHD Flow Line

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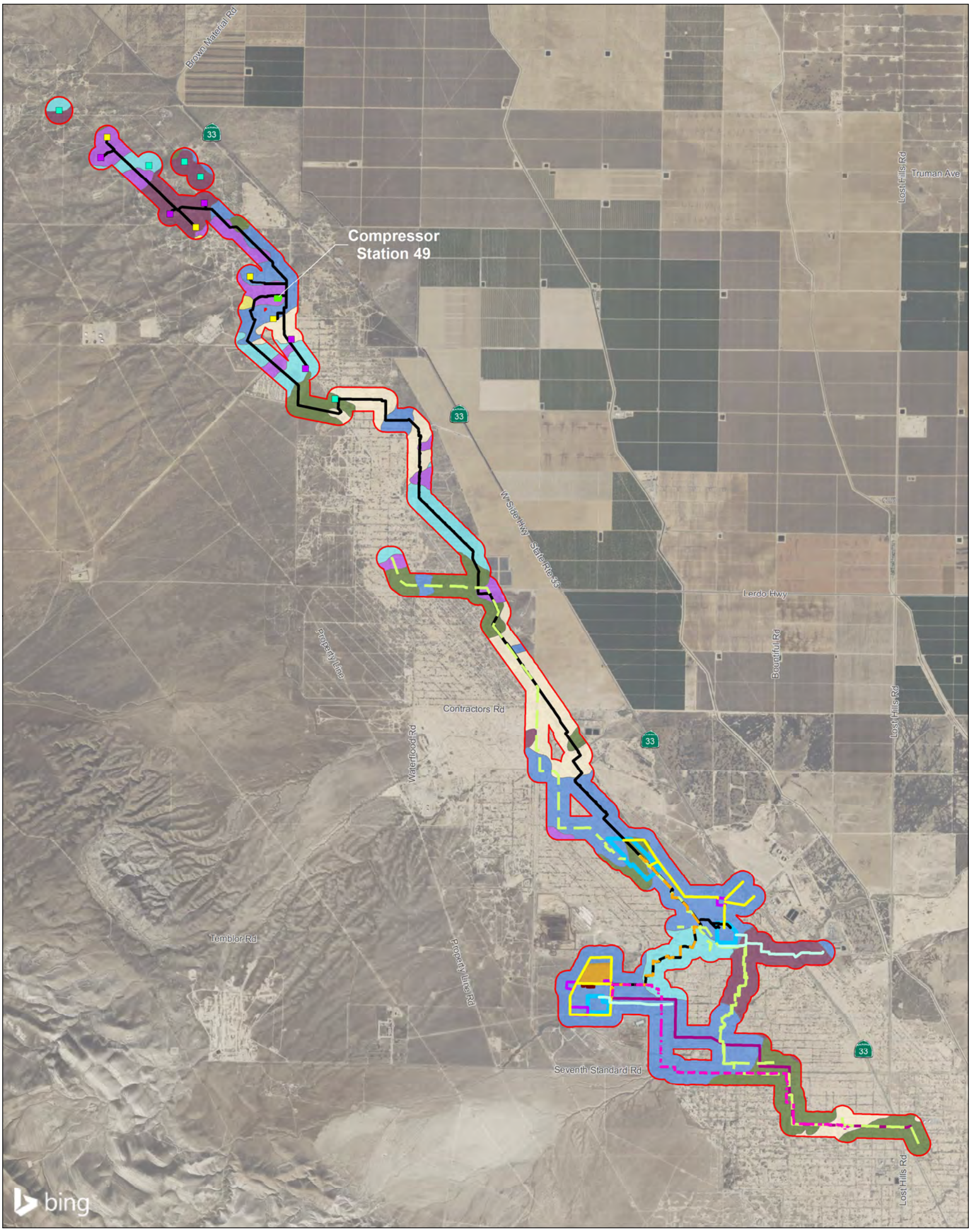
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Title

National Hydrography Dataset (NHD)

Notes

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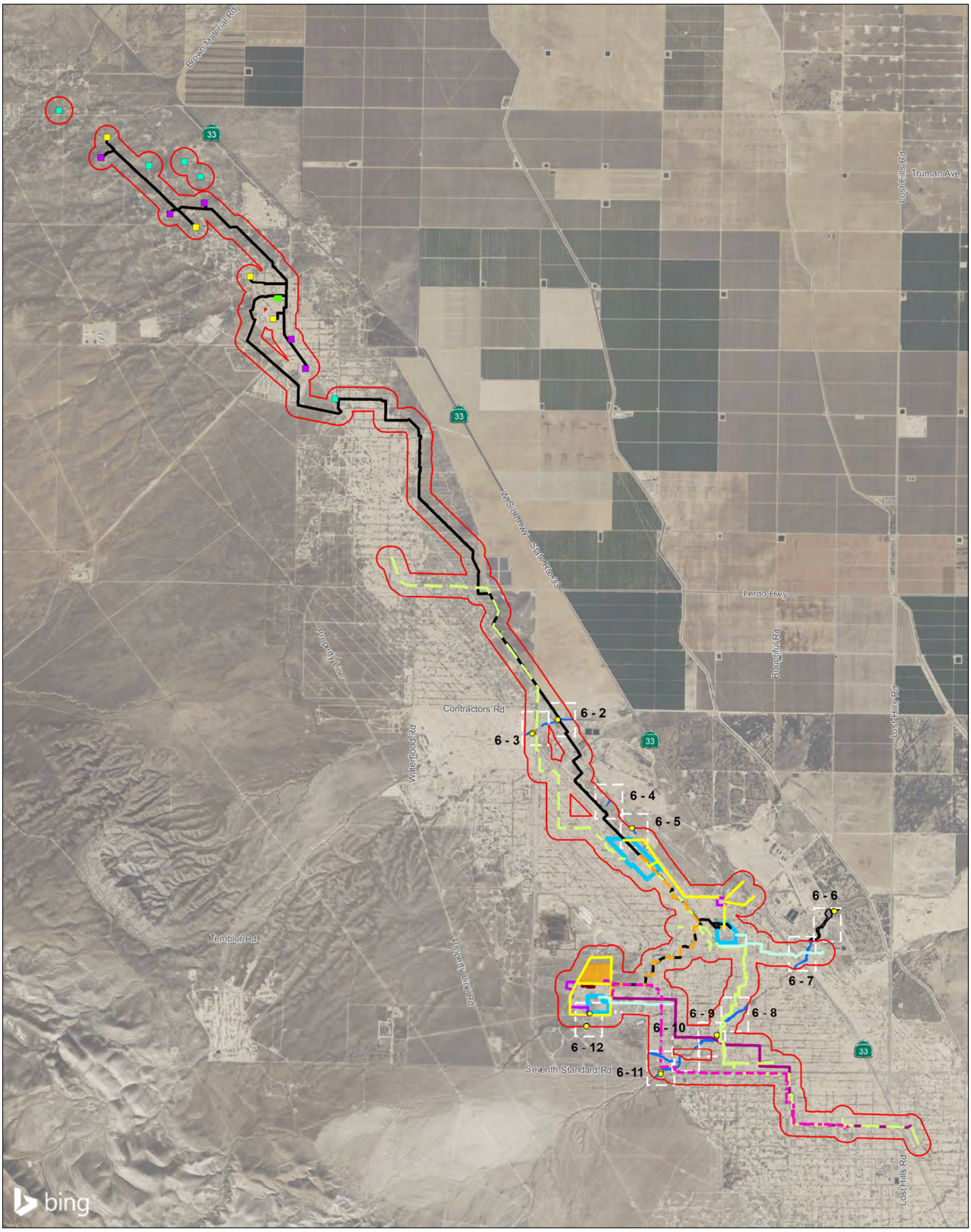
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Title

Historic Soils

Notes

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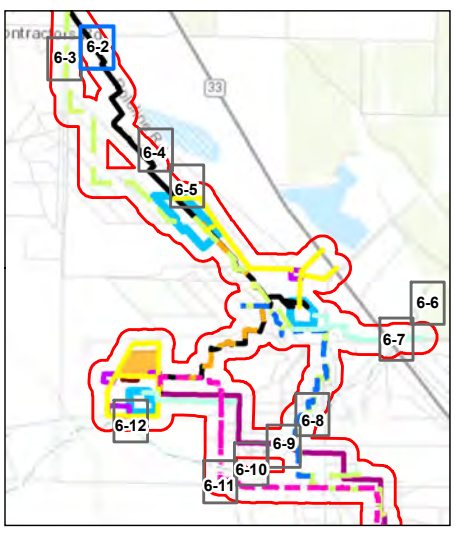

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Truman Ave
Lost Hills Rd
W Side Hwy
State Rte 33
Lerdo Hwy
Bountiful Rd
Property Line
Contractors Rd
Waterflood Rd
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Figure No.

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Potential Jurisdictional Waters

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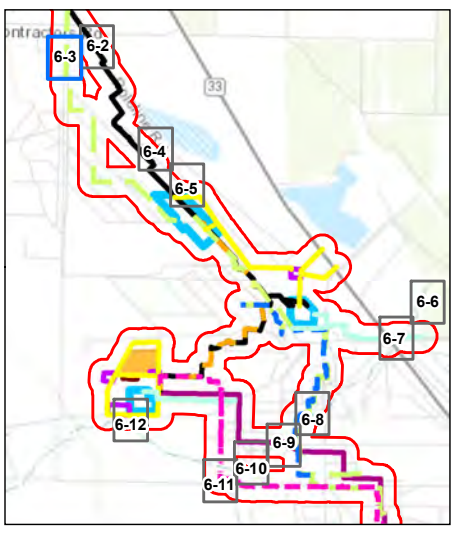
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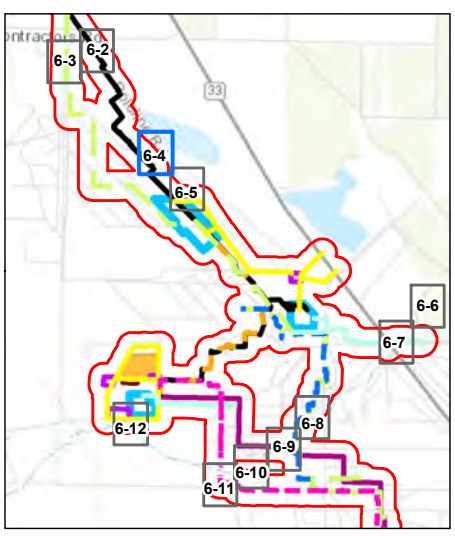
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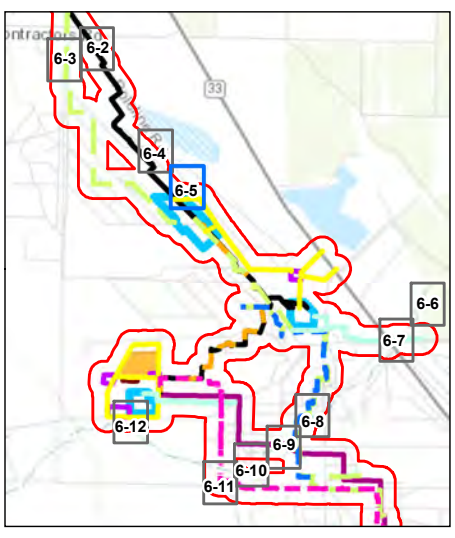
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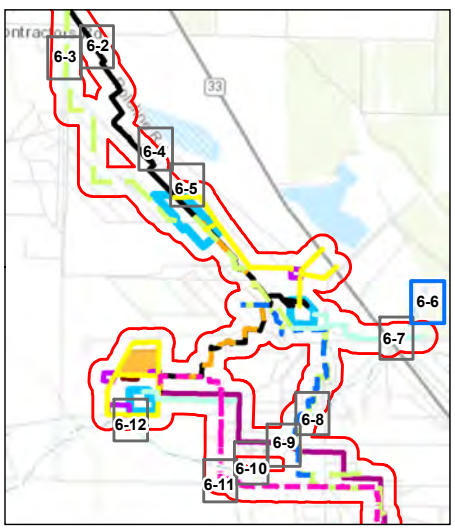
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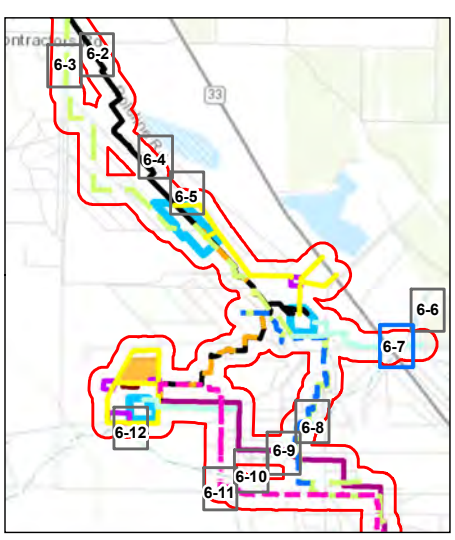
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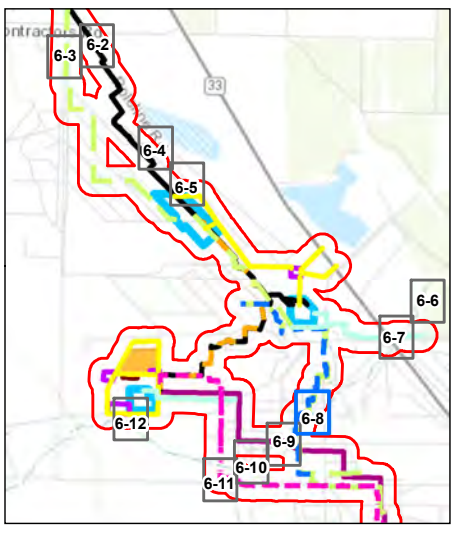
Title

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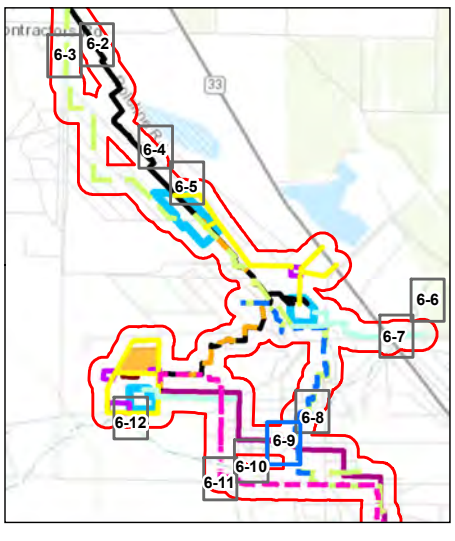
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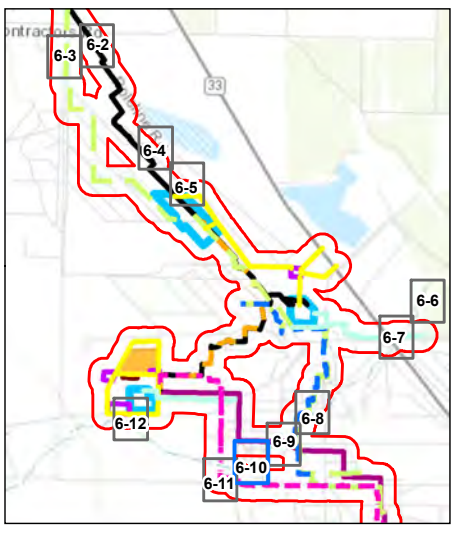
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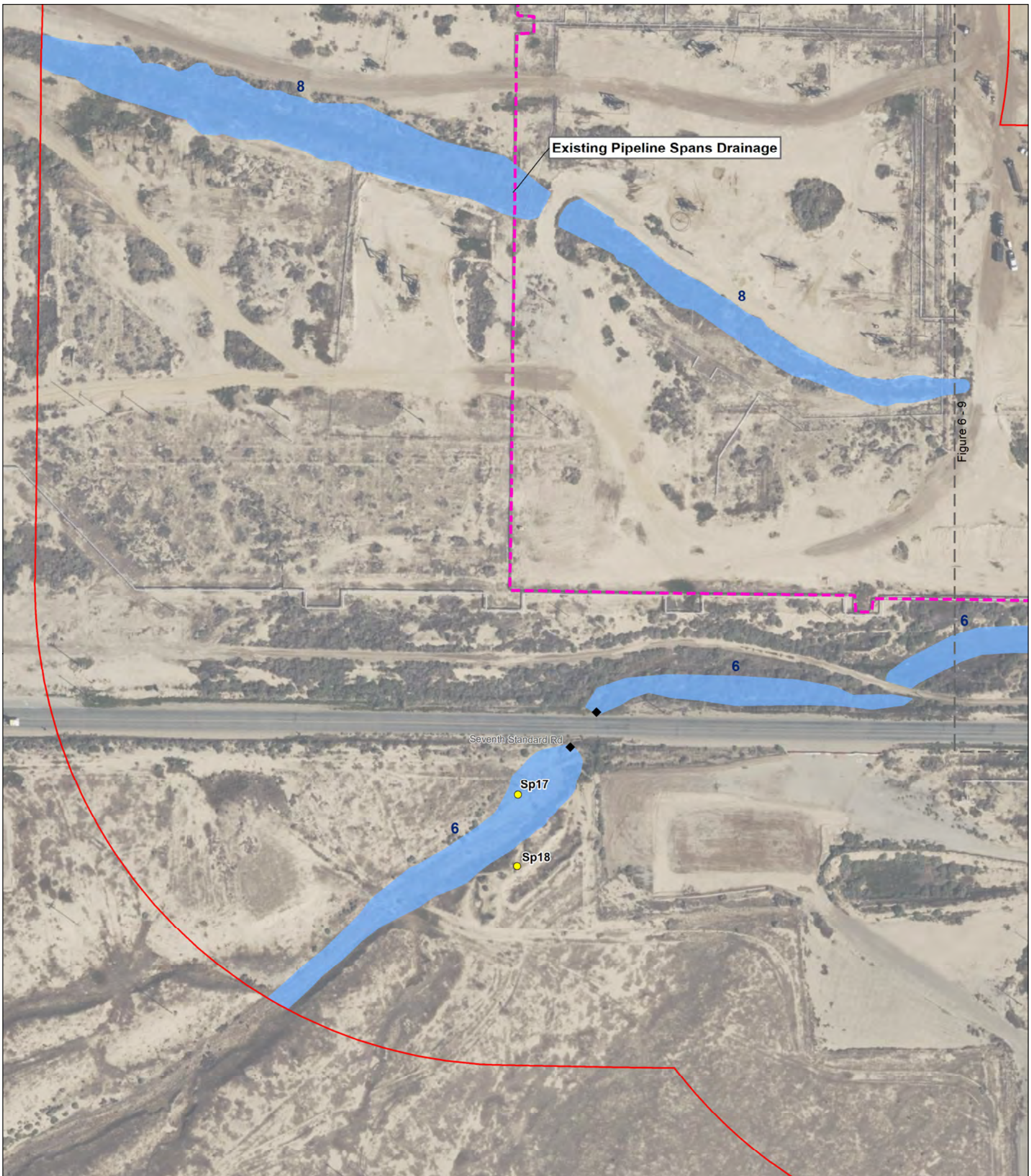
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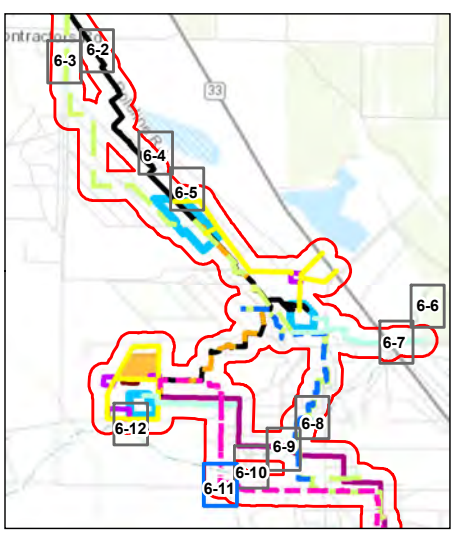
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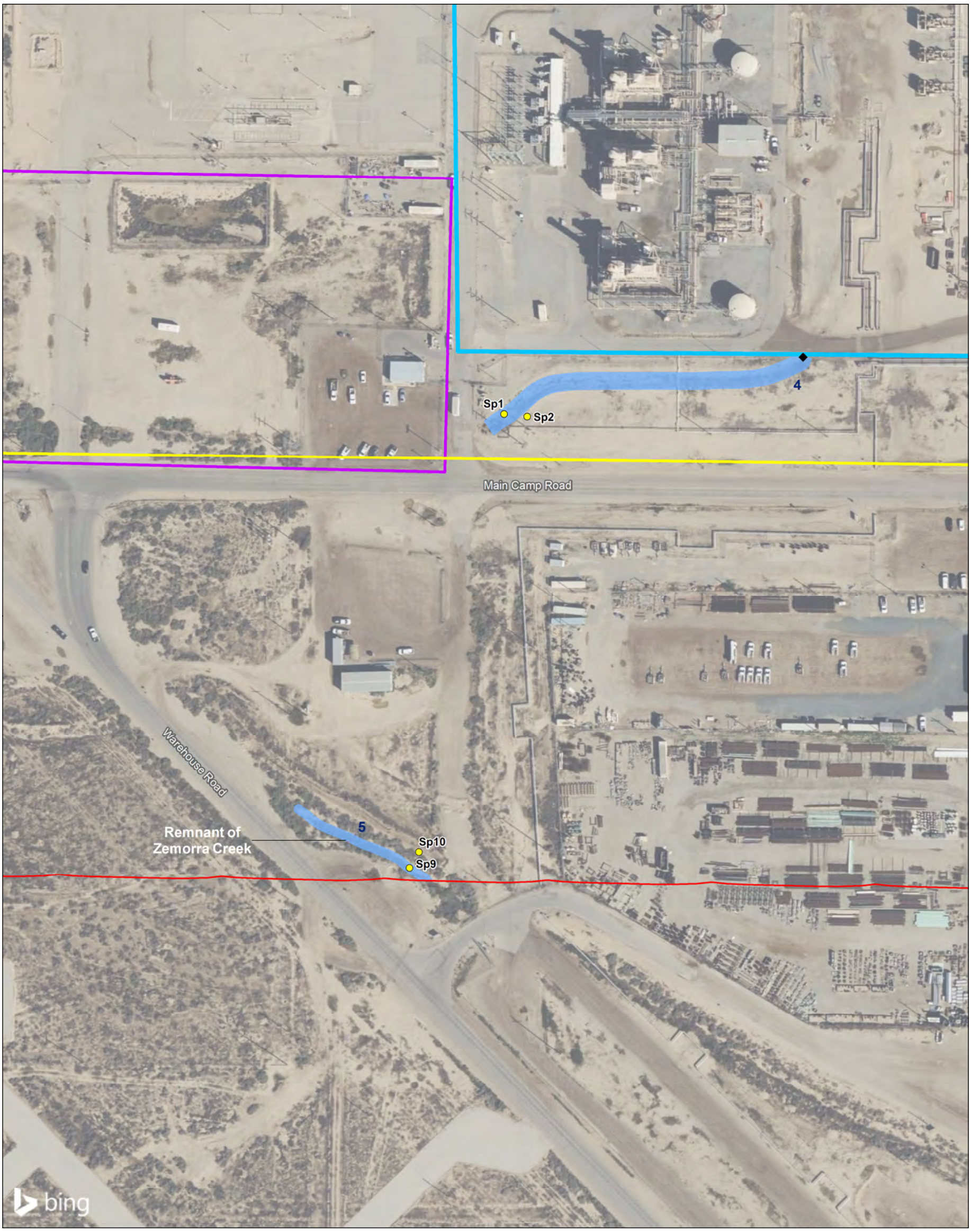
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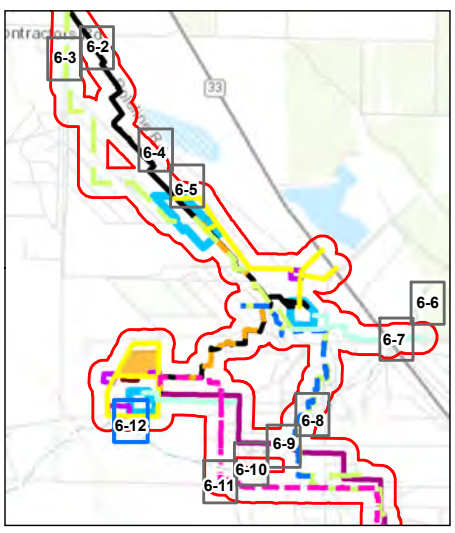
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Appendix B□ WETLAND DETERMINATION DATA FORMS AND ORDINARY HIGH-WATER MARK DATASHEETS

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Aera Belridge ERS City/County: Belridge oil field, western Kern County Sampling Date: 06/01/22

Applicant/Owner: Aera State: CA Sampling Point: SP1

Investigator(s): G. Hoetker, J. Byrd Section, Township, Range: S32, T29S, R21E

Landform (hillslope, terrace, etc.): excavated drainage ditch Local relief (concave, convex, none): Concave Slope (%): 1%

Subregion (LRR): LRR C Lat: 35.447616 Long: -119.734113° Datum: NAD83

Soil Map Unit Name: 174 – Kimberlina fine sandy loam, 0-2% slopes NWI classification: Riverine

Are climatic / hydrologic conditions on the site typical for this time of year? Yes ✓ No ____ (If no, explain in Remarks.)

Are Vegetation Y, Soil Y, or Hydrology ____ significantly disturbed? Are "Normal Circumstances" present? Yes ✓ No ____

Are Vegetation —, Soil —, or Hydrology — naturally problematic? N (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ____	No ✓	**Is the Sampled Area within a Wetland?** Yes ____ No ✓
Hydric Soil Present?	Yes ____	No ✓	
Wetland Hydrology Present?	Yes ____	No ✓	

Remarks: No wetland indicators; excavated drainage ditch; no OHWM; potential waters of the state

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: —)	Absolute % Cover	Dominant Species?	Indicator Status
1. —			
2.			
3.			
4.			
	— = Total Cover		
Sapling/Shrub Stratum (Plot size: —)			
1. —			
2.			
3.			
4.			
5.			
	— = Total Cover		
Herb Stratum (Plot size: 5')			
1. Salsola tragus	20%	Y	UPL
2.			
3.			
4.			
5.			
6.			
7.			
8.			
	20% = Total Cover		
Woody Vine Stratum (Plot size: —)	—		
1. —			
2.			
	— = Total Cover		

% Bare Ground in Herb Stratum 80% % Cover of Biotic Crust —

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 0 (A)

Total Number of Dominant Species Across All Strata: 1 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 0 (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:
OBL species ____	x 1 = ____
FACW species ____	x 2 = ____
FAC species ____	x 3 = ____
FACU species ____	x 4 = ____
UPL species ____	x 5 = ____
Column Totals: ____ (A)	____ (B)

Prevalence Index = B/A = ____

Hydrophytic Vegetation Indicators:

___ Dominance Test is >50%

___ Prevalence Index is ≤3.0[1]

___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)

___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes ____ No ✓

Remarks: No dominant hydrophytic vegetation.

SOIL

Sampling Point: SP1

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	%	Redox Features Color (moist)	%	Type[1]	Loc[2]	Texture	Remarks
0-5"	10YR 4/4	100%	—	—	—	—	sand	
5-16"	10YR 4/3	100%	—	—	—	—	loamy sand	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) (**LRR C**)
- ___ 1 cm Muck (A9) (**LRR D**)
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) (**LRR C**)
- ___ 2 cm Muck (A10) (**LRR B**)
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: —

Depth (inches): —

Hydric Soil Present? Yes ___ No ✓

Remarks:

Sandy soil top layer; loamy sand bottom layer — no hydric soil indicators

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) (**Nonriverine**)
- ___ Sediment Deposits (B2) (**Nonriverine**)
- ___ Drift Deposits (B3) (**Nonriverine**)
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) (**Riverine**)
- ___ Sediment Deposits (B2) (**Riverine**)
- ___ Drift Deposits (B3) (**Riverine**)
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes ___ No ✓ Depth (inches): ___

Water Table Present? Yes ___ No ✓ Depth (inches): ___

Saturation Present? (includes capillary fringe) Yes ___ No ✓ Depth (inches): ___

Wetland Hydrology Present? Yes ___ No ✓

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

No hydrology indicators

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Aera Belridge CCS City/County: Belridge Oil Field, Western Kern County Sampling Date: 06/01/22

Applicant/Owner: Aera State: CA Sampling Point: SP2

Investigator(s): G. Hoetker, J. Byrd Section, Township, Range: S32, T28S, R21E

Landform (hillslope, terrace, etc.): terrace - uplands Local relief (concave, convex, none): none Slope (%): 0

Subregion (LRR): LRRC Lat: 35.447627 Long: -119.734029 Datum: NAD83

Soil Map Unit Name: 174 - Kimberlina fine sandy loam, 0-2% slopes NWI classification: N/A - uplands

Are climatic / hydrologic conditions on the site typical for this time of year? Yes ____ No ____ (If no, explain in Remarks.)

Are Vegetation Y, Soil Y, or Hydrology ____ significantly disturbed? Are "Normal Circumstances" present? Yes ✓ No ____

Are Vegetation ____, Soil ____, or Hydrology ____ naturally problematic? N (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ____	No ✓	**Is the Sampled Area within a Wetland?** Yes ____ No ✓
Hydric Soil Present?	Yes ____	No ✓	
Wetland Hydrology Present?	Yes ____	No ✓	

Remarks: No wetland indicators; uplands adjacent to drainage ditch

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: —)	Absolute % Cover	Dominant Species?	Indicator Status
1.			
2.			
3.			
4.			
	— = Total Cover		
Sapling/Shrub Stratum (Plot size: —)			
1.			
2.			
3.			
4.			
5.			
	— = Total Cover		
Herb Stratum (Plot size: 5')			
1. Salsola tragus	5%		
2. Bromus madritensis ssp. rubens	5%		
3.			
4.			
5.			
6.			
7.			
8.			
	10% = Total Cover		
Woody Vine Stratum (Plot size: —)			
1.			
2.			
	— = Total Cover		

% Bare Ground in Herb Stratum ~90% % Cover of Biotic Crust —

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 0 (A)

Total Number of Dominant Species Across All Strata: 2 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 100% (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:
OBL species ____	x 1 = ____
FACW species ____	x 2 = ____
FAC species ____	x 3 = ____
FACU species ____	x 4 = ____
UPL species ____	x 5 = ____
Column Totals: ____ (A)	____ (B)

Prevalence Index = B/A = ____

Hydrophytic Vegetation Indicators:

- ___ Dominance Test is >50%
- ___ Prevalence Index is ≤3.0[1]
- ___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)
- ___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes ____ No ✓

Remarks: No dominant hydrophytic vegetation.

SOIL

Sampling Point: SP2

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	Matrix %	Redox Features Color (moist)	Redox Features %	Redox Features Type[1]	Redox Features Loc[2]	Texture	Remarks
0-16"	10YR 4/3	100%	—	—	—	—	loamy sand	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) **(LRR C)**
- ___ 1 cm Muck (A9) **(LRR D)**
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) **(LRR C)**
- ___ 2 cm Muck (A10) **(LRR B)**
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: —

Depth (inches): —

Hydric Soil Present? Yes ____ No ✓

Remarks: loamy sand; no hydric soil indicators

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) **(Nonriverine)**
- ___ Sediment Deposits (B2) **(Nonriverine)**
- ___ Drift Deposits (B3) **(Nonriverine)**
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) **(Riverine)**
- ___ Sediment Deposits (B2) **(Riverine)**
- ___ Drift Deposits (B3) **(Riverine)**
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes ____ No ✓ Depth (inches): ____

Water Table Present? Yes ____ No ✓ Depth (inches): ____

Saturation Present? (includes capillary fringe) Yes ____ No ✓ Depth (inches): ____

Wetland Hydrology Present? Yes ____ No ✓

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks: No hydrology indicators

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Aera Belridge, CCS City/County: Belridge western loam, oil field, County Sampling Date: 6/1/22

Applicant/Owner: Aera State: CA Sampling Point: SP3

Investigator(s): G. Hoetker, J. Byrd Section, Township, Range: S20, T29S, R21E

Landform (hillslope, terrace, etc.): drainage Local relief (concave, convex, none): concave Slope (%): 1%

Subregion (LRR): LRRC Lat: 35.483319° Long: -119.739537 Datum: NAD 83

Soil Map Unit Name: 211 - Panoche clay loam, 0-2% slopes NWI classification: Riverine

Are climatic / hydrologic conditions on the site typical for this time of year? Yes _____ No _____ (If no, explain in Remarks.)

Are Vegetation Y, Soil Y, or Hydrology Y significantly disturbed? Are "Normal Circumstances" present? Yes ✓ No _____

Are Vegetation _____, Soil _____, or Hydrology _____ naturally problematic? N (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes _____	No ✓	**Is the Sampled Area within a Wetland?** Yes _____ No ✓
Hydric Soil Present?	Yes _____	No ✓	
Wetland Hydrology Present?	Yes _____	No ✓	

Remarks: Remnant ephemeral stream w/ partially buried culvert, no OHWM, potential waters of the state; no wetland indicators

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: —)	Absolute % Cover	Dominant Species?	Indicator Status
1. —			
2.			
3.			
4.			
	—	= Total Cover	
Sapling/Shrub Stratum (Plot size: 10')			
1. Berberis pinnata	15%	Y	NI/upl
2.			
3.			
4.			
5.			
	15%	= Total Cover	
Herb Stratum (Plot size: 5')			
1. Hirschfeldia incana	30%	Y	NI/UPL
2. Centaurea melitensis	20%	Y	NI/UPL
3. Deinandra fasciculata	15%	Y	FAC
4.			
5.			
6.			
7.			
8.			
	65%	= Total Cover	
Woody Vine Stratum (Plot size: —)			
1. —			
2.			
	—	= Total Cover	

% Bare Ground in Herb Stratum ~35% % Cover of Biotic Crust —

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 1 (A)

Total Number of Dominant Species Across All Strata: 4 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 25% (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:	
OBL species	x 1 =	
FACW species	x 2 =	
FAC species	x 3 =	
FACU species	x 4 =	
UPL species	x 5 =	
Column Totals: (A)		(B)

Prevalence Index = B/A = _____

Hydrophytic Vegetation Indicators:

___ Dominance Test is >50%

___ Prevalence Index is ≤3.0[1]

___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)

___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes _____ No ✓

Remarks:

No dominant hydrophytic vegetation.

Sampling Point: SP 3

SOIL

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	Matrix %	Redox Features Color (moist)	Redox Features %	Type[1]	Loc[2]	Texture	Remarks
0-16"	10YR 4/4	100%	—	—	—	—	loamy sand	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) **(LRR C)**
- ___ 1 cm Muck (A9) **(LRR D)**
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) **(LRR C)**
- ___ 2 cm Muck (A10) **(LRR B)**
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: —

Depth (inches): —

Hydric Soil Present? Yes ____ No ✓

Remarks: No hydric soil indicators.

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) **(Nonriverine)**
- ___ Sediment Deposits (B2) **(Nonriverine)**
- ___ Drift Deposits (B3) **(Nonriverine)**
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) **(Riverine)**
- ___ Sediment Deposits (B2) **(Riverine)**
- ___ Drift Deposits (B3) **(Riverine)**
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes ____ No ✓ Depth (inches): —

Water Table Present? Yes ____ No ✓ Depth (inches): —

Saturation Present? (includes capillary fringe) Yes ____ No ____ Depth (inches): —

Wetland Hydrology Present? Yes ____ No ✓

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks: No hydrology indicators.

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Aera Belridge CCS City/County: Belridge Western Kern Oil Field, County Sampling Date: 06/01/2022

Applicant/Owner: Aera State: CA Sampling Point: SP4

Investigator(s): G. Huether, J. Byrd Section, Township, Range: S20, T29S, R21E

Landform (hillslope, terrace, etc.): terrace - uplands Local relief (concave, convex, none): none Slope (%): 0%

Subregion (LRR): LRR C Lat: 35.483294° Long: -119.739436° Datum: NAD 83

Soil Map Unit Name: 211 - Panoche clay loam, 0-2% slopes NWI classification: N/A - uplands

Are climatic / hydrologic conditions on the site typical for this time of year? Yes ✓ No ____ (If no, explain in Remarks.)

Are Vegetation T, Soil Y, or Hydrology ____ significantly disturbed? Are "Normal Circumstances" present? Yes ✓ No ____

Are Vegetation —, Soil —, or Hydrology — naturally problematic? N (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ____	No ✓	**Is the Sampled Area within a Wetland?** Yes ____ No ✓
Hydric Soil Present?	Yes ____	No ✓	
Wetland Hydrology Present?	Yes ____	No ✓	

Remarks: No wetland indicators; uplands adjacent to drainage

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: —)	Absolute % Cover	Dominant Species?	Indicator Status
1.			
2.			
3.			
4.			
	—	= Total Cover	
Sapling/Shrub Stratum (Plot size: —)			
1.			
2.			
3.			
4.			
5.			
	—	= Total Cover	
Herb Stratum (Plot size: —)			
1.			
2.			
3.			
4.			
5.			
6.			
7.			
8.			
	—	= Total Cover	
Woody Vine Stratum (Plot size: —)			
1.			
2.			
	—	= Total Cover	

% Bare Ground in Herb Stratum 100 % Cover of Biotic Crust —

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 0 (A)

Total Number of Dominant Species Across All Strata: 0 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 0% (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:
OBL species ____	x 1 = ____
FACW species ____	x 2 = ____
FAC species ____	x 3 = ____
FACU species ____	x 4 = ____
UPL species ____	x 5 = ____
Column Totals: ____ (A)	____ (B)

Prevalence Index = B/A = ____

Hydrophytic Vegetation Indicators:

___ Dominance Test is >50%

___ Prevalence Index is ≤3.0[1]

___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)

___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes ____ No ✓

Remarks: No vegetation.

SOIL

Sampling Point: SP4

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	%	Redox Features Color (moist)	%	Type[1]	Loc[2]	Texture	Remarks
0-8"	10YR 4/4	100	—	—	—	—	loamy sand	
restrictive layer below								

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) (**LRR C**)
- ___ 1 cm Muck (A9) (**LRR D**)
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) (**LRR C**)
- ___ 2 cm Muck (A10) (**LRR B**)
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: hardpan

Depth (inches): 8"

Hydric Soil Present? Yes ____ No ✓

Remarks:

No hydric soil indicators.

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) (**Nonriverine**)
- ___ Sediment Deposits (B2) (**Nonriverine**)
- ___ Drift Deposits (B3) (**Nonriverine**)
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) (**Riverine**)
- ___ Sediment Deposits (B2) (**Riverine**)
- ___ Drift Deposits (B3) (**Riverine**)
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes ____ No ✓ Depth (inches): ____

Water Table Present? Yes ____ No ✓ Depth (inches): ____

Saturation Present? (includes capillary fringe) Yes ____ No ✓ Depth (inches): ____

Wetland Hydrology Present? Yes ____ No ✓

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

No hydrology indicators.

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Aera Belridge CCS City/County: Belridge Oilfield, Western Kern County Sampling Date: 07/18/22

Applicant/Owner: Aera State: CA Sampling Point: SP5

Investigator(s): G. Huether, E. Martin, J. Pratt, C. Cortez Section, Township, Range: S33, T28S, R21E

Landform (hillslope, terrace, etc.): drainage - Chico Martinez Creek Local relief (concave, convex, none): Concave Slope (%): 1%

Subregion (LRR): LRR C Lat: 35.445175° Long: -119.715113° Datum: NAD83

Soil Map Unit Name: 174 - Lembert fine sandy loam, 0-2% slopes NWI classification: Riverine

Are climatic / hydrologic conditions on the site typical for this time of year? Yes ✓ No _____ (If no, explain in Remarks.)

Are Vegetation ✓, Soil ✓, or Hydrology ✓ significantly disturbed? Y Are "Normal Circumstances" present? Yes ✓ No _____

Are Vegetation _____, Soil _____, or Hydrology _____ naturally problematic? N (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes _____	No ✓	**Is the Sampled Area within a Wetland?** Yes _____ No ✓
Hydric Soil Present?	Yes _____	No ✓	
Wetland Hydrology Present?	Yes _____	No ✓	

Remarks: No wetland indicators observed. Chico Martinez Creek = ephemeral drainage channel; discontinuous ditch; potential waters of the State

VEGETATION – Use scientific names of plants.

	Absolute % Cover	Dominant Species?	Indicator Status
Tree Stratum (Plot size: —)			
1. — N/A			
2.			
3.			
4.			
	— = Total Cover		
Sapling/Shrub Stratum (Plot size: 10')			
1. Atriplex polycarpa	25%	Y	FACU
2.			
3.			
4.			
5.			
	25 = Total Cover		
Herb Stratum (Plot size: 5')			
1. Salsola tragus	10%	Y	FACU
2. Centaurea melitensis	5%	Y	NI/UPL
3. Amaranthus sp.	1%	N	NI/UPL
4.			
5.			
6.			
7.			
8.			
	16 = Total Cover		
Woody Vine Stratum (Plot size: —)			
1. N/A	—		
2.			
	— = Total Cover		

% Bare Ground in Herb Stratum ~84% % Cover of Biotic Crust —

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 0 (A)

Total Number of Dominant Species Across All Strata: 3 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 0% (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:
OBL species _____	x 1 = _____
FACW species _____	x 2 = _____
FAC species _____	x 3 = _____
FACU species _____	x 4 = _____
UPL species _____	x 5 = _____
Column Totals: _____ (A)	_____ (B)

Prevalence Index = B/A = _____

Hydrophytic Vegetation Indicators:

___ Dominance Test is >50%

___ Prevalence Index is ≤3.0[1]

___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)

___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes _____ No ✓

Remarks: No dominant hydrophytic vegetation.

SOIL

Sampling Point: SPS

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	%	Redox Features Color (moist)	%	Type[1]	Loc[2]	Texture	Remarks
0-0.25	—	—					Sandy Gravel	
0.25-16"	10YR 4/6	100%	—	—	—	—	Loamy Sand	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) (**LRR C**)
- ___ 1 cm Muck (A9) (**LRR D**)
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) (**LRR C**)
- ___ 2 cm Muck (A10) (**LRR B**)
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: —

Depth (inches): —

Hydric Soil Present? Yes _____ No ✓

Remarks:

No hydric soil indicators

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) (**Nonriverine**)
- ___ Sediment Deposits (B2) (**Nonriverine**)
- ___ Drift Deposits (B3) (**Nonriverine**)
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) (**Riverine**)
- ___ Sediment Deposits (B2) (**Riverine**)
- ___ Drift Deposits (B3) (**Riverine**)
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes _____ No ✓ Depth (inches): —

Water Table Present? Yes _____ No ✓ Depth (inches): —

Saturation Present? (includes capillary fringe) Yes _____ No ✓ Depth (inches): —

Wetland Hydrology Present? Yes _____ No ✓

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

No wetland hydrology

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Aera CCS - Chico Madrigal Creek City/County: Bakersfield Western Kern Sampling Date: 18 Jul 22

Applicant/Owner: Aera State: CA Sampling Point: SP 6

Investigator(s): G. Hoetker, E. Martin, J. Pratt, C. Cortez Section, Township, Range: S 33, T 28 S, R 21 E

Landform (hillslope, terrace, etc.): upland (mudpad) Local relief (concave, convex, none): flat Slope (%): 0%

Subregion (LRR): LRR C Lat: 35.445359° Long: -119.715101° Datum: _____

Soil Map Unit Name: 174 - Kimberlina fine sandy loam, 0-2% slopes NWI classification: N/A uplands

Are climatic / hydrologic conditions on the site typical for this time of year? Yes X No _____ (If no, explain in Remarks.)

Are Vegetation X, Soil X, or Hydrology X significantly disturbed? Are "Normal Circumstances" present? Yes X No _____

Are Vegetation _____, Soil _____, or Hydrology _____ naturally problematic? N (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes _____	No X	**Is the Sampled Area within a Wetland?** Yes _____ No X
Hydric Soil Present?	Yes _____	No X	
Wetland Hydrology Present?	Yes _____	No X	

Remarks:
Sample on edge of developed mud pad; uplands – no wetland indicators

VEGETATION – Use scientific names of plants.

	Absolute % Cover	Dominant Species?	Indicator Status
Tree Stratum (Plot size: –)			
1. N/A			
2.			
3.			
4.			
	= Total Cover		
Sapling/Shrub Stratum (Plot size: 10')			
1. A. polycarpa	45%	Y	FACU
2.			
3.			
4.			
5.			
	45% = Total Cover		
Herb Stratum (Plot size: 5')			
1. Bromus mad Rubus S	1%	N	UPL
2.			
3.			
4.			
5.			
6.			
7.			
8.			
	1% = Total Cover		
Woody Vine Stratum (Plot size: –)			
1. N/A			
2.			
	– = Total Cover		

% Bare Ground in Herb Stratum ~99% % Cover of Biotic Crust _____

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 0 (A)

Total Number of Dominant Species Across All Strata: 1 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 0 (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:	
OBL species	x 1 =	
FACW species	x 2 =	
FAC species	x 3 =	
FACU species	x 4 =	
UPL species	x 5 =	
Column Totals: (A)		(B)

Prevalence Index = B/A = _____

Hydrophytic Vegetation Indicators:

___ Dominance Test is >50%

___ Prevalence Index is ≤3.0[1]

___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)

___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes _____ No X

Remarks:
No dominant hydrophytic vegetation.

SOIL

Sampling Point: SP 6

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	%	Redox Features Color (moist)	%	Type[1]	Loc[2]	Texture	Remarks
≈10"	10YR 4/6	100					Loamy Sand	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) (**LRR C**)
- ___ 1 cm Muck (A9) (**LRR D**)
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) (**LRR C**)
- ___ 2 cm Muck (A10) (**LRR B**)
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: bedrock

Depth (inches): 10"

Hydric Soil Present? Yes ____ No X

Remarks:

No hydric soil indicators.

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) (**Nonriverine**)
- ___ Sediment Deposits (B2) (**Nonriverine**)
- ___ Drift Deposits (B3) (**Nonriverine**)
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) (**Riverine**)
- ___ Sediment Deposits (B2) (**Riverine**)
- ___ Drift Deposits (B3) (**Riverine**)
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes ____ No X Depth (inches): ____

Water Table Present? Yes ____ No X Depth (inches): ____

Saturation Present? (includes capillary fringe) Yes ____ No X Depth (inches): ____

Wetland Hydrology Present? Yes ____ No X

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

No wetland hydrology indicators.

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Aera Belridge CCS City/County: Belridge Oil Field, Western Kern County Sampling Date: 07/20/22

Applicant/Owner: Aera State: CA Sampling Point: SP7

Investigator(s): G. Hetter, E. Martin, J. Platt, C. Cortez Section, Township, Range: S22, T28S, R21E

Landform (hillslope, terrace, etc.): stream channel - Chico Martinez Creek Local relief (concave, convex, none): concave Slope (%): 1%

Subregion (LRR): Lrr c - Med CA Lat: 35.460661° Long: -119.698066° Datum: NAD 83

Soil Map Unit Name: 174 - Kimberlina fine sandy loam, 0-2% slopes NWI classification: Riverine/ephemeral

Are climatic / hydrologic conditions on the site typical for this time of year? Yes ✓ No ____ (If no, explain in Remarks.)

Are Vegetation N, Soil N, or Hydrology Y significantly disturbed? Are "Normal Circumstances" present? Yes Y No ____

Are Vegetation N, Soil N, or Hydrology N naturally problematic? (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ____	No ✓	**Is the Sampled Area within a Wetland?** Yes ____ No ✓
Hydric Soil Present?	Yes ____	No ✓	
Wetland Hydrology Present?	Yes ____	No ✓	

Remarks: Chico Martinez Creek - No wetland indicators present, OHWM present in some areas; bed & bank present; potential waters of the State

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: 30')	Absolute % Cover	Dominant Species?	Indicator Status
1. N/A			
2.			
3.			
4.			
	—	= Total Cover	
Sapling/Shrub Stratum (Plot size: 10')			
1. Atriplex polycarpa	35%	Y	FACU
2.			
3.			
4.			
5.			
	35%	= Total Cover	
Herb Stratum (Plot size: 5')			
1. N/A			
2.			
3.			
4.			
5.			
6.			
7.			
8.			
	—	= Total Cover	
Woody Vine Stratum (Plot size: 10')			
1. N/A			
2.			
	—	= Total Cover	

% Bare Ground in Herb Stratum ≈99% % Cover of Biotic Crust N/A

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 6 (A)

Total Number of Dominant Species Across All Strata: 1 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 0% (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:	
OBL species	x 1 =	
FACW species	x 2 =	
FAC species	x 3 =	
FACU species	x 4 =	
UPL species	x 5 =	
Column Totals: (A)		(B)

Prevalence Index = B/A = ____

Hydrophytic Vegetation Indicators:

___ Dominance Test is >50%

___ Prevalence Index is ≤3.0[1]

___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)

___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes ____ No ✓

Remarks: No dominant hydrophytic vegetation

SOIL

Sampling Point: SP7

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	%	Redox Features Color (moist)	%	Type[1]	Loc[2]	Texture	Remarks
0-25"	NA	100%	NA	—	—	—	gravel & cobbles	deposition on top layer
0.25-8"	10YR 4/4	100%	NA	—	—	—	loamy sand	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) **(LRR C)**
- ___ 1 cm Muck (A9) **(LRR D)**
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) **(LRR C)**
- ___ 2 cm Muck (A10) **(LRR B)**
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: hardpan

Depth (inches): 8"

Hydric Soil Present? Yes ____ No ✓

Remarks:

No hydric soil present

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) **(Nonriverine)**
- ___ Sediment Deposits (B2) **(Nonriverine)**
- ___ Drift Deposits (B3) **(Nonriverine)**
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) **(Riverine)**
- ___ Sediment Deposits (B2) **(Riverine)**
- ___ Drift Deposits (B3) **(Riverine)**
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes ____ No ✓ Depth (inches): —

Water Table Present? Yes ____ No ✓ Depth (inches): —

Saturation Present? (includes capillary fringe) Yes ____ No ✓ Depth (inches): —

Wetland Hydrology Present? Yes ____ No ✓

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

No wetland hydrology present

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Aera Belridge CCS City/County: Belridge Oil Field, Western Kern County Sampling Date: 7/20/12

Applicant/Owner: Aera State: CA Sampling Point: SP8

Investigator(s): G. HOETKER E MARTIN, J. Pratt, C. Corkz Section, Township, Range: S27, T28S, R21E

Landform (hillslope, terrace, etc.): CURVED TOP RIDGE Local relief (concave, convex, none): CONVEX Slope (%): 1 %

Subregion (LRR): LRR C Lat: 35.460569° Long: -119.697984 Datum: NAD 83

Soil Map Unit Name: 174 - Kimberlina fine sand, loam, 0-2% slopes NWI classification: NA ; upland

Are climatic / hydrologic conditions on the site typical for this time of year? Yes X No _____ (If no, explain in Remarks.)

Are Vegetation Y, Soil Y, or Hydrology Y significantly disturbed? Are "Normal Circumstances" present? Yes X No _____

Are Vegetation N, Soil N, or Hydrology N naturally problematic? (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes _____	No X	**Is the Sampled Area within a Wetland?** Yes _____ No X
Hydric Soil Present?	Yes _____	No X	
Wetland Hydrology Present?	Yes _____	No X	

Remarks: NO WETLAND INDICATORS PRESENT (UPLANDS)

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: 30')	Absolute % Cover	Dominant Species?	Indicator Status
1. NP			
2.			
3.			
4.			
	—	= Total Cover	
Sapling/Shrub Stratum (Plot size: 10')			
1. ATRIPLEX POLYCARPA	25%	Y	FACU
2.			
3.			
4.			
5.			
	25%	= Total Cover	
Herb Stratum (Plot size: 5')			
1. NP			
2.			
3.			
4.			
5.			
6.			
7.			
8.			
	—	= Total Cover	
Woody Vine Stratum (Plot size: 15')			
1. NP			
2.			
	—	= Total Cover	

% Bare Ground in Herb Stratum 100 % Cover of Biotic Crust —

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 0 (A)

Total Number of Dominant Species Across All Strata: 1 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 0% (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:
OBL species _____	x 1 = _____
FACW species _____	x 2 = _____
FAC species _____	x 3 = _____
FACU species _____	x 4 = _____
UPL species _____	x 5 = _____
Column Totals: _____ (A)	_____ (B)

Prevalence Index = B/A = _____

Hydrophytic Vegetation Indicators:

__ Dominance Test is >50%

__ Prevalence Index is ≤3.0[1]

__ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)

__ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes _____ No X

Remarks: NO DOMINANT HYDROPHYTIC VEGETATION PRESENT

SOIL

Sampling Point: SP8

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	%	Redox Features Color (moist)	%	Type[1]	Loc[2]	Texture	Remarks
0-8	10YR 4/4	100	NA				LOAMY SAND	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) (**LRR C**)
- ___ 1 cm Muck (A9) (**LRR D**)
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) (**LRR C**)
- ___ 2 cm Muck (A10) (**LRR B**)
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: HARD PAN

Depth (inches): 8"

Hydric Soil Present? Yes ____ No X

Remarks:

NO HYDRIC SOIL

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) (**Nonriverine**)
- ___ Sediment Deposits (B2) (**Nonriverine**)
- ___ Drift Deposits (B3) (**Nonriverine**)
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) (**Riverine**)
- ___ Sediment Deposits (B2) (**Riverine**)
- ___ Drift Deposits (B3) (**Riverine**)
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes ____ No X Depth (inches): ____

Water Table Present? Yes ____ No X Depth (inches): ____

Saturation Present? (includes capillary fringe) Yes ____ No X Depth (inches): ____

Wetland Hydrology Present? Yes ____ No X

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

NO WETLAND HYDROLOGY

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Aera Belridge CCS City/County: Belridge Oil Field, Western Kern County Sampling Date: 09/13/22

Applicant/Owner: Aera State: CA Sampling Point: SP9

Investigator(s): G. Woelber, L. Elms Section, Township, Range: S32, T28S, R21E

Landform (hillslope, terrace, etc.): remnant stream Local relief (concave, convex, none): Concave Slope (%): 1%

Subregion (LRR): LRR C Lat: 35.446109° Long: -119.734470° Datum: NAD83

Soil Map Unit Name: 174 – Kimberlina fine sandy loam, 0-2% slopes NWI classification: Riverine

Are climatic / hydrologic conditions on the site typical for this time of year? Yes _____ No _____ (If no, explain in Remarks.)

Are Vegetation ____, Soil ____, or Hydrology ____ significantly disturbed? N Are "Normal Circumstances" present? Yes ✓ No _____

Are Vegetation _____, Soil _____, or Hydrology _____ naturally problematic? N (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes _____	No ✓	**Is the Sampled Area within a Wetland?** Yes _____ No ✓
Hydric Soil Present?	Yes _____	No ✓	
Wetland Hydrology Present?	Yes _____	No ✓	

Remarks: Remnant of Zemorrian Creek, tributary to Chico Martinez Creek. No OHWM; potential waters of the State; no wetland indicators

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: —)	Absolute % Cover	Dominant Species?	Indicator Status
1. —			
2.			
3.			
4.			
	= Total Cover		
Sapling/Shrub Stratum (Plot size: 10')			
1. Atriplex polycarpa	2%	Y	FACW
2.			
3.			
4.			
5.			
	= Total Cover		
Herb Stratum (Plot size: 5')			
1. Bromus madritensis ssp. rubens	14%	Y	UPL
2. Centaurea melitensis	1%	Y	NI/UPL
3. Amsinckia sp.	1%	N	NI/UPL
4.			
5.			
6.			
7.			
8.			
	16% = Total Cover		
Woody Vine Stratum (Plot size: —)			
1.			
2.			
	= Total Cover		

% Bare Ground in Herb Stratum ~95% % Cover of Biotic Crust —

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 0 (A)

Total Number of Dominant Species Across All Strata: 3 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 0% (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:
OBL species _____	x 1 = _____
FACW species _____	x 2 = _____
FAC species _____	x 3 = _____
FACU species _____	x 4 = _____
UPL species _____	x 5 = _____
Column Totals: _____ (A)	_____ (B)

Prevalence Index = B/A = _____

Hydrophytic Vegetation Indicators:

___ Dominance Test is >50%

___ Prevalence Index is ≤3.0[1]

___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)

___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes _____ No ✓

Remarks: No dominant hydrophytic vegetation.

SOIL

Sampling Point: SP9

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	%	Redox Features Color (moist)	%	Type[1]	Loc[2]	Texture	Remarks
0-9"	10YR 4/3	100	—		—	—	loam	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) (**LRR C**)
- ___ 1 cm Muck (A9) (**LRR D**)
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) (**LRR C**)
- ___ 2 cm Muck (A10) (**LRR B**)
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: hardpan

Depth (inches): 9"

Hydric Soil Present? Yes ___ No ✓

Remarks:

No hydric soil indicators.

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) (**Nonriverine**)
- ___ Sediment Deposits (B2) (**Nonriverine**)
- ___ Drift Deposits (B3) (**Nonriverine**)
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) (**Riverine**)
- ___ Sediment Deposits (B2) (**Riverine**)
- ___ Drift Deposits (B3) (**Riverine**)
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes ___ No ✓ Depth (inches): ___

Water Table Present? Yes ___ No ✓ Depth (inches): ___

Saturation Present? (includes capillary fringe) Yes ___ No ✓ Depth (inches): ___

Wetland Hydrology Present? Yes ___ No ✓

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

No hydrology indicators.

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Aera Belridge CCS City/County: Belridge Western 0-1 Field, Kern County Sampling Date: 09/13/22

Applicant/Owner: Aera State: CA Sampling Point: SP10

Investigator(s): G. Haetker, L. Elms Section, Township, Range: S32, T28S, R21E

Landform (hillslope, terrace, etc.): terrace/uplands Local relief (concave, convex, none): none Slope (%): 0%

Subregion (LRR): LRRC Lat: 35.446147° Long: -119.734440 Datum: NAD83

Soil Map Unit Name: 174- Kimberlina fine sandy loam, 0-2% slopes NWI classification: N/A- uplands

Are climatic / hydrologic conditions on the site typical for this time of year? Yes ✓ No _____ (If no, explain in Remarks.)

Are Vegetation ✓, Soil ✓, or Hydrology _____ significantly disturbed? Are "Normal Circumstances" present? Yes ✓ No _____

Are Vegetation _____, Soil _____, or Hydrology _____ naturally problematic? N (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes _____	No ✓	**Is the Sampled Area within a Wetland?** Yes _____ No ✓
Hydric Soil Present?	Yes _____	No ✓	
Wetland Hydrology Present?	Yes _____	No ✓	

Remarks: No wetland indicators; uplands

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: —)	Absolute % Cover	Dominant Species?	Indicator Status
1. —			
2.			
3.			
4.			
	—	= Total Cover	
Sapling/Shrub Stratum (Plot size: 10')			
1. Atriplex polycarpa	35%	Y	FACU
2.			
3.			
4.			
5.			
		= Total Cover	
Herb Stratum (Plot size: 5')			
1. Bromus madritensis ssp. rubens	5%	Y	UPL
2. Salsola tragus	1%	N	FACU
3.			
4.			
5.			
6.			
7.			
8.			
	6%	= Total Cover	
Woody Vine Stratum (Plot size: —)			
1. —			
2.			
		= Total Cover	

% Bare Ground in Herb Stratum ≈ 94% % Cover of Biotic Crust —

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 0 (A)

Total Number of Dominant Species Across All Strata: 2 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 0% (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:
OBL species _____	x 1 = _____
FACW species _____	x 2 = _____
FAC species _____	x 3 = _____
FACU species _____	x 4 = _____
UPL species _____	x 5 = _____
Column Totals: _____ (A)	_____ (B)

Prevalence Index = B/A = _____

Hydrophytic Vegetation Indicators:

___ Dominance Test is >50%

___ Prevalence Index is ≤3.0[1]

___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)

___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes _____ No ✓

Remarks: No dominant hydrophytic vegetation.

SOIL

Sampling Point: SP10

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	%	Redox Features Color (moist)	%	Type[1]	Loc[2]	Texture	Remarks
0-10"	10YR 5/6	100%					loam	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) (**LRR C**)
- ___ 1 cm Muck (A9) (**LRR D**)
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) (**LRR C**)
- ___ 2 cm Muck (A10) (**LRR B**)
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: hardpan

Depth (inches): 10"

Hydric Soil Present? Yes _____ No ✓

Remarks:

No hydric soil indicators.

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) (**Nonriverine**)
- ___ Sediment Deposits (B2) (**Nonriverine**)
- ___ Drift Deposits (B3) (**Nonriverine**)
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) (**Riverine**)
- ___ Sediment Deposits (B2) (**Riverine**)
- ___ Drift Deposits (B3) (**Riverine**)
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes _____ No ✓ Depth (inches): _____

Water Table Present? Yes _____ No ✓ Depth (inches): _____

Saturation Present? (includes capillary fringe) Yes _____ No ✓ Depth (inches): _____

Wetland Hydrology Present? Yes _____ No ✓

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

No hydrology indicators.

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Kern Belridge CCS City/County: Belridge Western Kern County Sampling Date: 09/13/22

Applicant/Owner: Aera State: CA Sampling Point: SP11

Investigator(s): G. Hoether, L. Elms Section, Township, Range: S20, T28S, R21E

Landform (hillslope, terrace, etc.): drainage ditch Local relief (concave, convex, none): concave Slope (%): 1%

Subregion (LRR): LRRC Lat: 35.470284° Long: -119.728256° Datum: NAD83

Soil Map Unit Name: 174-Kimberlina fine sandy loam, 0-2% slopes NWI classification: Riverine

Are climatic / hydrologic conditions on the site typical for this time of year? Yes ✓ No ____ (If no, explain in Remarks.)

Are Vegetation ____, Soil ____, or Hydrology ____ significantly disturbed? N Are "Normal Circumstances" present? Yes ✓ No ____

Are Vegetation ____, Soil ____, or Hydrology ____ naturally problematic? N (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ____	No ✓	**Is the Sampled Area within a Wetland?** Yes ____ No ✓
Hydric Soil Present?	Yes ____	No ✓	
Wetland Hydrology Present?	Yes ____	No ✓	

Remarks: Drainage ditch along Pelican Rd. No wetland indicators. No OHWM. Potential waters of the State.

VEGETATION – Use scientific names of plants.

	Absolute % Cover	Dominant Species?	Indicator Status
Tree Stratum (Plot size: ~)			
1.			
2.			
3.			
4.			
	~ = Total Cover		
Sapling/Shrub Stratum (Plot size: 10')			
1. Atriplex polycarpa	10%	Y	FACU
2.			
3.			
4.			
5.			
	~ = Total Cover		
Herb Stratum (Plot size: ____)			
1. Bromus madritensis ssp rubens	5%	Y	UPL
2. Aristida sp.	1%	N	NI/FACU
3.			
4.			
5.			
6.			
7.			
8.			
	11% = Total Cover		
Woody Vine Stratum (Plot size: ~)			
1.			
2.			
	~ = Total Cover		

% Bare Ground in Herb Stratum ≈ 89% % Cover of Biotic Crust ~

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 0 (A)

Total Number of Dominant Species Across All Strata: 2 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 0% (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:
OBL species ____	x 1 = ____
FACW species ____	x 2 = ____
FAC species ____	x 3 = ____
FACU species ____	x 4 = ____
UPL species ____	x 5 = ____
Column Totals: ____ (A)	____ (B)

Prevalence Index = B/A = ____

Hydrophytic Vegetation Indicators:

- ___ Dominance Test is >50%
- ___ Prevalence Index is ≤3.0[1]
- ___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)
- ___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes ____ No ✓

Remarks: No dominant hydrophytic vegetation.

SOIL

Sampling Point: SP 11

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	%	Redox Features Color (moist)	%	Type[1]	Loc[2]	Texture	Remarks
0-2	—						flaky	- may have been layer of hydrophobic soil additive?
2-10	10YR 4/4	100	—				loamy sand	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) **(LRR C)**
- ___ 1 cm Muck (A9) **(LRR D)**
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) **(LRR C)**
- ___ 2 cm Muck (A10) **(LRR B)**
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: hardpan

Depth (inches): 10"

Hydric Soil Present? Yes ____ No ✓

Remarks: Soil had 2" layer of flaky soil that may have been imported fill - it was flaky and hydrophobic (repelled water). Eight inch layer of loamy sand underneath. No hydric soil indicators

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) **(Nonriverine)**
- ___ Sediment Deposits (B2) **(Nonriverine)**
- ___ Drift Deposits (B3) **(Nonriverine)**
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) **(Riverine)**
- ___ Sediment Deposits (B2) **(Riverine)**
- ___ Drift Deposits (B3) **(Riverine)**
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes ____ No ✓ Depth (inches): ____

Water Table Present? Yes ____ No ✓ Depth (inches): ____

Saturation Present? (includes capillary fringe) Yes ____ No ____ Depth (inches): ____

Wetland Hydrology Present? Yes ____ No ✓

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks: No hydrology indicators.

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Aera Belridge CCS City/County: Belridge Western Oil Field, Kern County Sampling Date: 04/13/22

Applicant/Owner: Aera State: CA Sampling Point: S1R

Investigator(s): G. Hoetker, L. Elms Section, Township, Range: S20, T28S, R21E

Landform (hillslope, terrace, etc.): terrace - uplands Local relief (concave, convex, none): _____ Slope (%): 1%

Subregion (LRR): LRRC Lat: 35.470268° Long: -119.728162° Datum: NAD 83

Soil Map Unit Name: 174 - Kimberlina fine sandy loam, 0-2% slopes NWI classification: N/A (upland)

Are climatic / hydrologic conditions on the site typical for this time of year? Yes _____ No _____ (If no, explain in Remarks.)

Are Vegetation ___, Soil ___, or Hydrology ___ significantly disturbed? N Are "Normal Circumstances" present? Yes ✓ No _____

Are Vegetation _____, Soil _____, or Hydrology _____ naturally problematic? N (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes _____	No ✓	**Is the Sampled Area within a Wetland?** Yes _____ No ✓
Hydric Soil Present?	Yes _____	No ✓	
Wetland Hydrology Present?	Yes _____	No ✓	

Remarks: Uplands adjacent to excavated drainage ditch. No wetland indicators.

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: —)	Absolute % Cover	Dominant Species?	Indicator Status
1.			
2.			
3.			
4.			
	= Total Cover		
Sapling/Shrub Stratum (Plot size: —)			
1. Atriplex polycarpa	15%	Y	FACU
2.			
3.			
4.			
5.			
	= Total Cover		
Herb Stratum (Plot size: 5')			
1. Bromus madritensis ssp. rubens	5%	Y	UPL
2. Centaurea melitensis	1%	N	NI/UPL
3.			
4.			
5.			
6.			
7.			
8.			
	6% = Total Cover		
Woody Vine Stratum (Plot size: —)			
1.			
2.			
	= Total Cover		

% Bare Ground in Herb Stratum ~94% % Cover of Biotic Crust —

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 0 (A)

Total Number of Dominant Species Across All Strata: 2 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 0% (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:	
OBL species	x 1 =	
FACW species	x 2 =	
FAC species	x 3 =	
FACU species	x 4 =	
UPL species	x 5 =	
Column Totals: (A)		(B)

Prevalence Index = B/A = _____

Hydrophytic Vegetation Indicators:

___ Dominance Test is >50%

___ Prevalence Index is ≤3.0[1]

___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)

___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes _____ No ✓

Remarks: No dominant hydrophytic vegetation.

SOIL

Sampling Point: SP12

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	%	Redox Features Color (moist)	%	Type[1]	Loc[2]	Texture	Remarks
0-10"	10YR 4/4	100%					sandy loam	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) (**LRR C**)
- ___ 1 cm Muck (A9) (**LRR D**)
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) (**LRR C**)
- ___ 2 cm Muck (A10) (**LRR B**)
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: hard pan

Depth (inches): 10"

Hydric Soil Present? Yes ____ No ✓

Remarks:

No hydric soil indicators

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) (**Nonriverine**)
- ___ Sediment Deposits (B2) (**Nonriverine**)
- ___ Drift Deposits (B3) (**Nonriverine**)
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) (**Riverine**)
- ___ Sediment Deposits (B2) (**Riverine**)
- ___ Drift Deposits (B3) (**Riverine**)
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes ____ No ✓ Depth (inches): ____

Water Table Present? Yes ____ No ✓ Depth (inches): ____

Saturation Present? (includes capillary fringe) Yes ____ No ✓ Depth (inches): ____

Wetland Hydrology Present? Yes ____ No ✓

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

No hydrology indicators.

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Aera Belridge CCS City/County: Belridge Old, Western Kern Co Sampling Date: 05/20/23

Applicant/Owner: Aera State: CA Sampling Point: SP15

Investigator(s): G. Hoetker Section, Township, Range: S19, T28S, R21E

Landform (hillslope, terrace, etc.): Low - part of remnant stream Local relief (concave, convex, none): concave Slope (%): 0%

Subregion (LRR): LRRC Lat: 35.481587 Long: -119.743045 Datum: NAD83

Soil Map Unit Name: 212 - Panoche clay loam, 2 to 5 percent slopes NWI classification: Riverine

Are climatic / hydrologic conditions on the site typical for this time of year? Yes ____ No ____ (If no, explain in Remarks.)

Are Vegetation ____, Soil ✓, or Hydrology ____ significantly disturbed? Are "Normal Circumstances" present? Yes ✓ No ____

Are Vegetation ____, Soil ____, or Hydrology ____ naturally problematic? N (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ____	No ✓	**Is the Sampled Area within a Wetland?** Yes ____ No ✓
Hydric Soil Present?	Yes ____	No ✓	
Wetland Hydrology Present?	Yes ✓	No ____	

Remarks: Basin in remnant stream; no OHWM; potential waters of the State only hydrology indicator is present.

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: 30')	Absolute % Cover	Dominant Species?	Indicator Status
1.			
2.			
3.			
4.			
	0 = Total Cover		
Sapling/Shrub Stratum (Plot size: 10')			
1.			
2.			
3.			
4.			
5.			
	0 = Total Cover		
Herb Stratum (Plot size: 5')			
1.			
2.			
3.			
4.			
5.			
6.			
7.			
8.			
	0 = Total Cover		
Woody Vine Stratum (Plot size: 10')			
1.			
2.			
	0 = Total Cover		

% Bare Ground in Herb Stratum 100% % Cover of Biotic Crust ____

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 0 (A)

Total Number of Dominant Species Across All Strata: 0 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 0 (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:
OBL species ____	x 1 = ____
FACW species ____	x 2 = ____
FAC species ____	x 3 = ____
FACU species ____	x 4 = ____
UPL species ____	x 5 = ____
Column Totals: ____ (A)	____ (B)

Prevalence Index = B/A = ____

Hydrophytic Vegetation Indicators:

___ Dominance Test is >50%

___ Prevalence Index is ≤3.0[1]

___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)

___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes ____ No ✓

Remarks: No vegetation; no hydrophytes in drainage

SOIL

Sampling Point: SP15

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	Matrix %	Redox Features Color (moist)	Redox Features %	Redox Features Type[1]	Redox Features Loc[2]	Texture	Remarks
0-4"	2.5Y 5/3	100					sl thy clay loam	2" + moist
4-16"	2.5Y 5/4	100					sandy loam	moist

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) (**LRR C**)
- ___ 1 cm Muck (A9) (**LRR D**)
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) (**LRR C**)
- ___ 2 cm Muck (A10) (**LRR B**)
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: _____

Depth (inches): _____

Hydric Soil Present? Yes _____ No ✓

Remarks:

No hydric soil indicators

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) (**Nonriverine**)
- ___ Sediment Deposits (B2) (**Nonriverine**)
- ___ Drift Deposits (B3) (**Nonriverine**)
- ✓ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) (**Riverine**)
- ___ Sediment Deposits (B2) (**Riverine**)
- ___ Drift Deposits (B3) (**Riverine**)
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes _____ No ✓ Depth (inches): _____

Water Table Present? Yes _____ No ✓ Depth (inches): _____

Saturation Present? (includes capillary fringe) Yes _____ No ✓ Depth (inches): _____

Wetland Hydrology Present? Yes ✓ No _____

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

surface soil cracks in basin; evidence of recent inundation

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Nova Belridge CCS City/County: Belridge Western Oil Field / Kern Co Sampling Date: 05/26/23

Applicant/Owner: Aera State: CA Sampling Point: SP16

Investigator(s): G. Hoefker Section, Township, Range: S19, T28S, R21E

Landform (hillslope, terrace, etc.): uplands Local relief (concave, convex, none): none Slope (%): 0

Subregion (LRR): LRR C Lat: 35.491542 Long: -119.743325 Datum: NAD83

Soil Map Unit Name: 212 - Panoche clay loam, 2 to 5 percent slopes NWI classification: N/A, uplands

Are climatic / hydrologic conditions on the site typical for this time of year? Yes ✓ No ____ (If no, explain in Remarks.)

Are Vegetation N, Soil N, or Hydrology N significantly disturbed? Are "Normal Circumstances" present? Yes ✓ No ____

Are Vegetation ____, Soil ____, or Hydrology ____ naturally problematic? N (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ____	No ✓	**Is the Sampled Area within a Wetland?** Yes ____ No ✓
Hydric Soil Present?	Yes ____	No ✓	
Wetland Hydrology Present?	Yes ____	No ✓	

Remarks: Uplands, no wetland indicators.

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: 30')	Absolute % Cover	Dominant Species?	Indicator Status
1. —			
2.			
3.			
4.			
	0 = Total Cover		
Sapling/Shrub Stratum (Plot size: 10')			
1. —			
2.			
3.			
4.			
5.			
	0 = Total Cover		
Herb Stratum (Plot size: 5')			
1. —			
2.			
3.			
4.			
5.			
6.			
7.			
8.			
	0 = Total Cover		
Woody Vine Stratum (Plot size: 10')			
1. —			
2.			
	0 = Total Cover		

% Bare Ground in Herb Stratum 100% % Cover of Biotic Crust —

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 0 (A)

Total Number of Dominant Species Across All Strata: 0 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 0% (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:	
OBL species	x 1 =	
FACW species	x 2 =	
FAC species	x 3 =	
FACU species	x 4 =	
UPL species	x 5 =	
Column Totals: (A)		(B)

Prevalence Index = B/A =

Hydrophytic Vegetation Indicators:

___ Dominance Test is >50%

___ Prevalence Index is ≤3.0[1]

___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)

___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes ____ No ✓

Remarks: No vegetation, no hydrophytic indicators.

SOIL

Sampling Point: SP16

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	%	Redox Features Color (moist)	%	Type[1]	Loc[2]	Texture	Remarks
0-6"	10YR 4/4	100					Sandy loam	
6-16"	impenetrable							hardpan

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) (**LRR C**)
- ___ 1 cm Muck (A9) (**LRR D**)
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) (**LRR C**)
- ___ 2 cm Muck (A10) (**LRR B**)
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: hardpan

Depth (inches): 6"

Hydric Soil Present? Yes ____ No ✓

Remarks:

No hydric soil indicators.

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) (**Nonriverine**)
- ___ Sediment Deposits (B2) (**Nonriverine**)
- ___ Drift Deposits (B3) (**Nonriverine**)
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) (**Riverine**)
- ___ Sediment Deposits (B2) (**Riverine**)
- ___ Drift Deposits (B3) (**Riverine**)
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes ____ No ✓ Depth (inches): ____

Water Table Present? Yes ____ No ✓ Depth (inches): ____

Saturation Present? (includes capillary fringe) Yes ____ No ✓ Depth (inches): ____

Wetland Hydrology Present? Yes ____ No ✓

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

No hydrology indicators.

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Aera Belridge CCS City/County: Belridge Western Oil Field, Kern Co. Sampling Date: 06/13/23

Applicant/Owner: Aera State: CA Sampling Point: SP17

Investigator(s): G. Hoetker Section, Township, Range: S24, T29S, R21E

Landform (hillslope, terrace, etc.): Chico Martinez Creek Local relief (concave, convex, none): concave Slope (%): 0%

Subregion (LRR): LRR C Lat: 35.440736 Long: -119.723367 Datum: NAD83

Soil Map Unit Name: 174 - Kimberlina fine sandy loam, 0-2% slopes NWI classification: Riverine

Are climatic / hydrologic conditions on the site typical for this time of year? Yes ✓ No ____ (If no, explain in Remarks.)

Are Vegetation ____, Soil ____, or Hydrology ____ significantly disturbed? N Are "Normal Circumstances" present? Yes ✓ No ____

Are Vegetation ____, Soil ____, or Hydrology ____ naturally problematic? N (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ____	No ✓	**Is the Sampled Area within a Wetland?** Yes ____ No ✓
Hydric Soil Present?	Yes ____	No ✓	
Wetland Hydrology Present?	Yes ____	No ✓	

Remarks: Section of Chico Martinez Creek south of 7th Standard Rd; no OHWM; no wetland indicators present, potential waters of the State

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: 30')	Absolute % Cover	Dominant Species?	Indicator Status
1.			
2.			
3.			
4.			
	—	= Total Cover	
Sapling/Shrub Stratum (Plot size: 10')			
1. Atriplex polycarpa	10%	Y	FACW
2.			
3.			
4.			
5.			
	—	= Total Cover	
Herb Stratum (Plot size: 5')			
1. Datura wrightii	15%	Y	UPL
2. Croton setiger	5%	Y	NL
3.			
4.			
5.			
6.			
7.			
8.			
	20%	= Total Cover	
Woody Vine Stratum (Plot size: 10')			
1.			
2.			
	—	= Total Cover	

% Bare Ground in Herb Stratum 80% % Cover of Biotic Crust —

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 0 (A)

Total Number of Dominant Species Across All Strata: 3 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 0% (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:
OBL species ____	x 1 = ____
FACW species ____	x 2 = ____
FAC species ____	x 3 = ____
FACU species ____	x 4 = ____
UPL species ____	x 5 = ____
Column Totals: ____ (A)	____ (B)

Prevalence Index = B/A = ____

Hydrophytic Vegetation Indicators:

___ Dominance Test is >50%

___ Prevalence Index is ≤3.0[1]

___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)

___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes ____ No ✓

Remarks: No dominant hydrophytic vegetation present.

SOIL

Sampling Point: SP17

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	%	Redox Features Color (moist)	%	Type[1]	Loc[2]	Texture	Remarks
0-16"	10YR5/6	100%					Sand	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) (**LRR C**)
- ___ 1 cm Muck (A9) (**LRR D**)
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) (**LRR C**)
- ___ 2 cm Muck (A10) (**LRR B**)
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: —

Depth (inches): —

Hydric Soil Present? Yes ____ No ✓

Remarks:

No hydric soil indicators.

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) (**Nonriverine**)
- ___ Sediment Deposits (B2) (**Nonriverine**)
- ___ Drift Deposits (B3) (**Nonriverine**)
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) (**Riverine**)
- ___ Sediment Deposits (B2) (**Riverine**)
- ___ Drift Deposits (B3) (**Riverine**)
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes ____ No ✓ Depth (inches): ____

Water Table Present? Yes ____ No ✓ Depth (inches): ____

Saturation Present? (includes capillary fringe) Yes ____ No ✓ Depth (inches): ____

Wetland Hydrology Present? Yes ____ No ✓

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

No hydrology indicators.

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Aera Belridge CCS City/County: Belridge Western Oil Field, Kern Co. Sampling Date: 06/13

Applicant/Owner: Aera State: CA Sampling Point: SP18

Investigator(s): G. Hoetker Section, Township, Range: S24, T29S, R21E

Landform (hillslope, terrace, etc.): slope next to creek Local relief (concave, convex, none): slightly convex Slope (%): 2%

Subregion (LRR): LRR C Lat: 35.440487 Long: -119.723336 Datum: NAD83

Soil Map Unit Name: 174 – Cimberlina fine sandy loam, 0-2% slopes NWI classification: N/A; uplands

Are climatic / hydrologic conditions on the site typical for this time of year? Yes ✓ No ____ (If no, explain in Remarks.)

Are Vegetation ____, Soil ____, or Hydrology ____ significantly disturbed? N Are "Normal Circumstances" present? Yes ✓ No ____

Are Vegetation ____, Soil ____, or Hydrology ____ naturally problematic? N (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ____	No ✓	**Is the Sampled Area within a Wetland?** Yes ____ No ✓
Hydric Soil Present?	Yes ____	No ✓	
Wetland Hydrology Present?	Yes ____	No ✓	

Remarks: Uplands; no wetland indicators

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: 30')	Absolute % Cover	Dominant Species?	Indicator Status
1. —			
2.			
3.			
4.			
	—	= Total Cover	
Sapling/Shrub Stratum (Plot size: 10')			
1. Atriplex polycarpa	20%	Y	FACW
2.			
3.			
4.			
5.			
		= Total Cover	
Herb Stratum (Plot size: 5')			
1. Bromus madritensis ssp rubens	30%	Y	
2. Amsinckia menziesii	10%	Y	
3. Lactuca serriola	5%	N	
4.			
5.			
6.			
7.			
8.			
		= Total Cover	
Woody Vine Stratum (Plot size: 10')			
1. —			
2.			
	—	= Total Cover	

% Bare Ground in Herb Stratum ~55% % Cover of Biotic Crust —

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 1 (A)

Total Number of Dominant Species Across All Strata: 3 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 0% (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:
OBL species ____	x 1 = ____
FACW species ____	x 2 = ____
FAC species ____	x 3 = ____
FACU species ____	x 4 = ____
UPL species ____	x 5 = ____
Column Totals: ____ (A)	____ (B)

Prevalence Index = B/A = ____

Hydrophytic Vegetation Indicators:

___ Dominance Test is >50%

___ Prevalence Index is ≤3.0[1]

___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)

___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes ____ No ✓

Remarks: No dominant hydrophytic vegetation present.

SOIL

Sampling Point: SP18

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	%	Redox Features Color (moist)	%	Type[1]	Loc[2]	Texture	Remarks
0-16"	10YR 5/6	100%					loam	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) (**LRR C**)
- ___ 1 cm Muck (A9) (**LRR D**)
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) (**LRR C**)
- ___ 2 cm Muck (A10) (**LRR B**)
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: ~~_____~~

Depth (inches): ~~_____~~

Hydric Soil Present? Yes _____ No ✓

Remarks:

No hydric soil indicators.

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) (**Nonriverine**)
- ___ Sediment Deposits (B2) (**Nonriverine**)
- ___ Drift Deposits (B3) (**Nonriverine**)
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) (**Riverine**)
- ___ Sediment Deposits (B2) (**Riverine**)
- ___ Drift Deposits (B3) (**Riverine**)
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes _____ No ✓ Depth (inches): _____

Water Table Present? Yes _____ No ✓ Depth (inches): _____

Saturation Present? (includes capillary fringe) Yes _____ No ✓ Depth (inches): _____

Wetland Hydrology Present? Yes _____ No ✓

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

No wetland hydrology indicators.

Area

Project: CCS (N 45 Baldridge) **Date:** 07/19/22 **Time:** 11:30
Project Number: 185805372 **Town:** W. Kern Co. **State:** CA
Stream: Chico Martinez Creek **Photo begin file#** **Photo end file#**
Investigator(s): G. Hecker, E Martin, J. Pratt, C Coates

Y ☑ / N ☐ Do normal circumstances exist on the site?

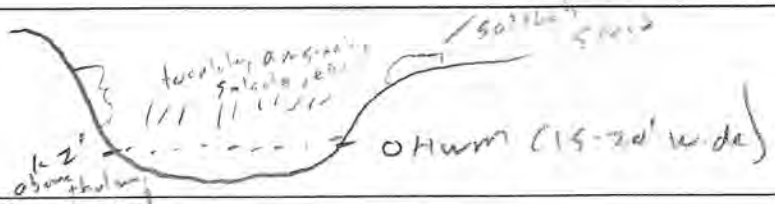
Y ☐ / N ☑ Is the site significantly disturbed?

Location Details: Chico Martinez Creek

Projection: 35.445175°, **Datum:** NAD 83
Coordinates: -119.715113°

Notes: 0.4-mile section of Chico Martinez Creek

Brief site description:

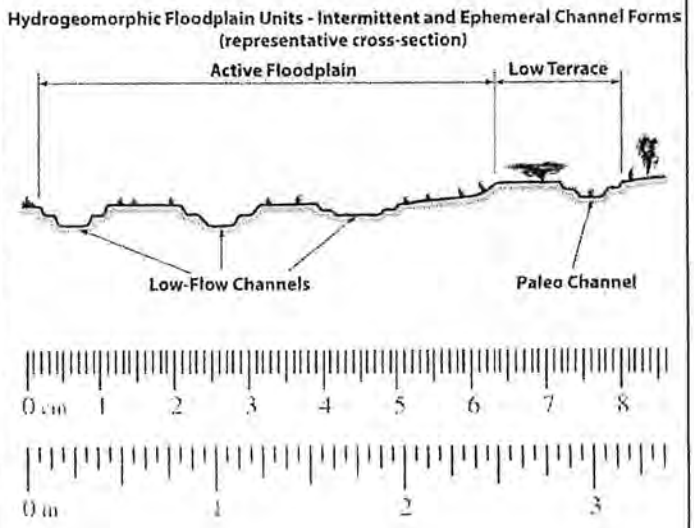


Checklist of resources (if available):

- ☑ Aerial photography
  Dates:
- ☑ Topographic maps
  Scale:
- ☐ Geologic maps
- ☐ Vegetation maps
- ☑ Soils maps
- ☐ Rainfall/precipitation maps
- ☑ Existing delineation(s) for site
- ☑ Global positioning system (GPS)
- ☐ Other studies
- ☐ Stream gage data
  Gage number:
  Period of record:
- ☐ Clinometer / level
- ☐ History of recent effective discharges
- ☐ Results of flood frequency analysis
- ☐ Most recent shift-adjusted rating
- ☐ Gage heights for 2-, 5-, 10-, and 25-year events and the most recent event exceeding a 5-year event

The dominant Wentworth size class that imparts a characteristic texture to each zone of a channel cross-section is recorded in the average sediment texture field under the characteristics section for the zone of interest.

Inches (in)	Millimeters (mm)	Wentworth size class	
10.08	256	Boulder	
2.56	64	Cobble	Gravel
0.157	4	Pebble	
		Granule	
0.079	2.00	Very coarse sand	
0.039	1.00	Coarse sand	
0.020	0.50	Medium sand	Sand
1/2 0.0098	0.25	Fine sand	
1/4 0.005	0.125	Very fine sand	
1/8 0.0025	0.0625	Coarse silt	
1/16 0.0012	0.031	Medium silt	
1/32 0.00061	0.0156	Fine silt	Silt
1/64 0.00031	0.0078	Very fine silt	
1/128 0.00015	0.0039	Clay	Mud



☑ **Walk the channel and floodplain within the study area to get an impression of the vegetation and geomorphology present at the site. Record any potential anthropogenic influences on the channel system in "Notes" above.**

☐ **Locate the low-flow channel (lowest part of the channel). Record observations.**

Characteristics of the low-flow channel: thin layer of cobble & gravel on surface, loamy sand below

Average sediment texture: _____

Total veg cover: 41 % Tree: ____ % Shrub: 25 % Herb: 16 %

Community successional stage:

☐ NA ☑ Mid (herbaceous, shrubs, saplings)

☐ Early (herbaceous & seedlings) ☐ Late (herbaceous, shrubs, mature trees)

Dominant species present: Atriplex polycarpa, Salsola tragus, Centaurea melitensis

Other: ☐ _____

☐ _____

☐ _____

☐ _____

☑ **Walk away from the low-flow channel along cross-section. Record characteristics of the low-flow/active floodplain boundary.**

Characteristics used to delineate the low-flow/active floodplain boundary:

☑ Change in total veg cover ☐ Tree ☐ Shrub ☐ Herb

☐ Change in overall vegetation maturity

☐ Change in dominant species present

☐ Other ☐ Presence of bed and bank

☐ Drift and/or debris

☐ Other: _____

☐ Other: _____

☑ **Continue walking the channel cross-section. Record observations below.**

Characteristics of the active floodplain:

Average sediment texture: same as above

Total veg cover: 41 % Tree: ____ % Shrub: 25 % Herb: 16 %

Community successional stage:

☐ NA ☑ Mid (herbaceous, shrubs, saplings)

☐ Early (herbaceous & seedlings) ☐ Late (herbaceous, shrubs, mature trees)

Dominant species present: Same as above

Other: ☐ _____

☐ _____

☐ _____

☐ _____

☑ **Continue walking the channel cross-section. Record indicators of the active floodplain/low terrace boundary.**

Characteristics used to delineate the active floodplain/ low terrace boundary:

- ☐ Change in average sediment texture
- ☐ Change in total veg cover ☐ Tree ☐ Shrub ☐ Herb
- ☐ Change in overall vegetation maturity
- ☐ Change in dominant species present
- ☐ Other
  - ☐ Presence of bed and bank
  - ☐ Drift and/or debris
  - ☐ Other: _____
  - ☐ Other: _____

☑ **Walk the active floodplain/low terrace boundary both upstream and downstream of the cross-section to verify that the indicators used to identify the transition are consistently associated the transition in both directions.**

Consistency of indicators used to delineate the active floodplain/low terrace boundary:

- Y ☑ N ☐ Change in average sediment texture
- Y ☑ N ☐ Change in total veg cover ☐ Tree ☐ Shrub ☐ Herb
- Y ☑ N ☐ Change in overall vegetation maturity
- Y ☑ N ☐ Change in dominant species present
- Y ☑ N ☐ Other:
  - Y ☑ N ☐ Presence of bed and bank
  - Y ☐ N ☐ Drift and/or debris
  - Y ☐ N ☐ Other: _____
  - Y ☐ N ☐ Other: _____

☐ **If the characteristics used to delineate the active floodplain/low terrace boundary were NOT consistently associated with the transition in both the upstream and downstream directions, repeat all steps above.**

☐ **Continue walking the channel cross-section. Record characteristics of the low terrace.**

Characteristics of the low terrace:

Average sediment texture: minimal gravel, loamy sand

Total veg cover: 25 % Tree: ____ % Shrub: ____ % Herb: 5 %

Community successional stage:

- ☐ NA
- ☑ Early (herbaceous & seedlings)
- ☐ Mid (herbaceous, shrubs, saplings)
- ☐ Late (herbaceous, shrubs, mature trees)

Dominant species present: Salsola tragus, Centaurea maculosa

Other:

- ☐ _____
- ☐ _____
- ☐ _____
- ☐ _____

☑ **If characteristics used to delineate the active floodplain/low terrace boundary were deemed reliable, acquire boundary.**

Active floodplain/low terrace boundary acquired via:

- ☐ Mapping on aerial photograph
- ☑ GPS
- ☐ Digitized on computer
- ☐ Other: _____

Project: Aera CCS (Chico Bridge) **Date:** 07/20/22 **Time:** 11:30
Project Number: 1858053772 **~~Town~~:** W. Kern Co. **State:** CA
Stream: Chico Martinez Creek **Photo begin file#** **Photo end file#**
Investigator(s): G. Hoetker, G. Martin, J. Pratt, C. Corley

Y ☑ / N ☐ Do normal circumstances exist on the site?

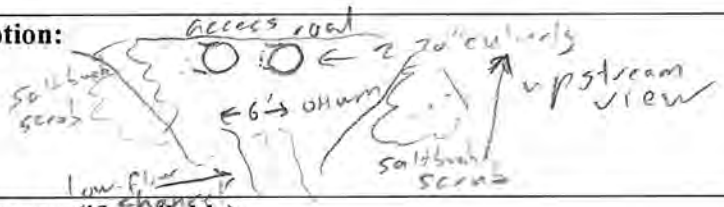
Y ☑ / N ☐ Is the site significantly disturbed?

Location Details: Chico Martinez Creek

Projection: 35.460661° **Datum:** NAD 83
Coordinates: 119.698066°

Notes: Small section of Chico Martinez Creek east of Hwy 33.

Brief site description:



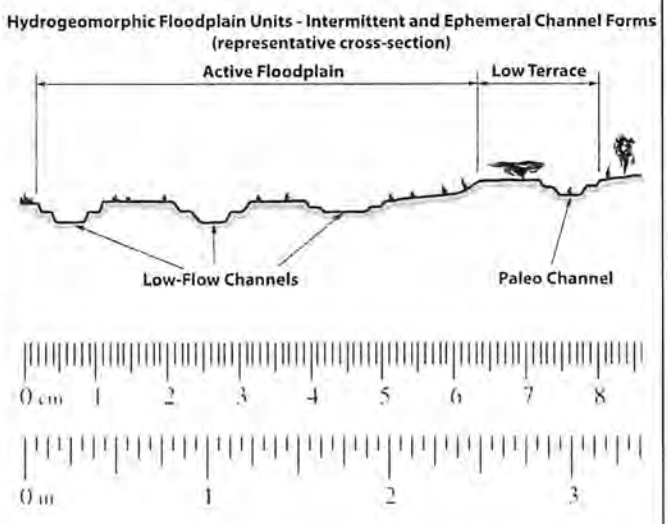
Checklist of resources (if available):

- ☑ Aerial photography
  Dates:
- ☑ Topographic maps
  Scale:
- ☐ Geologic maps
- ☐ Vegetation maps
- ☑ Soils maps
- ☐ Rainfall/precipitation maps
- ☐ Existing delineation(s) for site
- ☑ Global positioning system (GPS)
- ☐ Other studies

- ☐ Stream gage data
  Gage number:
  Period of record:
- ☐ Clinometer / level
- ☐ History of recent effective discharges
- ☐ Results of flood frequency analysis
- ☐ Most recent shift-adjusted rating
- ☐ Gage heights for 2-, 5-, 10-, and 25-year events and the most recent event exceeding a 5-year event

The dominant Wentworth size class that imparts a characteristic texture to each zone of a channel cross-section is recorded in the average sediment texture field under the characteristics section for the zone of interest.

Millimeters (mm)	Inches (in)	Wentworth size class	
10.08	256	Boulder	
2.56	64	Cobble	Gravel
0.157	4	Pebble	
0.079	2.00	Granule	
0.039	1.00	Very coarse sand	
0.020	0.50	Coarse sand	
0.0098 (1/2)	0.25	Medium sand	Sand
0.005 (1/4)	0.125	Fine sand	
0.0025 (1/8)	0.0625	Very fine sand	
0.0012 (1/16)	0.031	Coarse silt	
0.00061 (1/32)	0.0156	Medium silt	Silt
0.00031 (1/64)	0.0078	Fine silt	
0.00015 (1/128)	0.0039	Very fine silt	
		Clay	Mud



☑ **Walk the channel and floodplain within the study area to get an impression of the vegetation and geomorphology present at the site. Record any potential anthropogenic influences on the channel system in "Notes" above.**

☑ **Locate the low-flow channel (lowest part of the channel). Record observations.**

Characteristics of the low-flow channel:

Average sediment texture: loamy sand

Total veg cover: ____ % Tree: ____ % Shrub: 35 % Herb: ____ %

Community successional stage:

☐ NA ☑ Mid (herbaceous, shrubs, saplings)

☐ Early (herbaceous & seedlings) ☐ Late (herbaceous, shrubs, mature trees)

Dominant species present: Atriplex polycarpa

Other: ☐ ☐ ☐ ☐

☑ **Walk away from the low-flow channel along cross-section. Record characteristics of the low-flow/active floodplain boundary.**

Characteristics used to delineate the low-flow/active floodplain boundary: same as above

☐ Change in total veg cover ☐ Tree ☐ Shrub ☐ Herb

☐ Change in overall vegetation maturity

☐ Change in dominant species present

☐ Other ☐ Presence of bed and bank

☐ Drift and/or debris

☐ Other: ____

☐ Other: ____

☑ **Continue walking the channel cross-section. Record observations below.**

Characteristics of the low-flow channel:

Average sediment texture: loamy sand

Total veg cover: ____ % Tree: ____ % Shrub: 35 % Herb: ____ %

Community successional stage:

☐ NA ☑ Mid (herbaceous, shrubs, saplings)

☐ Early (herbaceous & seedlings) ☐ Late (herbaceous, shrubs, mature trees)

Dominant species present: Atriplex polycarpa

Other: ☐ ☐ ☐ ☐

☑ **Continue walking the channel cross-section. Record indicators of the active floodplain/low terrace boundary.**

Characteristics used to delineate the active floodplain/ low terrace boundary:

- ☐ Change in average sediment texture
- ☑ Change in total veg cover ☐ Tree ☑ Shrub ☐ Herb
- ☐ Change in overall vegetation maturity
- ☐ Change in dominant species present
- ☐ Other ☐ Presence of bed and bank
  - ☐ Drift and/or debris
  - ☐ Other: _____
  - ☐ Other: _____

☑ **Walk the active floodplain/low terrace boundary both upstream and downstream of the cross-section to verify that the indicators used to identify the transition are consistently associated the transition in both directions.**

Consistency of indicators used to delineate the active floodplain/low terrace boundary:

- Y ☐ N ☐ Change in average sediment texture
- Y ☑ N ☐ Change in total veg cover ☐ Tree ☑ Shrub 65% ☐ Herb
- Y ☐ N ☐ Change in overall vegetation maturity
- Y ☐ N ☐ Change in dominant species present
- Y ☐ N ☐ Other: Y ☑ N ☐ Presence of bed and bank
  - Y ☐ N ☐ Drift and/or debris
  - Y ☐ N ☐ Other: _____
  - Y ☐ N ☐ Other: _____

☐ **If the characteristics used to delineate the active floodplain/low terrace boundary were NOT consistently associated with the transition in both the upstream and downstream directions, repeat all steps above.**

☑ **Continue walking the channel cross-section. Record characteristics of the low terrace.**

Characteristics of the low terrace:

Average sediment texture: loamy sand

Total veg cover: ____ % Tree: ____ % Shrub: 65 % Herb: ____ %

Community successional stage:

- ☐ NA
- ☑ Mid (herbaceous, shrubs, saplings)
- ☐ Early (herbaceous & seedlings)
- ☐ Late (herbaceous, shrubs, mature trees)

Dominant species present: Atriplex polycarpa

Other:

- ☐ _____
- ☐ _____
- ☐ _____
- ☐ _____

☐ **If characteristics used to delineate the active floodplain/low terrace boundary were deemed reliable, acquire boundary.**

Active floodplain/low terrace boundary acquired via:

- ☐ Mapping on aerial photograph
- ☐ GPS
- ☐ Digitized on computer
- ☐ Other: _____

Appendix C□ SITE PHOTOGRAPHS

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C.2 Aquatic Resources Delineation Report

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Aera CarbonFrontier Project

Aquatic Resources Delineation Report

July 13, 2023

Prepared for:

Aera Energy LLC
10000 Ming Avenue
Bakersfield, CA 93311-1302

Prepared by:

Stantec Consulting Services Inc.
5500 Ming Avenue, Suite 410
Bakersfield, CA 93309

Sign-off Sheet

The conclusions in the Report titled Aquatic Resources Delineation Report for the CarbonFrontier Project are Stantec's professional opinion, as of the time of the Report, and concerning the scope described in the Report. The opinions in the document are based on conditions and information existing at the time the scope of work was conducted and do not take into account any subsequent changes. The Report relates solely to the specific project for which Stantec was retained and the stated purpose for which the Report was prepared. The Report is not to be used or relied on for any variation or extension of the project, or for any other project or purpose, and any unauthorized use or reliance is at the recipient's own risk.

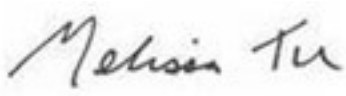
Stantec has assumed all information received from Aera Energy LLC (the "Client") and third parties in the preparation of the Report to be correct. While Stantec has exercised a customary level of judgment or due diligence in the use of such information, Stantec assumes no responsibility for the consequences of any error or omission contained therein.

This Report is intended solely for use by the Client in accordance with Stantec's contract with the Client. While the Report may be provided to applicable authorities having jurisdiction and others for whom the Client is responsible, Stantec does not warrant the services to any third party. The Report may not be relied upon by any other party without the express written consent of Stantec, which may be withheld at Stantec's discretion.

Prepared by 

(signature)

Geoff Hoetker, Senior Biologist

Reviewed by 

(signature)

Melissa Tu, Senior Biologist

Reviewed and approved by 

(signature)

Jared Varonin, Principal Biologist/Ecosystems Technical Resource Group Leader

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Executive Summary

On behalf of Aera Energy LLC (Aera), Stantec Consulting Services Inc. (Stantec) conducted a delineation of potential federal wetlands and waters of the United States (WOTUS), and waters of the State of California (waters of the State) for an approximately 3,252-acre Study Area for the CarbonFrontier Project located within the South and North Belridge oil fields in western Kern County, California (Appendix A, Figure 1). The Study Area is defined as the proposed Aera CarbonFrontier Project surface features footprint plus a 500-foot radius buffer.

The delineation was conducted within the Study Area on June 1, July 18, July 20, and September 13, 2022; and May 26 and June 13, 2023 in accordance with the *Corps of Engineers Wetlands Delineation Manual* (Environmental Laboratory 1987), the *Regional Supplement to the Corps of Engineers Wetland Delineation Manual: Arid West Region (Version 2.0)* (U.S. Army Corps of Engineers [USACE] 2008), *A Field Guide to the Identification of Ordinary High Water Mark (OHWM) in the Arid West Region of the United States* (Lichvar and McColley 2008), and the *Implementation Guidance for the State Wetland Definition and Procedures for Discharges of Dredged or Fill Material to Waters of the State* (State Water Resources Control Board [SWRCB] 2020). Data documenting presence/absence of vegetation, soils, and hydrology wetland parameters at the sample points within the Study Area during the delineation were collected on Arid West Region Wetland Determination Data Forms (Arid West – Version 2.0) (Appendix B). Where applicable, the OHWMs of aquatic features were delineated per Lichvar and McColley (2008), with data documented on OHWM datasheets (Appendix B). Photographs of the Study Area are included in Appendix C.

The purpose of this delineation of aquatic resources is to document and describe (if present): federal wetlands and WOTUS, waters of the State, and/or California Department of Fish and Wildlife (CDFW) streams in accordance with reporting standards for the USACE, the Central Valley Regional Water Quality Control Board (RWQCB). No potential federal wetlands or WOTUS were delineated or otherwise found to occur within the Study Area. Potential waters of the State features were delineated in the Study Area, including sections of Chico Martinez Creek, remnants of ephemeral streams, and various drainage ditches; these features may also be regulated as jurisdictional features by CDFW.

Stantec advises all interested parties to treat the determinations and supporting information contained herein as preliminary. Verification of jurisdictional boundaries are formally determined through permitting consultation with resource agencies.

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Abbreviations

Aera	Aera Energy LLC
Aera CarbonFrontier Project	Aera Carbon Capture and Sequestration Project
AJD	Approved Jurisdictional Delineation
Amsl	above mean sea level
CCS	carbon capture and sequestration
CDFW	California Department of Fish and Wildlife
CFGC	California Fish and Game Code
CO_2	carbon dioxide
CUP	Conditional Use Permit
CWA	Clean Water Act
ºF	degrees Fahrenheit
FAC	facultative plant
FACW	facultative wetland plant
FACU	facultative upland plant
GPS	Global Positioning System
HUC	Hydrologic Unit Code
MMt	million metric tons
NAD 83	North American Datum of 1983
NHD	National Hydrography Dataset
NI	no hydrophytic indicator status (by NWPL)
NRCS	National Resources Conservation Service
NWI	National Wetlands Inventory
NWPL	National Wetland Plant List
NWPR	Navigable Waters Protection Rule
OBL	obligate wetland plant
OHWM	ordinary high-water mark
Porter-Cologne Act	Porter-Cologne Water Quality Act
Rapanos	*Rapanos v. United States* (legal ruling)
Report	Aquatic Resources Delineation Report

RWQCB	Regional Water Quality Control Board
Sackett	*Sackett v. Environmental Protection Agency* (legal ruling)
SR-	State Route (Highway)
Stantec	Stantec Consulting Services Inc.
State	State of California
Study Area	proposed CCS facilities plus a 500-foot radius buffer
SWANCC	*Solid Waste Agency of Northern Cook County* (legal ruling)
SWRCB	State Water Resources Control Board
UIC	Underground Injection Control
UPL	upland plant
U.S.	United States
USACE	U.S. Army Corps of Engineers
USDA	U.S. Department of Agriculture
USEPA	U.S. Environmental Protection Agency
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
waters of the State	waters of the State of California
WDR	Waste Discharge Requirements
WQC	Water Quality Certification
WIS	Wetland Indicator Status
WOTUS	waters of the United States

1.0 INTRODUCTION

This Aquatic Resources Delineation Report (Report) prepared by Stantec Consulting Services Inc. (Stantec) is intended to document and assess potential jurisdiction of the aquatic resources within the Aera Energy LLC (Aera) South and North Belridge oil fields in support of the proposed Aera CarbonFrontier Project in western Kern County, California (Appendix A, Figure 1). Aquatic resource surveys were conducted for the Aera CarbonFrontier Project by Stantec Senior Biologist Geoff Hoetker with assistance from Logan Elms, Jasmin Byrd, Jared Pratt, Ethan Martin, and Cassandra Cortez, on June 1, July 18, July 20, and September 13, 2022; and May 26 and June 13, 2023. This Report summarizes the methods and results of the survey, as well as an assessment of potential jurisdictional aquatic resources within the Study Area. This Report may support future Project permitting for resources that may fall within the following jurisdictions:

- The U.S. Army Corps of Engineers (USACE), pursuant to Clean Water Act (CWA) Section 404;
- The Central Valley Regional Water Quality Control Board (RWQCB), pursuant to the State of California (State) Porter-Cologne Water Quality Control Act (California Water Code, Chapter 2, § 13050) and/or CWA Section 401; and/or
- The California Department of Fish and Wildlife (CDFW), pursuant to section 1602 of the California Fish and Game Code (CFGC).

Stantec advises all parties to treat the information contained herein as preliminary until the USACE, RWQCB, and/or CDFW provide verification of jurisdictional assessments.

1.1 PURPOSE OF THE REPORT

This delineation of aquatic resources has been prepared to evaluate the potential aquatic resources that may occur within the Study Area for the proposed Aera CarbonFrontier Project, which is defined as the proposed Aera CarbonFrontier Project footprint plus a 500-foot radius buffer. This Report is being prepared to support any new infrastructure or Aera CarbonFrontier Project activities and associated permitting that may be required in the Study Area.

1.2 STUDY AREA

The Study Area is located within the North and South Belridge oil fields, in an unincorporated area of western Kern County, approximately 14 miles west of the town of Buttonwillow, seven miles southwest of the town Lost Hills, and eleven miles north of the town of McKittrick, California. From the south, the Study Area spans an area in the vicinity of the intersection of Lost Hills Road and State Route (SR-) 33 (also known as the West Side Highway), northwestward through Seventh Standard Road, northward through the South Belridge Oil Field variously paralleling or oriented east of Pole Line Road through Lerdo Highway, then continuing along the vicinity of Pole Line Road to the North Belridge Oil Field (Appendix A. Figure 1).

The Study Area is approximately 13 miles long and is approximately 1,000 feet (0.19 mile) wide. The approximate centroid of the Study Area is located at the following coordinates: 35.501525°, -119.751895° (North American Datum

of 1983 [NAD 83]. The Study Area encompasses approximately 3,252 acres mainly within the Belridge and Blackwells Corner (1988) 7.5-minute U.S. Geological Survey (USGS) quadrangles, with small portions of the Study Area falling within the Lost Hills and Carneros Rocks USGS quadrangles.

To access the Study Area from Interstate 5, take the Buttonwillow SR-58 / McKittrick Highway exit and travel west on SR-58 for approximately eight miles; turn right onto Lokern Road and travel west approximately 7 miles; turn right on SR-33 and travel northwest approximately 2 miles to arrive at the southern end of the Study Area.

1.3 PROJECT DESCRIPTION

Aera has submitted an application to the Kern County Planning and Natural Resources Department to request approval of a Zoning Change and Conditional Use Permit (CUP) and will obtain any other required approvals, for the construction and operation of a carbon capture and sequestration (CCS) project in the South and North Belridge oil fields. The proposed Aera CarbonFrontier Project would require approvals for construction and operation of the proposed facilities (gas separation, compression, and pumping equipment), new carbon dioxide (CO_2) pipelines located primarily aboveground utilizing existing pipeline corridors, Underground Injection Control (UIC) Class VI geologic sequestration injection wells, CO_2 monitoring wells, and an underground carbon sequestration field for the storage of CO_2 in accordance with appropriate financial assurance mechanisms that ensure permanence in compliance with applicable regulatory standards.

The proposed Aera CarbonFrontier Project would capture CO_2 from existing produced gas streams (pre-combustion) and emissions from existing stationary sources (post-combustion) within the South Belridge Oil Field and transport the CO_2 through pipelines to the North Belridge Oil Field for injection at dedicated Class VI injection wells. The proposed underground CO_2 sequestration field, approximately 2,636 acres in size, would be located within the North Belridge Oil Field with surface and mineral rights held by Aera and other private owners. Oil and gas production activities would cease within the underground geologic formation where CO_2 would be stored, prior to commencement of the Project.

It is anticipated that the proposed Aera CarbonFrontier Project would capture and sequester up to 1.6 million metric tons (MMt) of CO_2 per year beginning in 2027 and will contribute to the goal of California for carbon neutrality by 2045 (Executive Order B-55-18) by reducing CO_2 emissions.

Implementation of the Aera CarbonFrontier Project would require permits from the United States (U.S.) Environmental Protection Agency (USEPA) for up to nine Class VI injection wells in compliance with the UIC program Class VI geologic sequestration regulations. The proposed CO_2 related facilities, pipelines, Class VI injection wells and associated CO_2 monitoring wells will be located within the CUP boundary. The proposed Aera CarbonFrontier Project would utilize up to 1,223 acre-feet per year (afy) (26,000 barrels of water per day) , sourced primarily from treated water associated with production and supplemented with existing freshwater entitlements, if available.

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2.0 ENVIRONMENTAL SETTING

2.1 LAND USES

The Belridge oil fields were discovered in the early 1900s, as oil naturally surfaced due to pressure in the geologic reservoir, with the first well drilled along the Chico Martinez Creek in April 1911 (Allan and Lalicata 2012). Since then, the Belridge oil fields developed into North and South Belridge oil fields. The Study Area lies along the South and North Belridge oil fields on the Antelope Plain, an alluvial piedmont consisting of coalescing alluvial fans from the Temblor Range to the west. The region slopes to the east towards the San Joaquin Valley. The Study Area is heavily disturbed with oil wells and well pads, oil and gas infrastructure, gas and steam pipelines, and multiple unnamed dirt or graveled access roads along with a few paved roads.

2.2 TOPOGRAPHY AND ELEVATION

The topography of the Study Areas is relatively flat, interrupted only by oil and gas infrastructure, and slopes gradually from west to east towards the San Joaquin Valley. The Study Area ranges from 675 feet above mean sea level (amsl) on the western edge down to 550 feet amsl on the eastern edge.

2.3 CLIMATE

Climate in the Study Area is based on historical weather data collected at Buttonwillow, California (Western Regional Climate Center 2022). The station is located approximately 15 miles east of the Study Area:

- **Type:** The climate of the area is characterized as Mediterranean with moderate winters and hot, dry summers.
- **Precipitation:** Precipitation in the Study Area primarily occurs as rain. The average annual rainfall is approximately 5.64 inches.
- **Air Temperature:** Air temperatures in the Study Area ranges between an average January temperature range of 46 degrees Fahrenheit (ºF) and an average July temperature of 82 ºF. The annual average temperature is approximately 63 ºF.
- **Growing Season:** The growing season (i.e., the longest continuous period of a non-freezing air temperature of 32ºF or higher) in the Study Area is approximately 321 days and occurs between approximately January 20 and December 6 (Weather Spark 2022).

2.4 HYDROLOGY AND GEOMORPHOLOGY

The Study Area is within Hydrologic Unit Code (HUC)-8 18030012 - Tulare-Buena Vista Lakes. This area is also mainly within the Lower Kern River Flood Canal HUC-10 Watershed 1803001216, with a section of the southern portion of the Study Area within the Upper Kern River Flood Canal HUC-10 Watershed 1803001212. The Study Area also includes the following HUC-12 Watersheds from north to south: unnamed-180300121502, Town of Lost Hills-180300121504, unnamed-180300121603, Kern River Flood Canal-Kern River Channel-180300121604, Kern River Flood Canal-180300121602, Chico Martinez Creek-180300121206, and Kern River Flood Canal-180300121207 (Appendix A, Figure 2).

The Study Area is located within the San Joaquin Valley groundwater basin, and in the Kern County groundwater subbasin. This groundwater subbasin extends from the Greenhorn Mountains to the east to the Temblor Range to the west. It shares its southeastern boundary with the White Wolf groundwater subbasin and its northern boundary with both the Tulare Lake and Tule Groundwater subbasin. Streamflow through the vicinity of the Study Area is generally directed from the Temblor Range to the west toward the Central Valley to the east.

Chico Martinez Creek, an ephemeral stream toward the southern end of the Study Area, is the most prominent remaining regional stream draining from the southwest to the northeast through the South Belridge Oil Field toward the Central Valley. The source of historic Chico Martinez Creek is located on the eastern slope of the Temblor Range (35.4188542, -119.8623563 WGS84) and it generally flows east where it terminates approximately 0.55 mile southwest of Lost Hills Highway Kern County, California (35.4610736, -119.6990172 WGS84). While the terminus of historic Chico Martinez Creek is located west of Lost Hills Highway based on historical data (USGS and National Wetlands Inventory [NWI]); a review of available aerial imagery (dating back to 1994) indicates it flows further east to approximately 1.10 miles east of Lost Hills Highway where it terminates at a north-south traversing agricultural canal/aqueduct. The Study Area includes three sections of historic Chico Martinez Creek:

1) Section of Chico Martinez Creek located approximately 0.45 mile south of the Aera Oasis Building (i.e., the main Aera office building at the South Belridge Oil Field), then continuing toward the northeast before reaching Seventh Standard Road.

2) Section of Chico Martinez Creek located approximately 0.45 mile southeast of the Aera Oasis Building and beginning approximately 700 feet north of Seventh Standard Road, then continuing toward the northeast; and

3) Section of Chico Martinez Creek beginning just south of the intersection of SR-33 and Treeline Road/Roustabout Road, crossing under SR-33, then continuing to the northeast.

Considered as a whole, sections of Chico Martinez Creek still appear to be channelized but these sections are interspersed with areas with no defined channel bed and bank. The system has been altered and segmented due to oil field development, the presence of SR-33 and other roads, and agricultural activities (to the east).

According to the U.S. Fish and Wildlife Service (USFWS) NWI (USFWS 2022) (Appendix A, Figure 3), the USGS National Hydrography Dataset (NHD) (USGS 2022) (Appendix A, Figure 4), USGS 7.5-minute topographic maps, and an analysis of historical aerial imagery, additional hydrologic features that have historically occurred within the Study Area include the following:

1) Two unnamed streams toward the northern end of the Study Area; no evidence of these features remains in the Study Area. There is channelization for these features visible on aerial imagery southwest of the Study Area;
2) Two unnamed streams northwest of Compressor Station 49; one stream formerly traversed through an area located 0.55 mile northwest of Compressor Station 49, and the other stream formerly traversed through an area located 1.45 miles northwest of Compressor Station 49. No evidence of these features remains in the Study Area; there is channelization for these features visible on aerial imagery approximately 1.2 miles west of the Study Area;



3) A short section of an unnamed stream west of Compressor Station 49; no evidence of this feature remains in the Study Area. There is channelization for this feature visible on aerial imagery approximately 0.3 mile west of the Study Area;
4) An unnamed ephemeral stream just south of Contractors Road; remnants of this feature remain within the Study Area, but this feature has been highly altered due to oil production activities. Channelization and remnants of canals along this feature are visible on aerial imagery west of the Study Area;
5) Zemorra Creek, toward the extreme southwestern corner of the Study Area south of Main Camp Road; this is a tributary that drains to the southeast toward Chico Martinez Creek. A small remnant of this feature currently exists in the Study Area; additional channelization for this feature is visible on aerial imagery west of the Study Area;
6) An unnamed stream toward the extreme southern end of the Study Area, approximately 0.45 mile south of Chico Martinez Creek; no evidence of this feature currently exists in the Study Area; there is channelization for this feature visible on aerial imagery approximately 0.8 mile southwest of the Study Area;
7) Various small historic artificially flooded marshes and/or ponds (some with nearby canals) formerly located throughout the Study Area; an accumulation of these features occurred north and west of the 2868 Steam Plant, and in the vicinity of the Section 20 Dehydration Facility and areas to the south (the 2868 Steam Plant and Section 20 Dehydration Facility are both located along Pole Line Road). No current evidence of these features was observed. Based on historical aerial imagery, they were removed prior to 2013, with most of these features likely removed many years ago; and,
8) Various ponds used by Aera for wastewater treatment/disposal and/or detention, retention, infiltration, or treatment of stormwater runoff; these features are assumed to be exempt from qualifying as waters of the State of California (waters of the State) per the wetland definitions provided in Section 3.d. in the *State Wetland Definition and Procedures for Discharges of Dredged or Fill Material to Waters of the State* (State Water Resources Control Board [SWRCB] 2019) and were not delineated.

The aforementioned unnamed streams likely were channelized from runoff from the Temblor Ranges and may have flowed unhindered at a point in their history. However, sections of these streams within the Study Area have been virtually eliminated as a result of historical fill, grading, and development of oil well and pipeline infrastructure and access roads (as described in Chapter 5.2).

The South and North Belridge oil fields, located near the western margin of the San Joaquin Basin, occupy a region of extensive sedimentary rocks of varying porosity and permeability, containing anticlinal folds and large pools of petroleum, much of which has been previously extracted in the early and middle 20th century. The age range of the pools and their corresponding geologic formations is from Pliocene-Miocene (23 to 2.58 million years ago) for the uppermost members, down to Oligocene (33.9 to 23 million years ago), and then down to Eocene (56 to 33.9 million years ago) oceanic sands at a depth of over 8,500 feet. The San Andreas Fault, the boundary of the Pacific and North American plates, borders the San Joaquin Basin on the west, approximately 10 miles from the oil fields, on the other side of the Temblor Range.

2.5 SOILS

According to the U.S. Department of Agriculture (USDA) Natural Resource Conservation Service (NRCS), four soil map units occur in the Study Area. The soils are described in the *Soil Survey of Kern County, California* (USDA NRCS 2022a). The map units are summarized in Table 1 and shown in Appendix A, Figure 5.



Table 1: Historic Soil Map Units within the Study Area.

Map Unit Symbol	Map Unit Name	Description	Hydric	Acreage in Study Area
174	Kimberlina fine sandy loam, 0-2% slopes	The Kimberlina series consists of very deep, well drained soils on flood plains and recent alluvial fans. These soils formed in mixed alluvium derived dominantly from igneous and/or sedimentary rock sources.	No	1,295.40
175	Kimberlina fine sandy loam, 2-5% slopes	The Kimberlina series consists of very deep, well drained soils on flood plains and recent alluvial fans. These soils formed in mixed alluvium derived dominantly from igneous and/or sedimentary rock sources.	No	232.05
176	Kimberlina fine sandy loam, 5-9% slopes	The Kimberlina series consists of very deep, well drained soils on flood plains and recent alluvial fans. These soils formed in mixed alluvium derived dominantly from igneous and/or sedimentary rock sources.	No	7.87
196	Milham sandy loam, 0 to 2 percent slopes Major Land Resource Area 17	The Milham series consists of very deep, well drained soils on alluvial fans, plains, low terraces, and fan remnants. These soils formed in mixed calcareous alluvium weathered from granitic and sedimentary rock.	No	559.60
197	Milham sandy loam, 2 to 5 percent slopes	The Milham series consists of very deep, well drained soils on alluvial fans, plains, low terraces, and fan remnants. These soils formed in mixed calcareous alluvium weathered from granitic and sedimentary rock.	No	383.16
211	Panoche clay loam, 0 to 2 percent slopes	The Panoche series consists of very deep, well drained soils on alluvial fans and flood plains. These soils formed in loamy calcareous alluvium from sedimentary rock.	No	442.39
212	Panoche clay loam, 2 to 5 percent slopes	The Panoche series consists of very deep, well drained soils on alluvial fans and flood plains. These soils formed in loamy calcareous alluvium from sedimentary rock.	No	344.96
Total				**3,251.96**

2.6 VEGETATION COMMUNITIES AND LAND COVER TYPES

Vegetation types in the Study Area were classified based on the vegetation alliance classification system described in *A Manual of California Vegetation, 2nd Edition* (Sawyer et al. 2009). Two dominant vegetation communities and one land cover type occurs in the Study Area and are described below.

2.6.1 Vegetation Communities

***Atriplex polycarpa* Shrubland Alliance (Allscale scrub)**

Allscale scrub occurs primarily in the southern half of the Study Area, where it has formed relatively open stands in the and/or is interspersed with annual grasslands, described below. Allscale (*Atriplex polycarpa)* scrub is characterized by an open to continuous canopy with a variable herbaceous layer including seasonal annuals and non-native grasses. The alliance is typically found in washes, playa lake beds and shores, dissected alluvial fans, rolling hills, terraces and edges or large low gradient washes. Soils may be carbonate rich, alkaline, sandy, or sandy clay loams (Sawyer et al. 2009).

Typically, allscale is dominant in the shrub canopy with white bursage (*Ambrosia dumosa*), cheesebush (*Ambrosia salsola*), fourwing saltbush (*Atriplex canescens*), red brome (*Bromus madritensis* ssp*. rubens*), small, seeded spurge (*Euphorbia polycarpa*), creosote bush (*Larrea tridentata*), and bladderpod (*Peritoma arborea*). Patches of the allscale scrub, dominated by allscale shrubs with non-native grasses, primarily bromes (*Bromus* spp.) and weeds including Russian thistle (*Salsola tragus*) and Maltese star thistle (*Centaurea melitensis*), occur along the historic ephemeral drainage.

***Bromus rubens* - *Schismus* (*arabicus, barbatus*) Herbaceous Semi-Natural Alliance (Red brome or Mediterranean grass grasslands)**

Annual grasslands are scattered throughout the Study Area, with an extensive stand located east of Pole Line Road. This alliance of non-native annual grasses is dominated by red brome and/or schismus (*Schismus arabicus* and/or *S. barbatus*). The alliance is highly adaptable and can be found in all topography settings and soil textures. Most of the grasslands in the Study Area had been subjected to grazing and/or mowing, making it difficult to find flowering heads of grasses for identification, but red brome and ripgut brome (*Bromus diandrus*) were confirmed in some areas. Other representative native and non-native forbs observed in grasslands on site included fiddleneck (*Amsinckia menziesii*), cheeseweed (*Malva parviflora*), red filaree (*Erodium cicutarium*), and occasional Russian thistle. Non-native annual grasslands occur primarily in the southern half of the Study Area.

2.6.2 Land Cover Types

Disturbed/Developed

Most of the Study Area is significantly disturbed by oil and gas infrastructure, modification, and activities including wells, well pads, pipelines, and access roads. In addition, historical drainages onsite have been altered through grading/and or fill with earthen berms and hummocks.

3.0 REGULATORY BACKGROUND

3.1 CLEAN WATER ACT SECTION 404

Section 404 of the CWA regulates the discharge of dredged material, placement of fill material, or certain types of excavation within federal waters of the United States (WOTUS) and authorizes the Secretary of the Army, through the Chief of Engineers, to issue permits for such actions. Permits can be issued for individual projects (individual permits) or for general categories of projects (nationwide permits). WOTUS are defined by the CWA as "rivers, creeks, streams, and lakes extending to their headwaters and any associated wetlands." Wetlands are defined by the CWA as "areas that are inundated or saturated by surface or groundwater at a frequency and duration sufficient to support a prevalence of vegetation typically adapted for life in saturated soil conditions." The USACE has adopted several revisions to their regulations in order to more clearly define WOTUS. Until the beginning of 2001, WOTUS included, among other things, isolated wetlands and lakes, intermittent streams, prairie potholes, and other waters that are not part of a tributary system to interstate waters or to navigable WOTUS. The protection of federal jurisdictional WOTUS has been historically contentious and subject to numerous legal decisions since 2001.

In 1986, the federal agencies (USACE and USEPA) implemented historic regulations (the 1986 Regulations) that defined WOTUS to mean traditional navigable waters, the territorial seas, interstate waters, and intrastate waters whose use or degradation could affect interstate or foreign commerce, as well as tributaries (streams that flow into larger streams or other bodies of water) of and wetlands adjacent to any of those waters.

The jurisdictional extent of USACE regulation changed with the 2001 *Solid Waste Agency of Northern Cook County* (*SWANCC*) *v. U.S. Army Corps of Engineers* ruling. The U.S. Supreme Court held that the USACE could not apply Section 404 of the CWA to extend their jurisdiction over an isolated quarry pit. The Court ruled that the CWA does not extend Federal regulatory jurisdiction over non-navigable, isolated, intra-state waters. However, the Court made it clear that non-navigable wetlands adjacent to navigable waters are still subject to USACE jurisdiction.

In 2006, the U.S. Supreme Court issued its seminal decision in the consolidated cases *Rapanos v. United States* and *Carabell v. United States* (collectively referred to as *Rapanos v. United States* (*Rapanos*). Justice Scalia narrowly interpreted the statutory term "waters of the United States" in a four-Justice plurality opinion, holding that CWA jurisdiction extended over only "relatively permanent, standing or continuously flowing bodies of water" that are connected to traditional navigable waters, plus wetlands with a "continuous surface connection" to such relatively permanent water bodies. Justice Kennedy wrote separately, concurring with the Court's judgment with respect to the facts of the case, but interpreted "waters of the United States" to include wetlands that possess a "significant nexus" to waters that are or were navigable in fact or that could reasonably be so made.

The Court's split decision and lack of a commanding majority opinion in *Rapanos* created confusion among the federal agencies and public. On December 2, 2008, the federal agencies released a regulatory guidance document, Clean Water Act Jurisdiction Following the U.S. Supreme Court's Decision in *Rapanos v. United States* & *Carabell v. United States* (USACE and USEPA 2008), addressing common questions about federal jurisdiction over WOTUS and clarifying the two jurisdictional standards from *Rapanos*. In the 2008 *Rapanos Guidance*, the federal agencies concluded that federal jurisdiction existed over certain waterbodies that meet the "relatively permanent" standard from

Justice Scalia's plurality opinion or Justice Kennedy's "significant nexus" standard, the latter of which would be determined by a fact-specific analysis.

Federal jurisdictional WOTUS protected under the CWA were defined in a 2015 Final Rule by USACE and USEPA; however, the Sixth Circuit U.S. Court of Appeals issued an order staying the new Clean Water Rule nationwide, pending a determination by the court on jurisdiction to review the rule. The 2015 Clean Water Rule was stayed, and the prior regulations published in 1986, along with some changes in 2008 as a result of the Rapanos U.S. Supreme Court decision, remained in effect.

On February 28, 2017, the Trump Administration issued Executive Order 13778, *"Restoring the Rule of Law, Federalism, and Economic Growth by Reviewing the 'Waters of the United States' Rule."* The executive order directed the USACE and USEPA to review the 2015 Rule for consistency with the policy outlined in Section 1 of the order and to issue a proposed rule rescinding or revising the 2015 Rule as appropriate and consistent with law. On September 12, 2019, the USACE and USEPA repealed the 2015 Rule and restored the previous regulatory regime as it existed prior to finalization of the 2015 Rule. This final rule, *"Definition of 'Waters of the United States'—Recodification of Pre-Existing Rules"* was published in the Federal Register on October 22, 2019.

On April 21, 2020, the USEPA and USACE published the Navigable Waters Protection Rule (NWPR) to define WOTUS. The agencies streamlined the definition to include four simple categories of jurisdictional waters, provided clear exclusions for many water features that traditionally have not been regulated, and defined terms in the regulatory text that had never been defined before. Congress, in the CWA, explicitly directed the agencies to protect "navigable waters." The NWPR regulated these waters and the core tributary systems that provide perennial or intermittent flow and excluded ephemeral waters. The final NWPR fulfilling Executive Order 13788 became effective on June 22, 2020; however, on August 30, 2021, the U.S. District Court for the District of Arizona vacated the NWPR finding "fundamental, substantive flaws that cannot be cured without revising or replacing the NWPR's definition."

On June 9, 2021, the USACE and USEPA under the Biden Administration announced their intent to revise the definition of WOTUS to protect more waterways, beginning a new rulemaking process that restores protections put in place before 2015.

On January 18, 2023, the federal agencies published the final "Revised Definition of 'Waters of the United States'" rule (2023 Rule) in the Federal Register, which became effective on March 20, 2023 (USACE and USEPA 2023). The 2023 Rule generally returns to the pre-2015 definition. The implications of the final 2023 WOTUS rule are such that many ephemeral waters not considered protected under the former 2020 NWPR would now be protected.

The 2023 Rule defines WOTUS to include:

1. Traditional navigable waters, the territorial seas, and interstate waters;
2. Impoundments of other jurisdictional WOTUS, except for those that qualify under category 5, below;
3. Tributaries to either of the above waters and tributaries that meet the "relatively permanent" standard or the "significant nexus" standard, (collectively, "jurisdictional tributaries");



4. Wetlands adjacent to traditional waters, wetlands adjacent and with a continuous surface connection to relatively permanent tributaries and impoundments, and wetlands adjacent to other jurisdictional tributaries when those wetlands meet the "significant nexus" standard; and

5. Intrastate lakes and ponds, streams, or wetlands that are not identified in categories 1–4 above that meet either the "relatively permanent" standard or the "significant nexus" standard.

On March 19, 2023, the U.S. District Court for the Southern District of Texas enjoined the 2023 Rule in Texas and Idaho pending its consideration of those states' legal challenges to the rule. On April 12, 2023, the U.S. District Court for the District of North Dakota similarly issued a preliminary injunction preventing the application of the 2023 Rule in 24 states: Alabama, Alaska, Arkansas, Florida, Georgia, Indiana, Iowa, Kansas, Louisiana, Mississippi, Missouri, Montana, Nebraska, New Hampshire, North Dakota, Ohio, Oklahoma, South Carolina, South Dakota, Tennessee, Utah, Virginia, West Virginia, and Wyoming. The federal agencies announced that, pending resolution of the litigation, they will apply the pre-2015 regulatory regime in the 26 states subject to injunctions and the 2023 Rule in the remaining 24 states, including California.

Most recently, on May 25, 2023, the U.S. Supreme Court issued its ruling in *Sackett v. Environmental Protection Agency (Sackett)*, which established a more stringent test to determine whether the CWA applies to certain categories of wetland. The Sackett family had backfilled a lot near Priest Lake in Idaho, and in agreeing that the Sacketts' lot is a wetland, the U.S. Court of Appeals for the 9th Circuit applied the test outlined by Justice Kennedy in Rapanos: whether there is a "significant nexus" between the wetlands and waters that are covered by the CWA, and whether the wetlands "significantly affect" the quality of those waters. With *Sackett*, the U.S. Supreme Court unanimously reversed the 9th Circuit's ruling, where in a majority opinion, lower courts were directed to apply a more stringent test in *Rapanos*, in which the CWA applies to a particular wetland only if it blends or flows into a neighboring water that is a channel for interstate commerce (SCOTUSblog 2023). While the Court decided that it is clear that some "adjacent" wetlands will also qualify under the CWA as "waters of the United States," wetlands that are entirely separate from traditional bodies of water will not qualify. The CWA will apply to wetlands that are "as a practical matter indistinguishable from waters of the United States" because they have a "continuous surface connection" with a larger body of water, "making it difficult to determine where the 'water' ends and the 'wetland' begins."

The result of the *Sackett* ruling is that certain adjacent wetlands formerly protected under the CWA will no longer be federally protected. The USACE and USEPA have acknowledged the Sackett ruling and indicated they will interpret the phrase "waters of the United States" consistent with the U.S. Supreme Court's decision in *Sackett*; the agencies will continue to review the decision to determine next steps (USACE 2023a), but no official guidance had been released at the time of the preparation of this Report.

3.2 CLEAN WATER ACT SECTION 401 AND PORTER-COLOGNE WATER QUALITY CONTROL ACT

Section 401 of the CWA ensures that federally permitted activities comply with the federal CWA and state water quality laws. Section 401 is implemented by California's RWQCB, triggered by the Section 404 permitting process. RWQCB issues a Water Quality Certification (WQC) via the Section 401 process that a proposed project complies with water quality standards and other conditions of California law. Evaluating the effects of a proposed project on both water quality and quantity (runoff) falls under the jurisdiction of the RWQCB. This certification typically precedes

USACE permit issuance. Any activities that would require a USACE Section 404 permit would also likely require a Section 401 WQC or a waiver from RWQCB.

In addition, the Porter-Cologne Water Quality Control Act (Porter-Cologne Act) serves as the primary water quality law in California and addresses two primary functions: water quality control planning and waste discharge regulation. The various RWQCBs are charged with protecting all waters of California, defined as "any surface water or groundwater, including saline waters, within the boundaries of the State." This encompasses all waters of the State, including those not under federal jurisdiction. The Porter-Cologne Act defines "waters of the State" very broadly, with no physical descriptors, and no interstate commerce limitation. In regulating discharges of dredged or fill material; therefore, the RWQCB jurisdiction is more broad than federal jurisdiction. The discharge of dredged or fill material may constitute a discharge of waste that could affect the quality of waters of the State. Under the Porter-Cologne Act, discharges of dredged or fill material to Waters of the State not subject to CWA Section 404 (i.e., non-USACE jurisdictional) are regulated by the RWQCB under the Porter-Cologne Act Article 4 Individual or General Waste Discharge Requirements (WDR). The WDR permit requirements ensure that the permitted activities comply with state water quality standards over the term of the action and are consistent with the requirements of the California Environmental Quality Act, the California Endangered Species Act, and the Porter-Cologne Act. Procedures for complying with WDR regulations, including submittal of an application with a project description and impact assessment, are similar to CWA Section 401 procedures.

In 2019, the SWRCB adopted the SWRCB *State Wetland Definition and Procedures for Discharges of Dredged or Fill Material to Waters of the State* for inclusion in the forthcoming Water Quality Control Plan for Inland Surface Waters and Enclosed Bays and Estuaries and Ocean Waters of California (SWRCB 2019).

The Water Boards (i.e., SWRCB and RWQCB) define an area as wetland as follows:

"An area is wetland if, under normal circumstances, (1) the area has continuous or recurrent saturation of the upper substrate caused by groundwater, or shallow surface water, or both; (2) the duration of such saturation is sufficient to cause anaerobic conditions in the upper substrate; and (3) the area's vegetation is dominated by hydrophytes or the area lacks vegetation."

Applicants must file an application with the California Water Boards (defined as the SWRCB and nine RWQCBs) for any activity that could result in the discharge of dredged or fill material to waters of the State in accordance with Title 23 California Code of Regulations Section 3855.

The SWRCB Procedures became effective on May 28, 2020, and this current guidance has been considered during the preparation of this Report. For the purposes of this Report, RWQCB jurisdiction (i.e., waters of the State) has been interpreted conservatively by Stantec as including most natural streambeds, areas extending from the streambed/thalweg to the outer edge of adjacent riparian vegetation, certain isolated wetlands or waters that may not be under USACE jurisdiction, and most artificial ditches and ponds that are not used for wastewater treatment/disposal; detention, retention, infiltration, or treatment of stormwater runoff subject to a stormwater permitting program; or agricultural crop irrigation or stock watering.



3.3 CALIFORNIA FISH AND GAME CODE SECTION 1602

Section 1602 of the CFGC requires a proponent proposing a project that may affect a river, stream, or lake to notify the CDFW before beginning the project. If activities will result in the diversion or obstruction of the natural flow of a stream, or substantially alter its bed, channel, or bank, or adversely affect existing fish and wildlife resources, a Lake and Streambed Alteration Agreement is required. A Lake and Streambed Alteration Agreement lists the CDFW conditions of approval relative to a proposed project and serves as an agreement between an applicant and the CDFW for the performance of activities subject to Section 1602. For the purposes of this Report, CDFW jurisdiction is interpreted as extending from the streambed/thalweg to the outer edge of adjacent riparian vegetation (for both natural and anthropogenic drainage features) and for this Study Area, is roughly equivalent to “waters of the State” as defined by the RWQCB.

4.0 METHODS

The aquatic resource assessment is broken down into three steps: a desktop review, a field assessment, and a jurisdictional assessment. Methods for each step are described below.

4.1 DESKTOP REVIEW

Prior to conducting fieldwork, the following resources were reviewed:

- USFWS NWI Wetland Mapper (USFWS 2022);
- Google Earth color aerial imagery dating back to 1994;
- USGS 7.5-minute topographic maps dating back to 1988;
- USGS National Hydrography Dataset (USGS 2022);
- USDA NRCS soils maps (USDA 2022a); and
- Local and state hydric soil lists (USDA NRCS 2022b)

These resources were used to identify potential aquatic features based on changes in vegetation, topographic changes, and/or visible drainage patterns. Prior to the field assessment, potential features were digitized into a working field map that was then used as a reference during the assessment.

4.2 FIELD ASSESSMENT

The delineation was conducted within the Study Area (Appendix A, Figure 6-1) in accordance with the *Corps of Engineers Wetlands Delineation Manual* (Environmental Laboratory 1987), the *Regional Supplement to the Corps of Engineers Wetland Delineation Manual: Arid West Region (Version 2.0)* (USACE 2008), *A Field Guide to the Identification of Ordinary High Water Mark (OHWM) in the Arid West Region of the United States* (Lichvar and McColley 2008), and the *Implementation Guidance for the State Wetland Definition and Procedures for Discharges of Dredged or Fill Material to Waters of the State* (SWRCB 2020).

An assessment and delineation of potentially jurisdictional waters was conducted within the Study Area by Stantec Senior Biologist Geoff Hoetker with assistance from Logan Elms, Jasmin Byrd, Jared Pratt, Ethan Martin, and Cassandra Cortez, on June 1, July 18, July 20, and September 13, 2022; and May 26 and June 13, 2023. Transects were walked throughout the Study Area, supplemented by driving within the Study Area where feasible. During the field assessment, hydrologic features observed were mapped over recent aerial photograph base maps using the ESRI® Collector for ArcGIS app on an Apple® iPad® coupled with an EOS Arrow 100 sub-meter external Global Positioning System (GPS) unit. Mapping was further refined in the office using ArcGIS (version 10.8.1) with aerial photograph base maps with sub-meter accuracy, and the total jurisdictional area for each regulatory jurisdiction was calculated.

Based on available historical mapping of aquatic features, combined with observations of surface conditions, 18 sample points/soil test pits were originally excavated within the Study Area (Appendix A, Figures 6-1 to 6-12). Each feature had at minimum paired sample points, with one point positioned within the aquatic feature and another point positioned in nearby uplands. Three pairs of sample points (six sample points total) were positioned along Chico Martinez Creek, which is a major drainage through the Belridge South Oil Field. A total of 18 sample points was

determined to be sufficient based on the relative homogeneity of conditions along the aquatic features and in adjacent uplands. Two of the sample points, SP13 and SP14, occurred in a former Study Area boundary but this general area has been removed from consideration as a project component in the current Study Area; therefore, no results for these sample points are presented in this Report other than their mention as a matter of continuity.

If feasible, soil test pits were excavated to a depth of approximately 16 inches (or to a restrictive layer if present) and evaluated for potential hydric soil indicators. Hydrophytic vegetation and wetland hydrology indicators were also evaluated in the vicinity of these sampling locations. Percent cover estimates for vegetation were conducted by visually estimating absolute percent cover for each plant species within a sample plot. Generally, sample plot sizes included a 10-foot radius for saplings and shrubs, and a 5-foot radius for herbs; there were no trees or woody vines present, therefore evaluations of these vegetative strata were not applicable. Plant species were identified to the lowest possible taxonomic level per *The Jepson Manual: Higher Plants of California* (Baldwin et al. 2012).

Positive indicators for each of the following three parameters are required for a wetland to meet the USACE criteria for jurisdictional wetland determination (Environmental Laboratory 1987). The three parameters are defined as follows:

- **Hydrophytic vegetation** is defined as macrophytic vegetation that is adapted to, and occurs in, areas where soils are frequently or permanently saturated of sufficient duration to exert a controlling influence on the plant species present. Plant species adjacent to the sample points were identified and included following the "50/20 rule," meaning that plant species in each vegetation stratum (i.e., tree, sapling/shrub, herb, and woody vine) were included in order of abundance until at least 50% of the total vegetation cover was accounted for, plus any other species that, by itself, accounts for at least 20% of the total. Plants are assigned a Wetland Indicator Status (WIS) based on their frequency of occurrence in wetland habitats following the most recent 2020 National Wetland Plant List (NWPL) (USACE 2020) and using the Indicator Ratings Definitions (Lichvar et al. 2012) as follows:
    - OBL (Obligate Wetland Plants): Almost always occur under natural conditions in wetlands. With few exceptions, these plants (herbaceous or woody) are found in standing water or seasonally saturated soils (14 or more consecutive days) near the surface;
    - FACW (Facultative Wetland Plants): Usually occur in wetlands but may occur in non-wetlands. These plants predominately occur with hydric soils, often in geomorphic settings where water saturates the soils or floods the soil surface at least seasonally;
    - FAC (Facultative Plants): Occur in wetlands and non-wetlands. These plants can grow in hydric, mesic, or xeric habitats. The occurrence of these plants in different habitats represents responses to a variety of environmental variables other than just hydrology, such as shade tolerance, soil pH, and elevation, and they have a wide tolerance of soil moisture conditions;
    - FACU (Facultative Upland Plants): Usually occur in non-wetlands but may occur in wetlands. These plants predominately occur on drier or more mesic sites in geomorphic settings, where water rarely saturates the soils or floods the soil surface seasonally; and,

- UPL (Upland Plants): Almost never occur under natural conditions in wetlands. These plants occupy mesic to xeric non-wetland habitats. They almost never occur in standing water or saturated soils. Typical growth forms include herbaceous, shrubs, woody vines, and trees.

The hydrophytic vegetation parameter is met when at least one of the following tests is fulfilled:

- The prevalent vegetation (more than 50% of the dominant plant species) is typically adapted to areas having wetland hydrology and hydric soil conditions and rated OBL, FACW, or FAC.
- The prevalence index, which is a value determined by accounting for the relative cover and WIS and ranges from 1 (only OBL species present) to 5 (only UPL species present), is less than or equal to 3.
- Vegetation has morphological adaptations to growing in inundated or saturated conditions.

In this Report, the abbreviations for the WIS categories have been inserted after the initial use of Latin/scientific names for identified dominant plants to reflect the hydrophytic indicator status as most recently presented by USACE (2020). Plants not listed by USACE (2020) have no hydrophytic indicator status (NI) and are treated as UPL.

- **Hydric Soils** are defined as soils that formed under conditions of saturation, flooding, or ponding long enough during the growing season to develop anaerobic conditions in the upper part (USDA Soil Conservation Service 1994; USDA NRCS 2018). Hydric soils are identified based on observable properties that result from prolonged saturated-anaerobic conditions. To assess whether hydric soil was present at each sample point, soil attributes (including color [hue, value, and chroma], redoximorphic features [color patterns in a soil formed by oxidation/reduction of iron and/or manganese that are caused by loss/depletion], or gain/concentration of pigment compared to the matrix color, mottling, texture, grain size, structure, streaking, etc.) were recorded on the delineation forms. Soil colors were assessed using the Munsell Soil Color Book (Munsell 2009).
- **Wetland hydrology** refers to inundation and/or saturation of the soil by flooding or a shallow water table for a prolonged period during the growing season, such that the character of the soil and vegetation are substantially different from areas that do not experience inundation/saturation in this manner. The identification of wetland hydrology follows the guidelines of Environmental Laboratory (1987) and USACE (2008). Visual evidence among the positive indicators of wetland hydrology includes surface water, high water table, or soil saturation; geomorphic features associated with inundation (e.g., channels, shorelines); and water marks, sediment deposits, or drift deposits.

Preliminary jurisdictional delineation maps are included in Appendix A, Figures 6-1 to 6-12. Data documenting presence/absence of vegetation, soils, and hydrology wetland parameters at the sample points within the Study Area during the delineation were collected on Arid West Region Wetland Determination Data Forms (Arid West – Version 2.0) (Appendix B). Where applicable, the OHWMs of aquatic features were delineated per Lichvar and McColley (2008), with data documented on OHWM datasheets (Appendix B). Photographs of the Study Area are included in Appendix C.



4.3 JURISDICTIONAL ASSESSMENT

Regarding the types of federal WOTUS regulated by the USACE, Stantec maintains the current approach based on our understanding of current policy and guidance:

1. The term “wetlands” includes WOTUS in the instances where all three wetland parameters (i.e., hydrophytic vegetation, hydric soil, and wetland hydrology) are present and the aquatic feature is non-isolated.

2. The term “other waters” typically encompasses drainages and other features bound by a definable OHWM with connectivity to jurisdictional waters and includes WOTUS lacking one or more of the three wetland parameters.

Potential jurisdictional boundaries for waters of the State under RWQCB jurisdiction were delineated per the SWRCB *Implementation Guidance for the State Wetland Definition and Procedures for Discharges of Dredged or Fill Material to Waters of the State* (SWRCB 2020). Under the SWRCB *Procedures*, the California Water Boards rely on delineations approved by USACE within the boundaries of WOTUS. Where federal jurisdiction does not extend to state waters, the proposed procedures direct applicants to use the methods described by Environmental Laboratory (1987) and USACE (2008). For the purposes of this delineation, waters of the State extend from the channel bed to the top of a bank or outer edge of riparian canopy (whichever is greater) and also include adjacent wetlands, non-federal isolated waters (if present), swales, and anthropogenic features such drainage ditches that are not considered to be jurisdictional federal WOTUS.

For the purposes of this delineation, CDFW jurisdiction has been conservatively considered to extend from the channel bed to the top of an adjacent bank or outer edge of adjacent riparian canopy (whichever is greater) and also may include smaller swales and certain anthropogenic drainage features such as drainage ditches not considered to be jurisdictional federal WOTUS.

5.0 RESULTS AND DISCUSSION

The following presents a description of the vegetation, soils, and hydrologic conditions in the Study Area, followed by the results of the preliminary determination of federal and state jurisdictional features. The information is based on the review of existing data and the field delineation conducted in June, July, and September 2022; and May and June 2023. Copies of data forms used during the delineation are included in Appendix B.

5.1 POTENTIAL JURISDICTIONAL FEATURES

Potential jurisdictional aquatic features observed in the Study Area include two excavated drainage ditches, remnant sections of two ephemeral streams, and Chico Martinez Creek. These features are described below, with photos in Appendix C.

5.1.1 Drainage Ditches

Two excavated drainage ditches were identified and delineated within the Study Area. An excavated trapezoidal drainage ditch was delineated within the southwestern section of Study Area north of Main Camp Road between the road and Gas Plant 32 (Appendix A, Figure 6-12). The ditch was excavated at some time in the past presumably to route runoff around the southern side of Gas Plant 32. The ditch is approximately 411 feet long, 20 feet wide, and skirts the southern boundary fence of Gas Plant 32; there is a 20-inch diameter culvert opening at the eastern end of the ditch under the fence line, but the other end of the culvert could not be located. In the vicinity of sample point 1 (SP1), excavated toward the centerline of the ditch, the vegetation was dominated by Russian thistle (*Salsola tragus*) (UPL) in the herb stratum; there were no tree, shrub, or woody vine strata present. The presence of this species did not support a dominance of hydrophytic vegetation. The substrate at SP1 included dark yellowish brown (10YR 4/4) sand at a depth of 0 to 5 inches of the soil profile and brown (10YR 4/3) loamy sand at a depth of 5 to 16 inches of the soil profile; no hydric soil indicators were observed. No surface water, high water table, saturation, or any other primary or secondary wetland hydrology indicators were observed. The ditch was completely dry at the time of the delineation. No evidence of an OHWM was observed along the ditch. In adjacent uplands, SP2 was excavated in an area that supported no hydrophytic vegetation, hydric soil, or wetland hydrology indicators.

The other excavated drainage ditch was delineated along the west side of Pole Line Road north of Tulare Road. The entire ditch is approximately 0.40-mile-long and 12-feet wide, but because of the shape and orientation of the Study Area, only two short sections of the ditch occur within the Study Area – a 330-foot section oriented southeast to northwest along the west edge of Pole Line Road (Appendix A, Figure 6-5), and a 271-foot section that spurs off from the southwest to the northeast located approximately 0.29 mile northwest of the other section (Appendix A, Figure 6-4). The function of the ditch is to accept runoff from Pole Line Road. In the vicinity of SP11, excavated toward the centerline of the ditch, the vegetation was dominated by allscale saltbush (*Atriplex polycarpa*) (FACU) in the shrub stratum and red brome (*Bromus madritensis* ssp. *rubens*) (NI) in the herb stratum; there were no tree or woody vine strata present. The substrate at SP11 included a 2-inch layer of soil-like material on the surface that was flaky and hydrophobic (i.e., repelled water); this was assumed to be a non-natural material and may have been some sort of soil additive or other substance. Below this layer was dark yellowish brown (10YR 4/4) loamy sand at a depth of 2 to 10 inches of the soil profile, where a restrictive layer was met; no hydric soil indicators were observed. No surface water, high water table, saturation, or any other primary or secondary wetland hydrology indicators were observed.



The ditch was completely dry at the time of the delineation. No evidence of an OHWM was observed along the ditch. In adjacent uplands, SP12 was excavated in an area that supported no hydrophytic vegetation, hydric soil, or wetland hydrology indicators.

An area with a third drainage located south of Roustabout Road and west of Lost Hills Road, where SP13 and SP14 were excavated in the vicinity, occurred in a former Study Area boundary but this general area has been removed from consideration as a project component in the current Study Area; no results for these sample points are presented in this Report.

5.1.2 Remnants of Ephemeral Streams

Sections of two remnants of ephemeral streams were identified and delineated within the Study Area. A remnant of an unnamed ephemeral stream was delineated south of Contractors Road (Appendix A, Figures 6-2 and 6-3). According to NWI and NHD mapping data (USFWS 2022, USGS 2022), this drainage formerly originated approximately 3.5 miles west of the Study Area in the Bacon Hills (foothills in the Temblor Range), proceeded west to east through the Study Area, and then continued approximately 0.4 mile along what is now the south side of Contractors Road before emptying to an area that is now occupied by orchards. Within and outside the Study Area, this drainage has been subjected to extensive historical disturbance from fill and grading and rarely conveys water. Based on Google Earth historical aerial imagery, this feature was altered west of Pole Line Road at some time between August 2006 and March 2007, where only segments of small dry ponds connected by culverts remain. Approximately 1,130-linear-feet of remnant sections of the stream were delineated within the Study Area west of Pole Line Road, where the stream then enters through a 36-inch diameter culvert that has become three-quarters buried with sediment then proceeds 90 feet east to a fence line. The drainage segments range from approximately 12 feet to 50 feet wide; the segments closest to Pole Line Road have the streambed and banks densely overgrown with weeds, and those furthest west of Pole Line Road are mostly devoid of vegetation. From the fence line east of Pole Line Road, the drainage continues to the east but could not be accessed because of the fence line. This remaining 580-foot section of the drainage on the other side of the fence has been delineated based on the apparent alignment of the drainage as evident on current aerial imagery.

In the vicinity of SP3, excavated toward the centerline of a stream remnant east of Pole Line Road, the vegetation was dominated by coyote brush (*Baccharis pilularis*) (NI) in the sapling/shrub stratum; and short-pod mustard (NI), tocalote (*Centaurea melitensis*) (NI), and salt grass (*Distichlis spicata*) (FAC) in the herb stratum; there were no tree or woody vine strata present. Collectively, these species did not support a dominance of hydrophytic vegetation. The substrate at SP3 included dark yellowish brown (10YR 4/4) loamy sand at a depth of 0 to 16 inches of the soil profile with no noticeable changes in composition throughout the profile; no hydric soil indicators were observed. No surface water, high water table, saturation, or any other primary or secondary wetland hydrology indicators were observed.

In the vicinity of SP15, excavated toward the centerline of a stream remnant west of Pole Line Road, there was no vegetation present and no dominance of hydrophytic vegetation. The substrate at SP15 included dark yellowish brown (10YR 4/4) sandy loam at a depth of 0 to 6 inches of the soil profile with no noticeable changes in composition throughout the profile; the soil became impenetrable at a depth of 6 inches; no hydric soil indicators were observed. No surface water, high water table, saturation, or any other primary or secondary wetland hydrology indicators were observed. The drainage was completely dry at the time of the delineation. No evidence of an OHWM was observed at this feature. It is likely that the remnant of this stream rarely conveys water, and only during heavy rain events. In



adjacent uplands, SP4 and SP16 were excavated in areas that supported no hydrophytic vegetation, hydric soil, or wetland hydrology indicators.

Approximately 1,146-linear-feet of remnant sections of Zemorra Creek were delineated toward the extreme southwestern corner of the Study Area in the vicinity of Main Camp Road (Appendix A, Figures 6-11 and 6-12); this is a tributary that drains to the southeast toward Chico Martinez Creek. According to NWI and NHD mapping data (USFWS 2022, USGS 2022), this drainage originates approximately 4.3 miles west of the Study Area in the Bacon Hills (foothills in the Temblor Range). The drainage at some point before 2005 experienced historical alteration leading through what is now the Study Area, where the drainage proceeds to the southeast under a dirt access road (presumably at one point through what is now likely a buried culvert) before continuing to the southeast toward Chico Martinez Creek.

In the vicinity of SP9, excavated toward the centerline of a remnant of Zemorra Creek, the vegetation was dominated by allscale saltbush (*Atriplex polycarpa*) (FACU) in the shrub stratum, and red brome (*Bromus madritensis* ssp. *rubens*) (NI) and tocalote (NI) in the herb stratum; there were no tree or woody vine strata present. The substrate at SP9 included brown (10YR 4/3) loam at a depth of 0 to 8 inches of the soil profile, where a restrictive layer was met; no hydric soil indicators were observed. No surface water, high water table, saturation, or any other primary or secondary wetland hydrology indicators were observed. The drainage was completely dry at the time of the delineation. No evidence of an OHWM was observed along the drainage. In adjacent uplands, SP10 was excavated in an area that supported no hydrophytic vegetation, hydric soil, or wetland hydrology indicators.

5.1.3 Chico Martinez Creek

As previously discussed in Section 2.4, three segments of Chico Martinez Creek traverse the Study Area (Figures 6-6 to 6-11. The first segment of Chico Martinez delineated is an approximately 0.08-mile section south of the Aera Oasis Building and south of Seventh Standard Road. In the vicinity of SP17, excavated toward the centerline of the stream, the vegetation was dominated by allscale saltbush (FACU) in the shrub stratum, and Jimson weed (*Datura wrightii*) (UPL) and turkey mullein (*Croton setiger*) (NL) in the herb stratum; there were no tree or woody vine strata present. Collectively, these species did not support a dominance of hydrophytic vegetation. The substrate at SP17 included yellowish brown (10YR 5/6) sand at a depth of 0 to 16 inches of the soil profile with no noticeable changes in composition throughout the profile; no hydric soil indicators were observed. No surface water, high water table, saturation, or any other primary or secondary wetland hydrology indicators were observed. The drainage was completely dry at the time of the delineation. No evidence of an OHWM was observed along this segment of Chico Martinez Creek. In adjacent uplands, SP18 was excavated in an area that supported no hydrophytic vegetation, hydric soil, or wetland hydrology indicators.

The second segment of Chico Martinez delineated is an approximately 0.83-mile section roughly southeast of the Aera Oasis Building and north of Seventh Standard Road. In the vicinity of SP5, excavated toward the centerline of the stream in a position where an OHWM was visible, the vegetation was dominated by allscale saltbush (FACU) in the sapling/shrub stratum and Russian thistle (UPL) in the herb stratum; there were no tree or woody vine strata present. Collectively, these species did not support a dominance of hydrophytic vegetation. The substrate at SP5 included a 0.25-inch layer of small gravels on the surface, with dark yellowish brown (10YR 4/6) loamy sand at a depth of 0.25 to 16 inches of the soil profile with no noticeable changes in soil composition throughout the profile; no hydric soil indicators were observed. No surface water, high water table, saturation, or any other primary or

secondary wetland hydrology indicators were observed. This section of the creek was completely dry at the time of the delineation. In adjacent uplands, SP-6 was excavated in an area that supported no hydrophytic vegetation, hydric soil, or wetland hydrology indicators.

The third segment of Chico Martinez delineated is an approximately 0.27-mile section in the vicinity of SR-33 toward the intersection of Treeline Road/Roustabout Road. The sample points for this segment, SP7 and SP8, were excavated in a section of Chico Martinez Creek just to the northeast that appeared in a former Study Area boundary but no longer occurs in the current Study Area boundary (Figure 6-6); the conditions along this entire extent of Chico Martinez were assessed to be similar enough to support the use of these points as surrogates for the segment of Chico Martinez Creek that remains in this vicinity of the current Study Area. In the vicinity of SP7, excavated toward the centerline of the stream in a position where an OHWM was visible, the vegetation was dominated by allscale saltbush (FACU) in the sapling/shrub stratum and Russian thistle (UPL) in the herb stratum; there were no tree, herb, or woody vine strata present. The presence of this species did not support a dominance of hydrophytic vegetation. The substrate at SP7 included a 0.25-inch layer of small gravels on the surface, with dark yellowish brown (10YR 4/4) loamy sand at a depth of 0.25 to 16 inches of the soil profile with no noticeable changes in composition throughout the profile; no hydric soil indicators were observed; no hydric soil indicators were observed. No surface water, high water table, saturation, or any other primary or secondary wetland hydrology indicators were observed. This section of the creek was completely dry at the time of the delineation. In adjacent uplands, SP-8 was excavated in an area that supported no hydrophytic vegetation, hydric soil, or wetland hydrology indicators.

It must be noted that at two sampling locations at two separate segments of Chico Martinez Creek (i.e., SP5 and SP7), the bounds of the OHWM were determined with supporting information included on OHWM datasheets (Appendix B); however, it should also be noted that Chico Martinez Creek was observed to feature discontinuous OHWMs (including stream stretches with and without OHWMs) consistent with “discontinuous ephemeral channels” per Lichvar and McColley (2008). This section of Chico Martinez Creek appears capable of conveying water, but likely only during and immediately after substantial rain events. As a result, the OHWM datasheets are included for informational purposes, but no OHWM has been mapped due to the substantial discontinuity of this feature along Chico Martinez Creek.

5.2 NEGATIVE DATA

Prior to field surveys, other potential aquatic features within the Study Area, such as the various small historic artificially flooded marshes, ponds and canals described in Section 2.4, were targeted based on available resources such as aerial imagery and historical NWI and NHD data. Upon examining these areas, no evidence of any of these features was observed. The substrate and vegetation in these areas where these features may have historically occurred were indistinguishable from adjacent uplands. These areas had likely been graded and filled by past activities; the areas revealed no continuity of concavity or channelization that would be suggestive of any stream flow. It appears likely that historical development associated with the grading and construction of oil wells, pipelines, access roads, and associated infrastructure has permanently altered the hydrology of the landscape in these areas, and where water may have once flowed or collected in these areas, perhaps only ephemerally or as a result of anthropogenic activities, it evidently no longer does.

5.3 PRELIMINARY JURISDICTIONAL DETERMINATION

Appendix A, Figures 6-1 to 6-12 include delineation maps for the potential jurisdictional features within the Study Area; the delineation maps have been prepared consistent with the *Updated Map and Drawing Standards for the South Pacific Division Regulatory Program* (USACE 2016). Table 2 presents the 14 sample points selected within the Study Area; a summary of vegetation, soil, and hydrology wetland parameters present/absent based on observed indicators recorded on USACE Arid West Region data sheets (Appendix B); and a characterization of the potential federal and state jurisdictional features occurring within the vicinity of the sample points.

Table 2. Preliminary Jurisdictional Determination Summary

Sample Point / Soil Pit	Hydrophytic Vegetation	Hydric Soil	Wetland Hydrology	Potential Jurisdiction[1]		
				Federal / USACE	State / RWQCB	CDFW Jurisdictional Areas
SP1	N	N	N	N/A	Waters of the State (Drainage Ditch)	Drainage Ditch
SP2	N	N	N	N/A (Uplands)	N/A (Uplands)	N/A (Uplands)
SP3	N	N	N	N/A	Waters of the State (Streambed)	Streambed
SP4	N	N	N	N/A (Uplands)	N/A (Uplands)	N/A (Uplands)
SP5	N	N	N	N/A	Waters of the State (Streambed)	Streambed
SP6	N	N	N	N/A (Uplands)	N/A (Uplands)	N/A (Uplands)
SP7	N	N	N	N/A	Waters of the State (Streambed)	Streambed
SP8	N	N	N	N/A (Uplands)	N/A (Uplands)	N/A (Uplands)
SP9	N	N	N	N/A	Waters of the State (Streambed)	Streambed
SP10	N	N	N	N/A (Uplands)	N/A (Uplands)	N/A (Uplands)
SP11	N	N	N	N/A	Waters of the State (Drainage Ditch)	Drainage Ditch
SP12	N	N	N	N/A (Uplands)	N/A (Uplands)	N/A (Uplands)
SP13[2]	--	--	--	--	--	--
SP14[2]	--	--	--	--	--	--
SP15	N	N	N	N/A	Waters of the State (Streambed)	Streambed
SP16	N	N	N	N/A (Uplands)	N/A (Uplands)	N/A (Uplands)
SP17	N	N	N	N/A	Waters of the State (Streambed)	Streambed
SP18	N	N	N	N/A (Uplands)	N/A (Uplands)	N/A (Uplands)

[1] Areas of potential jurisdiction are subject to final verification and approval by the regulatory agencies (i.e., USACE, RWQCB, and CDFW).

[2]. This area occurred in a former Study Area boundary, but this general area has been removed from consideration as a project component in the current Study Area, no results for these sample points are presented in this Report.

Table 3 quantifies the potential jurisdictional waters (in acres, square feet, and linear feet) for the delineated resources within the Study Area and includes footnotes summarizing the key characteristics of potential jurisdictional waters for each agency/regulatory jurisdiction based on Stantec's understanding of current regulatory guidance.

Table 3. Preliminary Jurisdictional Waters Totals in the Study Area

Potential Jurisdictional Waters[1]	Acres	Square Feet	Linear Feet
U.S. Army Corps of Engineers			
N/A[2]	N/A	N/A	N/A
Total Potential USACE Jurisdiction	**N/A**	**N/A**	**N/A**
Regional Water Quality Control Board			
Waters of the State (Drainage Ditch between Main Camp Rd and Gas Plant 32)	0.189	8,229	411
Waters of the State (Drainage Ditch along west side of Pole Line Road and north of Tulare Road)	0.155	6,741	602
Waters of the State (Streambed of Remnant Ephemeral Stream south of Contractors Road)	1.008	43,907	1,711
Waters of the State (Streambed of Remnant Sections of Zemorra Creek south of Main Camp Road)	1.195	52,030	1,446
Chico Martinez Creek (Streambed)	6.920	301,413	6,247
Total Potential RWQCB Jurisdiction	**9.467**	**412,320**	**10,417**
California Department of Fish and Wildlife			
Drainage Ditch between Main Camp Rd and Gas Plant 32	0.189	8,229	411
Drainage Ditch along west side of Pole Line Road and north of Tulare Road	0.155	6,741	602
Streambed of Remnant Ephemeral Stream south of Contractors Road	1.008	43,907	1,711
Streambed of Remnant Sections of Zemorra Creek south of Main Camp Road	1.195	52,030.16	1,446
Streambed of Chico Martinez Creek	6.920	301,413	6,247
Total Potential CDFW Jurisdiction	**9.467**	**412,320**	**10,417**

[1] Areas of potential jurisdiction are subject to final verification and approval by the regulatory agencies (i.e., USACE, RWQCB, and CDFW).

[2] No potential federal WOTUS were delineated with the Study Area due to lack of an OHWM and/or no evident connectivity to any other federal WOTUS recognized as a traditional navigable water.

6.0 SUMMARY AND CONCLUSIONS

6.1 FEDERAL WETLANDS/OTHER WATERS

The jurisdictional delineation did not identify any potential jurisdictional federal WOTUS within the Study Area. Based on the current definition of WOTUS and Stantec's professional opinion, because the potentially jurisdictional aquatic features within the Study Area either lack an OHWM and/or otherwise have no evident connectivity to any other federal WOTUS recognized as a traditional navigable water, these features likely do not qualify as potential WOTUS. No three-parameter wetlands meeting federal standards were delineated within the Study Area. The recent *Sackett* decision (USACE 2023) should have no influence on the status of WOTUS within the Study Area because there are no adjacent wetlands (or any other wetlands) within the Study Area.

A previous delineation of Chico Martinez Creek (Stantec 2021) asserted that Chico Martinez Creek was not a potential federal jurisdictional WOTUS, based on the USEPA and USACE 2020 NWPR (Code of Federal Regulations 33 Part 328) because as an ephemeral drainage, it was not considered jurisdictional and had no connectivity to a traditional navigable water (Stantec 2021).

There are no regional USACE Approved Jurisdictional Determinations (AJDs) reported within the vicinity of the South and North Belridge oil fields (USACE 2023b). The nearest known federally jurisdictional water is the California Aqueduct. Under 40 Code of Federal Regulations 230.3(3), the USACE considers the California Aqueduct "Waters of the United States" (Caltrans 2022) as defined below from the regulations:

> "All other waters such as intrastate lakes, rivers, streams (including intermittent streams), mudflats, sandflats, wetlands, sloughs, prairie potholes, wet meadows, playa lakes, or natural ponds, the use, degradation or destruction of which could affect interstate or foreign commerce including any such waters:
>
> a. Which are or could be used by interstate or foreign travelers for recreational or other purposes; or
>
> b. From which fish or shellfish are or could be taken and sold in interstate or foreign commerce; or
>
> c. Which are used or could be used for industrial purposes by industries in interstate commerce.

None of the aquatic features delineated in this Report have connectivity with the California Aqueduct. Chico Martinez Creek, the most significant regional drainage, reaches its terminus 1.80 miles west of the California Aqueduct.

6.2 WATERS OF THE STATE

The jurisdictional delineation identified potential jurisdictional waters of the State within the Study Area. Based on the current guidance for determining Waters of the State and Stantec's professional opinion, these include a total of 9.467 acres that may potentially fall under the jurisdiction of RWQCB. While the *State Wetland Definition and Procedures for Discharges of Dredged or Fill Material to Waters of the State* provide exemptions for ditches used for agricultural purposes (SWRCB 2019), there does not appear to be an exemption currently provided for ditches in other settings.

6.3 CDFW JURISDICTIONAL AREAS

The jurisdictional delineation identified potential CDFW jurisdictional areas within the Study Area. Based on Stantec's professional opinion, these include 9.467 acres that may potentially fall under the jurisdiction of CDFW. This total is identical to the RWQCB total because there is no additional riparian habitat acreage associated with any of the identified potential jurisdictional features.

6.4 CONCLUSION

Based on Stantec's preliminary assessment, the Study Area may include potentially jurisdictional waters. If the proposed Aera CarbonFrontier Project cannot completely avoid the potential jurisdictional waters delineated within the Study Area, Aera will likely need to procure regulatory permits from the RWQCB and/or CDFW. These may include WDRs from the Central Valley RWQCB for impacts to potential Waters of the State, and a CDFW Section 1602 Lake and Streambed Alteration Agreement.

The conclusions presented above represent Stantec's professional opinion based on our knowledge and experience with the applicable regulatory agencies, including their technical guidance documents and manuals. However, the USACE, RWQCB, and CDFW have final authority in determining the status and presence of jurisdictional wetlands/waters and the extent of their boundaries.

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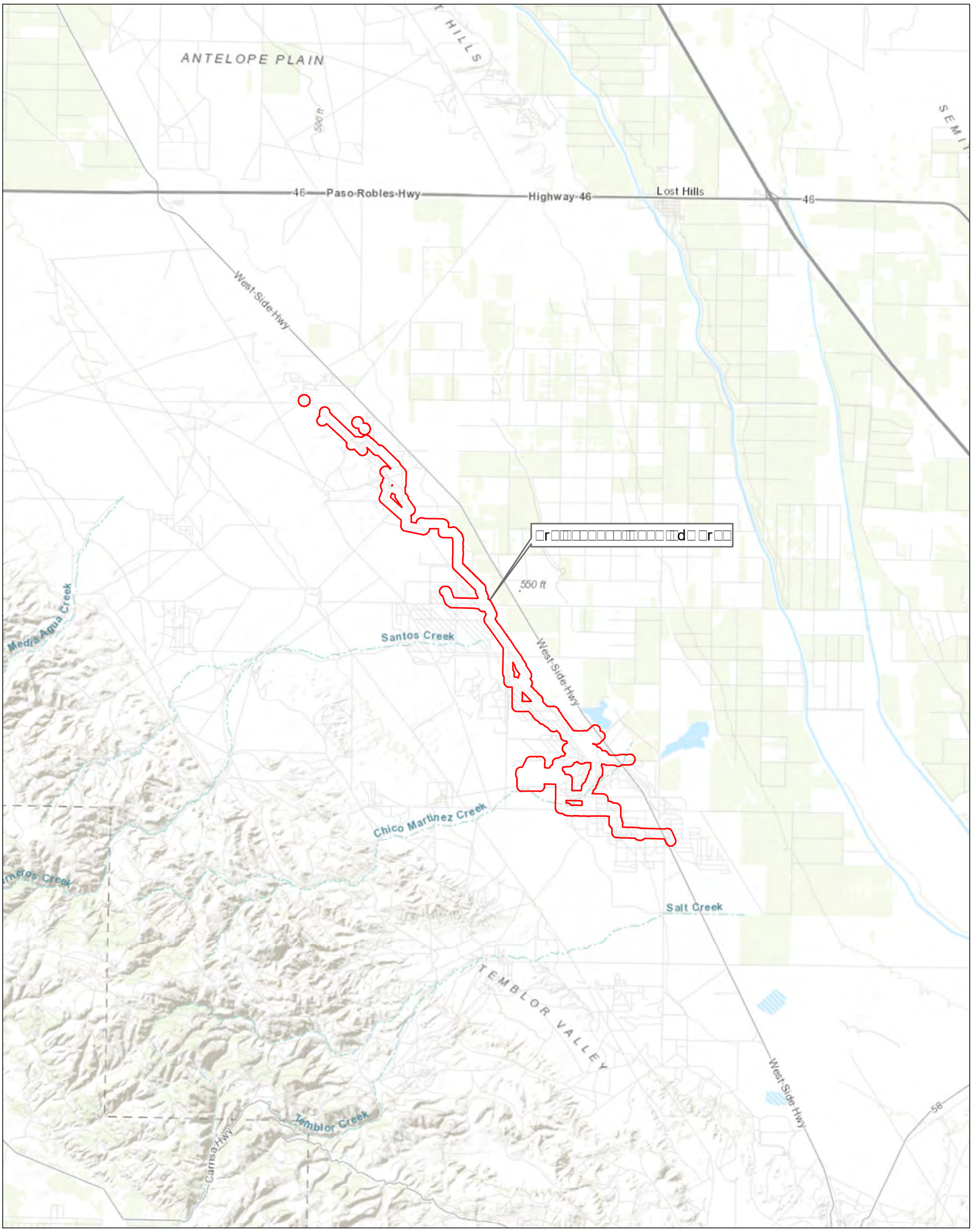


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Appendix A FIGURES







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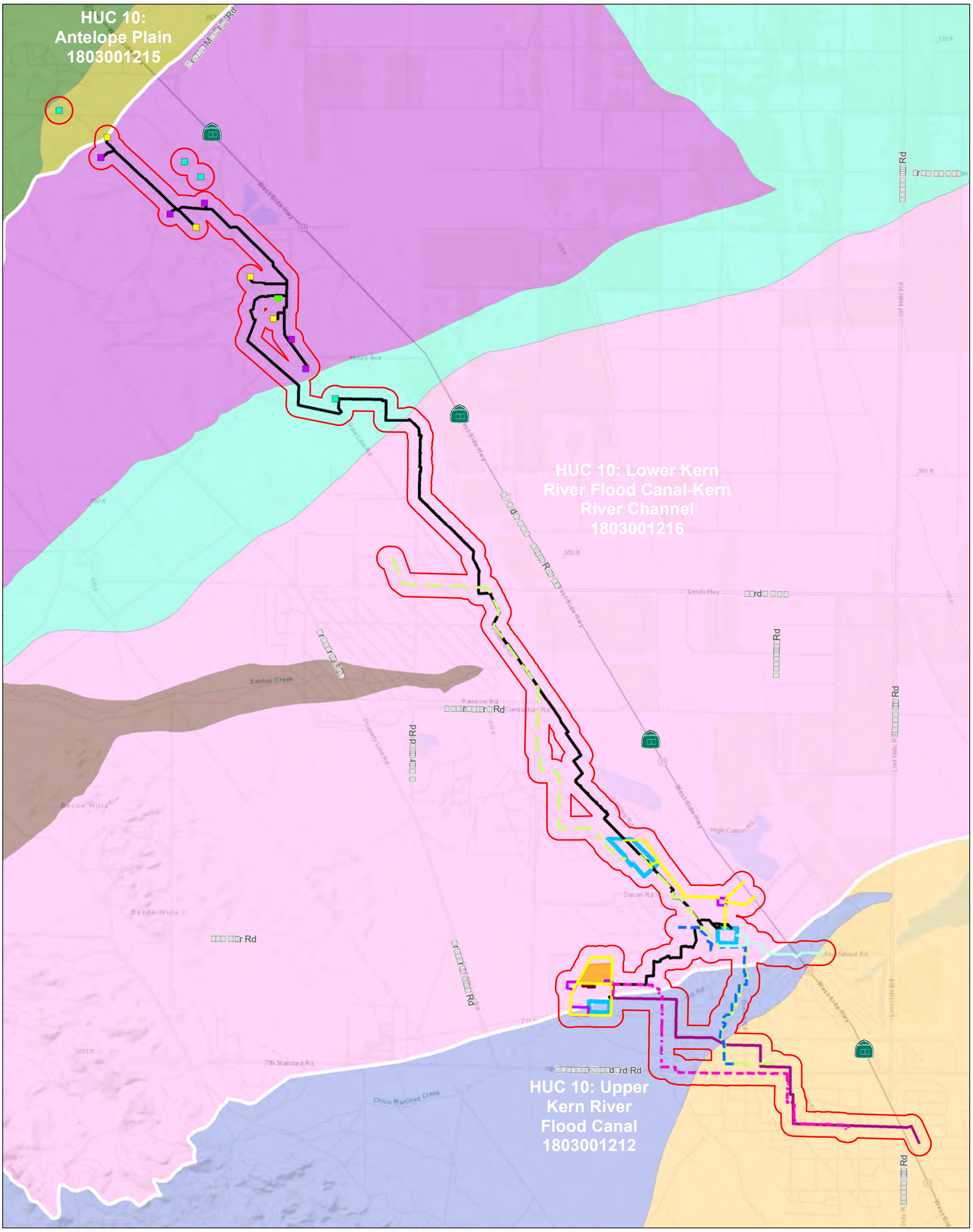
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Watershed Boundary Dataset: Hydrologic Unit 12

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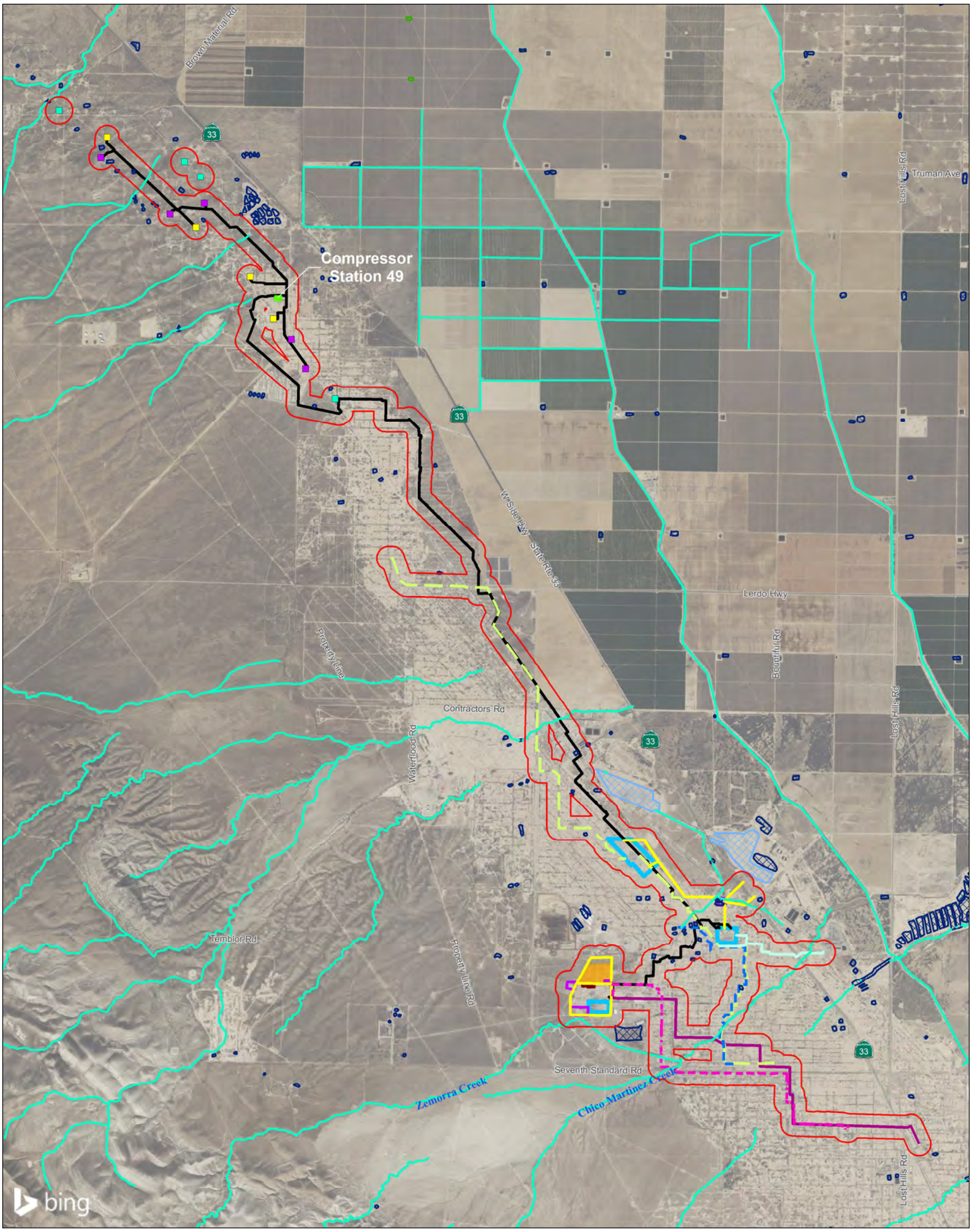
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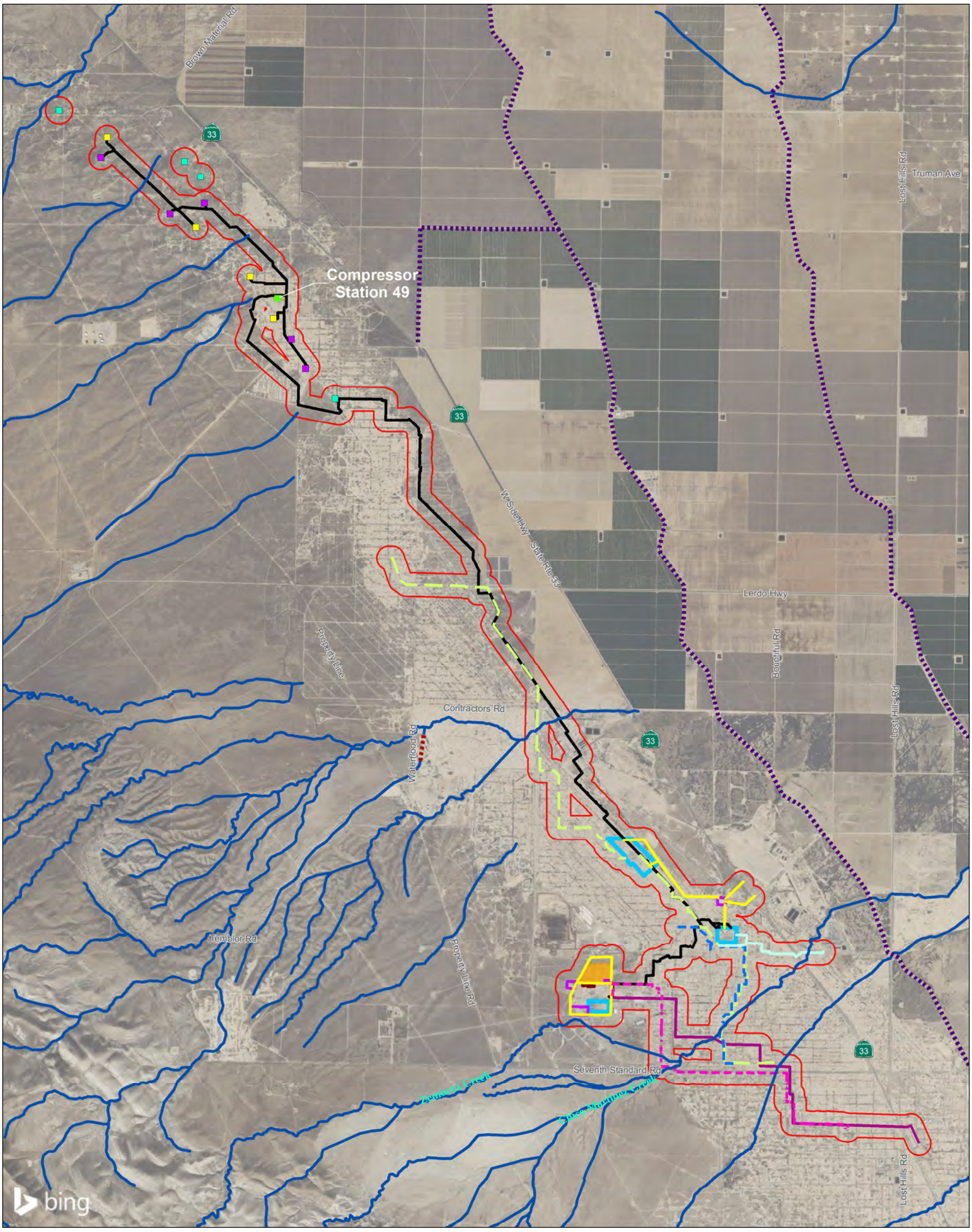
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National Wetlands Inventory (NWI)



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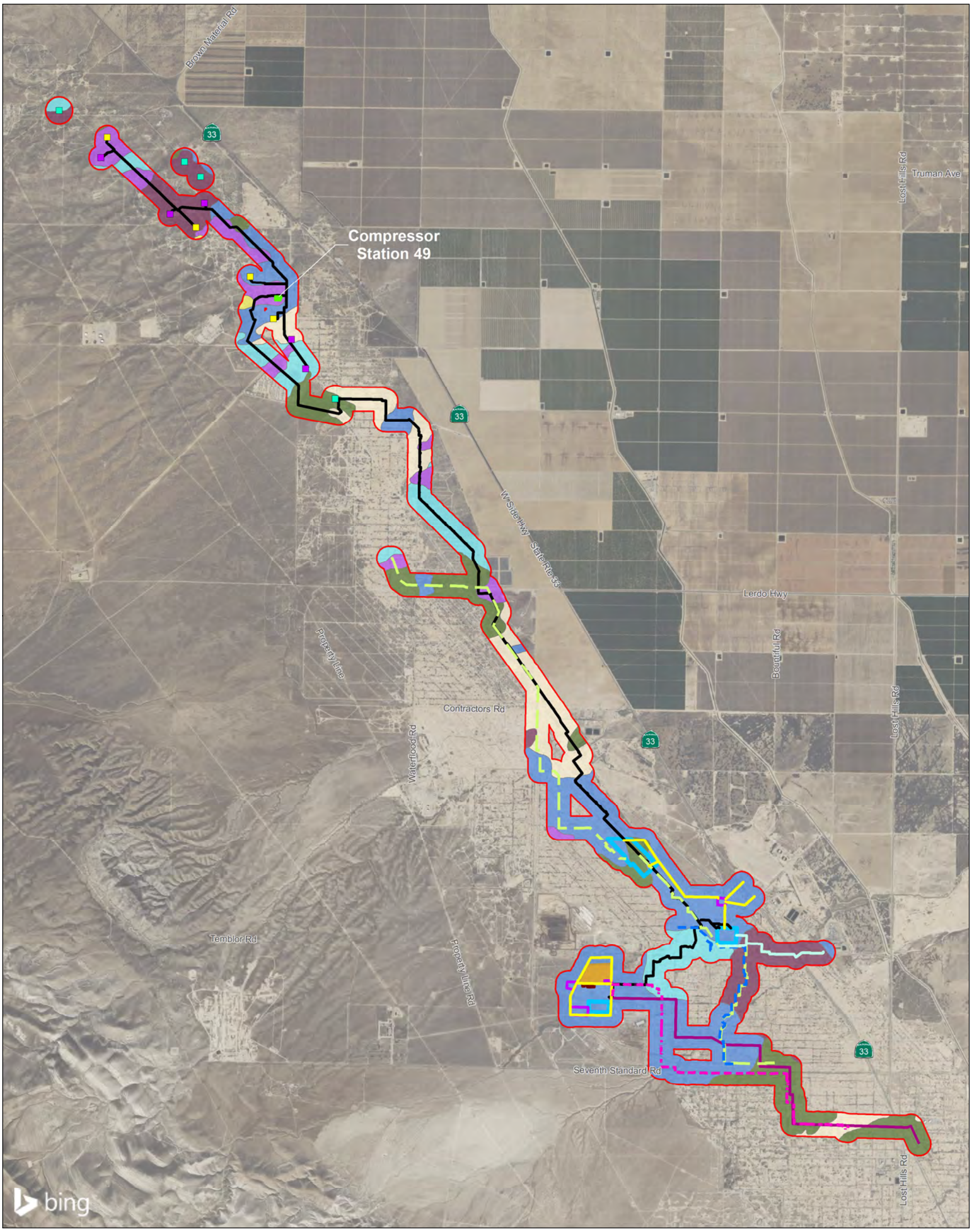
National Hydrography Dataset (NHD)

Notes

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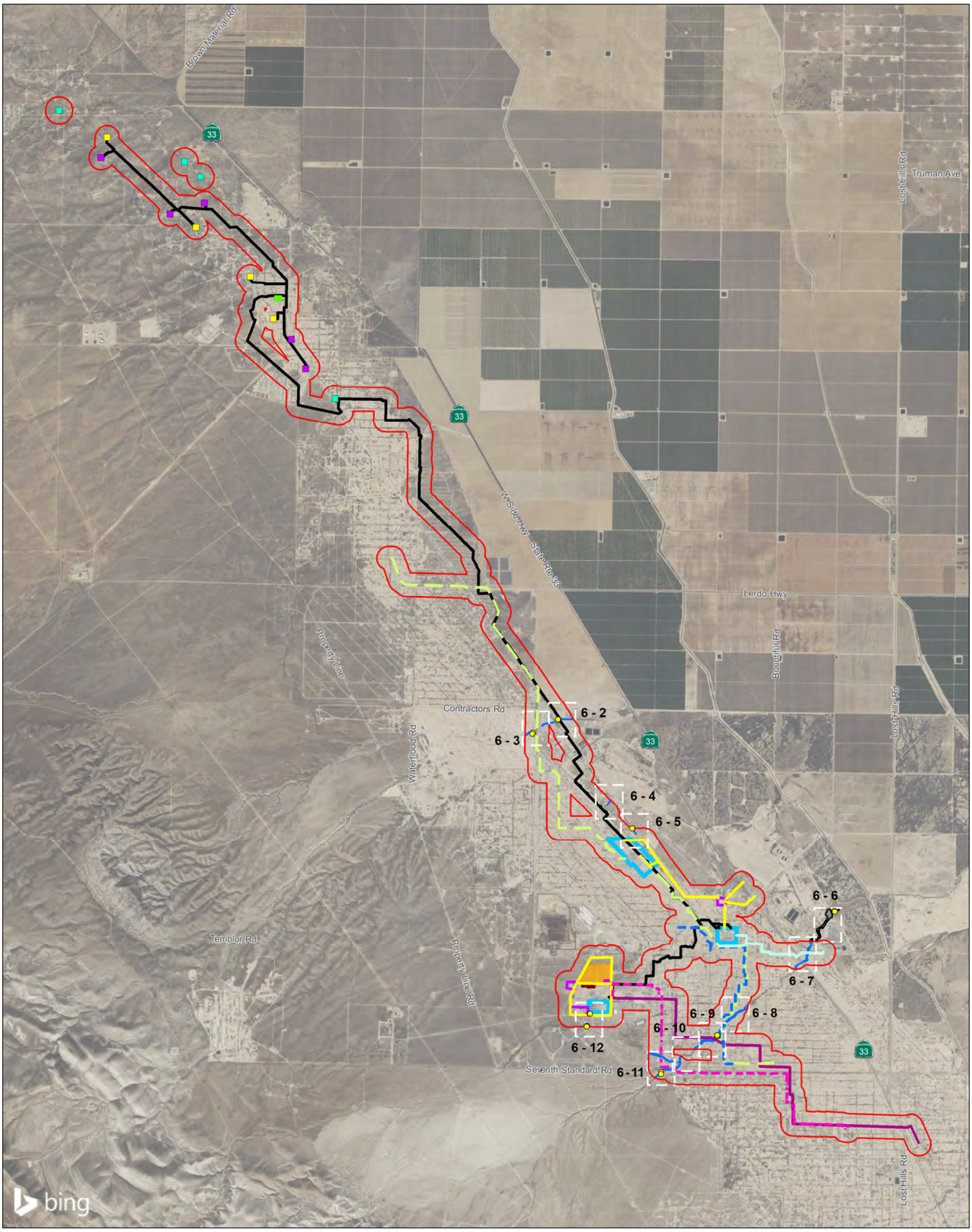
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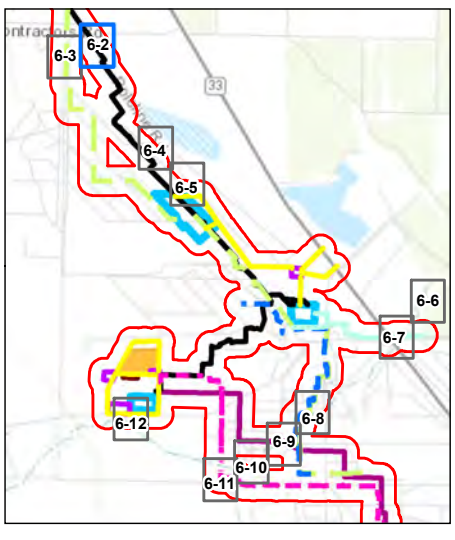
Title

Potential Jurisdictional Waters

Notes

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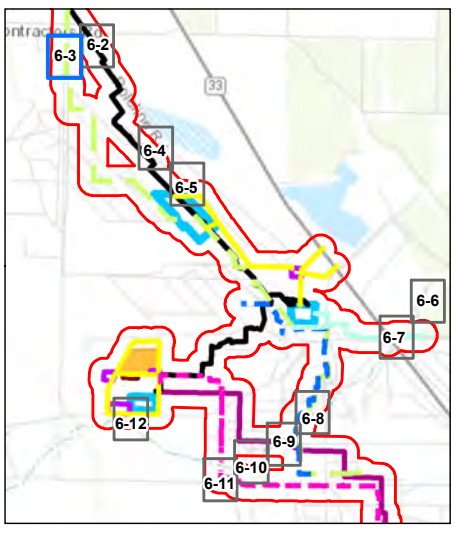
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Figure 6 - 2



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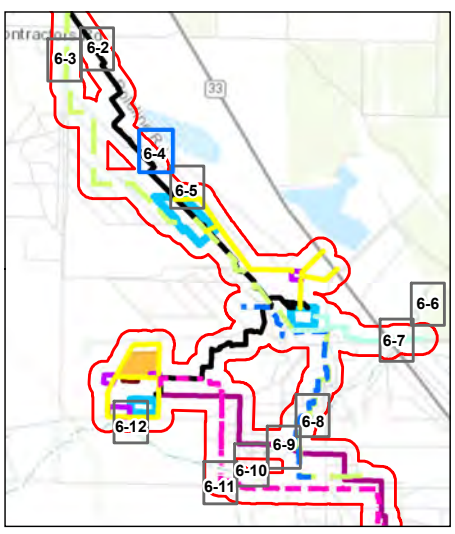
Figure No.

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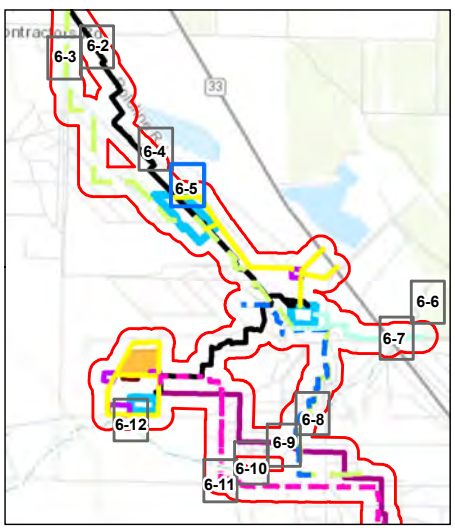
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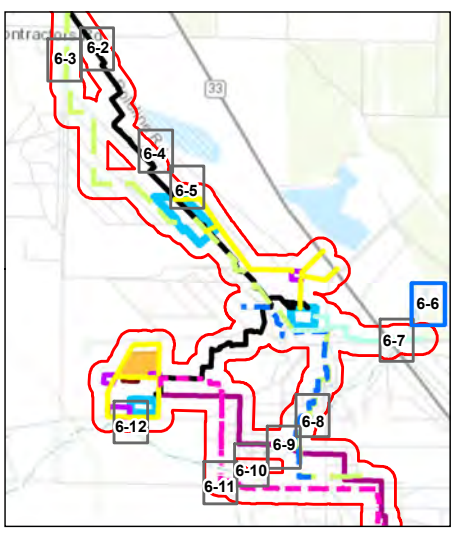
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Figure No.

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Potential Jurisdictional Waters

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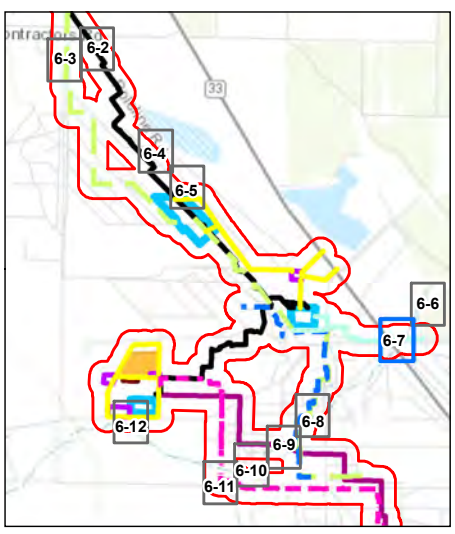
Figure 6 - 6

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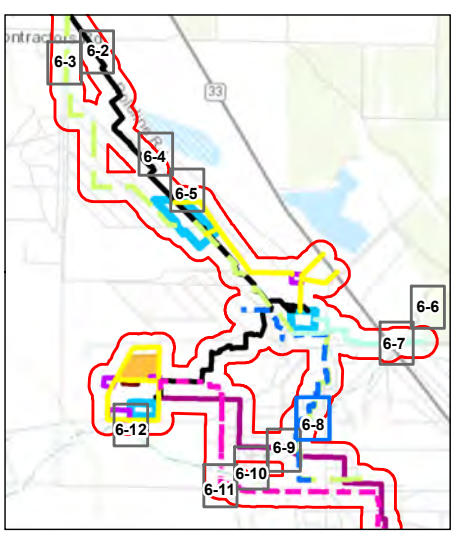
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Figure No.
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Title
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Title

Potential Jurisdictional Waters

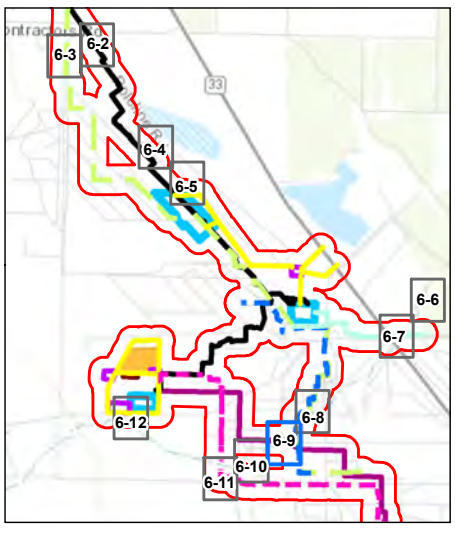
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Potential Jurisdictional Waters

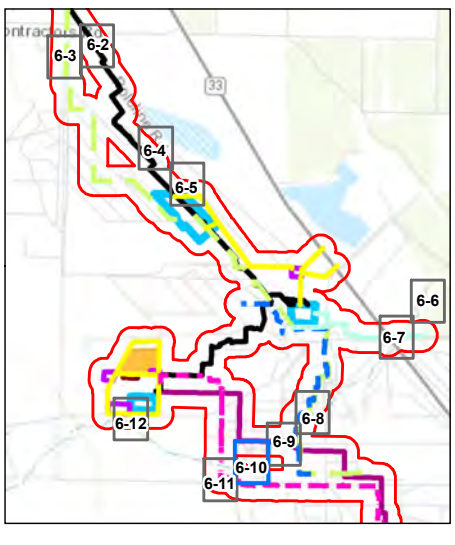
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Project Location

Client/Project

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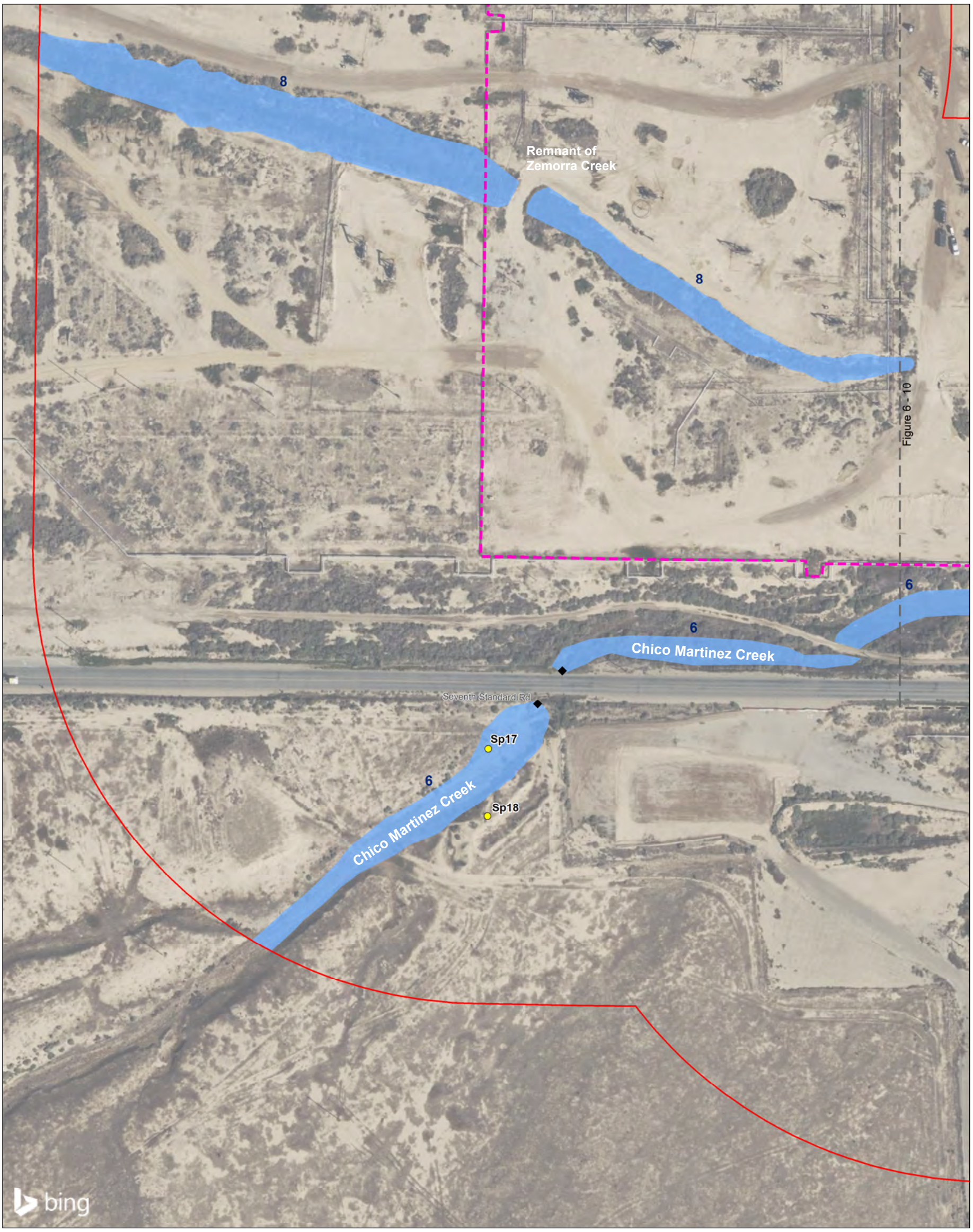
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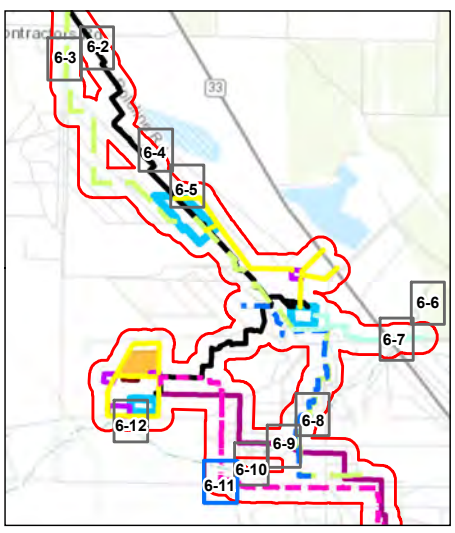
Title

Potential Jurisdictional Waters

Notes

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Project Location

Client/Project

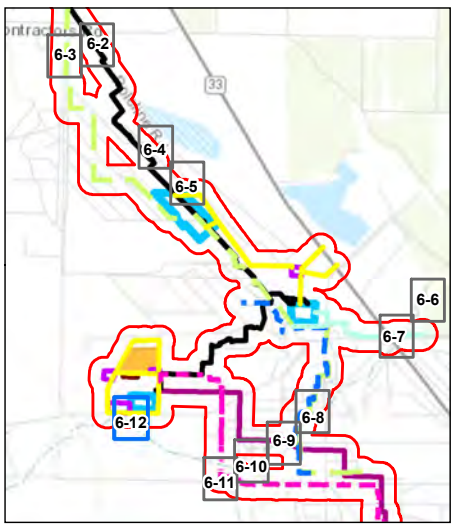
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Title

Potential Jurisdictional Waters


Main Camp Road
Sp1
Sp2
4
Warehouse Road
Remnant of
Zemorra Creek
5
Sp10
Sp9
bing


6-2
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Appendix B WETLAND DETERMINATION DATA FORMS AND ORDINARY HIGH-WATER MARK DATASHEETS



WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Aera Belridge ERS City/County: Belridge oil field, western Kern County Sampling Date: 06/01/22

Applicant/Owner: Aera State: CA Sampling Point: SP1

Investigator(s): G. Hoetker, J. Byrd Section, Township, Range: S32, T29S, R21E

Landform (hillslope, terrace, etc.): excavated drainage ditch Local relief (concave, convex, none): Concave Slope (%): 1%

Subregion (LRR): LRR C Lat: 35.447616 Long: -119.734113° Datum: NAD83

Soil Map Unit Name: 174 – Kimberlina fine sandy loam, 0-2% slopes NWI classification: Riverine

Are climatic / hydrologic conditions on the site typical for this time of year? Yes ✓ No ____ (If no, explain in Remarks.)

Are Vegetation Y, Soil Y, or Hydrology ____ significantly disturbed? Are "Normal Circumstances" present? Yes ✓ No ____

Are Vegetation —, Soil —, or Hydrology — naturally problematic? N (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ____	No ✓	**Is the Sampled Area within a Wetland?** Yes ____ No ✓
Hydric Soil Present?	Yes ____	No ✓	
Wetland Hydrology Present?	Yes ____	No ✓	

Remarks: No wetland indicators; excavated drainage ditch; no OHWM; potential waters of the state

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: —)	Absolute % Cover	Dominant Species?	Indicator Status
1. —			
2.			
3.			
4.			
	— = Total Cover		
Sapling/Shrub Stratum (Plot size: —)			
1. —			
2.			
3.			
4.			
5.			
	— = Total Cover		
Herb Stratum (Plot size: 5')			
1. Salsola tragus	20%	Y	UPL
2.			
3.			
4.			
5.			
6.			
7.			
8.			
	20% = Total Cover		
Woody Vine Stratum (Plot size: —)	—		
1. —			
2.			
	— = Total Cover		

% Bare Ground in Herb Stratum 80% % Cover of Biotic Crust —

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 0 (A)

Total Number of Dominant Species Across All Strata: 1 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 0 (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:
OBL species ____	x 1 = ____
FACW species ____	x 2 = ____
FAC species ____	x 3 = ____
FACU species ____	x 4 = ____
UPL species ____	x 5 = ____
Column Totals: ____ (A)	____ (B)

Prevalence Index = B/A = ____

Hydrophytic Vegetation Indicators:

___ Dominance Test is >50%

___ Prevalence Index is ≤3.0[1]

___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)

___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes ____ No ✓

Remarks: No dominant hydrophytic vegetation.

SOIL

Sampling Point: SP1

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	%	Redox Features Color (moist)	%	Type[1]	Loc[2]	Texture	Remarks
0-5"	10YR 4/4	100%	—	—	—	—	sand	
5-16"	10YR 4/3	100%	—	—	—	—	loamy sand	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) (**LRR C**)
- ___ 1 cm Muck (A9) (**LRR D**)
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) (**LRR C**)
- ___ 2 cm Muck (A10) (**LRR B**)
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: —

Depth (inches): —

Hydric Soil Present? Yes ___ No ✓

Remarks:

Sandy soil top layer; loamy sand bottom layer — no hydric soil indicators

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) (**Nonriverine**)
- ___ Sediment Deposits (B2) (**Nonriverine**)
- ___ Drift Deposits (B3) (**Nonriverine**)
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) (**Riverine**)
- ___ Sediment Deposits (B2) (**Riverine**)
- ___ Drift Deposits (B3) (**Riverine**)
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes ___ No ✓ Depth (inches): ___

Water Table Present? Yes ___ No ✓ Depth (inches): ___

Saturation Present? (includes capillary fringe) Yes ___ No ✓ Depth (inches): ___

Wetland Hydrology Present? Yes ___ No ✓

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

No hydrology indicators

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Aera Belridge CCS City/County: Belridge Oil Field, Western Kern County Sampling Date: 06/01/22

Applicant/Owner: Aera State: CA Sampling Point: SP2

Investigator(s): G. Hoetker, J. Byrd Section, Township, Range: S32, T28S, R21E

Landform (hillslope, terrace, etc.): terrace - uplands Local relief (concave, convex, none): none Slope (%): 0

Subregion (LRR): LRRC Lat: 35.447627 Long: -119.734029 Datum: NAD83

Soil Map Unit Name: 174 - Kimberlina fine sandy loam, 0-2% slopes NWI classification: N/A - uplands

Are climatic / hydrologic conditions on the site typical for this time of year? Yes ____ No ____ (If no, explain in Remarks.)

Are Vegetation Y, Soil Y, or Hydrology ____ significantly disturbed? Are "Normal Circumstances" present? Yes ✓ No ____

Are Vegetation ____, Soil ____, or Hydrology ____ naturally problematic? N (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ____	No ✓	**Is the Sampled Area within a Wetland?** Yes ____ No ✓
Hydric Soil Present?	Yes ____	No ✓	
Wetland Hydrology Present?	Yes ____	No ✓	

Remarks: No wetland indicators; uplands adjacent to drainage ditch

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: —)	Absolute % Cover	Dominant Species?	Indicator Status
1.			
2.			
3.			
4.			
	— = Total Cover		
Sapling/Shrub Stratum (Plot size: —)			
1.			
2.			
3.			
4.			
5.			
	— = Total Cover		
Herb Stratum (Plot size: 5')			
1. Salsola tragus	5%		
2. Bromus madritensis ssp. rubens	5%		
3.			
4.			
5.			
6.			
7.			
8.			
	10% = Total Cover		
Woody Vine Stratum (Plot size: —)			
1.			
2.			
	— = Total Cover		

% Bare Ground in Herb Stratum ~90% % Cover of Biotic Crust —

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 0 (A)

Total Number of Dominant Species Across All Strata: 2 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 100% (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:
OBL species ____	x 1 = ____
FACW species ____	x 2 = ____
FAC species ____	x 3 = ____
FACU species ____	x 4 = ____
UPL species ____	x 5 = ____
Column Totals: ____ (A)	____ (B)

Prevalence Index = B/A = ____

Hydrophytic Vegetation Indicators:

- ___ Dominance Test is >50%
- ___ Prevalence Index is ≤3.0[1]
- ___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)
- ___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes ____ No ✓

Remarks: No dominant hydrophytic vegetation.

SOIL

Sampling Point: SP2

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	Matrix %	Redox Features Color (moist)	Redox Features %	Redox Features Type[1]	Redox Features Loc[2]	Texture	Remarks
0-16"	10YR 4/3	100%	—	—	—	—	loamy sand	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) **(LRR C)**
- ___ 1 cm Muck (A9) **(LRR D)**
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) **(LRR C)**
- ___ 2 cm Muck (A10) **(LRR B)**
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: —

Depth (inches): —

Hydric Soil Present? Yes ____ No ✓

Remarks: loamy sand; no hydric soil indicators

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) **(Nonriverine)**
- ___ Sediment Deposits (B2) **(Nonriverine)**
- ___ Drift Deposits (B3) **(Nonriverine)**
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) **(Riverine)**
- ___ Sediment Deposits (B2) **(Riverine)**
- ___ Drift Deposits (B3) **(Riverine)**
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes ____ No ✓ Depth (inches): ____

Water Table Present? Yes ____ No ✓ Depth (inches): ____

Saturation Present? (includes capillary fringe) Yes ____ No ✓ Depth (inches): ____

Wetland Hydrology Present? Yes ____ No ✓

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks: No hydrology indicators

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Aera Belridge, CCS City/County: Belridge western loam, oil field, County Sampling Date: 6/1/22

Applicant/Owner: Aera State: CA Sampling Point: SP3

Investigator(s): G. Hoetker, J. Byrd Section, Township, Range: S20, T29S, R21E

Landform (hillslope, terrace, etc.): drainage Local relief (concave, convex, none): concave Slope (%): 1%

Subregion (LRR): LRRC Lat: 35.483319° Long: -119.739537 Datum: NAD 83

Soil Map Unit Name: 211 - Panoche clay loam, 0-2% slopes NWI classification: Riverine

Are climatic / hydrologic conditions on the site typical for this time of year? Yes _____ No _____ (If no, explain in Remarks.)

Are Vegetation Y, Soil Y, or Hydrology Y significantly disturbed? Are "Normal Circumstances" present? Yes ✓ No _____

Are Vegetation _____, Soil _____, or Hydrology _____ naturally problematic? N (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes _____	No ✓	**Is the Sampled Area within a Wetland?** Yes _____ No ✓
Hydric Soil Present?	Yes _____	No ✓	
Wetland Hydrology Present?	Yes _____	No ✓	

Remarks: Remnant ephemeral stream w/ partially buried culvert, no OHWM, potential waters of the state; no wetland indicators

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: —)	Absolute % Cover	Dominant Species?	Indicator Status
1. —			
2.			
3.			
4.			
	—	= Total Cover	
Sapling/Shrub Stratum (Plot size: 10')			
1. Berberis pinnata	15%	Y	NI/upl
2.			
3.			
4.			
5.			
	15%	= Total Cover	
Herb Stratum (Plot size: 5')			
1. Hirschfeldia incana	30%	Y	NI/UPL
2. Centaurea melitensis	20%	Y	NI/UPL
3. Deinandra fasciculata	15%	Y	FAC
4.			
5.			
6.			
7.			
8.			
	65%	= Total Cover	
Woody Vine Stratum (Plot size: —)			
1. —			
2.			
	—	= Total Cover	

% Bare Ground in Herb Stratum ~35% % Cover of Biotic Crust —

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 1 (A)

Total Number of Dominant Species Across All Strata: 4 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 25% (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:	
OBL species	x 1 =	
FACW species	x 2 =	
FAC species	x 3 =	
FACU species	x 4 =	
UPL species	x 5 =	
Column Totals: (A)		(B)

Prevalence Index = B/A = _____

Hydrophytic Vegetation Indicators:

___ Dominance Test is >50%

___ Prevalence Index is ≤3.0[1]

___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)

___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes _____ No ✓

Remarks:

No dominant hydrophytic vegetation.

Sampling Point: SP 3

SOIL

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	Matrix %	Redox Features Color (moist)	Redox Features %	Type[1]	Loc[2]	Texture	Remarks
0-16"	10YR 4/4	100%	—	—	—	—	loamy sand	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) **(LRR C)**
- ___ 1 cm Muck (A9) **(LRR D)**
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) **(LRR C)**
- ___ 2 cm Muck (A10) **(LRR B)**
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: —

Depth (inches): —

Hydric Soil Present? Yes ____ No ✓

Remarks: No hydric soil indicators.

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) **(Nonriverine)**
- ___ Sediment Deposits (B2) **(Nonriverine)**
- ___ Drift Deposits (B3) **(Nonriverine)**
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) **(Riverine)**
- ___ Sediment Deposits (B2) **(Riverine)**
- ___ Drift Deposits (B3) **(Riverine)**
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes ____ No ✓ Depth (inches): —

Water Table Present? Yes ____ No ✓ Depth (inches): —

Saturation Present? (includes capillary fringe) Yes ____ No ____ Depth (inches): —

Wetland Hydrology Present? Yes ____ No ✓

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks: No hydrology indicators.

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Aera Belridge CCS City/County: Belridge Western Kern Oil Field, County Sampling Date: 06/01/2022

Applicant/Owner: Aera State: CA Sampling Point: SP4

Investigator(s): G. Huether, J. Byrd Section, Township, Range: S20, T29S, R21E

Landform (hillslope, terrace, etc.): terrace - uplands Local relief (concave, convex, none): none Slope (%): 0%

Subregion (LRR): LRR C Lat: 35.483294° Long: -119.739436° Datum: NAD 83

Soil Map Unit Name: 211 - Panoche clay loam, 0-2% slopes NWI classification: N/A - uplands

Are climatic / hydrologic conditions on the site typical for this time of year? Yes ✓ No ____ (If no, explain in Remarks.)

Are Vegetation N, Soil N, or Hydrology ____ significantly disturbed? Are "Normal Circumstances" present? Yes ✓ No ____

Are Vegetation ____, Soil ____, or Hydrology ____ naturally problematic? N (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ____	No ✓	**Is the Sampled Area within a Wetland?** Yes ____ No ✓
Hydric Soil Present?	Yes ____	No ✓	
Wetland Hydrology Present?	Yes ____	No ✓	

Remarks: No wetland indicators; uplands adjacent to drainage

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: —)	Absolute % Cover	Dominant Species?	Indicator Status
1.			
2.			
3.			
4.			
	—	= Total Cover	
Sapling/Shrub Stratum (Plot size: —)			
1.			
2.			
3.			
4.			
5.			
	—	= Total Cover	
Herb Stratum (Plot size: —)			
1.			
2.			
3.			
4.			
5.			
6.			
7.			
8.			
	—	= Total Cover	
Woody Vine Stratum (Plot size: —)			
1.			
2.			
	—	= Total Cover	

% Bare Ground in Herb Stratum 100 % Cover of Biotic Crust —

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 0 (A)

Total Number of Dominant Species Across All Strata: 0 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 0% (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:
OBL species ____	x 1 = ____
FACW species ____	x 2 = ____
FAC species ____	x 3 = ____
FACU species ____	x 4 = ____
UPL species ____	x 5 = ____
Column Totals: ____ (A)	____ (B)

Prevalence Index = B/A = ____

Hydrophytic Vegetation Indicators:

___ Dominance Test is >50%

___ Prevalence Index is ≤3.0[1]

___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)

___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes ____ No ✓

Remarks: No vegetation.

SOIL

Sampling Point: SP4

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	%	Redox Features Color (moist)	%	Type[1]	Loc[2]	Texture	Remarks
0-8"	10YR 4/4	100	—	—	—	—	loamy sand	
restrictive layer below								

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) (**LRR C**)
- ___ 1 cm Muck (A9) (**LRR D**)
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) (**LRR C**)
- ___ 2 cm Muck (A10) (**LRR B**)
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: hardpan

Depth (inches): 8"

Hydric Soil Present? Yes ____ No ✓

Remarks:

No hydric soil indicators.

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) (**Nonriverine**)
- ___ Sediment Deposits (B2) (**Nonriverine**)
- ___ Drift Deposits (B3) (**Nonriverine**)
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) (**Riverine**)
- ___ Sediment Deposits (B2) (**Riverine**)
- ___ Drift Deposits (B3) (**Riverine**)
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes ____ No ✓ Depth (inches): ____

Water Table Present? Yes ____ No ✓ Depth (inches): ____

Saturation Present? (includes capillary fringe) Yes ____ No ✓ Depth (inches): ____

Wetland Hydrology Present? Yes ____ No ✓

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

No hydrology indicators.

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Aera Belridge CCS City/County: Belridge Oilfield, Western Kern County Sampling Date: 07/18/22

Applicant/Owner: Aera State: CA Sampling Point: SP5

Investigator(s): G. Huether, E. Martin, J. Pratt, C. Cortez Section, Township, Range: S33, T28S, R21E

Landform (hillslope, terrace, etc.): drainage - Chico Martinez Creek Local relief (concave, convex, none): Concave Slope (%): 1%

Subregion (LRR): LRR C Lat: 35.445175° Long: -119.715113° Datum: NAD83

Soil Map Unit Name: 174 - Lembert fine sandy loam, 0-2% slopes NWI classification: Riverine

Are climatic / hydrologic conditions on the site typical for this time of year? Yes ✓ No _____ (If no, explain in Remarks.)

Are Vegetation ✓, Soil ✓, or Hydrology ✓ significantly disturbed? Y Are "Normal Circumstances" present? Yes ✓ No _____

Are Vegetation _____, Soil _____, or Hydrology _____ naturally problematic? N (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes _____	No ✓	**Is the Sampled Area within a Wetland?** Yes _____ No ✓
Hydric Soil Present?	Yes _____	No ✓	
Wetland Hydrology Present?	Yes _____	No ✓	

Remarks: No wetland indicators observed. Chico Martinez Creek = ephemeral drainage channel; discontinuous ditch; potential waters of the State

VEGETATION – Use scientific names of plants.

	Absolute % Cover	Dominant Species?	Indicator Status
Tree Stratum (Plot size: —)			
1. — N/A			
2.			
3.			
4.			
	— = Total Cover		
Sapling/Shrub Stratum (Plot size: 10')			
1. Atriplex polycarpa	25%	Y	FACU
2.			
3.			
4.			
5.			
	25 = Total Cover		
Herb Stratum (Plot size: 5')			
1. Salsola tragus	10%	Y	FACU
2. Centaurea melitensis	5%	Y	NI/UPL
3. Amaranthus sp.	1%	N	NI/UPL
4.			
5.			
6.			
7.			
8.			
	16 = Total Cover		
Woody Vine Stratum (Plot size: —)			
1. N/A	—		
2.			
	— = Total Cover		

% Bare Ground in Herb Stratum ~84% % Cover of Biotic Crust —

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 0 (A)

Total Number of Dominant Species Across All Strata: 3 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 0% (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:
OBL species _____	x 1 = _____
FACW species _____	x 2 = _____
FAC species _____	x 3 = _____
FACU species _____	x 4 = _____
UPL species _____	x 5 = _____
Column Totals: _____ (A)	_____ (B)

Prevalence Index = B/A = _____

Hydrophytic Vegetation Indicators:

___ Dominance Test is >50%

___ Prevalence Index is ≤3.0[1]

___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)

___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes _____ No ✓

Remarks: No dominant hydrophytic vegetation.

SOIL

Sampling Point: SPS

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	%	Redox Features Color (moist)	%	Type[1]	Loc[2]	Texture	Remarks
0-0.25	—	—					Sandy Gravel	
0.25-16"	10YR 4/6	100%	—	—	—	—	Loamy Sand	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) (**LRR C**)
- ___ 1 cm Muck (A9) (**LRR D**)
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) (**LRR C**)
- ___ 2 cm Muck (A10) (**LRR B**)
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: —

Depth (inches): —

Hydric Soil Present? Yes _____ No ✓

Remarks:

No hydric soil indicators

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) (**Nonriverine**)
- ___ Sediment Deposits (B2) (**Nonriverine**)
- ___ Drift Deposits (B3) (**Nonriverine**)
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) (**Riverine**)
- ___ Sediment Deposits (B2) (**Riverine**)
- ___ Drift Deposits (B3) (**Riverine**)
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes _____ No ✓ Depth (inches): —

Water Table Present? Yes _____ No ✓ Depth (inches): —

Saturation Present? (includes capillary fringe) Yes _____ No ✓ Depth (inches): —

Wetland Hydrology Present? Yes _____ No ✓

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

No wetland hydrology

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Aera CCS - Chico Madrigal Creek City/County: Bakersfield Western Kern Sampling Date: 18 Jul 22

Applicant/Owner: Aera State: CA Sampling Point: SP 6

Investigator(s): G. Hoetker, E. Martin, J. Pratt, C. Cortez Section, Township, Range: S 33, T 28 S, R 21 E

Landform (hillslope, terrace, etc.): upland (mudpad) Local relief (concave, convex, none): flat Slope (%): 0%

Subregion (LRR): LRR C Lat: 35.445359° Long: -119.715101° Datum: _____

Soil Map Unit Name: 174 - Kimberlina fine sandy loam, 0-2% slopes NWI classification: N/A uplands

Are climatic / hydrologic conditions on the site typical for this time of year? Yes X No _____ (If no, explain in Remarks.)

Are Vegetation X, Soil X, or Hydrology X significantly disturbed? Are "Normal Circumstances" present? Yes X No _____

Are Vegetation _____, Soil _____, or Hydrology _____ naturally problematic? N (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes _____	No X	**Is the Sampled Area within a Wetland?** Yes _____ No X
Hydric Soil Present?	Yes _____	No X	
Wetland Hydrology Present?	Yes _____	No X	

Remarks:
Sample on edge of developed mud pad; uplands – no wetland indicators

VEGETATION – Use scientific names of plants.

	Absolute % Cover	Dominant Species?	Indicator Status
Tree Stratum (Plot size: –)			
1. N/A			
2.			
3.			
4.			
	= Total Cover		
Sapling/Shrub Stratum (Plot size: 10')			
1. A. polycarpa	45%	Y	FACU
2.			
3.			
4.			
5.			
	45% = Total Cover		
Herb Stratum (Plot size: 5')			
1. Bromus mad Rubus S	1%	N	UPL
2.			
3.			
4.			
5.			
6.			
7.			
8.			
	1% = Total Cover		
Woody Vine Stratum (Plot size: –)			
1. N/A			
2.			
	– = Total Cover		

% Bare Ground in Herb Stratum ~99% % Cover of Biotic Crust _____

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 0 (A)

Total Number of Dominant Species Across All Strata: 1 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 0 (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:	
OBL species	x 1 =	
FACW species	x 2 =	
FAC species	x 3 =	
FACU species	x 4 =	
UPL species	x 5 =	
Column Totals: (A)		(B)

Prevalence Index = B/A = _____

Hydrophytic Vegetation Indicators:

___ Dominance Test is >50%

___ Prevalence Index is ≤3.0[1]

___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)

___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes _____ No X

Remarks:
No dominant hydrophytic vegetation.

SOIL

Sampling Point: SP 6

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	%	Redox Features Color (moist)	%	Type[1]	Loc[2]	Texture	Remarks
≈10"	10YR 4/6	100					Loamy Sand	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) (**LRR C**)
- ___ 1 cm Muck (A9) (**LRR D**)
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) (**LRR C**)
- ___ 2 cm Muck (A10) (**LRR B**)
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: bedrock

Depth (inches): 10"

Hydric Soil Present? Yes ____ No X

Remarks:

No hydric soil indicators.

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) (**Nonriverine**)
- ___ Sediment Deposits (B2) (**Nonriverine**)
- ___ Drift Deposits (B3) (**Nonriverine**)
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) (**Riverine**)
- ___ Sediment Deposits (B2) (**Riverine**)
- ___ Drift Deposits (B3) (**Riverine**)
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes ____ No X Depth (inches): ____

Water Table Present? Yes ____ No X Depth (inches): ____

Saturation Present? (includes capillary fringe) Yes ____ No X Depth (inches): ____

Wetland Hydrology Present? Yes ____ No X

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

No wetland hydrology indicators.

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Aera Belridge CCS City/County: Belridge Oil Field, Western Kern County Sampling Date: 07/20/22

Applicant/Owner: Aera State: CA Sampling Point: SP7

Investigator(s): G. Hetter, E. Martin, J. Platt, C. Cortez Section, Township, Range: S22, T28S, R21E

Landform (hillslope, terrace, etc.): stream channel - Chico Martinez Creek Local relief (concave, convex, none): concave Slope (%): 1%

Subregion (LRR): Lrr c - Med CA Lat: 35.460661° Long: -119.698066° Datum: NAD 83

Soil Map Unit Name: 174 - Kimberlina fine sandy loam, 0-2% slopes NWI classification: Riverine/ephemeral

Are climatic / hydrologic conditions on the site typical for this time of year? Yes ✓ No ____ (If no, explain in Remarks.)

Are Vegetation N, Soil N, or Hydrology Y significantly disturbed? Are "Normal Circumstances" present? Yes Y No ____

Are Vegetation N, Soil N, or Hydrology N naturally problematic? (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ____	No ✓	**Is the Sampled Area within a Wetland?** Yes ____ No ✓
Hydric Soil Present?	Yes ____	No ✓	
Wetland Hydrology Present?	Yes ____	No ✓	

Remarks: Chico Martinez Creek - No wetland indicators present, OHWM present in some areas; bed & bank present; potential waters of the State

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: 30')	Absolute % Cover	Dominant Species?	Indicator Status
1. N/A			
2.			
3.			
4.			
	—	= Total Cover	
Sapling/Shrub Stratum (Plot size: 10')			
1. Atriplex polycarpa	35%	Y	FACU
2.			
3.			
4.			
5.			
	35%	= Total Cover	
Herb Stratum (Plot size: 5')			
1. N/A			
2.			
3.			
4.			
5.			
6.			
7.			
8.			
	—	= Total Cover	
Woody Vine Stratum (Plot size: 10')			
1. N/A			
2.			
	—	= Total Cover	

% Bare Ground in Herb Stratum ≈99% % Cover of Biotic Crust N/A

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 6 (A)

Total Number of Dominant Species Across All Strata: 1 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 0% (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:	
OBL species	x 1 =	
FACW species	x 2 =	
FAC species	x 3 =	
FACU species	x 4 =	
UPL species	x 5 =	
Column Totals: (A)		(B)

Prevalence Index = B/A = ____

Hydrophytic Vegetation Indicators:

___ Dominance Test is >50%

___ Prevalence Index is ≤3.0[1]

___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)

___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes ____ No ✓

Remarks: No dominant hydrophytic vegetation

SOIL

Sampling Point: SP7

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	%	Redox Features Color (moist)	%	Type[1]	Loc[2]	Texture	Remarks
0-25"	NA	100%	NA	—	—	—	gravel & cobbles	deposition on top layer
0.25-8"	10YR 4/4	100%	NA	—	—	—	loamy sand	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) **(LRR C)**
- ___ 1 cm Muck (A9) **(LRR D)**
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) **(LRR C)**
- ___ 2 cm Muck (A10) **(LRR B)**
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: hardpan

Depth (inches): 8"

Hydric Soil Present? Yes ____ No ✓

Remarks:

No hydric soil present

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) **(Nonriverine)**
- ___ Sediment Deposits (B2) **(Nonriverine)**
- ___ Drift Deposits (B3) **(Nonriverine)**
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) **(Riverine)**
- ___ Sediment Deposits (B2) **(Riverine)**
- ___ Drift Deposits (B3) **(Riverine)**
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes ____ No ✓ Depth (inches): —

Water Table Present? Yes ____ No ✓ Depth (inches): —

Saturation Present? (includes capillary fringe) Yes ____ No ✓ Depth (inches): —

Wetland Hydrology Present? Yes ____ No ✓

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

No wetland hydrology present

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Aera Belridge CCS City/County: Belridge Oil Field, Western Kern County Sampling Date: 7/20/12

Applicant/Owner: Aera State: CA Sampling Point: SP8

Investigator(s): G. HOETKER E MARTIN, J. Pratt, C. Corkz Section, Township, Range: S27, T28S, R21E

Landform (hillslope, terrace, etc.): CURVED TOP RIDGE Local relief (concave, convex, none): CONVEX Slope (%): 1 %

Subregion (LRR): LRR C Lat: 35.460569° Long: -119.697984 Datum: NAD 83

Soil Map Unit Name: 174 - Kimberlina fine sand, loam, 0-2% slopes NWI classification: NA ; upland

Are climatic / hydrologic conditions on the site typical for this time of year? Yes X No _____ (If no, explain in Remarks.)

Are Vegetation Y, Soil Y, or Hydrology Y significantly disturbed? Are "Normal Circumstances" present? Yes X No _____

Are Vegetation N, Soil N, or Hydrology N naturally problematic? (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes _____	No X	**Is the Sampled Area within a Wetland?** Yes _____ No X
Hydric Soil Present?	Yes _____	No X	
Wetland Hydrology Present?	Yes _____	No X	

Remarks: NO WETLAND INDICATORS PRESENT (UPLANDS)

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: 30')	Absolute % Cover	Dominant Species?	Indicator Status
1. NP			
2.			
3.			
4.			
	—	= Total Cover	
Sapling/Shrub Stratum (Plot size: 10')			
1. ATRIPLEX POLYCARPA	25%	Y	FACU
2.			
3.			
4.			
5.			
	25%	= Total Cover	
Herb Stratum (Plot size: 5')			
1. NP			
2.			
3.			
4.			
5.			
6.			
7.			
8.			
	—	= Total Cover	
Woody Vine Stratum (Plot size: 15')			
1. NP			
2.			
	—	= Total Cover	

% Bare Ground in Herb Stratum 100 % Cover of Biotic Crust —

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 0 (A)

Total Number of Dominant Species Across All Strata: 1 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 0% (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:
OBL species _____	x 1 = _____
FACW species _____	x 2 = _____
FAC species _____	x 3 = _____
FACU species _____	x 4 = _____
UPL species _____	x 5 = _____
Column Totals: _____ (A)	_____ (B)

Prevalence Index = B/A = _____

Hydrophytic Vegetation Indicators:

__ Dominance Test is >50%

__ Prevalence Index is ≤3.0[1]

__ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)

__ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes _____ No X

Remarks: NO DOMINANT HYDROPHYTIC VEGETATION PRESENT

SOIL

Sampling Point: SP8

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	%	Redox Features Color (moist)	%	Type[1]	Loc[2]	Texture	Remarks
0-8	10YR 4/4	100	NA				LOAMY SAND	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) (**LRR C**)
- ___ 1 cm Muck (A9) (**LRR D**)
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) (**LRR C**)
- ___ 2 cm Muck (A10) (**LRR B**)
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: HARD PAN

Depth (inches): 8"

Hydric Soil Present? Yes ____ No X

Remarks:

NO HYDRIC SOIL

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) (**Nonriverine**)
- ___ Sediment Deposits (B2) (**Nonriverine**)
- ___ Drift Deposits (B3) (**Nonriverine**)
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) (**Riverine**)
- ___ Sediment Deposits (B2) (**Riverine**)
- ___ Drift Deposits (B3) (**Riverine**)
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes ____ No X Depth (inches): ____

Water Table Present? Yes ____ No X Depth (inches): ____

Saturation Present? (includes capillary fringe) Yes ____ No X Depth (inches): ____

Wetland Hydrology Present? Yes ____ No X

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

NO WETLAND HYDROLOGY

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Aera Belridge CCS City/County: Belridge Oil Field, Western Kern County Sampling Date: 09/13/22

Applicant/Owner: Aera State: CA Sampling Point: SP9

Investigator(s): G. Woelber, L. Elms Section, Township, Range: S32, T28S, R21E

Landform (hillslope, terrace, etc.): remnant stream Local relief (concave, convex, none): Concave Slope (%): 1%

Subregion (LRR): LRR C Lat: 35.446109° Long: -119.734470° Datum: NAD83

Soil Map Unit Name: 174 – Kimberlina fine sandy loam, 0-2% slopes NWI classification: Riverine

Are climatic / hydrologic conditions on the site typical for this time of year? Yes _____ No _____ (If no, explain in Remarks.)

Are Vegetation ____, Soil ____, or Hydrology ____ significantly disturbed? N Are "Normal Circumstances" present? Yes ✓ No _____

Are Vegetation _____, Soil _____, or Hydrology _____ naturally problematic? N (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes _____	No ✓	**Is the Sampled Area within a Wetland?** Yes _____ No ✓
Hydric Soil Present?	Yes _____	No ✓	
Wetland Hydrology Present?	Yes _____	No ✓	

Remarks: Remnant of Zemorrian Creek, tributary to Chico Martinez Creek. No OHWM; potential waters of the State; no wetland indicators

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: —)	Absolute % Cover	Dominant Species?	Indicator Status
1. —			
2.			
3.			
4.			
	= Total Cover		
Sapling/Shrub Stratum (Plot size: 10')			
1. Atriplex polycarpa	2%	Y	FACW
2.			
3.			
4.			
5.			
	= Total Cover		
Herb Stratum (Plot size: 5')			
1. Bromus madritensis ssp. rubens	14%	Y	UPL
2. Centaurea melitensis	1%	Y	NI/UPL
3. Amsinckia sp.	1%	N	NI/UPL
4.			
5.			
6.			
7.			
8.			
	16% = Total Cover		
Woody Vine Stratum (Plot size: —)			
1.			
2.			
	= Total Cover		

% Bare Ground in Herb Stratum ~95% % Cover of Biotic Crust —

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 0 (A)

Total Number of Dominant Species Across All Strata: 3 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 0% (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:
OBL species _____	x 1 = _____
FACW species _____	x 2 = _____
FAC species _____	x 3 = _____
FACU species _____	x 4 = _____
UPL species _____	x 5 = _____
Column Totals: _____ (A)	_____ (B)

Prevalence Index = B/A = _____

Hydrophytic Vegetation Indicators:

___ Dominance Test is >50%

___ Prevalence Index is ≤3.0[1]

___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)

___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes _____ No ✓

Remarks: No dominant hydrophytic vegetation.

SOIL

Sampling Point: SP9

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	%	Redox Features Color (moist)	%	Type[1]	Loc[2]	Texture	Remarks
0-9"	10YR 4/3	100	—		—	—	loam	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) (**LRR C**)
- ___ 1 cm Muck (A9) (**LRR D**)
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) (**LRR C**)
- ___ 2 cm Muck (A10) (**LRR B**)
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: hardpan

Depth (inches): 9"

Hydric Soil Present? Yes ___ No ✓

Remarks:

No hydric soil indicators.

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) (**Nonriverine**)
- ___ Sediment Deposits (B2) (**Nonriverine**)
- ___ Drift Deposits (B3) (**Nonriverine**)
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) (**Riverine**)
- ___ Sediment Deposits (B2) (**Riverine**)
- ___ Drift Deposits (B3) (**Riverine**)
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes ___ No ✓ Depth (inches): ___

Water Table Present? Yes ___ No ✓ Depth (inches): ___

Saturation Present? (includes capillary fringe) Yes ___ No ✓ Depth (inches): ___

Wetland Hydrology Present? Yes ___ No ✓

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

No hydrology indicators.

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Aera Belridge CCS City/County: Belridge Western 0-1 Field, Kern County Sampling Date: 09/13/22

Applicant/Owner: Aera State: CA Sampling Point: SP10

Investigator(s): G. Haetker, L. Elms Section, Township, Range: S32, T28S, R21E

Landform (hillslope, terrace, etc.): terrace/uplands Local relief (concave, convex, none): none Slope (%): 0%

Subregion (LRR): LRRC Lat: 35.446147° Long: -119.734440 Datum: NAD83

Soil Map Unit Name: 174- Kimberlina fine sandy loam, 0-2% slopes NWI classification: N/A- uplands

Are climatic / hydrologic conditions on the site typical for this time of year? Yes ✓ No _____ (If no, explain in Remarks.)

Are Vegetation ✓, Soil ✓, or Hydrology _____ significantly disturbed? Are "Normal Circumstances" present? Yes ✓ No _____

Are Vegetation _____, Soil _____, or Hydrology _____ naturally problematic? N (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes _____	No ✓	**Is the Sampled Area within a Wetland?** Yes _____ No ✓
Hydric Soil Present?	Yes _____	No ✓	
Wetland Hydrology Present?	Yes _____	No ✓	

Remarks: No wetland indicators; uplands

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: —)	Absolute % Cover	Dominant Species?	Indicator Status
1. —			
2.			
3.			
4.			
	—	= Total Cover	
Sapling/Shrub Stratum (Plot size: 10')			
1. Atriplex polycarpa	35%	Y	FACU
2.			
3.			
4.			
5.			
		= Total Cover	
Herb Stratum (Plot size: 5')			
1. Bromus madritensis ssp. rubens	5%	Y	UPL
2. Salsola tragus	1%	N	FACU
3.			
4.			
5.			
6.			
7.			
8.			
	6%	= Total Cover	
Woody Vine Stratum (Plot size: —)			
1. —			
2.			
		= Total Cover	

% Bare Ground in Herb Stratum ≈ 94% % Cover of Biotic Crust —

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 0 (A)

Total Number of Dominant Species Across All Strata: 2 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 0% (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:
OBL species _____	x 1 = _____
FACW species _____	x 2 = _____
FAC species _____	x 3 = _____
FACU species _____	x 4 = _____
UPL species _____	x 5 = _____
Column Totals: _____ (A)	_____ (B)

Prevalence Index = B/A = _____

Hydrophytic Vegetation Indicators:

___ Dominance Test is >50%

___ Prevalence Index is ≤3.0[1]

___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)

___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes _____ No ✓

Remarks: No dominant hydrophytic vegetation.

SOIL

Sampling Point: SP10

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	%	Redox Features Color (moist)	%	Type[1]	Loc[2]	Texture	Remarks
0-10"	10YR 5/6	100%					loam	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) (**LRR C**)
- ___ 1 cm Muck (A9) (**LRR D**)
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) (**LRR C**)
- ___ 2 cm Muck (A10) (**LRR B**)
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: hardpan

Depth (inches): 10"

Hydric Soil Present? Yes _____ No ✓

Remarks:

No hydric soil indicators.

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) (**Nonriverine**)
- ___ Sediment Deposits (B2) (**Nonriverine**)
- ___ Drift Deposits (B3) (**Nonriverine**)
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) (**Riverine**)
- ___ Sediment Deposits (B2) (**Riverine**)
- ___ Drift Deposits (B3) (**Riverine**)
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes _____ No ✓ Depth (inches): _____

Water Table Present? Yes _____ No ✓ Depth (inches): _____

Saturation Present? (includes capillary fringe) Yes _____ No ✓ Depth (inches): _____

Wetland Hydrology Present? Yes _____ No ✓

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

No hydrology indicators.

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Kern Belridge CCS City/County: Belridge Western Kern County Sampling Date: 09/13/22

Applicant/Owner: Aera State: CA Sampling Point: SP11

Investigator(s): G. Hoether, L. Elms Section, Township, Range: S20, T28S, R21E

Landform (hillslope, terrace, etc.): drainage ditch Local relief (concave, convex, none): concave Slope (%): 1%

Subregion (LRR): LRRC Lat: 35.470284° Long: -119.728256° Datum: NAD83

Soil Map Unit Name: 174-Kimberlina fine sandy loam, 0-2% slopes NWI classification: Riverine

Are climatic / hydrologic conditions on the site typical for this time of year? Yes ✓ No ____ (If no, explain in Remarks.)

Are Vegetation ____, Soil ____, or Hydrology ____ significantly disturbed? N Are "Normal Circumstances" present? Yes ✓ No ____

Are Vegetation ____, Soil ____, or Hydrology ____ naturally problematic? N (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ____	No ✓	**Is the Sampled Area within a Wetland?** Yes ____ No ✓
Hydric Soil Present?	Yes ____	No ✓	
Wetland Hydrology Present?	Yes ____	No ✓	

Remarks: Drainage ditch along Pelican Rd. No wetland indicators. No OHWM. Potential waters of the State.

VEGETATION – Use scientific names of plants.

	Absolute % Cover	Dominant Species?	Indicator Status
Tree Stratum (Plot size: ~)			
1.			
2.			
3.			
4.			
	~ = Total Cover		
Sapling/Shrub Stratum (Plot size: 10')			
1. Atriplex polycarpa	10%	Y	FACU
2.			
3.			
4.			
5.			
	~ = Total Cover		
Herb Stratum (Plot size: ____)			
1. Bromus madritensis ssp rubens	5%	Y	UPL
2. Aristida sp.	1%	N	NI/FACU
3.			
4.			
5.			
6.			
7.			
8.			
	11% = Total Cover		
Woody Vine Stratum (Plot size: ~)			
1.			
2.			
	~ = Total Cover		

% Bare Ground in Herb Stratum ≈ 89% % Cover of Biotic Crust ~

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 0 (A)

Total Number of Dominant Species Across All Strata: 2 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 0% (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:
OBL species ____	x 1 = ____
FACW species ____	x 2 = ____
FAC species ____	x 3 = ____
FACU species ____	x 4 = ____
UPL species ____	x 5 = ____
Column Totals: ____ (A)	____ (B)

Prevalence Index = B/A = ____

Hydrophytic Vegetation Indicators:

- ___ Dominance Test is >50%
- ___ Prevalence Index is ≤3.0[1]
- ___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)
- ___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes ____ No ✓

Remarks: No dominant hydrophytic vegetation.

SOIL

Sampling Point: SP 11

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	%	Redox Features Color (moist)	%	Type[1]	Loc[2]	Texture	Remarks
0-2	—						flaky	- may have been layer of hydrophobic soil additive?
2-10	10YR 4/4	100	—				loamy sand	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) **(LRR C)**
- ___ 1 cm Muck (A9) **(LRR D)**
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) **(LRR C)**
- ___ 2 cm Muck (A10) **(LRR B)**
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: hardpan

Depth (inches): 10"

Hydric Soil Present? Yes ____ No ✓

Remarks: Soil had 2" layer of flaky soil that may have been imported fill - it was flaky and hydrophobic (repelled water). Eight inch layer of loamy sand underneath. No hydric soil indicators

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) **(Nonriverine)**
- ___ Sediment Deposits (B2) **(Nonriverine)**
- ___ Drift Deposits (B3) **(Nonriverine)**
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) **(Riverine)**
- ___ Sediment Deposits (B2) **(Riverine)**
- ___ Drift Deposits (B3) **(Riverine)**
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes ____ No ✓ Depth (inches): ____

Water Table Present? Yes ____ No ✓ Depth (inches): ____

Saturation Present? (includes capillary fringe) Yes ____ No ____ Depth (inches): ____

Wetland Hydrology Present? Yes ____ No ✓

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks: No hydrology indicators.

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Aera Belridge CCS City/County: Belridge Western Oil Field, Kern County Sampling Date: 04/13/22

Applicant/Owner: Aera State: CA Sampling Point: S1R

Investigator(s): G. Hoetker, L. Elms Section, Township, Range: S20, T28S, R21E

Landform (hillslope, terrace, etc.): terrace - uplands Local relief (concave, convex, none): _____ Slope (%): 1%

Subregion (LRR): LRRC Lat: 35.470268° Long: -119.728162° Datum: NAD 83

Soil Map Unit Name: 174 - Kimberlina fine sandy loam, 0-2% slopes NWI classification: N/A (upland)

Are climatic / hydrologic conditions on the site typical for this time of year? Yes _____ No _____ (If no, explain in Remarks.)

Are Vegetation ___, Soil ___, or Hydrology ___ significantly disturbed? N Are "Normal Circumstances" present? Yes ✓ No _____

Are Vegetation _____, Soil _____, or Hydrology _____ naturally problematic? N (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes _____	No ✓	**Is the Sampled Area within a Wetland?** Yes _____ No ✓
Hydric Soil Present?	Yes _____	No ✓	
Wetland Hydrology Present?	Yes _____	No ✓	

Remarks: Uplands adjacent to excavated drainage ditch. No wetland indicators.

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: —)	Absolute % Cover	Dominant Species?	Indicator Status
1.			
2.			
3.			
4.			
	= Total Cover		
Sapling/Shrub Stratum (Plot size: —)			
1. Atriplex polycarpa	15%	Y	FACU
2.			
3.			
4.			
5.			
	= Total Cover		
Herb Stratum (Plot size: 5')			
1. Bromus madritensis ssp. rubens	5%	Y	UPL
2. Centaurea melitensis	1%	N	NI/UPL
3.			
4.			
5.			
6.			
7.			
8.			
	6% = Total Cover		
Woody Vine Stratum (Plot size: —)			
1.			
2.			
	= Total Cover		

% Bare Ground in Herb Stratum ~94% % Cover of Biotic Crust —

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 0 (A)

Total Number of Dominant Species Across All Strata: 2 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 0% (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:	
OBL species	x 1 =	
FACW species	x 2 =	
FAC species	x 3 =	
FACU species	x 4 =	
UPL species	x 5 =	
Column Totals: (A)		(B)

Prevalence Index = B/A = _____

Hydrophytic Vegetation Indicators:

___ Dominance Test is >50%

___ Prevalence Index is ≤3.0[1]

___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)

___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes _____ No ✓

Remarks: No dominant hydrophytic vegetation.

SOIL

Sampling Point: SP12

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	%	Redox Features Color (moist)	%	Type[1]	Loc[2]	Texture	Remarks
0-10"	10YR 4/4	100%					sandy loam	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) (**LRR C**)
- ___ 1 cm Muck (A9) (**LRR D**)
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) (**LRR C**)
- ___ 2 cm Muck (A10) (**LRR B**)
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: hard pan

Depth (inches): 10"

Hydric Soil Present? Yes ____ No ✓

Remarks:

No hydric soil indicators

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) (**Nonriverine**)
- ___ Sediment Deposits (B2) (**Nonriverine**)
- ___ Drift Deposits (B3) (**Nonriverine**)
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) (**Riverine**)
- ___ Sediment Deposits (B2) (**Riverine**)
- ___ Drift Deposits (B3) (**Riverine**)
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes ____ No ✓ Depth (inches): ____

Water Table Present? Yes ____ No ✓ Depth (inches): ____

Saturation Present? (includes capillary fringe) Yes ____ No ✓ Depth (inches): ____

Wetland Hydrology Present? Yes ____ No ✓

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

No hydrology indicators.

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Aera Belridge CCS City/County: Belridge Old, Western Kern Co Sampling Date: 05/20/23

Applicant/Owner: Aera State: CA Sampling Point: SP15

Investigator(s): G. Hoetker Section, Township, Range: S19, T28S, R21E

Landform (hillslope, terrace, etc.): Low - part of remnant stream Local relief (concave, convex, none): concave Slope (%): 0%

Subregion (LRR): LRRC Lat: 35.481587 Long: -119.743045 Datum: NAD83

Soil Map Unit Name: 212 - Panoche clay loam, 2 to 5 percent slopes NWI classification: Riverine

Are climatic / hydrologic conditions on the site typical for this time of year? Yes ____ No ____ (If no, explain in Remarks.)

Are Vegetation ____, Soil ✓, or Hydrology ____ significantly disturbed? Are "Normal Circumstances" present? Yes ✓ No ____

Are Vegetation ____, Soil ____, or Hydrology ____ naturally problematic? N (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ____	No ✓	**Is the Sampled Area within a Wetland?** Yes ____ No ✓
Hydric Soil Present?	Yes ____	No ✓	
Wetland Hydrology Present?	Yes ✓	No ____	

Remarks: Basin in remnant stream; no OHWM; potential waters of the State only hydrology indicator is present.

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: 30')	Absolute % Cover	Dominant Species?	Indicator Status
1.			
2.			
3.			
4.			
	0 = Total Cover		
Sapling/Shrub Stratum (Plot size: 10')			
1.			
2.			
3.			
4.			
5.			
	0 = Total Cover		
Herb Stratum (Plot size: 5')			
1.			
2.			
3.			
4.			
5.			
6.			
7.			
8.			
	0 = Total Cover		
Woody Vine Stratum (Plot size: 10')			
1.			
2.			
	0 = Total Cover		

% Bare Ground in Herb Stratum 100% % Cover of Biotic Crust ____

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 0 (A)

Total Number of Dominant Species Across All Strata: 0 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 0 (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:
OBL species ____	x 1 = ____
FACW species ____	x 2 = ____
FAC species ____	x 3 = ____
FACU species ____	x 4 = ____
UPL species ____	x 5 = ____
Column Totals: ____ (A)	____ (B)

Prevalence Index = B/A = ____

Hydrophytic Vegetation Indicators:

___ Dominance Test is >50%

___ Prevalence Index is ≤3.0[1]

___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)

___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes ____ No ✓

Remarks: No vegetation; no hydrophytes in drainage

SOIL

Sampling Point: SP15

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	Matrix %	Redox Features Color (moist)	Redox Features %	Redox Features Type[1]	Redox Features Loc[2]	Texture	Remarks
0-4"	2.5Y 5/3	100					sl thy clay loam	2" + moist
4-16"	2.5Y 5/4	100					sandy loam	moist

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) (**LRR C**)
- ___ 1 cm Muck (A9) (**LRR D**)
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) (**LRR C**)
- ___ 2 cm Muck (A10) (**LRR B**)
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: _____

Depth (inches): _____

Hydric Soil Present? Yes _____ No ✓

Remarks:

No hydric soil indicators

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) (**Nonriverine**)
- ___ Sediment Deposits (B2) (**Nonriverine**)
- ___ Drift Deposits (B3) (**Nonriverine**)
- ✓ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) (**Riverine**)
- ___ Sediment Deposits (B2) (**Riverine**)
- ___ Drift Deposits (B3) (**Riverine**)
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes _____ No ✓ Depth (inches): _____

Water Table Present? Yes _____ No ✓ Depth (inches): _____

Saturation Present? (includes capillary fringe) Yes _____ No ✓ Depth (inches): _____

Wetland Hydrology Present? Yes ✓ No _____

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

surface soil cracks in basin; evidence of recent inundation

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Nova Belridge CCS City/County: Belridge Western Oil Field / Kern Co Sampling Date: 05/26/23

Applicant/Owner: Aera State: CA Sampling Point: SP16

Investigator(s): G. Hoefker Section, Township, Range: S19, T28S, R21E

Landform (hillslope, terrace, etc.): uplands Local relief (concave, convex, none): none Slope (%): 0

Subregion (LRR): LRR C Lat: 35.491542 Long: -119.743325 Datum: NAD83

Soil Map Unit Name: 212 - Panoche clay loam, 2 to 5 percent slopes NWI classification: N/A, uplands

Are climatic / hydrologic conditions on the site typical for this time of year? Yes ✓ No ____ (If no, explain in Remarks.)

Are Vegetation N, Soil N, or Hydrology N significantly disturbed? Are "Normal Circumstances" present? Yes ✓ No ____

Are Vegetation ____, Soil ____, or Hydrology ____ naturally problematic? N (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ____	No ✓	**Is the Sampled Area within a Wetland?** Yes ____ No ✓
Hydric Soil Present?	Yes ____	No ✓	
Wetland Hydrology Present?	Yes ____	No ✓	

Remarks: Uplands, no wetland indicators.

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: 30')	Absolute % Cover	Dominant Species?	Indicator Status
1. —			
2.			
3.			
4.			
	0 = Total Cover		
Sapling/Shrub Stratum (Plot size: 10')			
1. —			
2.			
3.			
4.			
5.			
	0 = Total Cover		
Herb Stratum (Plot size: 5')			
1. —			
2.			
3.			
4.			
5.			
6.			
7.			
8.			
	0 = Total Cover		
Woody Vine Stratum (Plot size: 10')			
1. —			
2.			
	0 = Total Cover		

% Bare Ground in Herb Stratum 100% % Cover of Biotic Crust —

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 0 (A)

Total Number of Dominant Species Across All Strata: 0 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 0% (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:	
OBL species	x 1 =	
FACW species	x 2 =	
FAC species	x 3 =	
FACU species	x 4 =	
UPL species	x 5 =	
Column Totals: (A)		(B)

Prevalence Index = B/A =

Hydrophytic Vegetation Indicators:

___ Dominance Test is >50%

___ Prevalence Index is ≤3.0[1]

___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)

___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes ____ No ✓

Remarks: No vegetation, no hydrophytic indicators.

SOIL

Sampling Point: SP16

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	%	Redox Features Color (moist)	%	Type[1]	Loc[2]	Texture	Remarks
0-6"	10YR 4/4	100					Sandy loam	
6-16"	impenetrable							hardpan

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) (**LRR C**)
- ___ 1 cm Muck (A9) (**LRR D**)
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) (**LRR C**)
- ___ 2 cm Muck (A10) (**LRR B**)
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: hardpan

Depth (inches): 6"

Hydric Soil Present? Yes ____ No ✓

Remarks:

No hydric soil indicators.

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) (**Nonriverine**)
- ___ Sediment Deposits (B2) (**Nonriverine**)
- ___ Drift Deposits (B3) (**Nonriverine**)
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) (**Riverine**)
- ___ Sediment Deposits (B2) (**Riverine**)
- ___ Drift Deposits (B3) (**Riverine**)
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes ____ No ✓ Depth (inches): ____

Water Table Present? Yes ____ No ✓ Depth (inches): ____

Saturation Present? (includes capillary fringe) Yes ____ No ✓ Depth (inches): ____

Wetland Hydrology Present? Yes ____ No ✓

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

No hydrology indicators.

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Aera Belridge CCS City/County: Belridge Western Oil Field, Kern Co. Sampling Date: 06/13/23

Applicant/Owner: Aera State: CA Sampling Point: SP17

Investigator(s): G. Hoetker Section, Township, Range: S24, T29S, R21E

Landform (hillslope, terrace, etc.): Chico Martinez Creek Local relief (concave, convex, none): concave Slope (%): 0%

Subregion (LRR): LRR C Lat: 35.440736 Long: -119.723367 Datum: NAD83

Soil Map Unit Name: 174 - Kimberlina fine sandy loam, 0-2% slopes NWI classification: Riverine

Are climatic / hydrologic conditions on the site typical for this time of year? Yes ✓ No ____ (If no, explain in Remarks.)

Are Vegetation ____, Soil ____, or Hydrology ____ significantly disturbed? N Are "Normal Circumstances" present? Yes ✓ No ____

Are Vegetation ____, Soil ____, or Hydrology ____ naturally problematic? N (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ____	No ✓	**Is the Sampled Area within a Wetland?** Yes ____ No ✓
Hydric Soil Present?	Yes ____	No ✓	
Wetland Hydrology Present?	Yes ____	No ✓	

Remarks: Section of Chico Martinez Creek south of 7th Standard Rd; no OHWM; no wetland indicators present, potential waters of the State

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: 30')	Absolute % Cover	Dominant Species?	Indicator Status
1.			
2.			
3.			
4.			
	—	= Total Cover	
Sapling/Shrub Stratum (Plot size: 10')			
1. Atriplex polycarpa	10%	Y	FACW
2.			
3.			
4.			
5.			
	—	= Total Cover	
Herb Stratum (Plot size: 5')			
1. Datura wrightii	15%	Y	UPL
2. Croton setiger	5%	Y	NL
3.			
4.			
5.			
6.			
7.			
8.			
	20%	= Total Cover	
Woody Vine Stratum (Plot size: 10')			
1.			
2.			
	—	= Total Cover	

% Bare Ground in Herb Stratum 80% % Cover of Biotic Crust —

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 0 (A)

Total Number of Dominant Species Across All Strata: 3 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 0% (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:
OBL species ____	x 1 = ____
FACW species ____	x 2 = ____
FAC species ____	x 3 = ____
FACU species ____	x 4 = ____
UPL species ____	x 5 = ____
Column Totals: ____ (A)	____ (B)

Prevalence Index = B/A = ____

Hydrophytic Vegetation Indicators:

___ Dominance Test is >50%

___ Prevalence Index is ≤3.0[1]

___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)

___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes ____ No ✓

Remarks: No dominant hydrophytic vegetation present.

SOIL

Sampling Point: SP17

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	%	Redox Features Color (moist)	%	Type[1]	Loc[2]	Texture	Remarks
0-16"	10YR5/6	100%					Sand	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) (**LRR C**)
- ___ 1 cm Muck (A9) (**LRR D**)
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) (**LRR C**)
- ___ 2 cm Muck (A10) (**LRR B**)
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: —

Depth (inches): —

Hydric Soil Present? Yes ____ No ✓

Remarks:

No hydric soil indicators.

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) (**Nonriverine**)
- ___ Sediment Deposits (B2) (**Nonriverine**)
- ___ Drift Deposits (B3) (**Nonriverine**)
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) (**Riverine**)
- ___ Sediment Deposits (B2) (**Riverine**)
- ___ Drift Deposits (B3) (**Riverine**)
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes ____ No ✓ Depth (inches): ____

Water Table Present? Yes ____ No ✓ Depth (inches): ____

Saturation Present? (includes capillary fringe) Yes ____ No ✓ Depth (inches): ____

Wetland Hydrology Present? Yes ____ No ✓

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

No hydrology indicators.

WETLAND DETERMINATION DATA FORM – Arid West Region

Project/Site: Aera Belridge CCS City/County: Belridge Western Oil Field, Kern Co. Sampling Date: 06/13

Applicant/Owner: Aera State: CA Sampling Point: SP18

Investigator(s): G. Hoetker Section, Township, Range: S24, T29S, R21E

Landform (hillslope, terrace, etc.): slope next to creek Local relief (concave, convex, none): slightly convex Slope (%): 2%

Subregion (LRR): LRR C Lat: 35.440487 Long: -119.723336 Datum: NAD83

Soil Map Unit Name: 174 – Cimberlina fine sandy loam, 0-2% slopes NWI classification: N/A; uplands

Are climatic / hydrologic conditions on the site typical for this time of year? Yes ✓ No ____ (If no, explain in Remarks.)

Are Vegetation ____, Soil ____, or Hydrology ____ significantly disturbed? N Are "Normal Circumstances" present? Yes ✓ No ____

Are Vegetation ____, Soil ____, or Hydrology ____ naturally problematic? N (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ____	No ✓	**Is the Sampled Area within a Wetland?** Yes ____ No ✓
Hydric Soil Present?	Yes ____	No ✓	
Wetland Hydrology Present?	Yes ____	No ✓	

Remarks: Uplands; no wetland indicators

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: 30')	Absolute % Cover	Dominant Species?	Indicator Status
1. —			
2.			
3.			
4.			
	—	= Total Cover	
Sapling/Shrub Stratum (Plot size: 10')			
1. Atriplex polycarpa	20%	Y	FACW
2.			
3.			
4.			
5.			
		= Total Cover	
Herb Stratum (Plot size: 5')			
1. Bromus madritensis ssp rubens	30%	Y	
2. Amsinckia menziesii	10%	Y	
3. Lactuca serriola	5%	N	
4.			
5.			
6.			
7.			
8.			
		= Total Cover	
Woody Vine Stratum (Plot size: 10')			
1. —			
2.			
	—	= Total Cover	

% Bare Ground in Herb Stratum ~55% % Cover of Biotic Crust —

Dominance Test worksheet:

Number of Dominant Species That Are OBL, FACW, or FAC: 1 (A)

Total Number of Dominant Species Across All Strata: 3 (B)

Percent of Dominant Species That Are OBL, FACW, or FAC: 0% (A/B)

Prevalence Index worksheet:

Total % Cover of:	Multiply by:
OBL species ____	x 1 = ____
FACW species ____	x 2 = ____
FAC species ____	x 3 = ____
FACU species ____	x 4 = ____
UPL species ____	x 5 = ____
Column Totals: ____ (A)	____ (B)

Prevalence Index = B/A = ____

Hydrophytic Vegetation Indicators:

___ Dominance Test is >50%

___ Prevalence Index is ≤3.0[1]

___ Morphological Adaptations[1] (Provide supporting data in Remarks or on a separate sheet)

___ Problematic Hydrophytic Vegetation[1] (Explain)

[1]Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic.

Hydrophytic Vegetation Present? Yes ____ No ✓

Remarks: No dominant hydrophytic vegetation present.

SOIL

Sampling Point: SP18

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	%	Redox Features Color (moist)	%	Type[1]	Loc[2]	Texture	Remarks
0-16"	10YR 5/6	100%					loam	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains. [2]Location: PL=Pore Lining, M=Matrix.

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ___ Histosol (A1)
- ___ Histic Epipedon (A2)
- ___ Black Histic (A3)
- ___ Hydrogen Sulfide (A4)
- ___ Stratified Layers (A5) (**LRR C**)
- ___ 1 cm Muck (A9) (**LRR D**)
- ___ Depleted Below Dark Surface (A11)
- ___ Thick Dark Surface (A12)
- ___ Sandy Mucky Mineral (S1)
- ___ Sandy Gleyed Matrix (S4)
- ___ Sandy Redox (S5)
- ___ Stripped Matrix (S6)
- ___ Loamy Mucky Mineral (F1)
- ___ Loamy Gleyed Matrix (F2)
- ___ Depleted Matrix (F3)
- ___ Redox Dark Surface (F6)
- ___ Depleted Dark Surface (F7)
- ___ Redox Depressions (F8)
- ___ Vernal Pools (F9)

Indicators for Problematic Hydric Soils[3]:

- ___ 1 cm Muck (A9) (**LRR C**)
- ___ 2 cm Muck (A10) (**LRR B**)
- ___ Reduced Vertic (F18)
- ___ Red Parent Material (TF2)
- ___ Other (Explain in Remarks)

[3]Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic.

Restrictive Layer (if present):

Type: ~~_____~~

Depth (inches): ~~_____~~

Hydric Soil Present? Yes _____ No ✓

Remarks:

No hydric soil indicators.

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required; check all that apply)

- ___ Surface Water (A1)
- ___ High Water Table (A2)
- ___ Saturation (A3)
- ___ Water Marks (B1) (**Nonriverine**)
- ___ Sediment Deposits (B2) (**Nonriverine**)
- ___ Drift Deposits (B3) (**Nonriverine**)
- ___ Surface Soil Cracks (B6)
- ___ Inundation Visible on Aerial Imagery (B7)
- ___ Water-Stained Leaves (B9)
- ___ Salt Crust (B11)
- ___ Biotic Crust (B12)
- ___ Aquatic Invertebrates (B13)
- ___ Hydrogen Sulfide Odor (C1)
- ___ Oxidized Rhizospheres along Living Roots (C3)
- ___ Presence of Reduced Iron (C4)
- ___ Recent Iron Reduction in Tilled Soils (C6)
- ___ Thin Muck Surface (C7)
- ___ Other (Explain in Remarks)

Secondary Indicators (2 or more required)

- ___ Water Marks (B1) (**Riverine**)
- ___ Sediment Deposits (B2) (**Riverine**)
- ___ Drift Deposits (B3) (**Riverine**)
- ___ Drainage Patterns (B10)
- ___ Dry-Season Water Table (C2)
- ___ Crayfish Burrows (C8)
- ___ Saturation Visible on Aerial Imagery (C9)
- ___ Shallow Aquitard (D3)
- ___ FAC-Neutral Test (D5)

Field Observations:

Surface Water Present? Yes _____ No ✓ Depth (inches): _____

Water Table Present? Yes _____ No ✓ Depth (inches): _____

Saturation Present? (includes capillary fringe) Yes _____ No ✓ Depth (inches): _____

Wetland Hydrology Present? Yes _____ No ✓

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

No wetland hydrology indicators.

Area

Project: CCS (N 45 Baldridge) **Date:** 07/19/22 **Time:** 11:30
Project Number: 185805372 **Town:** W. Kern Co. **State:** CA
Stream: Chico Martinez Creek **Photo begin file#** **Photo end file#**
Investigator(s): G. Hecker, E Martin, J. Pratt, C Coates

Y ☑ / N ☐ Do normal circumstances exist on the site?

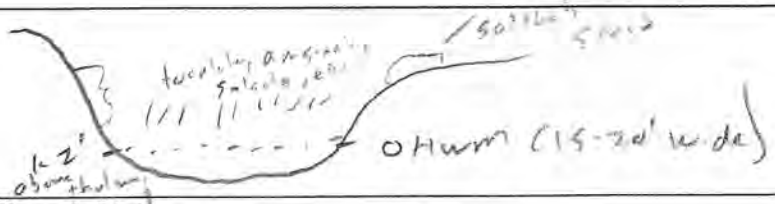
Y ☐ / N ☑ Is the site significantly disturbed?

Location Details: Chico Martinez Creek

Projection: 35.445175°, **Datum:** NAD 83
Coordinates: -119.715113°

Notes: 0.4-mile section of Chico Martinez Creek

Brief site description:

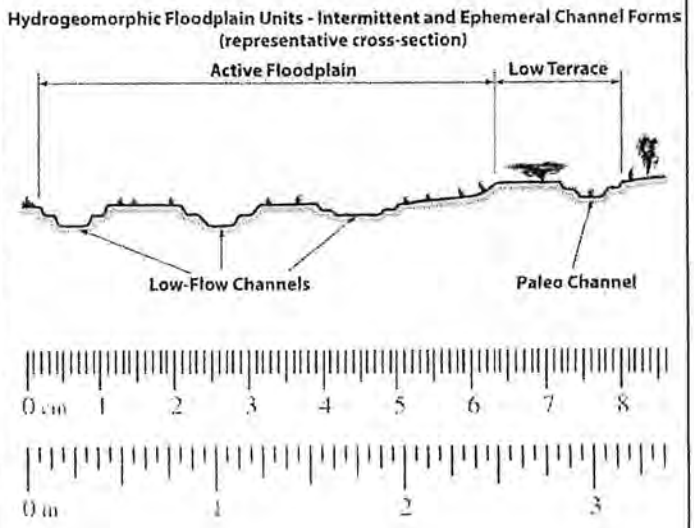


Checklist of resources (if available):

- ☑ Aerial photography
  Dates:
- ☑ Topographic maps
  Scale:
- ☐ Geologic maps
- ☐ Vegetation maps
- ☑ Soils maps
- ☐ Rainfall/precipitation maps
- ☑ Existing delineation(s) for site
- ☑ Global positioning system (GPS)
- ☐ Other studies
- ☐ Stream gage data
  Gage number:
  Period of record:
- ☐ Clinometer / level
- ☐ History of recent effective discharges
- ☐ Results of flood frequency analysis
- ☐ Most recent shift-adjusted rating
- ☐ Gage heights for 2-, 5-, 10-, and 25-year events and the most recent event exceeding a 5-year event

The dominant Wentworth size class that imparts a characteristic texture to each zone of a channel cross-section is recorded in the average sediment texture field under the characteristics section for the zone of interest.

Inches (in)	Millimeters (mm)	Wentworth size class	
10.08	256	Boulder	
2.56	64	Cobble	Gravel
0.157	4	Pebble	
		Granule	
0.079	2.00	Very coarse sand	
0.039	1.00	Coarse sand	
0.020	0.50	Medium sand	Sand
1/2 0.0098	0.25	Fine sand	
1/4 0.005	0.125	Very fine sand	
1/8 0.0025	0.0625	Coarse silt	
1/16 0.0012	0.031	Medium silt	
1/32 0.00061	0.0156	Fine silt	Silt
1/64 0.00031	0.0078	Very fine silt	
1/128 0.00015	0.0039	Clay	Mud



☑ **Walk the channel and floodplain within the study area to get an impression of the vegetation and geomorphology present at the site. Record any potential anthropogenic influences on the channel system in "Notes" above.**

☐ **Locate the low-flow channel (lowest part of the channel). Record observations.**

Characteristics of the low-flow channel: thin layer of cobble & gravel on surface, loamy sand below

Average sediment texture: _____

Total veg cover: 41 % Tree: ____ % Shrub: 25 % Herb: 16 %

Community successional stage:

☐ NA ☑ Mid (herbaceous, shrubs, saplings)

☐ Early (herbaceous & seedlings) ☐ Late (herbaceous, shrubs, mature trees)

Dominant species present: Atriplex polycarpa, Salsola tragus, Centaurea melitensis

Other: ☐ _____

☐ _____

☐ _____

☐ _____

☑ **Walk away from the low-flow channel along cross-section. Record characteristics of the low-flow/active floodplain boundary.**

Characteristics used to delineate the low-flow/active floodplain boundary:

☑ Change in total veg cover ☐ Tree ☐ Shrub ☐ Herb

☐ Change in overall vegetation maturity

☐ Change in dominant species present

☐ Other ☐ Presence of bed and bank

☐ Drift and/or debris

☐ Other: _____

☐ Other: _____

☑ **Continue walking the channel cross-section. Record observations below.**

Characteristics of the active floodplain:

Average sediment texture: same as above

Total veg cover: 41 % Tree: ____ % Shrub: 25 % Herb: 16 %

Community successional stage:

☐ NA ☑ Mid (herbaceous, shrubs, saplings)

☐ Early (herbaceous & seedlings) ☐ Late (herbaceous, shrubs, mature trees)

Dominant species present: Same as above

Other: ☐ _____

☐ _____

☐ _____

☐ _____

☑ **Continue walking the channel cross-section. Record indicators of the active floodplain/low terrace boundary.**

Characteristics used to delineate the active floodplain/ low terrace boundary:

- ☐ Change in average sediment texture
- ☐ Change in total veg cover ☐ Tree ☐ Shrub ☐ Herb
- ☐ Change in overall vegetation maturity
- ☐ Change in dominant species present
- ☐ Other
  - ☐ Presence of bed and bank
  - ☐ Drift and/or debris
  - ☐ Other: _____
  - ☐ Other: _____

☑ **Walk the active floodplain/low terrace boundary both upstream and downstream of the cross-section to verify that the indicators used to identify the transition are consistently associated the transition in both directions.**

Consistency of indicators used to delineate the active floodplain/low terrace boundary:

- Y ☑ N ☐ Change in average sediment texture
- Y ☑ N ☐ Change in total veg cover ☐ Tree ☐ Shrub ☐ Herb
- Y ☑ N ☐ Change in overall vegetation maturity
- Y ☑ N ☐ Change in dominant species present
- Y ☑ N ☐ Other:
  - Y ☑ N ☐ Presence of bed and bank
  - Y ☐ N ☐ Drift and/or debris
  - Y ☐ N ☐ Other: _____
  - Y ☐ N ☐ Other: _____

☐ **If the characteristics used to delineate the active floodplain/low terrace boundary were NOT consistently associated with the transition in both the upstream and downstream directions, repeat all steps above.**

☐ **Continue walking the channel cross-section. Record characteristics of the low terrace.**

Characteristics of the low terrace:

Average sediment texture: minimal gravel, loamy sand

Total veg cover: 25 % Tree: ____ % Shrub: ____ % Herb: 5 %

Community successional stage:

- ☐ NA
- ☑ Early (herbaceous & seedlings)
- ☐ Mid (herbaceous, shrubs, saplings)
- ☐ Late (herbaceous, shrubs, mature trees)

Dominant species present: Salsola tragus, Centaurea maculosa

Other:

- ☐ _____
- ☐ _____
- ☐ _____
- ☐ _____

☑ **If characteristics used to delineate the active floodplain/low terrace boundary were deemed reliable, acquire boundary.**

Active floodplain/low terrace boundary acquired via:

- ☐ Mapping on aerial photograph
- ☑ GPS
- ☐ Digitized on computer
- ☐ Other: _____

Project: Aera CCS (Chico Bridge) **Date:** 07/20/22 **Time:** 11:30
Project Number: 1858053772 **~~Town~~:** W. Kern Co. **State:** CA
Stream: Chico Martinez Creek **Photo begin file#** **Photo end file#**
Investigator(s): G. Hoetker, G. Martin, J. Pratt, C. Corley

Y ☑ / N ☐ Do normal circumstances exist on the site?

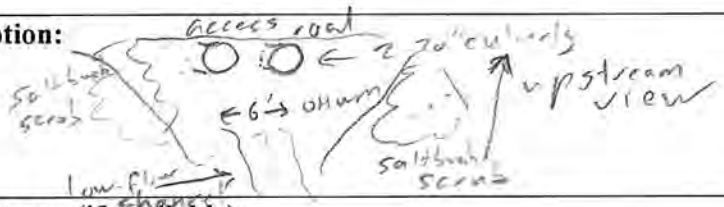
Y ☑ / N ☐ Is the site significantly disturbed?

Location Details: Chico Martinez Creek

Projection: 35.460661° **Datum:** NAD 83
Coordinates: 119.698066°

Notes: Small section of Chico Martinez Creek east of Hwy 33.

Brief site description:



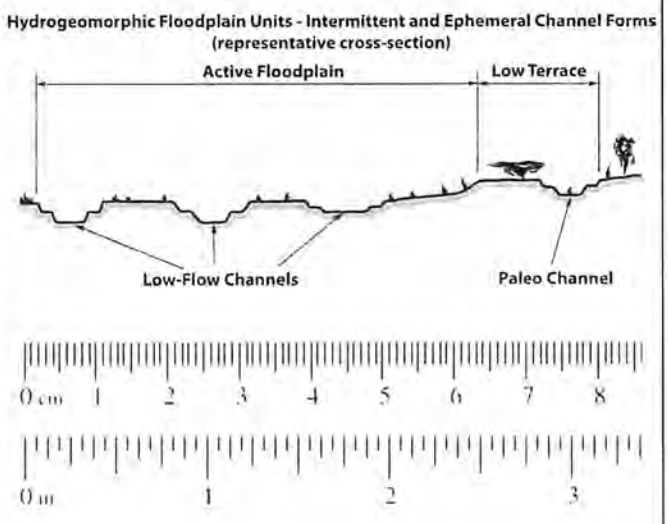
Checklist of resources (if available):

- ☑ Aerial photography
  Dates:
- ☑ Topographic maps
  Scale:
- ☐ Geologic maps
- ☐ Vegetation maps
- ☑ Soils maps
- ☐ Rainfall/precipitation maps
- ☐ Existing delineation(s) for site
- ☑ Global positioning system (GPS)
- ☐ Other studies

- ☐ Stream gage data
  Gage number:
  Period of record:
- ☐ Clinometer / level
- ☐ History of recent effective discharges
- ☐ Results of flood frequency analysis
- ☐ Most recent shift-adjusted rating
- ☐ Gage heights for 2-, 5-, 10-, and 25-year events and the most recent event exceeding a 5-year event

The dominant Wentworth size class that imparts a characteristic texture to each zone of a channel cross-section is recorded in the average sediment texture field under the characteristics section for the zone of interest.

Millimeters (mm)	Inches (in)	Wentworth size class	
10.08	256	Boulder	
2.56	64	Cobble	Gravel
0.157	4	Pebble	
0.079	2.00	Granule	
0.039	1.00	Very coarse sand	
0.020	0.50	Coarse sand	
0.0098 (1/2)	0.25	Medium sand	Sand
0.005 (1/4)	0.125	Fine sand	
0.0025 (1/8)	0.0625	Very fine sand	
0.0012 (1/16)	0.031	Coarse silt	
0.00061 (1/32)	0.0156	Medium silt	Silt
0.00031 (1/64)	0.0078	Fine silt	
0.00015 (1/128)	0.0039	Very fine silt	
		Clay	Mud



☑ **Walk the channel and floodplain within the study area to get an impression of the vegetation and geomorphology present at the site. Record any potential anthropogenic influences on the channel system in "Notes" above.**

☑ **Locate the low-flow channel (lowest part of the channel). Record observations.**

Characteristics of the low-flow channel:

Average sediment texture: loamy sand

Total veg cover: ____ % Tree: ____ % Shrub: 35 % Herb: ____ %

Community successional stage:

☐ NA ☑ Mid (herbaceous, shrubs, saplings)

☐ Early (herbaceous & seedlings) ☐ Late (herbaceous, shrubs, mature trees)

Dominant species present: Atriplex polycarpa

Other: ☐ ☐ ☐ ☐

☑ **Walk away from the low-flow channel along cross-section. Record characteristics of the low-flow/active floodplain boundary.**

Characteristics used to delineate the low-flow/active floodplain boundary: same as above

☐ Change in total veg cover ☐ Tree ☐ Shrub ☐ Herb

☐ Change in overall vegetation maturity

☐ Change in dominant species present

☐ Other ☐ Presence of bed and bank

☐ Drift and/or debris

☐ Other: ____

☐ Other: ____

☑ **Continue walking the channel cross-section. Record observations below.**

Characteristics of the low-flow channel:

Average sediment texture: loamy sand

Total veg cover: ____ % Tree: ____ % Shrub: 35 % Herb: ____ %

Community successional stage:

☐ NA ☑ Mid (herbaceous, shrubs, saplings)

☐ Early (herbaceous & seedlings) ☐ Late (herbaceous, shrubs, mature trees)

Dominant species present: Atriplex polycarpa

Other: ☐ ☐ ☐ ☐

☑ **Continue walking the channel cross-section. Record indicators of the active floodplain/low terrace boundary.**

Characteristics used to delineate the active floodplain/ low terrace boundary:

- ☐ Change in average sediment texture
- ☑ Change in total veg cover ☐ Tree ☑ Shrub ☐ Herb
- ☐ Change in overall vegetation maturity
- ☐ Change in dominant species present
- ☐ Other ☐ Presence of bed and bank
  - ☐ Drift and/or debris
  - ☐ Other: _____
  - ☐ Other: _____

☑ **Walk the active floodplain/low terrace boundary both upstream and downstream of the cross-section to verify that the indicators used to identify the transition are consistently associated the transition in both directions.**

Consistency of indicators used to delineate the active floodplain/low terrace boundary:

- Y ☐ N ☐ Change in average sediment texture
- Y ☑ N ☐ Change in total veg cover ☐ Tree ☑ Shrub 65% ☐ Herb
- Y ☐ N ☐ Change in overall vegetation maturity
- Y ☐ N ☐ Change in dominant species present
- Y ☐ N ☐ Other: Y ☑ N ☐ Presence of bed and bank
  - Y ☐ N ☐ Drift and/or debris
  - Y ☐ N ☐ Other: _____
  - Y ☐ N ☐ Other: _____

☐ **If the characteristics used to delineate the active floodplain/low terrace boundary were NOT consistently associated with the transition in both the upstream and downstream directions, repeat all steps above.**

☑ **Continue walking the channel cross-section. Record characteristics of the low terrace.**

Characteristics of the low terrace:

Average sediment texture: loamy sand

Total veg cover: ____ % Tree: ____ % Shrub: 65 % Herb: ____ %

Community successional stage:

- ☐ NA
- ☑ Mid (herbaceous, shrubs, saplings)
- ☐ Early (herbaceous & seedlings)
- ☐ Late (herbaceous, shrubs, mature trees)

Dominant species present: Atriplex polycarpa

Other:

- ☐ _____
- ☐ _____
- ☐ _____
- ☐ _____

☐ **If characteristics used to delineate the active floodplain/low terrace boundary were deemed reliable, acquire boundary.**

Active floodplain/low terrace boundary acquired via:

- ☐ Mapping on aerial photograph
- ☐ GPS
- ☐ Digitized on computer
- ☐ Other: _____

Appendix C SITE PHOTOGRAPHS



Stantec

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Appendix D
Cultural Resources

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D-1 Cultural Resources Survey Report

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AERA CARBONFRONTIER PROJECT

Cultural Resources Survey Report

July 19, 2023

Prepared for:
Aera Energy, LLC
10000 Ming Avenue
Bakersfield, California 93311

Prepared by:
Mitch Evans
Santos Ceniceros-Rodríguez
Fiadh Kelly
Stantec Consulting Services, Inc.
2646 Santa Maria Way, Suite 107
Santa Maria, California 93455

Project Number:
185805372

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The conclusions in the Report titled *Aera CarbonFrontier Project – Cultural Resources Survey Report* are Stantec's professional opinion, as of the time of the Report, and concerning the scope described in the Report. The opinions in the document are based on conditions and information existing at the time the scope of work was conducted and do not take into account any subsequent changes. The Report relates solely to the specific project for which Stantec was retained and the stated purpose for which the Report was prepared. The Report is not to be used or relied on for any variation or extension of the project, or for any other project or purpose, and any unauthorized use or reliance is at the recipient's own risk.

Stantec has assumed all information received from Aera Energy, LLC (the "Client"), and third parties in the preparation of the Report to be correct. While Stantec has exercised a customary level of judgment or due diligence in the use of such information, Stantec assumes no responsibility for the consequences of any error or omission contained therein.

This Report is intended solely for use by the Client in accordance with Stantec's contract with the Client. While the Report may be provided to applicable authorities having jurisdiction and others for whom the Client is responsible, Stantec does not warrant the services to any third party. The report may not be relied upon by any other party without the express written consent of Stantec, which may be withheld at Stantec's discretion.

Prepared by Mitch Evans

Mitch Evans, MA, RPA

Reviewed by E. Timothy Jones

E. Timothy Jones, MA, RPA

Approved by Eric K Snelling

Eric Snelling, Project Manager

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1 MANAGEMENT SUMMARY

Between May 2022 and June 2023, Stantec Consulting Services, Inc. (Stantec) conducted a Phase I cultural resources investigation on behalf of Aera Energy LLC (Aera), of approximately 1,544 acres of land in Belridge oil fields (North and South), Kern County (the "Project"). The Project would require federal actions including the issuance of Class VI Underground Injection Control (UIC) permits from the United States (U.S.) Environmental Protection Agency (USEPA). However, the Project is Categorically Excluded from further review under the National Environmental Policy Act (NEPA); the Safe Drinking Water Act UIC program is exempt from performing an Environmental Impact Statement (EIS) under section 101(2)(C) and an alternatives analysis under section 101(2)(E) of NEPA under a functional equivalence analysis[1]. Although the Project is exempt from NEPA, in their purview, the USEPA has determined the Project is an undertaking subject to Section 106 of the National Historic Preservation Act (NHPA) of 1966, as amended and its implementing regulations (36 Code of Federal Regulations [CFR] 800), pursuant to subpart 800.3(a)).

The Project is additionally subject to compliance with the California Environmental Quality Act (CEQA) requirements regarding its impacts on cultural resources. CEQA (Public Resources Code [PRC] Sections 21000 etc.) requires that, before approving most discretionary projects, the lead agency must identify and examine any significant adverse environmental effects that may result from activities associated with such projects (PRC Sections 21083.2 and 21084.1). CEQA explicitly requires that the study examine whether the project may result in a significant adverse change to "historical resources" and "unique archaeological resources." Kern County is the CEQA Lead Agency for the Project.

Under these requirements, a cultural resources inventory was conducted to address NHPA and CEQA requirements to determine impacts of the proposed Project on any cultural resources eligible for nomination to the California Register of Historical Resources (CRHR) (PRC 5024.1; 14 CCR 4850 *et seq.*) and/or to the National Register of Historic Places (NRHP) (40 CFR 1508.27(b)(8)). The purpose of this study is to evaluate resources for CRHR and NRHP eligibility, and to assess the proposed Project's potential impacts on historical resources, archaeological resources, and historic properties.

The study consisted of an archival records search of the entire Area of Potential Effect (APE) and the surrounding Study Area (1-mile radius around the APE) and an intensive pedestrian survey of the entire APE, including the route of the new pipeline (north and south) and injection area. The records search was

[1] United States Court of Appeals, Eighth Circuit. 1991. Western Nebraska Resources Council v. US EPA, 943 F.2d 867, 871–72 (8th Cir. 1991) and EPA Associate General Counsel Opinion (August 20, 1979). No, 90-2158, United States Court of Appeals, Eighth Circuit. 943 F.2d 867 (8th Cir. 1991). Decided September 3, 1991.

conducted at the Southern San Joaquin Valley Information Center (SSJVIC) of the California Historical Resources Information System (CHRIS) at California State University, Bakersfield (CSUB). The records search revealed that nine previous studies have been conducted within the APE and an additional 17 have been conducted within the surrounding Study Area. No resources had previously been recorded within the APE, however, one prehistoric isolate and two historic sites have been previously recorded within the surrounding Study Area.

The pedestrian survey included 15-20-meter parallel transects of Project footprint, which includes the proposed carbon capture and sequestration (CCS) Project and its ancillary facilities and equipment, including new CO_2 pipelines, injection wells, CO_2 monitoring wells, and an underground carbon sequestration field/zone (the geologic formation where CO_2 would be stored at a depth of approximately 8,500 feet below ground surface). The planned CO_2 pipeline will be located on Aera Energy property. Access/egress for the Project will be along existing paved and dirt roads extending throughout the property primarily via Main Camp Road (northeast-southwest trending) and Pole Line Road (northwest-southeast trending). Portions of the proposed pipeline will extend across areas of open land with no existing access/egress. The Project may include repair/improvements of existing access roads to ensure safe and efficient delivery of equipment to the carbon capture facility sites during the construction period and for ongoing operation and maintenance activities.

As a result of the Phase I archaeological investigation,107 cultural resources were identified within the study area. These resources consisted of 105 historic-period archaeological and architectural resources, 25 isolated discoveries, one multicomponent site, and one prehistoric site. Of these, five sites were identified as potentially significant under either NRHP or CRHR eligible. Stantec recommends avoidance of cultural resources that appear NRHP/CRHR eligible.

2 PROJECT DESCRIPTION

Aera has submitted an application to the Kern County Planning and Natural Resources Department to request approval of a Zoning Change and Conditional Use Permit (CUP) and any other required approvals, if any, for the construction and operation of a CCS project in the South and North Belridge oil fields. The proposed Project would require approvals for additions and improvements to the existing oil field facilities (gas separation, compression, and pumping equipment), new carbon dioxide (CO_2) pipelines located primarily aboveground utilizing existing pipeline corridors, UIC Class VI geologic sequestration injection wells, CO_2 monitoring wells, and an underground carbon sequestration field for the storage of CO_2 in accordance with appropriate financial assurance mechanisms that ensure permanence in compliance with applicable regulatory standards.

The proposed Project would capture CO_2 from existing produced gas streams (pre-combustion) and emissions from existing stationary sources (post-combustion) within the South Belridge Oil Field and transport the CO_2 through pipelines to the North Belridge Oil Field for injection at dedicated Class VI injection wells. The proposed underground CO_2 sequestration field, approximately 2,636 acres in size, would be located within the North Belridge Oil Field with surface and mineral rights held by Aera and

other private owners. Oil and gas production activities would cease within the Underground geologic formation here CO_2 would be stored, prior to commencement of the proposed Project.

It is anticipated that the proposed Project would capture and sequester up to 1.6 million metric tons (MMt) of CO_2 per year beginning in 2027 and will contribute to the goal of California for carbon net-neutrality by 2045 (Executive Order B-55-18) by reducing industrial CO_2 emissions.

Implementation of the Project would require permits from the USEPA for up to nine Class VI injection wells in compliance with the UIC program Class VI geologic sequestration regulations. The proposed CO_2 related facilities, pipelines, Class VI injection wells and associated CO_2 monitoring wells will be located within the CUP boundary. The proposed Project would utilize, on average, up to 1,223 acre-feet per year (afy) (26,000 barrels of water per day) for use in the CO_2 capture facilities for up to 20 years of operation. primarily sourced from existing Belridge oil field produced water. Fresh water would be sourced from existing State Water Project entitlements with the Belridge Water Storage District and from existing Aera-owned groundwater wells located in the Buena Vista Water Storage District

3 PROJECT LOCATION

The Project is located within the North and South Belridge oil fields in an unincorporated area of western Kern County, approximately 14 miles west of Buttonwillow, six miles south of Lost Hills, and eleven miles north of McKittrick, California (Figure 1 – Appendix A). The APE is on lands owned and operated by Aera Energy. From the south, the APE spans an area in the vicinity of the intersection of Lost Hills Road and State Route (SR) 33 (also known as the West Side Highway), northwestward through Seventh Standard Road, northward through the South Belridge Oil Field variously paralleling or oriented east of Pole Line Road through Lerdo Highway, then continuing along the vicinity of Pole Line Road to the North Belridge Oil Field.

The APE Survey Area is approximately 13 miles long, approximately 250 feet wide, and encompasses approximately 1,167 acres primarily within the Belridge and Blackwells Corner (1988) 7.5-minute U.S. Geological Survey (USGS) topographic quadrangles, with smaller portions within the Lost Hills and Carneros Rocks USGS topographic quadrangles (Figure 2 – Appendix A). To access the APE from Interstate 5, take the Buttonwillow SR-58 / McKittrick Highway exit and travel west on SR-58 for approximately eight miles; turn right onto Lokern Road and travel west approximately 7.3 miles; turn right on SR-33 and travel northwest approximately 2.5 miles to arrive at the southern end of the APE.

4 REGULATORY FRAMEWORK

This study was conducted to meet CEQA requirements regarding cultural resources on lands proposed for development. CEQA (PRC Sections 21000 etc.) requires that, before approving most discretionary projects, the lead agency must identify and examine any significant adverse environmental effects that may result from activities associated with such projects (PRC Sections 21083.2 and 21084.1). CEQA explicitly requires that the initial study examine whether the project may have a significant effect on “historical resources” and “unique archaeological resources.” Under these requirements, a cultural

resources inventory was conducted to determine impacts of the proposed project on cultural resources potentially eligible for nomination to the CRHR.

4.1 California Environmental Quality Act

CEQA (California PRC Section 21000 et seq.) (1970) established that historical and archaeological resources are afforded consideration and protection by the CEQA (14 CCR Section 21083.2, 14 CCR Section 15064). CEQA Guidelines define significant cultural resources under three regulatory designations: historical resources, tribal cultural resources, and unique archaeological resources. These designations permit for a fair amount of overlap.

A historical resource is a “resource listed in, or determined to be eligible by the State Historical Resources Commission, for listing in the CRHR”; or “a resource listed in a local register of historical resources or identified as significant in a historical resource survey meeting the requirements of Section 5024.1(g) of the PRC”; or “any object, building, structure, site, area, place, record, or manuscript which a lead agency determines to be historically significant or significant in the architectural, engineering, scientific, economic, agricultural, educational, social, political, military, or cultural annals of California, provided the agency’s determination is supported by substantial evidence in light of the whole record” (14 CCR Section 15064.5[a][3]). Historical resources automatically listed in the CRHR include California cultural resources listed in or formally determined eligible for the NRHP and California Registered Historical Landmarks from No. 770 onward (PRC 5024.1[d]). Locally listed resources are entitled to a presumption of significance unless a preponderance of evidence in the record indicates otherwise.

Tribal cultural resources (TCRs) are similar to the traditional cultural property designation within the NHPA guidance. These can be sites, features, places, cultural landscapes, and sacred places or objects that have cultural value or significance to a Tribe. To qualify as a TCR, it must either be 1) listed on or eligible for listing on the California Register or a local historic register or, 2) or is a resource that the lead agency, at its discretion and supported by substantial evidence, determines should be treated as a TCR (PRC Section 21074). TCRs can include “non-unique archaeological resources” (see “unique archaeological resource” below) that, rather than being important for “scientific” value as a resource, can also be significant because of the sacred and/or cultural tribal value of the resource. Tribal representatives are considered experts appropriate for providing substantial evidence regarding the locations, types, and significance of TCRs within their traditionally and cultural affiliated geographic area (PRC Section 21080.3.1(a)).

Under CEQA, a resource is generally considered historically significant if it meets the criteria for listing in the CRHR. A resource must meet at least one of the following criteria (PRC 5024.1; 14 CCR Section 15064.5[a][3]):

> Is associated with events that have made a significant contribution to the broad patterns of California’s history and cultural heritage. Title 14, CCR Section 4852(b)(1) adds, “is associated with events that have made a significant contribution to the broad patterns of local or regional history, or the cultural heritage of California or the United States.”

Is associated with the lives of persons important in our past. Title 14, CCR Section 4852(b)(2) adds, "is associated with the lives of persons important to local, California, or national history."

Embodies the distinctive characteristics of a type, period, region, or method of construction; or represents the work of an important creative individual; or possesses high artistic values. Title 14, CCR 4852(b)(3) allows a resource to be CRHR eligible if it represents the work of a master.

Has yielded, or may be likely to yield, information important in prehistory or history. Title 14, CCR 4852(b)(4) specifies that importance in prehistory or history can be defined at the scale of "the local area, California, or the nation."

Historical resources must also possess integrity of location, design, setting, materials, workmanship, feeling, and association (14 CCR 4852[c]).

An archaeological artifact, object, or site can meet CEQA's definition of a unique archaeological resource even if it does not qualify as a historical resource (PRC 21083.2[g]; 14 CCR 15064.5[c][3]). An archaeological artifact, object, or site is considered a unique archaeological resource if "it can be clearly demonstrated that, without merely adding to the current body of knowledge, there is a high probability that it meets any of the following criteria (PRC 21083.2[g]):

Contains information needed to answer important scientific research questions and there is a demonstrable public interest in that information.

Has a special and particular quality such as being the oldest of its type or the best available example of its type.

Is directly associated with a scientifically recognized important prehistoric or historic event or person."

4.2 Criteria for Substantial Adverse Change to Historical Resources

As quoted below, the CEQA statute (California PRC Section 21000 et seq.) defines how to determine if actions will, or have, created adverse effects to historical resources.

"A project that may cause a substantial adverse change in the significance of an historical resource is a project that may have a significant effect on the environment. For purposes of this section, an historical resource is a resource listed in, or determined to be eligible for listing in, the California Register of Historical Resources. Historical resources included in a local register of historical resources, as defined in subdivision (k) of Section 5020.1 or deemed significant pursuant to criteria set forth in subdivision (g) of Section 5024.1, are presumed to be historically or culturally significant for purposes of this section, unless the preponderance of the evidence demonstrates that the resource is not historically or culturally significant. The fact that a resource is not listed in, or determined to be eligible for listing in, the California Register of Historical Resources, not included in a local register of historical resources, or not deemed significant pursuant to criteria set forth in subdivision (g) of Section 5024.1 shall not preclude a lead agency from determining whether the



resource may be an historical resource for purposes of this section" (California PRC Section 21084.1).

4.3 Public Resources Code 5097.98

This section discusses the procedures that need to be followed upon the discovery of Native American human remains. The NAHC, upon notification of the discovery of human remains is required to contact the County Coroner pursuant to subdivision (c) of Section 7050.5 of the Health and Safety Code and shall immediately notify those persons it believes to be the most likely descendants.

4.4 Health and Safety Code 7050.5

This code establishes that any person, who knowingly mutilates, disinters, wantonly disturbs, or willfully removes any human remains in or from any location without authority of law is guilty of a misdemeanor. It further defines procedures for the discovery and treatment of Native American human remains.

4.5 National Historic Preservation Act

The Project is considered an undertaking subject to compliance with Section 106 of the NHPA of 1966, as amended, and its implementing regulations (36 CFR 800). The issuance of Class VI UIC permits is a federal action subject to historic resources consultation in accordance with Section 106, including the identification, evaluation, and NHPA Section 106 consultation process with the State Historic Preservation Office (SHPO) within California Department of Parks and Recreation (DPR). The purpose of the archaeological study was to identify and document any cultural resources within the APE, to evaluate such resources for NRHP eligibility, and to assess future project effects on historic properties. The APE was designed to consider both direct and indirect effects on cultural resources from the undertaking. An APE is defined as "the geographic area or areas within which an undertaking may directly or indirectly cause changes in the character or use of historic properties, if any properties exist" (36 CFR 800.16(d)). The APE for direct effects for this undertaking is confined to the Project footprint, which includes the proposed CCS Project and its ancillary facilities and equipment (new CO_2 pipelines, injection wells, CO_2 monitoring wells, and an underground carbon sequestration field). It is expected that any potential adverse impacts from the Project will be contained within this direct APE.

The NHPA provides a regulatory framework to ensure that significant cultural resources are recognized and protected during federal projects and programs through the Section 106 (36 CFR 800) compliance process. For compliance with the NHPA, cultural resource significance is evaluated in terms of eligibility for listing in the NRHP. Properties eligible for the NRHP are considered historic properties. Section 106 of the NHPA requires that federal agencies consider the potential effects of undertakings on historic properties. The purpose of this cultural resources study is to identify and document cultural resources within the APE, to evaluate those resources for NRHP eligibility, and to assess Project effects on historic properties.



4.6 National Register of Historic Places Eligibility Criteria

The criteria for determining eligibility for listing in the NRHP is defined in 36 CFR 60.4. Agencies evaluate potential historic properties discovered in the Identification phase in consultation with the SHPO to determine if the resources are eligible for inclusion in the NRHP. Cultural resources generally more than 50 years old may be considered eligible for listing and they must meet one or more of the following criteria:

- Criterion A: Be associated with events that have made a significant contribution to the broad patterns of America's history
- Criterion B: Be associated with the lives of persons significant to our past
- Criterion C: Embody the distinctive characteristics of a type, period, or method of construction, or represents the work of a master, or possesses high artistic value, or represents a significant and distinguishable entity whose components may lack individual distinction
- Criterion D: They must have yielded or may be likely to yield information important in prehistory or history

In addition to meeting at least one of the above-listed criteria, a determination of eligibility for the NRHP must consider the resource's integrity. A property's integrity is grounded in an understanding of the property's physical characteristics and how those characteristics relate to its significance. The NRHP defines seven aspects of integrity: location, design, setting, materials, workmanship, feeling, and association. An archaeological site, building, structure, district, or object that meets one of the NRHP significance criteria and has enough integrity to convey that historical significance is considered eligible for listing in the NRHP and is a historic property under Section 106 of the NHPA. A full explanation of the procedures for evaluating historic resources can be found in publications issued by the National Park Service, including National Register Bulletin 15, How to Apply the National Register Criteria for Evaluation (NPS 1990).

4.7 Criteria for Adverse Effects

The NHPA (36 CFR Section 800.5) defines how to determine if actions will, or have, created adverse effects to historic resources.

An adverse effect is found when an undertaking may directly or indirectly alter any of the characteristics of a historic property that qualify the property for inclusion in the NRHP in a manner that would diminish the integrity of the property's location, design, setting, materials, workmanship, feeling, or association.

Consideration shall be given to all qualifying characteristics of a historic property, including those that may have been identified subsequent to the original evaluation of the property's eligibility for the NRHP. Adverse effects may include reasonably foreseeable effects caused by the undertaking that may occur later in time, be farther removed in distance or be cumulative.



Adverse effects on historic properties include but are not limited to the following:

i. Physical destruction of or damage to all or part of the property;

ii. Alteration of a property, including restoration, rehabilitation, repair, maintenance, stabilization, hazardous material remediation, and provision of handicapped access, that is not consistent with the Secretary's standards for the treatment of historic properties (36 CFR part 68) and applicable guidelines;

iii. Removal of the property from its historic location;

iv. Change of the character of the property's use or of physical features within the property's setting that contribute to its historic significance;

v. Introduction of visual, atmospheric or audible elements that diminish the integrity of the property's significant historic features;

vi. Neglect of a property which causes its deterioration, except where such neglect and deterioration are recognized qualities of a property of religious and cultural significance to an Indian tribe or Native Hawaiian organization; and

vii. Transfer, lease, or sale of property out of Federal ownership or control without adequate and legally enforceable restrictions or conditions to ensure long-term preservation of the property's historic significance.

4.8 Native American Graves Protection and Repatriation Act

The Native American Graves Protection and Repatriation Act (NAGPRA) (25 United States Code [USC] Section 3001) and its implementing regulations (43 CFR Part 10) presents a systematic process for determining the rights of lineal descendants and Indian tribes to certain Native American human remains, funerary objects, sacred objects, or objects of cultural patrimony with which they are affiliated.

NAGPRA defines the following terms:

> (1) "burial site" means any natural or prepared physical location, whether originally below, on, or above the surface of the earth, into which as a part of the death rite or ceremony of a culture, individual human remains are deposited.
>
> (2) "cultural affiliation" means that there is a relationship of shared group identity which can be reasonably traced historically or prehistorically between a present day Indian tribe or Native Hawaiian organization and an identifiable earlier group.
>
> (3) "cultural items" means human remains and-
>
> (A) "associated funerary objects" which shall mean objects that, as a part of the death rite or ceremony of a culture, are reasonably believed to have been placed with individual human remains either at the time of death or later, and both the human remains and associated funerary objects are presently in the possession or control of a Federal agency or museum, except that

other items exclusively made for burial purposes or to contain human remains shall be considered as associated funerary objects.

(B) “unassociated funerary objects” which shall mean objects that, as a part of the death rite or ceremony of a culture, are reasonably believed to have been placed with individual human remains either at the time of death or later, where the remains are not in the possession or control of the Federal agency or museum and the objects can be identified by a preponderance of the evidence as related to specific individuals or families or to known human remains or, by a preponderance of the evidence, as having been removed from a specific burial site of an individual culturally affiliated with a particular Indian tribe,

(C) "sacred objects" which shall mean specific ceremonial objects which are needed by traditional Native American religious leaders for the practice of traditional Native American religions by their present day adherents, and

(D) "cultural patrimony" which shall mean an object having ongoing historical, traditional, or cultural importance central to the Native American group or culture itself, rather than property owned by an individual Native American, and which, therefore, cannot be alienated, appropriated, or conveyed by any individual regardless of whether or not the individual is a member of the Indian tribe or Native Hawaiian organization and such object shall have been considered inalienable by such Native American group at the time the object was separated from such group.

5 ENVIRONMENTAL BACKGROUND

The APE is within the western San Joaquin Valley (SJV), which accounts for the southern half of the Central Valley of the Great Valley Geomorphic Province. The Great Valley Geomorphic Province is an alluvial plain about 50 miles wide and 400 miles long in the central part of California. The southwestern margin of the valley is renowned for its oil fields trapped within anticlinal uplifts. The SJV is surrounded by three mountain ranges: the Sierra Nevada on the east, the Temblor Range on the west, and the Tehachapi Range on the south. The Belridge oil fields were discovered in the early 1900s, as oil naturally surfaced due to pressure in the geologic reservoir. The first well was drilled along Chico Martinez Creek in April 1911 (Allan and Lalicata 2012). Since then, the Belridge Oil Fields were developed into North and South Belridge oil fields. The APE is heavily disturbed with oil wells and well pads, oil and gas infrastructure, gas and steam pipelines, and multiple unnamed dirt or graveled access roads and a few paved roads.

5.1 Natural Setting

The APE lies along the South and North Belridge oil fields on the Antelope Plain, an alluvial piedmont consisting of coalescing alluvial fans from the Temblor Range to the west. The region slopes to the east towards the SJV. The topography of the APE is relatively flat, interrupted only by oil and gas infrastructure, and consists of grades between 0 and 9 percent slope and elevations range from

approximately 675 feet above mean sea level (amsl) on the western edge down to 550 feet amsl on the eastern edge of the APE.

The APE is within the SJV groundwater basin and the Kern County groundwater subbasin. This groundwater subbasin extends from the Greenhorn Mountains in the east to the Temblor Range in the west. Streamflow through the vicinity of the APE is generally directed from the Temblor Range in the west toward the Central Valley in the east. Chico Martinez Creek, an ephemeral stream at the southern end of the APE, is the most prominent regional stream draining southwest/northeast through the South Belridge Oil Field toward the Central Valley. Sections of Chico Martinez Creek within the APE appear to be channelized but are interspersed with no defined channel bed and bank. Chico Martinez Creek has been altered and segmented due to oil field development and road construction.

Soil types mapped across the APE are composed predominantly of Kimberlina fine sandy loam, with minor amounts of Milham sandy loam and Panoche clay loam. The Kimberlina series consists of very deep, well-drained soils on flood plains and recent alluvial fans. These soils formed in mixed alluvium derived mostly from igneous and/or sedimentary rock sources. The Milham series consists of very deep, well-drained soils on alluvial fans, plains, low terraces, and fan remnants. These soils formed in mixed calcareous alluvium weathered from granitic and sedimentary rock. The Panoche series consists of very deep, well-drained soils on alluvial fans and flood plains. These soils formed in loamy calcareous alluvium from sedimentary rock (USDA NRCS 2022).

The climate of the area is characterized as Mediterranean with moderate winters and hot, dry summers. Precipitation primarily occurs as rain with an average annual rainfall of approximately 5.64 inches. Air temperatures range between an average January temperature of 45.8 degrees Fahrenheit (ºF) and an average July temperature of 81.9 ºF. The annual average temperature is approximately 63.4 ºF. Climate is based on historical weather data collected at Buttonwillow, California (Western Regional Climate Center 2022), located approximately 15 miles east of the APE.

5.2 Vegetation and Wildlife

The primary vegetation within the APE is classified as *Atriplex polycarpa* Shrubland Alliance (Allscale scrub) and native and non-native grasslands. Allscale scrub occurs primarily in the southern half of the Study Area. Allscale (*Atriplex polycarpa)* scrub is characterized by an open to continuous canopy with a variable herbaceous layer including seasonal annuals and non-native grasses. The alliance is typically found in washes, playa lake beds and shores, dissected alluvial fans, rolling hills, terraces and edges or large low gradient washes. Soils may be carbonate rich, alkaline, sandy, or sandy clay loams (Sawyer et al. 2009).

Typically, allscale is dominant in the shrub canopy with annual bursage (*Ambrosia acanthicarpa*), fourwing saltbush (*Atriplex canescens*), red brome (*Bromus madritensis* ssp. *rubens*), small, seeded spurge (*Euphorbia polycarpa*), and coyote brush (*Baccharis pilularis*). Patches of the allscale scrub, dominated by allscale shrubs with non-native grasses, primarily bromes (*Bromus* spp.) and weeds including Russian thistle (*Salsola tragus*), occur along a historic ephemeral drainage within the APE.

Common animals in the area include numerous bird species, the black-tailed jackrabbit (*Lepus californicus*), desert cottontail rabbit (*Sylvilagus audubonii*), kangaroo rat (*Dipodomys sp.*), coyote (*Canis latrans),* San Joaquin antelope squirrel (*Ammospermophilus nelson),* side-blotched lizards (*Uta stansburiana*), Northern Pacific Rattlesnake (*Crotalus oreganus)* and California whiptail lizards (Aspidoscelis tigris munda).

6 CULTURAL BACKGROUND

6.1 Ethnography and Archaeology

The North and South Belridge oil fields and the surrounding areas are within the ethnographic territory of the Southern Valley Yokuts. The Southern Valley Yokuts have been the subject of considerable study by numerous researchers (e.g., Gifford and Schneck 1926; Kroeber 1925; and Wallace 1978a). The Southern Valley Yokuts' homeland was centered near water sources including the Tulare, Buena Vista, and Kern Lakes and connecting sloughs and rivers. Prior to the emergence of modern agricultural practices in the region, the SJV was a landscape dominated by networks of interconnecting watercourses, lakes, and sloughs at historic contact (e.g., Sutton 1997:3). The Southern Valley Yokuts, primarily the Wowol, Tachi, and Chunut tribes, occupied the Tulare Lake Basin (Cook 1955). Tulare Lake, part of the larger Tulare Lake Basin, was a large freshwater lake formed by the consolidation of alluvial fan dams generated by the Kings River to the east and Los Gatos Creek to the west (Atwater et al. 1986). People inhabited the Tulare Lake region from at least 13,000 calibrated years before present (CYBP) to after historic contact (Sutton 2019:293). At its maximum, the lake covered some 100 square miles and boasted a diverse biotic community that supported a large population of various Yokut tribes (Preston 1981). Buena Vista Lake, which was the second largest lake in the Tulare Lake Basin, was fed by the waters of the Kern River and was connected with Kern and Tulare Lakes via sloughs. During the mid-20th century, Buena Vista Lake dried up after its tributary rivers were impounded by the construction of Isabella Dam for agricultural and municipal water uses.

Natural and anthropogenic factors have heavily impacted the integrity of archaeological sites in the Central Valley. Fluctuations in temperature since the Pleistocene created different periods of increased precipitation and flooding which morphed the Valley's terrain. These floods either washed away artifacts from the earliest periods or deeply deposited them under alluvial soils (Aviña 1999:9; Rosenthal et al. 2007:150). Agricultural development, levee construction, and river erosion during historic times have also contributed to the destruction of surface sites (Rosenthal et al. 2007:149). Artifacts have also been taken by private collectors through time, making interpretation more difficult since this precludes analysis by anthropologists and the provenience which provides context is likely lost (Sutton 2019:293). Our interpretations of the early peopling of the Central Valley are also impacted by biases in data introduced by poor sampling strategies in the past. Early archaeological work in the Central Valley focused primarily on the recovery of artifacts and burials while ignoring dietary remains and technological features (Rosenthal et al. 2007:150). Burials and artifacts alone cannot present an accurate picture of past events.

Continuing work has refined our understanding of the Central Valley's archaeological record (Rosenthal et al. 2007:149; Sutton 2019; Jones and Perry 2012). The Southern part of the Central Valley has fewer

recorded sites than the rest of the Valley north of the King's River which is the traditional historic divide between Northern and Southern Yokut territories (Rosenthal et al. 2007:148). Because of this, data from the rest of the Valley is necessary to have a wholistic understanding of the cultural patterns of the southern section of the valley. The chronology used in this report will be organized using Fredrickson's (1973, 1974) California adaptation of Willey and Phillips' (1958) classification scheme as modified by Rosenthal et al. (2007). This classification scheme will be applied because it is comprehensive enough to provide a chronological framework for the cultural patterns that appear throughout the Valley and, because it incorporates newer radiocarbon dates (Groza 2002; LaJeunesse and Pryor 1996; Meyer and Rosenthal 1997) adjusted with modern calibration curves.

6.2 Prehistory

6.2.1 Paleo-Indian (11,550 to 8550 cal B.C.)

During the terminal Pleistocene, western California's climate was more seasonal than today, with cooler temperatures, greater effective precipitation, and a longer rainy season (West 2000:19-20). At the onset of the Holocene, temperatures in western California increased as precipitation decreased gradually (Adam and West 1983; West 2000). By 10,100 CYBP, Tulare Lake was stable and shallow reaching depths ranging from 64m to 58m (Sutton 2019:289-290). The earliest accepted evidence of human occupation of the Central Valley are basally thinned and fluted projectile points (Rosenthal et al. 2007:151). These points are dated in other parts of North America to at least 12,900 CYBP (Sutton 2019:276). In the SJV, these points have only been found in Tracy Lake, the Woolfsen mound (CA-MER-215), and the Tulare Lake Basin (Heizer 1938; Moratto 1984; Peak and Weber 1978; Rosenthal et al. 2007:151). It is assumed that these first peoples were generally nomadic with their subsistence being based on large game hunting and fishing. There is no direct evidence from western California that these early people hunted Pleistocene megafauna, but it is highly likely (Erlandson et al. 2007; Jones and Perry 2012; Rosenthal and Meyer 2004; Sutton 2019). Stemmed points are also found in association with fluted points. It is currently theorized that stemmed points may be coeval with Clovis fluted technologies or older (Erlandson 2012:28-30; Sutton 2019).

6.2.2 Lower Archaic (8550 to 5550 cal B.C.)

In the Central Valley, the Lower Archaic is mostly represented by isolated finds (Rosenthal et al. 2007:151). These finds include stemmed points, chipped stone crescents, flaked stone artifacts, and concave base points (Fenega 1992; Wallace 1991). The only Central Valley archaeological site definitively dated to the Lower Archaic was found on the past shoreline of Buena Vista Lake (KER-116). Radiocarbon dates from freshwater mussels at KER-116 ranged from 7175 and 6450 cal. B.C. (Fredrickson and Grossman: 1977; Hartzell 1992). Lithics recovered at KER-116 include three chipped stone crescents, a stemmed projectile point fragment, a carved stone atlatl spur, and a few small-flaked-stone implements (Rosenthal et al. 2007:151). A faunal assemblage recovered from KER-116 shows that freshwater fish and mussels, waterfowl, and artiodactyls were consumed (Hartzell 1992). While milling tools are largely absent from Valley floor assemblages, including KER-116, Lower Archaic sites in the

adjoining Sierra Nevada and Coast Range foothills contain abundant milling equipment and other indications of reliance on plant foods (Meyer and Rosenthal 1997; Rosenthal et al. 2007:152). How Valley and Foothill adaptations during the Lower Archaic relate to each other is unclear (Rosenthal et al. 2007:152). The establishment of cultural interaction spheres is also seen in Lower Archaic Valley deposits. A variety of stemmed points styles are found in Lower Archaic deposits of Tulare basin that resemble styles from throughout California and from the Great Basin. Marine shell beads from California are also found in archaeological deposits in the Great Basin that are coeval to the Lower Archaic. Obsidian from the Eastern Sierra mountains is found in Lower Archaic Great Basin deposits. (Rosenthal et al. 2007:152).

6.2.3 Middle Archaic (5550 to 550 cal B.C.)

During the Middle Archaic, California's climate became warmer and dryer causing the decline and desiccation of Tulare Lake and the decline of other western lakes as well (Benson et al. 2002; Davis 1999; White et al. 2002). Sea levels also began to rise at this time causing the Central Valley to become a wetland environment (Atwater and Belknap 1980; Goman and Wells 2000). The archaeological record shows more diversified subsistence-settlement patterns during this time. Some sites show evidence of an increasing emphasis on seed processing while others show placement of emphasis on hunting, fowling, and fishing (Rosenthal et al. 2007:153). Artifacts from this period include Haliotis shell ornaments in varied geometric shapes, Olivella and Haliotis beads, distinctive spindle-shaped charmstones, cobble mortars, chisel-ended pestles, heavy projectile points, and mortars and pestles. A tradition of extended westerly oriented burials known as the Windmiller Pattern appears throughout the SJV (Fredrickson 1973, 1974; Moratto 1984). Bones were extensively utilized for tools, such as for awls, fish spear tips, saws, and pressure flakers which were used in the manufacture of flaked-stone implements such as projectile points. Sites also show increasing residential stability along river corridors of the Sacramento and San Joaquin Valleys (Rosenthal et al. 2007:153)

6.2.4 Upper Archaic (550 cal B.C. to cal A.D. 1100)

In the Upper Archaic, there was an abrupt turn to cooler, wetter, and more stable climate and the refilling of lakes that had desiccated in the middle Holocene (Rosenthal et al. 2007:155). The archaeological record for the Upper Archaic is better preserved and understood compared to preceding periods. There is evidence for the existence of different cultural groups in the Central Valley at this time. Large mounded villages associated with Berkley pattern assemblages appear in the lower Sacramento Valley (Rosenthal et al. 2007:156). Berkley pattern village sites have extensive debris and features that reflect long-term residential occupation (Bouey 1995:348-349). The Windmiller cultural pattern is still seen in archaeological assemblages from this time (Bennyhoff 1994b,c). Little is known about the cultures that occupied the Southern SJV during the Upper Archaic (Siefkin 1999:56-57). Southern SJV Upper Archaic village sites that have been excavated also show signs of long-term occupation and exploitation of aquatic and terrestrial environments for food (Hartzell 1992: 304-305). New types of bone tools and other implements made of bone such as wands, tubes, and ornaments appear in the archaeological record. Groups throughout the valley varied in what they harvested. Foods that were consumed by different



groups included acorns, salmon, shellfish, rabbits and deer. In the SJV, People were still using obsidian sourced from the east side of the Sierra Nevada and, some southern SJV sites used obsidian from the North Coast Ranges (Rosenthal et al. 2007:157).

6.2.5 Emergent Occupation (cal A.D. 1100 to Historic)

The Climate in the Central Valley at this time was relatively unchanged from that of the Late Holocene, but flooding and drought events did occur. The archaeological record of the Emergent Occupation is the most substantial and comprehensive compared to earlier periods and shows the most diversity (Bennyhoff 1977). After 1,000 A.D., many archaic traditions and tools disappeared throughout the central valley and new cultural traditions similar to those seen by European-Americans at contact emerge (Rosenthal et al. 2007:157). Between about A.D. 1000 and 1300, the bow and arrow is introduced to the Central Valley and replaces the atlatl (Bennyhoff 1994a). Villages are structured around rivers, tributaries, and deltas (Rosenthal et al. 2007:158). Two broad phases occur at this time: the Lower and Upper Emergent.

Artifacts associated with the Lower Emergent phase include banjo-type *Haliotis* (abalone) ornaments, bird bone whistles, soapstone pipes, and rectangular *Olivella* sequin beads (Rosenthal et al.2007:158). During the Lower Emergent, the Stockton serrated point is developed in the delta area (Dougherty 1990). Panoche side-notched points and cottonwood points are found in Lower Emergent Occupation deposits in SJV (Hartzell 1992:173; Moratto 2002; Olsen and Payen 1983; Pritchard 1970; Siefken 1999:152-154) Gunther-barbed points are introduced in the northern Sacramento Valley During the Lower Emergent (Basgall and Hildebrandt 1989:123; Jaffke 1997). Artifacts associated with the Upper Emergent, include corner-notched and desert series arrow points, *Olivella* lipped and clam disk beads and bead drills, magnesite cylinders, hopper mortars, and village sites with pits resembling known ethnographic settlements (Beardsley 1954:77-79; Bennyhoff, in Elsasser 1978:44; Fredrickson 1984; Moratto 1984: 213; Pritchard:1970, 1983). Mammal, fish, and bird bone are found in Upper Emergent period middens from many sites. More mortars and pestles appear throughout the valley after 1,000 A.D. with small seeds, acorn, pine nuts, manzanita becoming more economically important in the northern Central Valley (Miksicek 1999; Wohlgemuth 2004).

6.3 Historic Period

European contact with the Yokuts initiated in 1772, when a detachment of Spanish soldiers under the command of Pedro Fages ventured through the Tejon Pass into the SJV. The only other significant 18th century Spanish contact with the Southern Valley Yokuts was a visit by friar Francisco Garcés in 1776. No significant European contact with the Southern Valley Yokuts occurs again until the beginning of the 19th century when Spaniards more actively entered and proselytized the area. While Spanish colonization and missionization heavily altered the traditional socio-cultural practices of the Yokuts, the Spanish never successfully took over the southern valley. During the time when California was part of Mexico (1822-1846), the most significant Mexican influence was a severe malaria outbreak in 1833 that killed approximately 75 percent of the Native population (Wallace 1978a:459-460). With the annexation of

California by the United States, the discovery of gold in Sutter's Mill, and the incorporation of California as a State by the U.S. Government, the SJV was overrun with settlers who occupied native lands.

At contact, the native populations of the central valley were numerous, and their socio-cultural practices were rich and complex. Archaeological assemblages dating to between cal A.D. 1000 to 1769 such as arrow points, increased variation in burials, pottery, shaped mortars and pestles, changes in arrow point styles, and *Olivella* bead blanks all indicate that people in the area were engaged in a rich and expansive interaction sphere. Many of these objects and associated practices were still largely in use at European contact (Rosenthal et al. 2007:157). It is estimated that 100,000 Native people lived in the central valley between A.D. 1772 and 1821 (Cook 1955, 1976, 1978; Moratto 1984:171).

The Spanish presence in the region played a part in the dispersal of native populations from the foothills and depopulation of entire villages (Cook 1955:55-56). The indigenous population in the region was severely reduced by European diseases introduced by the Spanish. The precipitous decline of Indigenous population and disruption of traditional lifeways by the Spanish Mission system left the surviving Natives despondent and unresistant making the process of dispossession by Euro-Americans relatively easy as the settlers, sometimes forcibly, removed Indian families and communities (Wallace 1978b:469). The few surviving Southern Valley Yokuts were sent to the Tejon reservation established at the base of the Tehachapi Mountains, or to the Fresno reservation near Madera. These reservations failed to prosper, and in 1859, the Native Americans who remained on them were moved to the Tule River reservation.

Historic period effects on the landscape began with ranching and mineral extraction during the mid-1850s; gold mining was an important local enterprise as well as stock-raising and farming and to a lesser extent. By 1850, approximately 300,000 people immigrated to California from around the world in search of gold. People that moved into the SJV paid little mind to the oil seeps they saw along the Old Road when they entered the valley until the early 1860's. The first oil refinery was erected in Titusville, Pennsylvania in 1861 after it was discovered that bitumen from the seeps could be refined into kerosene.

By 1865, oil was exploited throughout Southern California. One of the most significant oil discoveries in California occurred in Kern County in the lower SJV. The Kern County oil fields cover a large swath of land beginning at the base of the Tehachapi Mountains and running north through the lower SJV toward the community of Taft (Caltrans 2013). The resulting oil discoveries in Kern County drew thousands of skilled and unskilled workers into the southern SJV and almost immediately created boomtowns, such as McKittrick, Taft, Arbuckle, Fellows, and Reward (Caltrans 2013). The railroad lines that traveled from the SJV oil fields to various refineries in the state were essential in the growth and success of the oil fields. From 1903 to 1906, California became the top oil producing state. Oil discoveries in the kern region ended with WWII but the area remains a major source of oil to the present day.

6.3.1 Belridge Oil Field

Belridge oil field is 13 miles long by three miles wide. The property is sectioned into North, Middle, and South Belridge for land holding reasons. It overlies three large petroleum reservoirs: the Tulare pool, the Diatomite pool, and the Sub-Monterey pool. The field lies above the crest of a large, elongated anticline. Continuous vertical oil columns ranging up to 1,300 ft are trapped along the crest of the anticline (Allan et



al. 2010). Natural faults created by extension of the growing anticline and movement of the San Andreas fault allow hydrocarbons to leak from source beds to overlying soils (Allan et al. 2010:5).

The Tulare pool is twelve miles long by three miles wide and covers 10,500 acres. The Tulare pool is relatively shallow running 400 to 1,000 ft beneath the overlying alluvium deposited over the last circa 12,000 years. The Tulare pool is used as a source of heavy (11-15° API) oil. The soils of the Tulare pool are highly porous and permeable. The Tulare reservoir rests directly on top of the Diatomite reservoirs. The Tulare reservoir was the focus of field development and production until technological advances shifted the focus to the deeper Diatomite rocks.

The Diatomite pool is fifteen miles long by three-quarters of a mile wide and covers 8,000 acres. It runs 800 to 2,000 ft in depth. The Diatomite pool is used as a source of light (23-39° API) oil. The reservoir rock of the diatomite pool is composed of the silica left behind by the diatoms that were deposited through time. The Belridge diatomite has a high matrix porosity (50-70%) in its upper levels, is highly compressible (100-300 x 10^{-6} psi^{-1}) and has a very low matrix permeability (0.1-3.0md) (Rahman et al. 2011). Because of the low matrix permeability of the diatomite, the pools were commercially unproductive until 1977 when the hydraulic fracture method could be applied successfully to retrieve the oil.

The Sub-Monterey pools are four miles long by one mile wide. They span from 6-9,400 ft in depth and have a productive size of 1,600 acres. Gas and light oil are extracted from the Sub-Monterey pools. Natural fractures caused by tectonic movement allows the oil trapped in the Sub-Monterey pool to rise to the surface and seep into the other pools. The following section will present a history of Belridge oil field and wells that were dug to access these petroleum deposits from 1911 to the present. This history presented here borrows heavily from Allan and Lallicata's *The Belridge Giant Oil Field - 100 Years of History and a Look to a Bright Future* (2012).

Belridge Oil Field was founded by five families when the Tulare & Diatomite pools were tapped into with the excavation of Well #101 in 1911. Well #101, located in South Belridge, allowed Belridge Oil Co. to begin producing heavy oil. The Tulare and Diatomite pools were accessed again in 1912 in North Belridge. During the 1920's, approximately 100 wells were drilled in South Belridge and thirty wells in North Belridge. By the late-1920s, steel derricks and diesel engines replaced wooden derricks powered by steam because of the increased safety, efficiency, and ability to handle longer casing strings (Allan and Lalicata 2012).

In the 1930's, the Sub-Monterey pools were discovered and developed in North Belridge and production was further expanded with the addition of 170 more wells. The deeper Temblor Sand sub-Monterey reservoirs were discovered at 6,000 to 8,000 ft (1800-2450 m) in North Belridge and became important petroleum resources for World War II. In 1932, the Discovery well for 64 Zone, well 64-27N, was drilled into the sub-Monterey formations. In June 1934, General Petroleum drilled Berry 1-30 to TD at 11,377 ft (3468 m), the deepest well in world at the time. The well utilized mud log and driller's log only because electric logs were not in use in California at the time.

From 1930-1948 a total of 148 wells (8 dry holes) were drilled in the sub-Monterey pools. From 1936-1984, 540 billion cubic feet of gas (BCFG) were injected for gas storage and pressure maintenance. the

sub-Monterey pools reached peak production of 135 MMCFG/day and 13,950 barrels of oil (BO)/day in 1938 (Allan and Lalicata 2012). The discovery well for Y Sand; well 47-27N, was excavated into the sub-Monterey formations in 1941. During the 1950's an unknown number of wells were drilled. From 1956-59, the In-situ combustion pilot method is employed by in Belridge field. In 1963, the use of Cyclic steaming begins. The In-situ combustion project was carried out by Mobil from 1963-1968. 1966 was the discovery year for Carneros Sand sub-Monterey formations.

The first successful hydraulicly fractured well was drilled into the Belridge Diatomite in 1977 making these deposits lucrative. In 1979, the shareholders of Belridge Oil Co. approved the merger of their company with Shell Oil Co. In 1986, the use of water injection began to mitigate subsidence (sinking of soils due to the subterranean voids created by oil extraction). In the same year, production peaked at 172,700 BO/day and 114.4 million cubic feet of gas (MMCFG)/day. From 1987-2007, the Aquifer Lift project was carried out and completed on east flank to reduce aquifer inflow.

The first horizontal wells were drilled in South Belridge in 1993; forty-six wells were drilled by Shell and twenty were drilled by Mobil. The nature of the deposits created too many complications to be profitable so attention was switched to the diatomite reserves. In 1995, four horizontal wells were drilled into the diatomite pools and completed by Shell. In 1996, Mobil drilled a horizontal well in the southeast nose of the field. Aera Energy LLC was formed in 1997 from Shell and Mobil assets. At this time, the horizontal well drilling started by Mobil was expanded upon the formation of Aera Energy LLC. The first four wells were technically successful but economic failures. In 2001, the Program for recompletions and add-pays began. In 2002, Production peaks at 76,100 BO/day, 52.9 MMCFG/day. By 2011, the field had 46 active wells. In September of 2022, ExxonMobil and Shell sold Aera Energy to IKAV (Jacobs 2022).

6.4 Current Land Use

The APE is within existing developed oil and gas fields in the North and South Belridge oil fields, in an unincorporated area of western Kern County. The North and South Belridge oil fields are active and have been operating to some extent since 1911. Surface ownership of the land is privately held by Aera Energy. Much of the land is highly developed by Aera Energy's oil extraction efforts and continues to be developed further. The cumulative development includes the drilling of new wells, the construction of derricks, pumpjacks, steam boilers and injection systems, systems to support these, including the Belridge Water Softening Plant, and constructing basic amenities and offices (such as the Oasis office) for the operation of these infrastructures. This is largely in support of the Aera Energy wells on the 64 Zone lease (Formerly Shell's Oceanic lease), the Belridge I-III leases, and the Diatomite Thermal Recovery lease, the latter especially containing many Enhanced Oil Recovery wells and injection platforms. Furthermore, there is a planned recycling facility with construction underway within the APE.

The surrounding land use of the APE consists of densely developed privately owned oil and gas fields, primarily those owned by Chevron, Aera Energy, and multiple smaller oil companies such as E & B Natural Resources Management Co and Belridge Energy Resources, Inc. who share in the use of the land to operate wells on leases such as the Hopkins lease, the Weber lease, and the Mission lease.

Multiple corporations, such as RHC and Wesco Distribution, use the land to store and assemble derrick parts, oil tankers, construction equipment, and modular offices.

Land uses not directly related to the oil extraction within the APE include maintenance of the power transmission lines on Pole Line Road by Pacific Gas and Electric Company, and the conservation and development of water resources for the region by the Belridge Water Storage District, as well as the maintenance of public roads such as Highway 33, by Caltrans. Outside the APE the land is developed largely for grazing cattle and agriculture, although the land is also home to the (currently abandoned) Belridge Elementary School in the former town of Belridge.

7 METHODOLOGY

The cultural resource study completed for the Project consisted of a records search conducted by the Southern San Joaquin Valley Information Center (SSJVIC) of the California Historical Resources Information System (CHRIS) at CSUB, an intensive pedestrian survey of the entire approximately 1,167-acre APE, as well as a Sacred Lands File Search (SLFS) with the Native American Heritage Commission (NAHC) in West Sacramento. The methodology used during the current study is provided below.

7.1 Records Search

On April 4 and August 15, 2022, CHRIS archival records searches were conducted by the SSJVIC on behalf of Stantec. The search entailed a review of all previously documented prehistoric and historic-period cultural resources, including archaeological sites, features, and isolated finds located within the Study Area (Figure 4 - Confidential), as well as a review of all known cultural resource survey reports, excavation reports, and regional overviews. The purpose of the records search was to determine the number of cultural resource studies and known archaeological resources in the APE, and the 1-mile radius Study Area. Additionally, as part of the records search the following sources were reviewed:

- Google Earth imagery;
- Historical Aerial imagery; and,
- USGS topographic quadrangle maps:
    - Lost Hills, CA (1914; 1914 ed., 1928 ed., 1938 ed., 1947 ed.) 1:125,000;
    - Belridge, CA (1943; 1953; 1957 ed.) 1:31,680;
    - Blackwell, Ca (1943) 1:31,680;
    - Bakersfield (1948) 1:250,000;
    - Carneros Rocks, Ca (1959; 1961 ed.) 1:24,000;
    - McKittrick, Ca (1912; 19112 ed., 1920 ed., 1934 ed., 1943 ed.) 1:125,000; and,
    - Simmler, Ca (1943) 1: 62:500.

Literature from the West Kern Oil Museum's library was also reviewed to provide historical context.

The record searches identified nine reports of the APE (Aviña 1999; BioSystems Analysis, Inc. 1989; Brunzell 2011; 2013b; Fredrickson 1985; Palm-Leach et al. 2010; Schiffman and Monday 1982; Snethkamp 1991; Unknown 1987), and 17 reports within the Study Area (Table 1; Figure 3 – Appendix

A). The records searches revealed that no resources are previously recorded in the APE, and three resources have been previously recorded in the Study Area (Table 2).

Table 1. Cultural Resources Studies of the APE and Study Area

Author	Year	Title	Report Type	Results	Location	Report Reference No.
Schiffman, Robert A. and Monday, Nyle C.	1982	Archaeological Evaluation for the Proposed Belridge Field Cogeneration Plant, Kern County, California	Archaeological Field Study	Negative	Within APE	KE-01485
Fredrickson, David A.	1985	West Coast Cogeneration Project: Belridge	Archaeological Field Study	Positive	Within APE	KE-00403
Unknown	1987	Report on the Cultural Resources Assessment of the Proposed San Joaquin Valley Pipeline	Archaeological Field Study	Positive	Within APE	KE-01840
Schiffman, Robert A.	1987	Archaeological Investigation for the San Joaquin Valley Pipeline, Kern County, California	Archaeological Field study and Excavation	Positive	Within Study Area	KE-01268
BioSystems Analysis, Inc.	1989	Technical report of cultural resources studies for the proposed WTG-West, Inc. Los Angeles to San Francisco and Sacramento, California Fiber Optic Cable Project	Archaeological/ Architectural/historical Field Study	Positive	Within APE	KE-00172
Snethkamp, Pandora	1991	Phase I Archaeological Survey Proposed Mobil Oil 17Z Pipeline, Western Kern County, CA	Archaeological Field Study	Negative	Within APE	KE-01565
Avina, Mike	1999	Cultural Resources Inventory Report for Williams Communications, Inc. Fiber Optic Cable System Installation Project, San Luis Obispo to Bakersfield, Volume I	Archaeological Field Study	Positive	Within APE	KE-02278

Author	Year	Title	Report Type	Results	Location	Report Reference No.
Knudson, Holly D.	2001	Review of the Proposed Bechtel Telecommunications/AT&T Wireless Services Project "Belridge"	Archaeological Field Study	Negative	Within Study Area	KE-02659
Thal, Erika	2004	Proposed Cellular Tower Project in Kern County, CA: Site CA-1444A/ Belridge	Archaeological Field Study	Negative	Within Study Area	KE-02945
Hatoff, Brian W.	2007	Verizon Cellular Communications Tower Site - Missouri Triangle 19620 Highway 33 McKittrick, Kern County, California: Results of Archaeological Survey for Verizon Cellular Communications Tower Site	Archaeological Field Study	Negative	Within Study Area	KE-03709
Romani, John F	2009	Improvements to Lerdo Highway from State Route 33 East to Interstate 5 (approximately 11.5 miles), Lost Hills Area, Kern County, California	Archaeological Field Study	Negative	Within Study Area	KE-03837
Palm-Leach, Laura, et al.	2010	Cultural Resources Inventory of Caltrans District 6 Rural Conventional Highways in Fresno, Western Kern, Kings, Madera, and Tulare Counties Summary of Methods and Findings	Archaeological Field Study	Positive	Within APE	KE-03777
Wills, Carrie D.	2011	Cultural Resources Records Search and Site Visit for Sprint Nextel Candidate SF97XC002-A (North Belridge), 17186 SR-33, Lost Hills, Kern County, California	Archaeological Field Study	Negative	Within Study Area	KE-04173
Brunzell, David	2011	Cultural Resources Assessment of Aera Energy LLC Water Disposal Project and Aquifer Exemption - South Belridge Field, Kern County, California (BCR	Archaeological Field Study	Negative	Within APE	KE-04300

Author	Year	Title	Report Type	Results	Location	Report Reference No.
		Consulting Project Number SYN1108)				
Brunzell, David	2012a	Cultural Resources Assessment of Aera Energy LLC Titan Oil and Gas Exploration Project, Unincorporated Kern County, California (BCR Consulting Project Number SYN1205)	Archaeological Field Study	Negative	Within Study Area	KE-04301
Brunzell, David	2012b	Cultural Resources Assessment of Aera Energy LLC 856L-1N Oil and Gas Exploration Project, Unincorporated Kern County, California (BCR Consulting Project Number SYN1226)	Archaeological Field Study	Negative	Within Study Area	KE-04304
Brunzell, David	2012c	Cultural Resources Assessment of Aera Energy LLC 835A-12 Oil and Gas Exploration Project, Unincorporated Kern County, California (BCR Consulting Project Number SYN1226)	Archaeological Field Study	Negative	Within Study Area	KE-04305
Brunzell, David	2012d	Cultural Resources Assessment of Aera Energy LLC 823G-26N Oil and Gas Exploration Project, Unincorporated Kern County, California (BCR Consulting Project Number SYN1226)	Archaeological Field Study	Negative	Within Study Area	KE-04306
Brunzell, David	2012e	Cultural Resources Assessment of Aera Energy LLC 837G-35N Oil and Gas Exploration Project, Unincorporated KernCounty, California (BCR Consulting Project Number SYN1226)	Archaeological Field Study	Negative	Within Study Area	KE-04307
Brunzell, David	2013a	Cultural Resources Study of Aera Energy LLC IGOR A Sec 28SHL Oil and Gas	Archaeological Field Study	Negative	Within Study Area	KE-04641

Author	Year	Title	Report Type	Results	Location	Report Reference No.
		Exploration Project, Unincorporated Kern County, California				
Brunzell, David	2013b	Cultural Resources Assessment of Aera Energy LLC IGOR A Sec 247 NB Oil and Gas Exploration Project, Unincorporated Kern County, California (BCR Consulting Project Number SYN1226)	Archaeological Field Study	Negative	Within APE	KE-04303
Loftus, Shannon	2013	Cultural Resource Records Search and Site Survey for AT&T Site BK0344-01 Missouri Triangle 19620 Highway 33, McKittrick, Kern County, California 93251	Archaeological Field Study	Negative	Within Study Area	KE-04590
Peterson, Cher and Wills, Carrie	2015	Cultural Resources Records Search and Site Visit Results for Verizon Wireless Candidate Belridge & Hwy 33, West Side Highway, Lost Hills, Kern County, California	Archaeological Field Study	Negative	Within Study Area	KE-04714
Whitley, David S.	2016a	Phase 1 Survey, Freeport McMoRan Oil and Gas Hopkins Lease, Kern County, California	Archaeological Field Study	Positive	Within Study Area	KE-04982
Whitley, David S.	2016b	Phase I Survey, Freeport McMoRan Oil and Gas King Ellis Lease, Kern County , California	Archaeological Field Study	Negative	Within Study Area	KE-04991
Whitley, David S.	2018	Cultural Resources Survey, Glasspoint Solar Phase 1 Project, Study Area, Kern County, California	Archaeological Field Study	Negative	Within Study Area	KE-05214

There have been no previously documented resources within the APE. However, there are three cultural resources documented within the Study Area, as described below (Table 2).

P-15-019637 is a projectile point made from crypto crystalline silicate. The resource was originally recorded in 2015 (Azpitarte 2015). The projectile point features middle stage flaking and displays breakage on both the proximal and distal ends (Azpitarte 2015) and appears to be a Vandenberg Contracting Stem within the larger Coastal Contracting Stem Cluster (Justice 2002: 242).

P-15-02116 consists of the remains of a historic period brick boiler pad/firebox associated with steam energy production and/or the heating of crude oil. The resource was originally recorded in 1985 and was noted as consisting of a few red fired/glazed bricks within fire affected soil and approximately 12 purple bottle glass fragments (Lewy and Uli 1985).

P-15-02117 consists of a large distribution of well fractured red glazed fire bricks and yellow kiln bricks in five separate concentrations, a few purple and blue bottle glass fragments, oxidated soils, and abandoned wells associated with the remains of a large, fired boiler plant and steam operated drilling site. The resource was originally recorded in 1985 (Howard and Uli 1985).

The records search did not identify any cultural resources that are listed or eligible for listing on local, State, or federal registers within the Study Area.

Table 2. Cultural Resources Previously Recorded Within the Study Area

Primary No.	Trinomial	Type	Age	Location	Description
P-15-019637	-	Isolate	Prehistoric	Within Study Area	AP16. Isolate: Crypto Crystalline Silicate Projectile Point
P-15-02116	CA-KER-002116	Site	Historic	Within Study Area	AH02. Foundations/structure pads); AH04. Privies/dumps/ trash scatters
P-15-02117	CA-KER-002117	Site	Historic	Within Study Area	AH02. Foundations/structure pads; AH04.Privies/dumps/ trash scatters

Review of aerial imagery and topographic maps indicate that the APE was predominantly undeveloped land until 1937. By 1942, moderate amounts of petroleum extraction-related development (roads, tanks, and oil derricks) as well as significant development (buildings, residential complex, ponds, and greater concentrations of oil derricks) are visible in surrounding areas. By 1953, the South Belridge Lease Camp expanded to include a school, swimming pool, landing strip, water tanks, and oil tanks. By 1984, the formerly undeveloped land to the northeast of the APE was cultivated for agricultural use and all residential buildings appear to have been demolished. Development and expansion are seen to have largely continued through 1979. No significant changes in the configuration of the APE and surrounding land are evident following 1979, however, pipelines tracing the proposed path of the CCS alignment are visible in photography from 2005.

7.2 Native American Notification/Sacred Lands File Search

On August 19, 2022, Stantec, on behalf of Aera, contacted the NAHC and requested a SLFS for the Study Area. The NAHC acknowledged via email to have received the request on August 23, 2022, and indicated a response is pending.

7.3 Field Methods

A pedestrian survey of the entire approximately 1,167-acre APE (including a 150-foot buffer on either side of the alignment) was conducted. Given the history of the area, Stantec archaeologists anticipated points of historical interest, such as wells, irrigation canal ditches, retaining ponds, old roadways, refuse scatters, historic oil wells and drills (derricks), isolated historic artifacts such as bottles and bricks, and lithic scatters and various isolated artifacts. Stantec archaeologists Mitch Evans, Jeremiah Camp, Joseph Cusack, Fiadh Kelly, Santos Ceniceros-Rodríguez, Santos, and Saeed Sawaed completed the survey. The initial survey was completed in 2022, on May 2 through 5, May 9 through 12, October 3 through 6, and October 25 through 28, 2022. Additional field surveys were completed during February 13-24 and May 5 and 19, 2023.

The survey was conducted by walking parallel transects along the proposed Project corridor, spaced approximately 15 to 20 meters apart. Stantec examined surface and subsurface exposures such as rodent burrows and cut banks for physical manifestations of prehistoric and historic cultural constituents. Surface visibility was good to excellent throughout the APE. Documentation included field notes, photographs, and sub-meter GPS data collection. The crew followed guidelines and standards specific to survey and recordation within oil fields (BLM, 2016). Cultural resources were recorded on DPR 523 forms (Appendix B – confidential). Two regions in the southeastern extent of the APE measuring 2.8km^2 and 2.7km^2 were surveyed via vehicle due to site-specific conditions (high density of oil pumpjacks/derricks in active operation, restricted access to the DTR area, and powered equipment in active operation).

The extent of the survey coverage was recorded with Environmental Systems Research Institute (ESRI) Field Maps for ArcGIS and an *Arrow Lite* GPS receiver with submeter horizontal accuracy utilizing Universal Transverse Mercator (UTM), North American Datum of 1983 (NAD 83), Zone 11, meters, as the spatial reference. Photographs were taken with Apple iPhones and/or iPads to document resources and the environment within the APE and surrounding areas. The extent of the survey coverage is shown on the Belridge, Blackwells Corner, Lost Hills, and Carneros Rocks 7.5-minute USGS topographic quadrangles (see Figure 2).

8 SURVEY RESULTS

Ground visibility in the APE during survey was good and ranged from 80 to 95 percent. In total, the survey team observed 107 cultural resources within the APE (Appendix B). One hundred-one (101) of the resources are historic period, 80 sites and 21 isolate historic resources. Three of the 107 inventoried resources are prehistoric. One prehistoric site consists of a shell midden, a stone sphere, and chipped stone tools (282103-BN-1A). One multi-component site (272028-BC-1A) was also identified. This site has

several prehistoric sandstone discoidal artifacts consistent with Milling Stone Horizon sites dating to 9000BP (Sutton 1978), and the historic component consists of an assemblage of metal pipelines, valves, various concrete debris, and fencing with braided cord associated with oil well #2-28, as well as anchor hooks and concrete footings used for hoisting and securing a tower derrick. Seventeen resources are historic wells or sites containing historic wells on multiple historic leases (Belridge, Mannel Minor, J.D. Martin (Texaco), & Shell Oceanic). The wells' years of drilling range from 1907 to 1965 (Table 3).

Table 3. Historic Wells Located Within Study Area

Field ID	Type	Location	Description	Township, Range	Section
272026-BC-2A	Site	In survey area	AH10 (Machinery), AH2 (Foundations). Well cellar and wellhead. Well #15. Drilled 1917.	T27S, R20E	26
272027-BC-24A	Site	In survey area	AH4 (Trash/debris scatter). Bricks and amethyst glass. Plugged historic well #21. On 1931 lease but drilled 1942.	T27S, R20E	27
272027-BC-25A	Site	In survey area	AH4 (Trash/debris scatter). Bricks and debris. Plugged well #19. Drilled 1918.	T27S, R20E	27
272027-BC-26A	Site	In survey area	AH2 (Foundations), AH10 (Machinery). Well pad/foundation and wellhead. Well #16. On 1931 lease but drilled 1941.	T27S, R20E	27
272021-BC-1A	Site	In survey area	AH2 (Foundations), AH4 (Debris Scatter). Various wooden structures and oilfield debris. Well #2	T27S, R20E	21
272021-BC-2A	Site	In survey area	Well #22	T27S, R20E	21
272022-BC-1A	Site	In survey area	AH2 (Foundations), AH4 (Debris Scatter), AH5 (Wells/Cisterns), AH6 (Water Conveyance Features), AH10 (Machinery). 3 oil wells and worker quarters with garbage dump	T27S, R20E	22
272027-BC-12A	Site	In survey area	AH16 (Other). Historic well #8-27. Drilled in 1930.	T27S, R20E	27

Field ID	Type	Location	Description	Township, Range	Section
272027-BC-16A	Site	In survey area	Well #6-27, drilled 1938	T27S, R20E	27
272027-BC-17A	Site	In survey area	Well #7-27, drilled 1937	T27S, R20E	27
272027-BC-18A	Site	In survey area	Well #9-27, drilled 1941	T27S, R20E	27
272028-BC-1A	Site	Not in survey area	AP2 (Lithic Scatter), AH2 (Foundations), AH4 (Debris Scatter), AH10 (Machinery) AH11 (Wall/Fence). Historic oilfield debris, piping, fences; prehistoric Milling Stone Horizon discoidal artifacts and ochre fragments. Well #2-28, drilled 1938	T27S, R20E	28
272028-BC-3A	Site	In survey area	Well #1-28, drilled 1937	T27S, R20E	28
272028-BC-4A	Site	In survey area	Well #16-28, drilled 1939	T27S, R20E	28
272035-BC-7A	Site	In survey area	AH16 (Other). Abandoned well #5. Drilled 1916.	T27S, R20E	35
272035-BC-8A	Site	In survey area	AH16 (Other). Historic well #1. Drilled 1917.	T27S, R20E	35
282001-BC-1A	Site	In survey area	Well #9-1, drilled 1940	T28S, R20E	1
282132-BN-7A	Site	In survey area	AH10 (Machinery). Threaded pipes. Well #363	T21S, R21E	32

9 NRHP/CRHR ELIGIBILITY RECOMMENDATIONS

Preliminary NRHP/CRHR eligibility recommendations for cultural resources identified in the APE are included in this section. Of the 107 cultural resources identified, three sites are historically significant discovery wells, of which two meet the criteria (Criterion A/1) for listing on the NRHP/CRHP due to the significance of the discovery of oil for the region and the greater implications for the California and United States. These discovery oil wells sparked the development and expansion of wells within the pool basin areas (Allan 2012). The prehistoric component of resources 282103-BN-1A and 272028-BC-1A contain evidence for considerable antiquity and have the potential to yield information important in prehistory of the region and the greater California. The cultural constituents at these two prehistoric sites have the potential to yield information on chronology, technology, exchange, and subsistence and settlement patterns within the San Joaquin Valley region, and therefore, these sites are recommended eligible under Criterion D/4. The 102 remaining resources were inventoried, evaluated, based on recommendations provided by the BLM but do not appear NRHP/CRHR eligible. These historic oil industry resources were inventoried as individual resources, although additional study may indicate these resources are contributing elements to a larger historic district.

Five (5) of the cultural resources identified in the APE appear to be eligible for listing in the NRHP/CRHR and are listed below (Table 4).

Table 4. Eligibility Recommendations

Period	ID#	T/S/R	Section	Lat/Long	UTM	NRHP/CRHR Eligibility Justification
Historic – Oil well and potential associated structure (demolished)	272021-BC-1A	T27S, R20E	21	35.559275, -119.816603	244707.79 mE / 3938718.30 mN	Criterion A/1. Site represents oil extraction infrastructure for the 1930s. Well #2 of the Tidewater Associated Oil Company, associated with the expansion of oil extraction in response to adjacent discovery well (272022-BC-1A).
Historic – Oil well and encampment	272022-BC-1A	T27S, R20E	22	35.559641, -119.813536	244987 mE/ 3938751 mN	Criterion A, D/1, 4. Belridge-A #1 discovery well, oil workers camp debris
Historic – A domestic water line and a	272027-BC-2A	T27S, R20E	27	35.544500, -119.798917	246264.64 mE / 3937033.28 mN	Criterion A/1. Historic site discovery well. It's well #64-27, 1800s land grant, 1930s well operation.

Period	ID#	T/S/R	Section	Lat/Long	UTM	NRHP/CRHR Eligibility Justification
discovery well						
Multi-component – Historic well and prehistoric groundstone and lithic scatter	272028-BC-1A	T27S, R20E	28	35.556522, -119.817214	244643.66 mE / 3938414.44 mN	Criterion D/4. The site contains unique constituents consistent with Milling Stone Horizon. The site has the potential to yield information important in prehistory. Additional investigation at the site would be needed to confirm the presence of potential Milling Stone horizon components.
Prehistoric – Lithic scatter and shell midden scatter	282103-BN-1A	T29S, R21E	3	35.439419, -119.703656	254583.00 mE / 3925133.67 mN	Criterion D/4. The resource artifacts are consistent with rare and presumed temporally and geographically diagnostic artifacts in Southern California. Additional testing and analysis needed to confirm recommendation.

10 MANAGEMENT RECOMMENDATIONS

10.1 Introduction

As part of the current cultural resource inventory, 1,167 acres of land within the Belridge oil fields (North and South) were inventoried to determine whether significant cultural resources would be affected by the proposed Project (see Figure 2). A total of 107 cultural resources were identified during the survey. Stantec is of the opinion that 5 of the 107 cultural resources in the APE may be eligible for inclusion in the NRHP/CRHR (see Table 3, Table 4, and Appendix B). None of the other resources identified within the APE are recommended eligible for listing in the NRHP/CRHR. Portions of the APE have a moderate sensitivity for intact subsurface cultural resources, and human remains may be unearthed when working in proximity of prehistoric resources.

If historic properties in the APE cannot be avoided by the Project, it is recommended that a Historic Property Treatment Plan (HPTP) be developed and implemented for the Project. A Memorandum of Agreement should be prepared to implement the HPTP, with, at a minimum, the Environmental Protection Agency and the State Historic Preservation Officer as signatory parties, and Kern County as a concurring

party (see 36 CFR §800.16). The HPTP, at a minimum, should address: 1) NRHP eligible resources, 2) cultural resource monitoring, 3) exclusionary fencing to protect historic properties, 4) accidental discovery procedures, 5) the treatment of human remains, and 6) Native American involvement.

Recommendations for the treatment of cultural resources and human remains are presented below.

10.2 NRHP/CRHR Eligible Resources

The Project may result in physical disturbance of historic properties. If these resources cannot be avoided by the proposed Project, the lead agency will consult the State Historic Preservation Officer at the California Office of Historic Preservation to address the adverse effects of the proposed Project. The results of this consultation may result in the need for further study.

272021-BC-1A

Site Description

272021-BC-1A is a historic oil extraction and distribution infrastructure site from Aera Well #2 date to the 1930's. The site consists of four features: a series of abandoned, partially buried pipelines of unknown length (Feature 1), an idle oil well (Feature 2), two wrecked wooden structures (Features 3 & 4) and plugged Aera Well #2 with well pad (Feature 5). The site contains one artifact, a historic tin can with church-key opening (Artifact 1). The site is associated with oil production in the Belridge fields certainly as far back as the 1950s according to aerial photography, the use of wooden structures on the site suggests a possible older date for the site; remaining constituents, however, date to the 1950s.

NRHP/CRHR Eligibility Evaluation

It is Stantec's opinion that 272021-BC-1A is eligible for listing in the NRHP under Criterion A and listing in the CRHR under Criterion 1 as the site is associated with events that have made a significant contribution to the broad patterns of local or regional history of California and the United States. As discussed above, the discovery of the Sub-Monterey Pools in the 1930's established new zones of oil extraction in North Belridge, wells expanded within the production limits of the Sub-Monterey Pool and became important petroleum resources for WWII (Allan 2012). Feature 1 is Well #2 of the Tidewater Associated Oil Company, associated with the expansion of oil extraction in response to adjacent discovery well (272022-BC-1A) for the Sub-Monterey Pool production zone 64.

The cultural materials at 272021-BC-1A can be analyzed to address such historic archaeology research domains as oil worker camp activities, chronology, technology, and distribution of oil extraction, distribution, and refinery machinery and equipment. Site chronology has been addressed in this text, although diagnostic remains can tighten the period of utilization at the site. The period of significance for 272021-BC-1A has been established from the 1930's-1950's. The clear impact oil development has had on the surrounding area and economy underscores the importance of 272021-BC-1A to the region and the history of oil exploration in California.

Integrity

272021-BC-1A appears to possess substantial integrity by satisfying multiple aspects or qualities of this historic resource. The site moderately retains its integrity of location as the oil well derrick superstructure has been demolished and well capped, the subsurface components of the well are present and exist in the same location as when first drilled. In addition, a second idle well is present within the site maintaining land use patterns within the site location. None of these changes and during the production life of an oil well has adversely affected the site's overall setting and feeling. The superstructure of the well has been demolished potentially affecting the assessment of design and materials, although during the historic use of the well it was and maintains to be routine procedure to maintain and upgrade producing wells and cap underperforming, unprofitable wells, therefore, design and remains consistent with the region. The historic constituent features combined and deposited that remain are intact and have maintained configuration from the historic use of the area. The overall environment and feel have remained consistent with development being consistent with the historic land use of oil extraction and distribution. The site possesses integrity of association, the existing well is a discovery well for the sub-Monterey formations, a catalyst for further expansion of oil extraction infrastructure from the 1930's and 1950's.

272022-BC-1A

Site Description

The site consists of a cement foundation (Feature 1), a red brick stain (Feature 2), cement and brick rubble debris concentration (Feature 4), historic refuse scatter (feature 5), sump (Feature 6), and water storage reservoir (Feature 7), an indirect heating boiler (Feature 8), and multiple pipelines (Features 9, 10, & 11). Two wells occupy the site, a discovery well labeled as Belridge-A #1 to the north and one well to the south. The site exhibits evidence of substantial diagnostic surface artifacts as well as evidence for subsurface features. The oil well was abandoned in the 1930s and has been exploited under multiple leases since then.

NRHP/CRHR Eligibility Evaluation

It is Stantec's opinion that 272022-BC-1A. is eligible for listing in the NRHP under Criterion A and listing in the CRHR under Criterion 1 as the site is associated with events that have made a significant contribution to the broad patterns of local or regional history of California and the United States. The site is recommended eligible under Criterion D and 4 as the site may be likely to yield information important to history. Belridge-A#1, on the Richfield Oil Co of California lease (1944), has been identified as a discovery well for the Sub-Monterey Formation reservoirs. Stantec's intensive survey identified surface and subsurface constituents consisting of historic structure foundations and a historic debris field containing diagnostic constituents.

The cultural materials at 272022-BC-1A can be analyzed to address such historic archaeology research domains as oil worker camp lifestyle, chronology, technology, and distribution of oil extraction, distribution, and refinery machinery and equipment. Site chronology has been addressed in this text via various records and maps, although diagnostic artifacts can calibrate the period of utilization at the site.

The clear impact oil development has had on the surrounding area and economy underscores the importance of 272021-BC-1A to the region and the history of oil exploration in California.

Integrity

272022-BC-1A appears to possess good overall integrity, despite disturbances that include the obvious disassembling of the oil derrick and demolition of associated structure(s). Undisturbed portions of the site, including the areas of demolition debris and refuse deposition, can provide direct chronostratigraphic data necessary to identify periods of occupation and associated assemblages. The site retains integrity of location as the refuse deposit feature does not appear to have been altered, the materials of the demolished structure are present in the location of deposition. The site's overall setting and feel has not been compromised and is likely consistent with the time of occupation, although expanded. Overall, these features retain integrity of workmanship. Integrity of design and materials is minimal to moderate as the oil well derrick has been removed and possible oil workers camp/structure have been demolished.

272027-BC-2A

Site Description

272027-BC-2A is a historic discovery well (64-27N) site. The well drilled in 1932 and the discovery well for 64 Zone in sub-Monterey formation. Between 1936-1984 540 BCFG injected for gas storage and pressure maintenance. In 1938 the well performance peaked with production of the well reaching 135 MMCFG/day and 13,950 BO/day. The site consists of a concrete well foundation and oil derrick labelled "64-27". The well is specifically a prospect well whose details were made confidential during its peak production and drilling periods and has continued producing significant amounts of oil; the site therefore is one of the few remaining of its kind representing significant events in the history of oil exploration in California.

NRHP/CRHR Eligibility Evaluation

It is Stantec's recommendation that 272027-BC-2A. is eligible for listing in the NRHP under Criterion A and listing in the CRHR under Criterion 1. Stantec's intensive survey of the site identified surface and subsurface (well and foundations) cultural constituents consisting of historic oil extraction and distribution infrastructure. The cultural materials identified at 272027-BC-2A have been identified by *BLM Oil Fields Site Documentation, Survey Standards and Reporting Bakersfield Field Office* to warrant inventory. Aera has identified the discovery wells and associated oil pool zones as significant markers in the property's historic utilization and expansion (Allan 2012). Stantec does not anticipate this eligibility will preclude the use of the well for injection.

Integrity

272027-BC-2A appears to possess substantial integrity by satisfying multiple aspects or qualities of this historic resource. The site clearly retains its integrity of location as the oil well derrick superstructure remains, although portions have been retrofitted to updated components, the subsurface components of the well are present and exist in the same location as when first drilled. Minor domestic development in

the form of a water line has occurred, although this may lend to the utilization of the area by oil workers while working the well; none of this has adversely affected the site's overall setting and feeling. The superstructure of the well has been retrofitted potentially affecting the assessment of design and materials, although during the historic use of the well it was and maintains to be routine procedure to maintain and upgrade producing wells, therefore design and remains consistent with the region. The historic constituent features combined and deposited that remain are intact and have maintained configuration from the historic use of the area. The overall environment and feel have remained consistent with development being consistent with the historic land use of oil extraction and distribution. The site possesses integrity of association, the existing well is a discovery well for the sub-Monterey formations, a catalyst for further expansion of oil extraction infrastructure through the 1930's.

272028-BC-1A

Site Description

272028-BC-1A is a multi-component site surrounding Aera Energy Well #2-28, which is an idle well. The site is approximately 423 ft north-to-south and 335 ft east-to-west. The site consists of ten features and fourteen artifacts. The prehistoric artifacts include sandstone disks, some lithic flakes, a hammer stone, and ochre that has been worked. Prehistoric features include a sparse ochre scatter (Feature 11) and a scatter of a complete stone disk and multiple stone disk fragments (Feature 10) exhibiting various production methodologies and sizes. These artifacts may be affiliated with the Milling Stone Horizon, which dates to 9000BP (Sutton 1978) and has been identified in numerous instances in coastal southern California, potentially lending further evidence for the Middle Holocene Western Nexus. The historic-period component of this resource includes glass and metal parts, while historic features include a debris pile (Feature 1), a steel pipe fence post connected by braided cord (Feature 4), concrete footings (Features 2 & 3), anchor hooks (Features 5 & 6), and pipelines (Features 7 & 8), a valve (Feature 9).

NRHP/CRHR Eligibility Evaluation

It is Stantec's opinion that 272028-BC-1A. is eligible for listing in the NRHP under Criterion D and listing in the CRHR under Criterion 4 as the site may be likely to yield information important in prehistory. Stantec's intensive survey identified surface cultural constituents consisting of groundstone, chipped stone flakes, and historic oil extraction and distribution infrastructure. The cultural materials identified as 272028-BC-1A can be analyzed to address such basic prehistoric archaeology research domains as chronology, technology, and exchange, and subsistence and settlement patterns within the San Joaquin Valley, southern California. Site chronology can be addressed through radiocarbon dating of the marine shell present at the site. Lithic technology can be addressed through analysis of lithic reduction, use wear, and material sourcing. Chemical sourcing (X-Ray fluorescence) can be used to analyze trade patterns of toolstone. The site contains constituents consistent with Milling Stone Horizon. Analysis of archaeological assemblages may add to the greater dataset for this period. Comparative analysis with other discoidal artifacts throughout southern California may provide insight into the purpose of this rare artifact type. Additional investigation at the site would be needed to confirm the presence of potential Milling Stone horizon components.

Integrity

272028-BC-1A appears to possess good overall integrity from both the prehistoric and historic components, despite minor surface disturbances in the form of surface grading. The surface grading likely exposed the numerous prehistoric stone discoidal fragments scatter throughout portions of the site. Spoils piles are still present on site possibly containing cultural constituents. Other disturbances to the prehistoric component are due to the establishment of the historic oil well, associated oil distribution infrastructure, and construction of the dirt access roads. The well structure is no longer present and the well abandoned, although a majority of the historic constituents, piping, foundations, rigging, are present and undisturbed. Portions of the disturbed area north of the well foundation has exposed several chipped stone flakes of varying material types. Based on the moderate impacts to the prehistoric component and minimal impacts to the historic component, the site has good integrity. Overall, with the exception of the oil derrick superstructure, these constituents retain integrity of materials, design, setting, feeling, and workmanship.

282103-BN-1A

Site Description

282103-BN-1A is a prehistoric lithic, groundstone and shell midden deposit containing one feature and five artifacts. Artifact 1 is a sandstone sphere measuring 6.53 cm in diameter. Artifact 2 is a piece of Pismo clam shell, Artifact 3 is a sandstone chopping tool, Artifact 4 is a rhyolite flake, and Artifact 5 is a CCS flake. *Mitylus* sp. was also observed. Feature 1 is a large combined sparse shell midden and sparse lithic scatter. Collection of Artifact 1 is recommended by the recorders of this resource due to proximity to operating facilities.

NRHP/CRHR Eligibility Evaluation:

It is Stantec's recommendation that 282103-BN-1A is eligible for listing in the NRHP under Criterion D and listing in the CRHR under Criterion 4 as the site may be likely to yield information important in prehistory. Stantec's intensive survey identified surface cultural constituents consisting of groundstone, chipped stone flakes, and marine shell. The cultural materials identified as 282103-BN-1A can be analyzed to address such basic prehistoric archaeology research domains as chronology, technology, and exchange, and subsistence and settlement patterns within the San Joaquin Valley, southern California, and the Great Basin. Site chronology can be addressed through radiocarbon dating of the marine shell present at the site. Lithic technology can be addressed through analysis of lithic reduction, use wear, and material sourcing. Chemical sourcing (X-Ray fluorescence) can be used to analyze trade patterns of toolstone. Analysis of archaeological assemblages may clarify the questions concerning the Middle Holocene Western Nexus. The fine-grained sandstone sphere (Artifact 1) is of an artifact type that has been associated with the Middle Holocene Western Nexus, an interaction sphere linking coastal southern California and the northwestern Great Basin some 5,000 years ago (Sutton & Koerper 2009). Further analysis is recommended for the marine shell present at the site.

Integrity

282103-BN-1A appears to possess good overall integrity, despite disturbances that include a surface scrape and spoils berm on the northern extent of the resource. Although disturbed, the surface artifacts and midden would indicate a potential for further subsurface deposits to be intact. The shell constituents can provide chronostratigraphic data necessary to identify periods of occupation and associated assemblages. The Site is bounded on all four sides by paved roads and oil pipeline infrastructure runs through the western extent; however, the site integrity has sustained minor impacts by a relatively inconsequential surface scrape, and the soils remain onsite. Overall, the site appears to retain good integrity.

10.3 Cultural Resource Monitoring

10.3.1 Historical Resources

Twelve historic-period and multi-component period resources were identified within the APE that are eligible for listing in the NRHP/CRHR. Cultural resource monitoring is recommended for Project activities conducted in the vicinity of these resources.

10.3.2 Prehistoric Resources

Newly identified prehistoric archaeological sites 282103-BN-1A and multi-component archaeological site 272028-BC-1A are within the APE. The two resources both exhibit unique artifacts consistent with other lower archaic prehistoric archaeological sites and both may contain a subsurface component. Due to this study's eligibility recommendations for these two prehistoric resources, monitoring is recommended for Project activities conducted in the vicinity of these resources.

10.3.3 Exclusionary Fencing

Exclusionary fencing should be placed at 282103-BN-1A, 272028-BC-1A, and 272022-BC-1A. The fencing should be placed in coordination with a qualified archaeologist. Because 272022-BC and 282103-BN-1A are in proximity to the proposed Project components, it is recommended that these resources be avoided, and the scope of Project activities in these areas be reconsidered.

10.4 Accidental Discoveries

10.4.1 Archaeological Deposits

The methods and techniques used by Stantec are considered sufficient for the identification of cultural resources visible at the ground surface. However, there is always a possibility that buried archaeological deposits could be found during construction and earth disturbing activities. As a result, prior to the initiation of any additional ground-disturbing activities, field personnel should be alerted to the possibility of buried prehistoric or historic cultural deposits.

In the event that field personnel encounter buried cultural materials, work in the immediate vicinity of the find should cease and a qualified archaeologist contacted to evaluate the finds and make recommendations. The archaeologist shall have the authority to stop or divert construction excavation as necessary. All such deposits should be avoided by project activities until the archaeologist has evaluated the situation and provided direction for further procedures. Upon completion of the evaluation, a report should be prepared documenting the methods and results, as well as recommendations. The report should be submitted to the project proponent, EPA, Kern County, and the SSJVIC. If the qualified archaeologist finds that any cultural resources are present meet eligibility requirements for listing on the NRHP/CRHR, plans for the treatment, evaluation, and mitigation of the impacts to the find will need to be developed.

10.4.2 Human Remains

In the event that human remains, or unassociated funerary objects or grave goods are encountered, State Health and Safety Code Section 7050.5 states that no further disturbance shall occur until the County Coroner has made a determination of origin and disposition pursuant to Public Resources Code Section 5097.98. The County Coroner must be notified of the find immediately. If the remains are determined to be prehistoric, the coroner will notify the Native American Heritage Commission (NAHC) within 24 hours of the identification. The NAHC will determine a Most Likely Descendant (MLD). With the permission of the landowner or his/her authorized representative, the MLD may inspect the site and provide recommendations for the proper treatment of the remains and associated grave goods. The MLD shall complete the inspection within 48 hours of notification by the NAHC.

In addition to the County Coroner, qualified archaeologist(s) shall be contacted immediately to comply with applicable laws and regulations (e.g., the Native American Graves Protection and Repatriation Act as outlined at 43 CFR 10) and Archaeological Resources Protection Act 43 CFR 7).

10.5 Native American Consultation and Monitoring

Native American consultation should be implemented during Project construction. Native American monitoring should occur during ground disturbing activities at known prehistoric resources.



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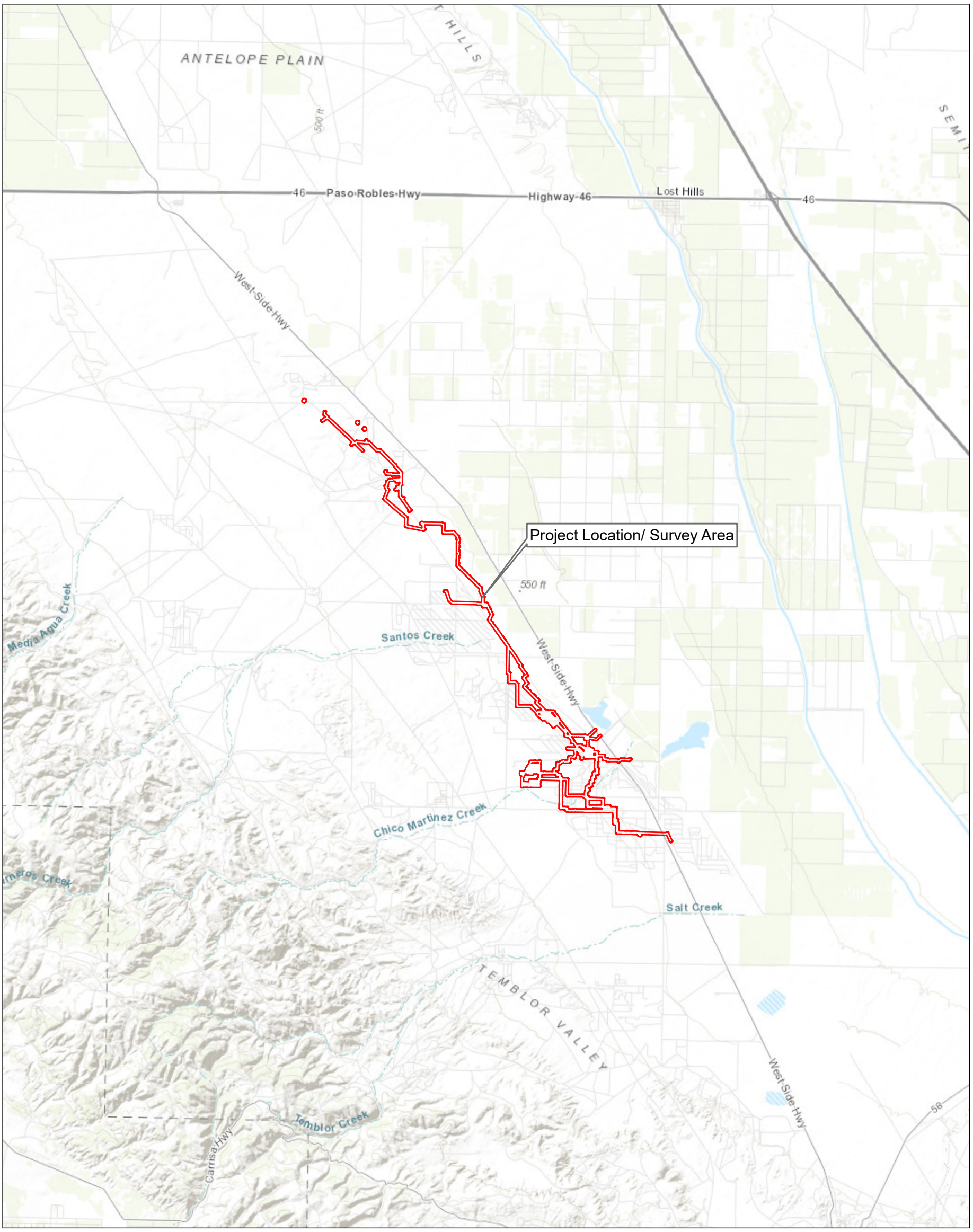
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APPENDIX A
Figures







Project Location/ Survey Area

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Stantec AERA

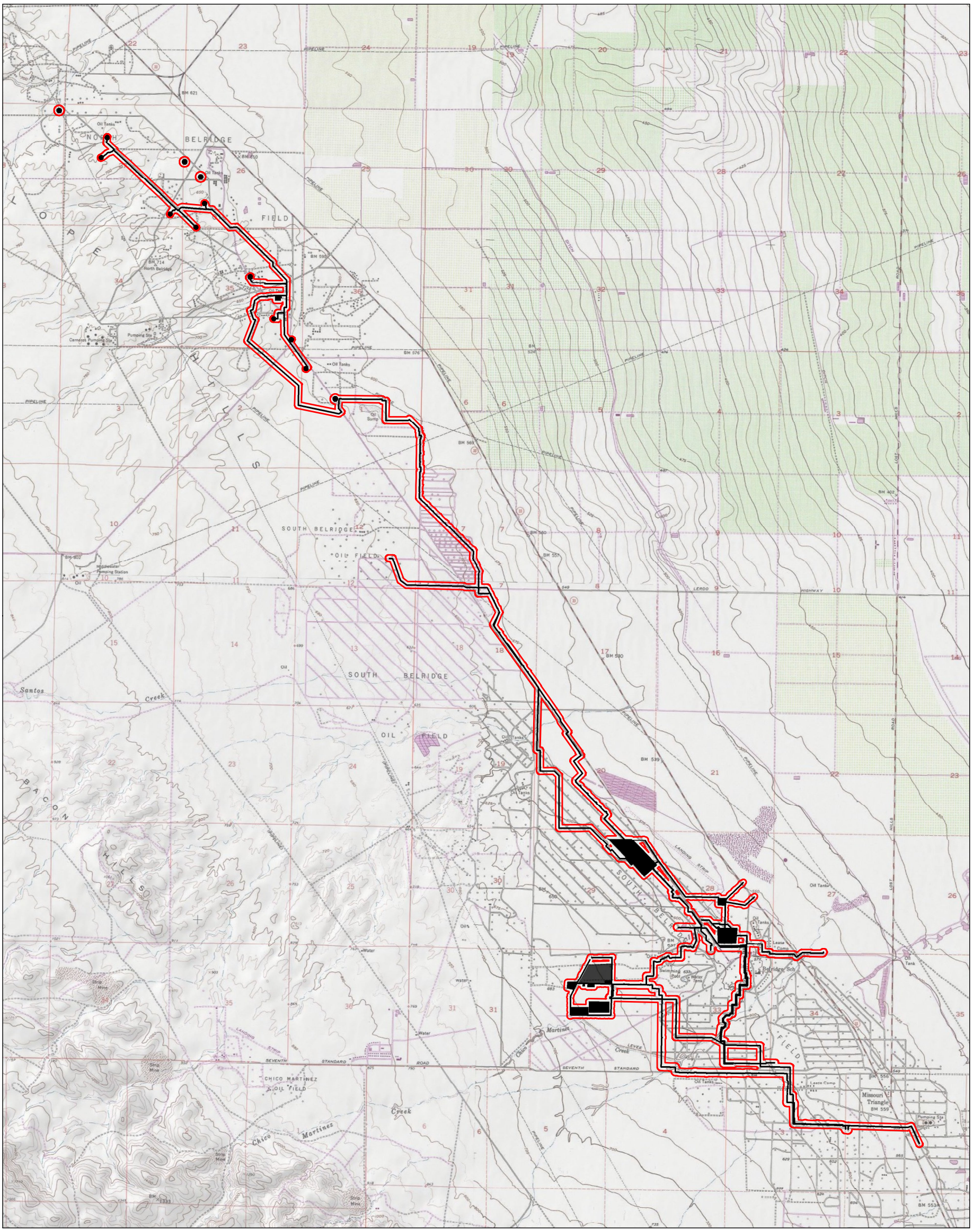
Project Location Kern County, California	Prepared by DL on 2023-06-06 TR by SET on 2023-06-06 IR by ME on 2023-06-06
Client/Project Aera Energy LLC Aera CarbonFrontier Project Archaeological Survey Report	185805407
Figure No. **1**	
Title **Project Location / Study Area**	

Notes

1. Coordinate System: NAD 1983 StatePlane California V FIPS 0405 Feet
2. Data Sources: CalGEM, 2019, Parcels from Kern County 2020. Stantec 2022,2023.
3. Background: Sources: Esri, GEBCO, NOAA, National Geographic, Garmin, HERE, Geonames.org, and other contributors
Sources: Esri, HERE, Garmin, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), (c) OpenStreetMap contributors, and the GIS User Community
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors

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Survey Area

Area of Potential Effect (APE)

0 4,500 9,000 Feet

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Stantec AERA

Project Location
Kern County, California

Prepared by DL on 2023-06-06
TR by SET on 2023-06-06
IR by CH on 2023-06-06

Client/Project
185805407
Aera Energy LLC
Aera CarbonFrontier Project
Archaeological Survey Report

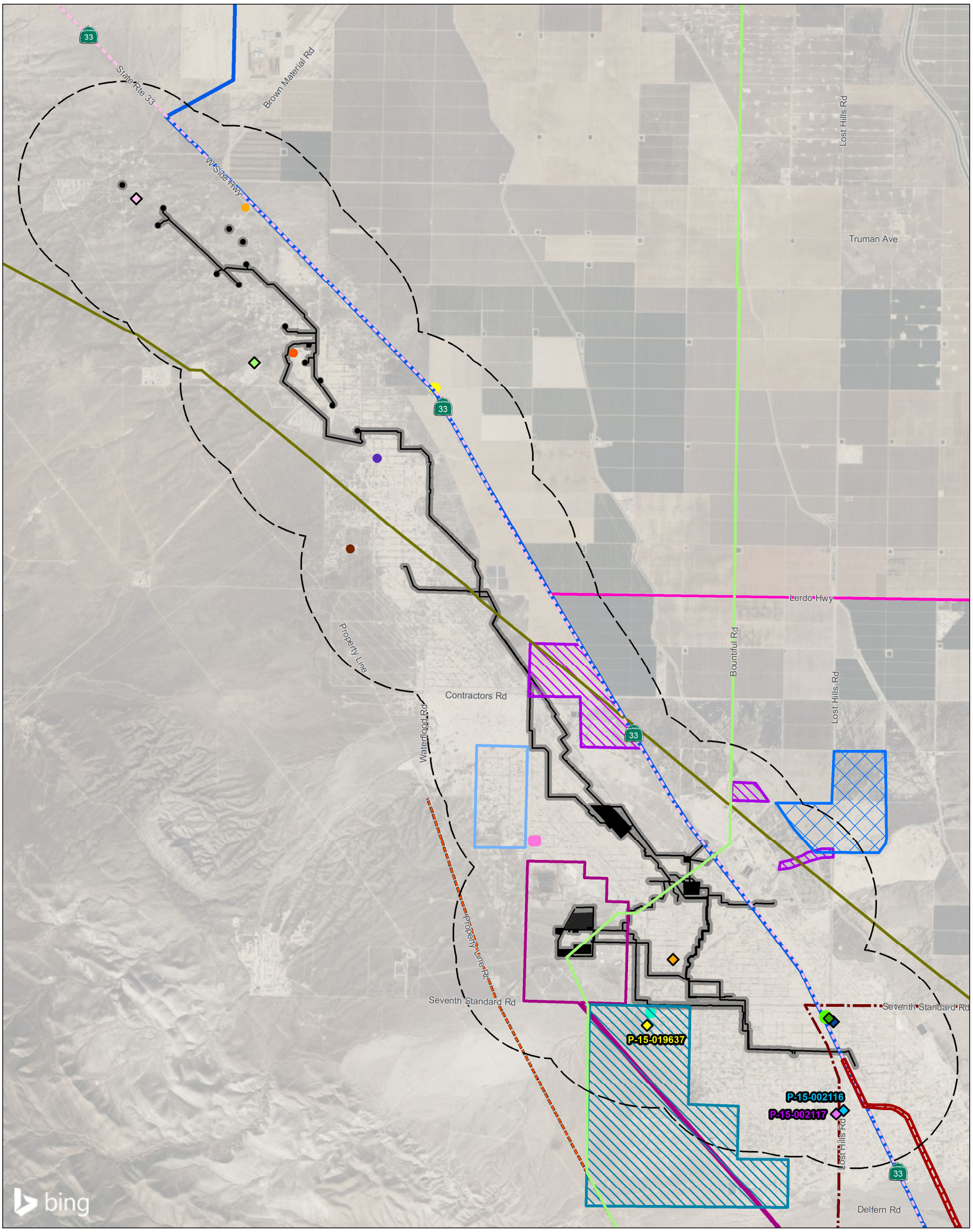
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2

Title
Area of Potential Effect

Notes
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2. Data Sources: CalGEM, 2019, Parcels from Kern County 2020. Stantec 2022,2023.
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Area of Potential Effect (APE)

Survey Area

1-mi Records Search Buffer

Reports

KE-02945

KE-04307

KE-02659

KE-03709

KE-04303

KE-00172

KE-01840

KE-02278

KE-03777

KE-03837

KE-00403

KE-01268

KE-01485

KE-04173

KE-04300

KE-04301

KE-04304

KE-04305

KE-04641

KE-04714

KE-04982

KE-04991

KE-01565

KE-04306

KE-04590

KE-05214

0 1 2 Miles

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Stantec AERA

Project Location
Kern County,
California

Prepared by DL on 2023-06-06
TR by SET on 2023-06-06
IR by CH on 2023-06-06

Client/Project
185805407
Aera Energy LLC
Aera CarbonFrontier Project
Archaeological Survey Report

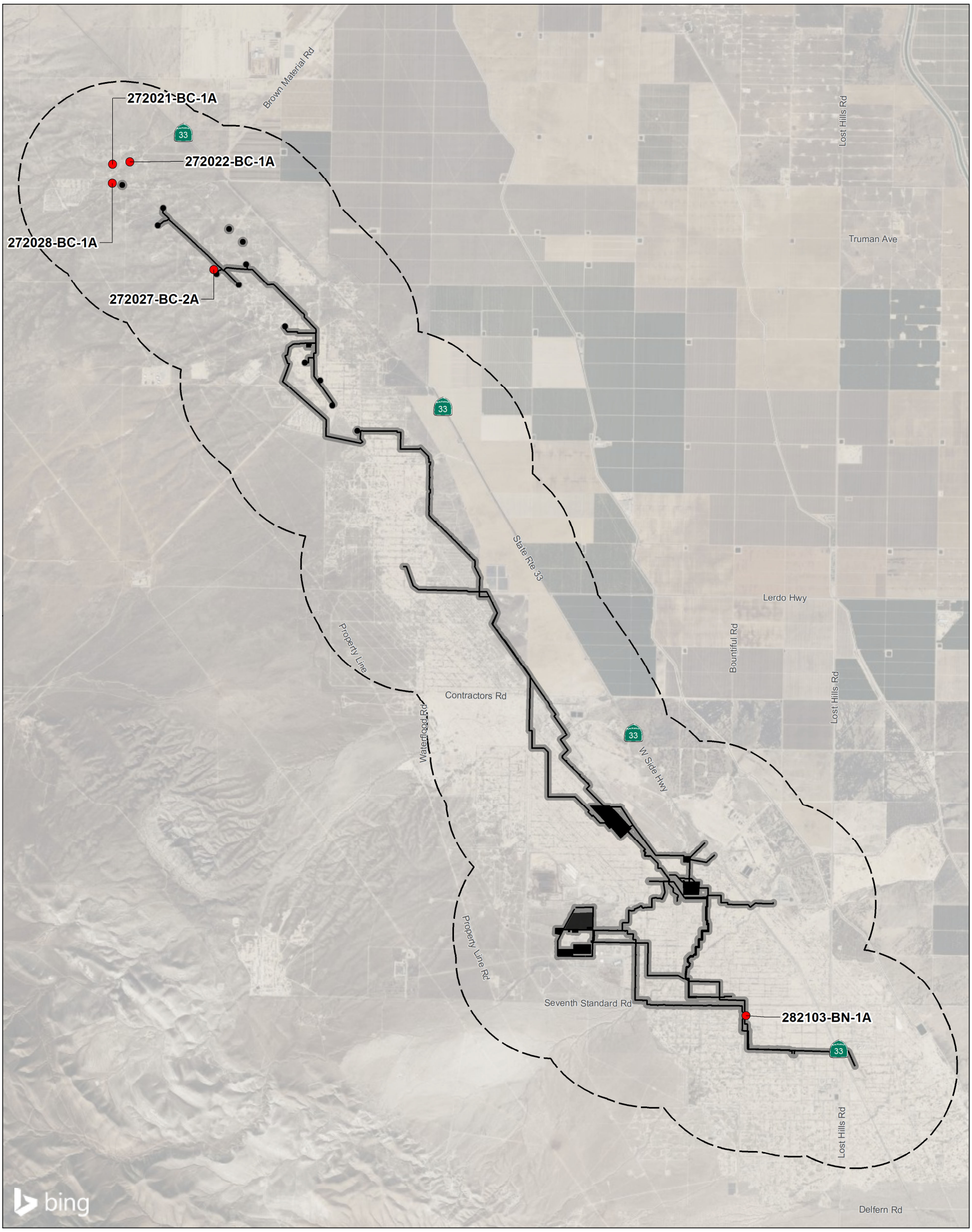
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3

Title
Record Search Results

Notes
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2. Data Sources: CalGEM, 2019, Parcels from Kern County 2020. Stantec 2022,2023.
3. Background: © 2023 Microsoft Corporation © 2023 Maxar ©CNES (2023) Distribution Airbus DS

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Area of Potential Effect (APE)

Survey Area

1-mi Records Search Buffer

Survey Findings

CONFIDENTIAL

0 1 2 Miles

(At original document size of 11x17)
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Stantec AERA

Project Location
Kern County,
California

Prepared by DL on 2023-06-06
TR by SET on 2023-06-06
IR by CH on 2023-06-06

Client/Project
185805407
Aera Energy LLC
Aera CarbonFrontier Project
Archaeological Survey Report

Figure No.
4

Title
Survey Findings

Notes
1. Coordinate System: NAD 1983 StatePlane California V FIPS 0405 Feet
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APPENDIX B
- CONFIDENTIAL -
Department of Parks and Recreation 523 Site Records

D-2 Sacred Lands File Search; NAHC Response

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VICE CHAIRPERSON
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Raymond C. Hitchcock
Miwok/Nisenan

NAHC HEADQUARTERS
1550 Harbor Boulevard
Suite 100
West Sacramento,
California 95691
(916) 373-3710
nahc@nahc.ca.gov
NAHC.ca.gov

October 20, 2022

Michael T. Evans
STANTEC

Via Email to: Mitch.Evans@stantec.com

Re: Belridge Carbon Capture and Sequestration Project, Kern County

Dear Mr. Evans:

A record search of the Native American Heritage Commission (NAHC) Sacred Lands File (SLF) was completed for the information you have submitted for the above referenced project. The results were negative. However, the absence of specific site information in the SLF does not indicate the absence of cultural resources in any project area. Other sources of cultural resources should also be contacted for information regarding known and recorded sites.

Attached is a list of Native American tribes who may also have knowledge of cultural resources in the project area. This list should provide a starting place in locating areas of potential adverse impact within the proposed project area. I suggest you contact all of those indicated; if they cannot supply information, they might recommend others with specific knowledge. By contacting all those listed, your organization will be better able to respond to claims of failure to consult with the appropriate tribe. If a response has not been received within two weeks of notification, the Commission requests that you follow-up with a telephone call or email to ensure that the project information has been received.

If you receive notification of change of addresses and phone numbers from tribes, please notify me. With your assistance, we can assure that our lists contain current information.

If you have any questions or need additional information, please contact me at my email address: Cameron.vela@nahc.ca.gov.

Sincerely,

Cameron Vela

Cameron Vela
Cultural Resources Analyst

Attachment

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Appendix E
Geology and Paleontological Resources

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E.1 Desktop Geohazards and Geotechnical Assessment

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Stantec

AERA CARBONFRONTIER PROJECT

Desktop Geohazards and Geotechnical Assessment

July 21, 2023

Prepared for:

Aera Energy LLC
10000 Ming Avenue
Bakersfield, CA 93311

Prepared by:

Stantec Consulting Services Inc.
2646 Santa Maria Way, Suite 107
Santa Maria, CA 93455

Project No.: 185805372



Revision	Description	Author	Date	Quality Check	Date	Independent Review	Date
0	First Draft	Z. Dascalos	03/15/23	K. Grasso	03/16/23	J. Fischer	4/10/23
1	Revisions	E. Snelling	6/25/23	C. Taylor	6/26/23	J. Fischer	6/26/23
2	Revisions	E. Snelling	7/19/23	C. Taylor	7/21/23	J. Fischer	7/21/23



This document entitled AERA CARBONFRONTIER PROJECT (the "Project") Desktop Geohazards and Geotechnical Assessment was prepared by Stantec Consulting Services Inc. ("Stantec") for the account of Aera Energy LLC (the "Client"). Any reliance on this document by any third party is strictly prohibited. The material in it reflects Stantec's professional judgement in light of the scope, schedule and other limitations stated in the document and in the contract between Stantec and the Client. The opinions in the document are based on conditions and information existing at the time the document was published and do not take into account any subsequent changes. In preparing the document, Stantec did not verify information supplied to it by others. Any use which a third party makes of this document is the responsibility of such third party. Such third party agrees that Stantec shall not be responsible for costs or damages of any kind, if any, suffered by it or any other third party as a result of decisions made or actions taken based on this document.

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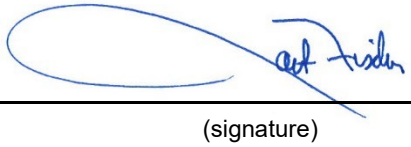
Zoe Dascalos

Staff Environmental Scientist

Reviewed by  _____
(signature)

Kyla Grasso, MS, PG, QISP

Associate Geologist, Geohazards and Geomorphology

Reviewed by  _____
(signature)

Jaret Fischer, PE

Principal Engineer

Approved by  _____

Eric Snelling

Project Manager

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Figure 3h. Project Geology Map....20
Figure 3i. Project Geology Map....21

Abbreviations

Aera	Aera Energy LLC
amsl	Above mean sea level
BBLS	Barrels
bgs	Below Ground Surface
BWSD	Belridge Water Storage District
CalGEM	Department of Conservation Division of Oil, Gas and Geothermal Resources
CCS	Carbon Capture and Sequestration
CDWR	California Department of Water Resources
CFR	Code of Federal Regulation
CGS	California Geologic Survey
CO_2	Carbon Dioxide
County	Kern County
CUP	Conditional Use Permit
CUPA	Certified Unified Program Agency
DOGGR	Department of Conservation Division of Oil, Gas and Geothermal Resources
EIR	Environmental Impact Report
EPA	Environmental Protection Agency
InSAR	Interferometric Synthetic Aperture Radar
M	Magnitude
mm	millimeter
Mmt	Million metric tons
NRCS	Natural Resources Conservation Service
PGA	Peak Ground Acceleration
RADARSAT SAR	Radar Satellite Synthetic Aperture Radar
RWQCB	Regional Water Quality Control Board
SR	State Route
SJVAPCD	San Joaquin Valley Air Pollution Control District

Stantec	Stantec Consulting Services Inc.
SWRCB	State Water Resources Control Board
UIC	Underground Injection Control
USDA	United States Department of Agriculture
USDW	Underground Sources of Drinking Water
USGS	United States Geological Survey



1.0 INTRODUCTION

Stantec Consulting Services Inc. (Stantec) has prepared this Desktop Geohazards and Geotechnical Assessment on behalf of Aera Energy LLC (Aera) for the CarbonFrontier Project (Project), located in the South and North Belridge oil fields in western Kern County, California (Project Site). The Project Vicinity Location is shown in Figure 1. The Study Area includes the proposed Project components within the North and South Belridge oil fields.

1.1 PROJECT DESCRIPTION

Aera has submitted an application to the Kern County Planning and Natural Resources Department to request approval of a Zone Change and Conditional Use Permit (CUP) and will obtain any other required approvals for the construction and operation for the proposed Project in the South and North Belridge oil fields.

The proposed Project would capture carbon dioxide (CO_2) from existing produced-gas streams (pre-combustion) and emissions from existing stationary sources (post-combustion) and transport the CO_2 from South Belridge through a pipeline to the North Belridge Oil Field for injection via nine dedicated Underground Injection Control (UIC) Class VI injection wells. It is anticipated that the proposed Project would capture approximately 30 million metric tons of CO_2 throughout its estimated 20-year lifetime[1].

The Project site is primarily contained within the South and North Belridge oil fields, in the Central Valley portion of western Kern County. The South Belridge and North Belridge oil fields are contiguous and cover an area of approximately thirteen miles long and three miles wide. The proposed CO_2 capture facilities are located within the developed portion of the South Belridge Oil Field and include the separation, dehydration, compression, and cooling of CO_2 from both pre-combustion (Pre-C) and produced gas streams from post-combustion (Post-C) flue gas. The proposed CO_2 sequestration field is located within the North Belridge Oil Field, which is predominately developed with oil and gas production.

Gas produced from the Tulare and Diatomite formations via existing oil wells within South and North Belridge would be mixed and conditioned using existing and modified process equipment. Mixing of the Diatomite and Tulare gas streams would start at the Del Sur Field Compressors. Using the existing (modified) compressors, the mixed stream would be transported, via an existing gas pipeline to a pre-combustion CO_2 capture facility to be located near Gas Plant 32. The carbon capture facility will include three steel towers of varying height (not exceeding 120 feet), and between 2 to 12 feet in diameter. The gas stream would first be treated to remove sulfur at existing sulferox (SOX) plants. The de-sulfurized stream would then be cooled to reduce water content and condense heavy hydrocarbons. Then, CO_2 would be removed from the hydrocarbon gas streams using a physical solvent or a traditional amine

[1] Note, the operational life of the proposed Project will be controlled by the sequestration reservoir's storage capacity (currently undergoing review) and volume of CO_2 captured per year which will fluctuate.

In each of the three post-combustion CO_2 capture facilities within Co-generation Plant 32 (at Gas Plant 32) and Steam Generator Stations (SGS) 2868 and 2972, the flue gas would be cooled, then passed through an absorber column where an absorbent will chemically react with and bind about 90% of the CO_2. The remaining flue gas (primarily oxygen, nitrogen, and the remaining uncaptured CO_2), would be vented to atmosphere. The rich absorbent carrying CO_2 is piped to the regenerator column, where through the application of heat, the CO_2 would be released and captured in relatively pure concentration. The CO_2 would be then compressed, dehydrated, stripped of oxygen, and piped to the sequestration site. Oil and gas production activities within the proposed sequestration zone, known as the 64 zone, would cease as a result of the implementation of the proposed Project.

A new approximately 10-mile, 6- to 12-inch pipeline would be constructed to deliver CO_2 from the capture facilities to the proposed injection wells. The pipeline would be primarily installed aboveground, except where the pipeline would cross main access roads (below ground) within the oil field properties. Distribution piping, each approximately 4- to 8-inches in size, would extend from the main pipeline to the proposed injection wells. The distribution pipelines would also be primarily aboveground on pipe supports, except where the pipelines cross main access roads (below ground) within the oil field.

The proposed Project includes re-purposing five existing oil wells and drilling four new wells for CO_2 injection. Additionally, four existing wells would be converted to monitoring wells to monitor the CO_2 plume. Up to four additional monitoring wells may also be constructed, either as repurposed oil wells and/or new wells. The proposed Project would also require plugging and abandonment of up to 40 existing oil wells within the North Belridge Oil Field in accordance with state and federal requirements to prevent leakage of CO_2 from the sequestration zone. Additionally, up to 40 wells previously abandoned within the North Belridge Oil Field would be re-abandoned to meet current state and federal plugging requirements. Finally, 13 wells that are adjacent to SGS 2868 and SGS 2972 will need to be abandoned prior to construction of the CO_2 capture facilities at these two locations.

Refer to Figures 2a through 2h for the location of the Study Area.

1.2 PURPOSE AND SCOPE OF WORK

1.2.1 Purpose

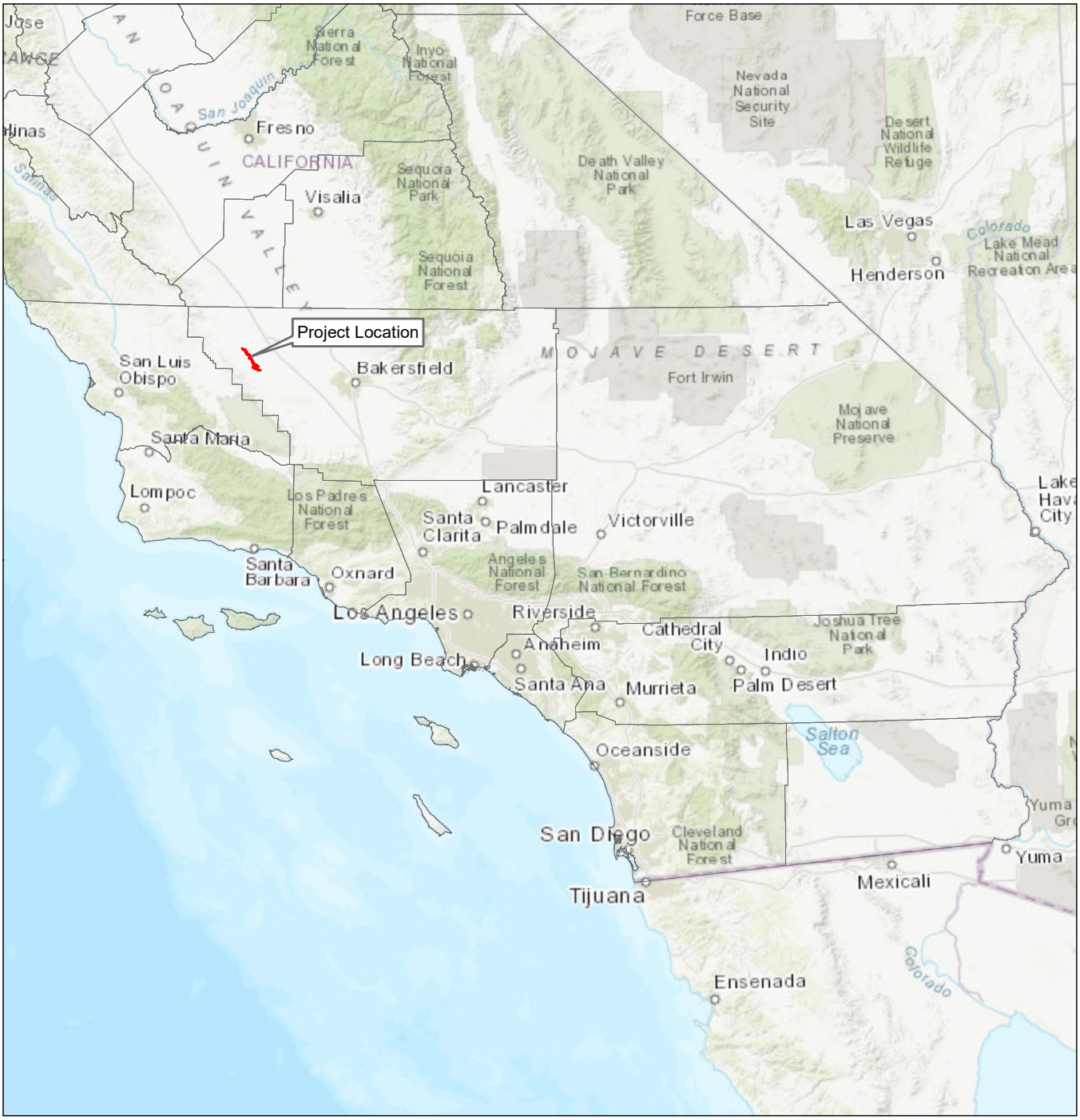
The purpose of this Desktop Geohazards and Geotechnical Assessment is to evaluate relevant publicly available information and data provided by Aera for the Project Site and provide an overview of geologic conditions which represent potential geotechnical hazards associated with the proposed Project. This report has been prepared in general accordance with accepted geotechnical engineering principles and in general conformance with the approved scope of services.

1.2.2 Scope of Work

Stantec performed a desktop-level evaluation of the geologic and soil hazards that may affect future development of the Project Site. The Scope of Work for this Desktop Geohazards and Geotechnical Assessment included:

- Review of relevant published geologic information consisting of the following: U.S. Geological Survey published maps and reports, State of California-issued geologic and hazard maps, and County of Kern Safety Element;
- Review and summarize regional and local geology and identify potential geotechnical and geologic hazards;
- Research and identify relevant geologic hazards, such as fault rupture, seismic shaking or spreading, liquefaction, landslide, subsidence, erosion, slope stability, shallow groundwater, and collapsible soils, based on readily available information; and
- Production of this Desktop Geohazards and Geotechnical Assessment with associated maps in support of the Environmental Impact Report (EIR) prepared by the County.







Project Location

0 30 60 Miles

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Stantec AERA

Project Location	Prepared by DL on 2023-05-16
Kern County,	TR by SET on 2023-05-16
California	IR by BK on 2023-05-16
Client/Project	185805407

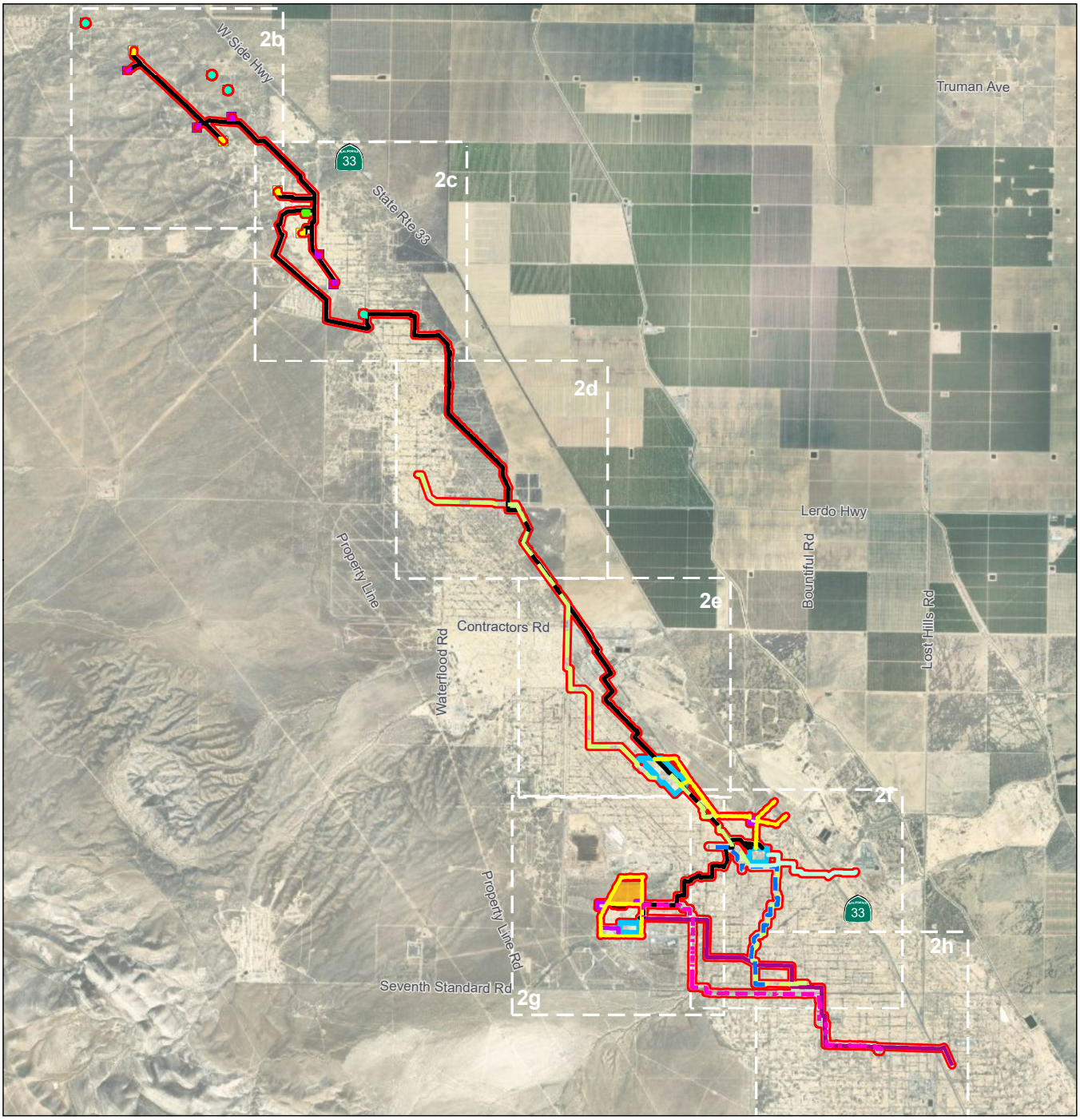
Aera Energy LLC
Aera CarbonFrontier Project

Figure No.
1

Title
Project Vicinity

Notes
1. Coordinate System: NAD 1983 StatePlane California V FIPS 0405 Feet
2. Data Sources: CalGEM 2019,2022,2023, Stantec 2022, 2023.
3. Background: Sources: Esri, GEBCO, NOAA, National Geographic, Garmin, HERE, Geonames.org, and other contributors
Sources: Esri, HERE, Garmin, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), (c) OpenStreetMap contributors, and the GIS User Community
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors

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Notes

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3. Background: Sources: Esri, GEBCO, NOAA, National Geographic, Garmin, HERE, Geonames.org, and other contributors
Source: Esri, Maxar, Earthstar Geographics, and the GIS User Community
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors

- Study Area

Project Components

- Proposed CO_2 Injection Wells
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- Proposed Monitoring Wells
- Existing Del Sur Gas Line to Gas Plant 32
- Existing Steam Line Routes
- Proposed CO_2 Pipelines
- Potential Produced Water Lines Routes
- Potential Power Line Routes
- Potential Steam Line Routes
- Tulare CVR to GP32 (Optional)
- Proposed Compressor Booster Station
- Potential Substation Locations
- Pre-Combustion Facilities
- Proposed CO_2 Capture Facility
- Proposed Staging Area Adjacent to Gas Plant 32

0 0.65 1.3 Miles

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Project Location
Kern County,
California

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TR by SET on 2023-05-17
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Client/Project 185805407

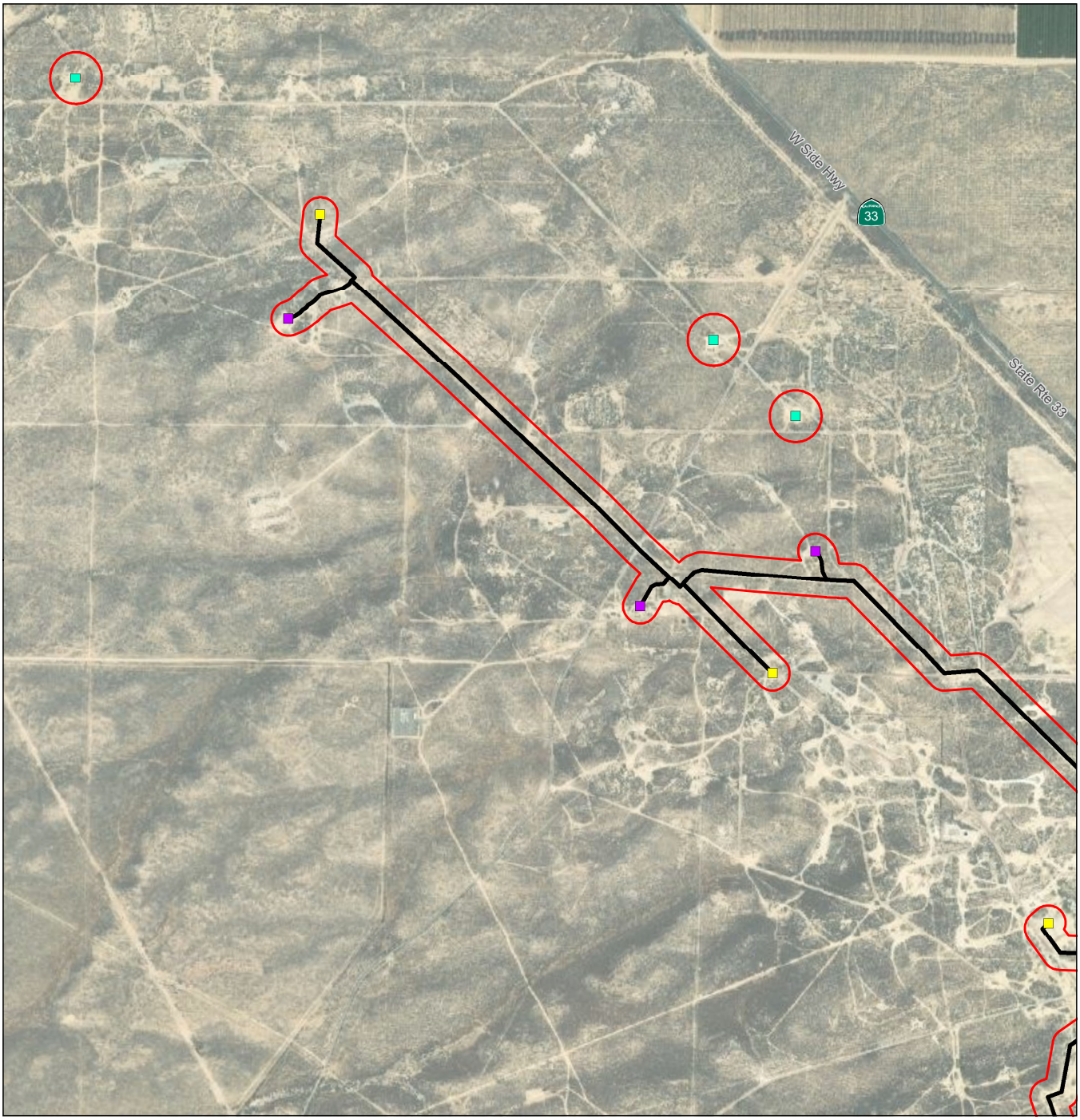
Aera Energy LLC
Aera CarbonFrontier Project

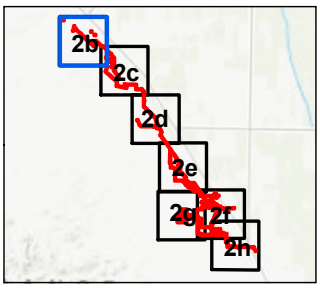
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Title
Project Location

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0 750 1,500 Feet

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Stantec AERA

Project Location
Kern County,
California

Prepared by DL on 2023-05-17
TR by SET on 2023-05-17
IR by BK on 2023-05-17

Client/Project
185805407

Aera Energy LLC
Aera CarbonFrontier Project

Figure No.
2b

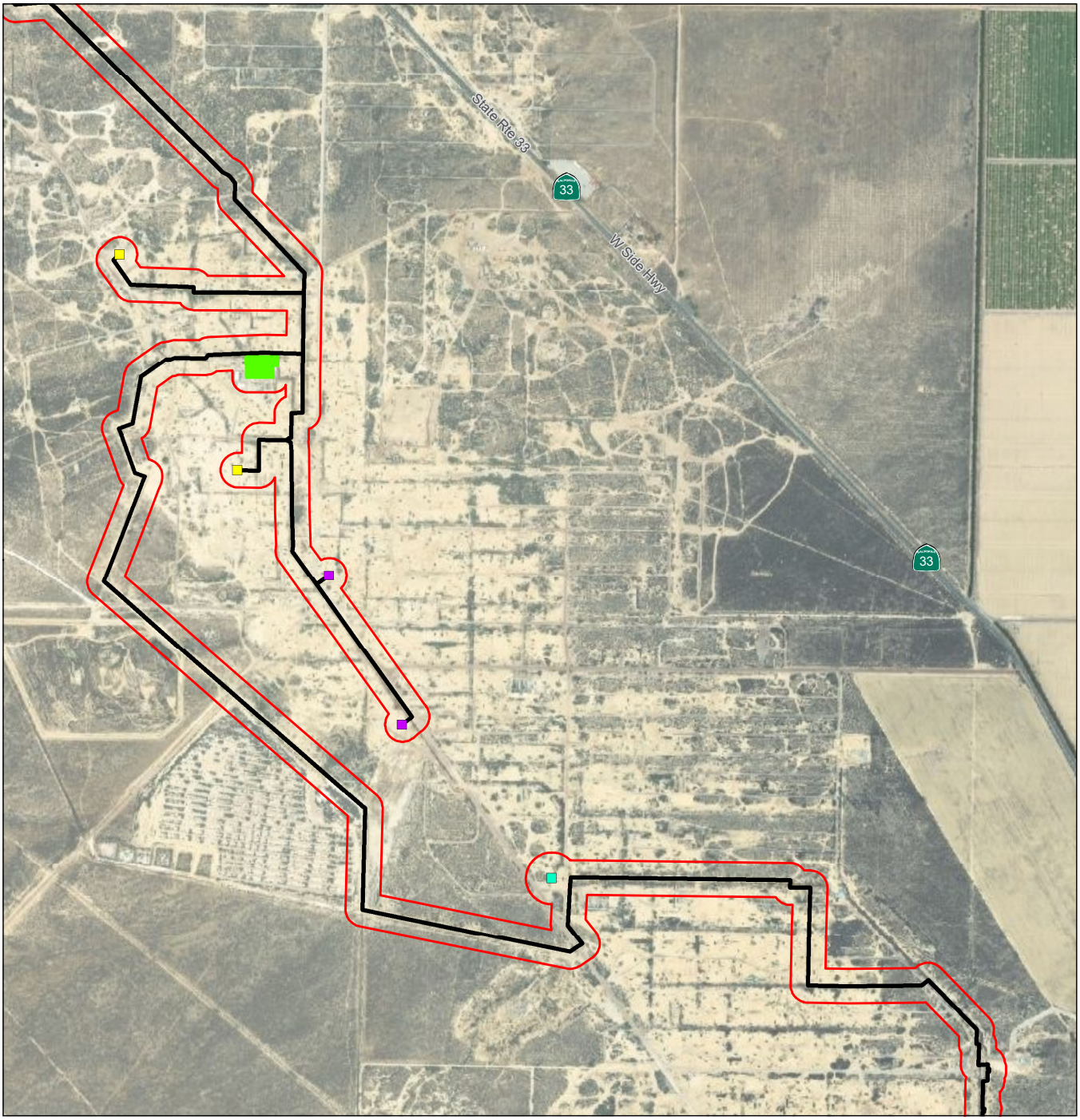
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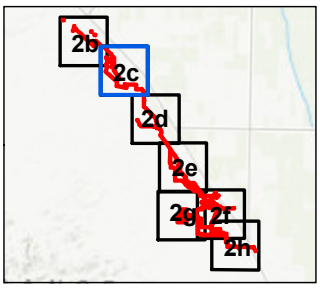
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1. Coordinate System: NAD 1983 StatePlane California V FIPS 0405 Feet
2. Data Sources:CalGEM 2019, Stantec 2022, 2023.
3. Background: Sources: Esri, HERE, Garmin, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), (c) OpenStreetMap contributors, and the GIS User Community
Source: Esri, Maxar, Earthstar Geographics, and the GIS User Community

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Study Area

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0 750 1,500 Feet

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N

Stantec AERA

Project Location
Kern County,
California

Prepared by DL on 2023-05-17
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Client/Project 185805407

Aera Energy LLC
Aera CarbonFrontier Project

Figure No.
2c

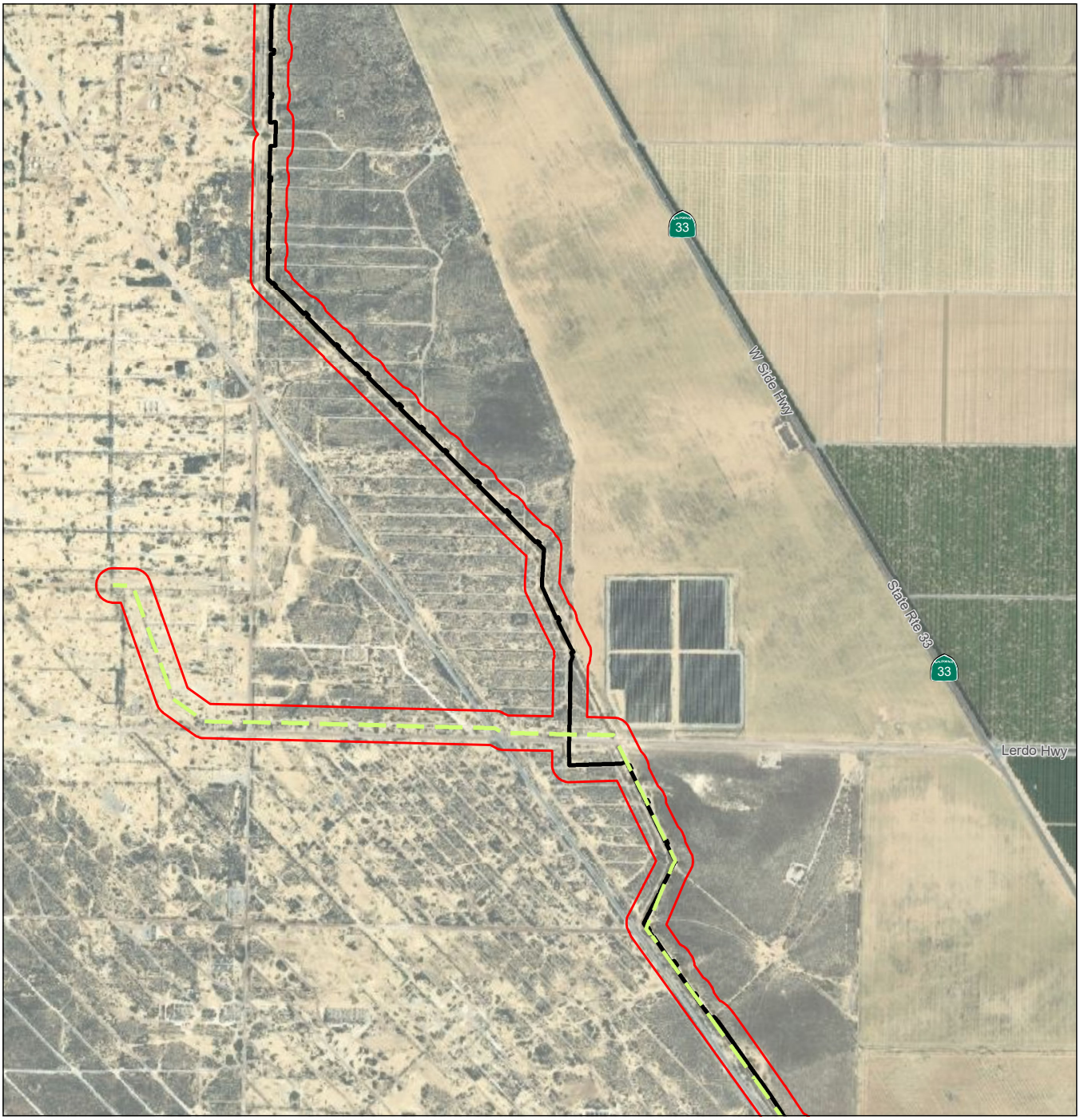
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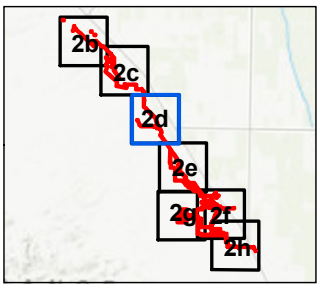
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0 750 1,500 Feet

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N

Stantec AERA

Project Location
Kern County,
California

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Client/Project 185805407

Aera Energy LLC
Aera CarbonFrontier Project

Figure No.
2d

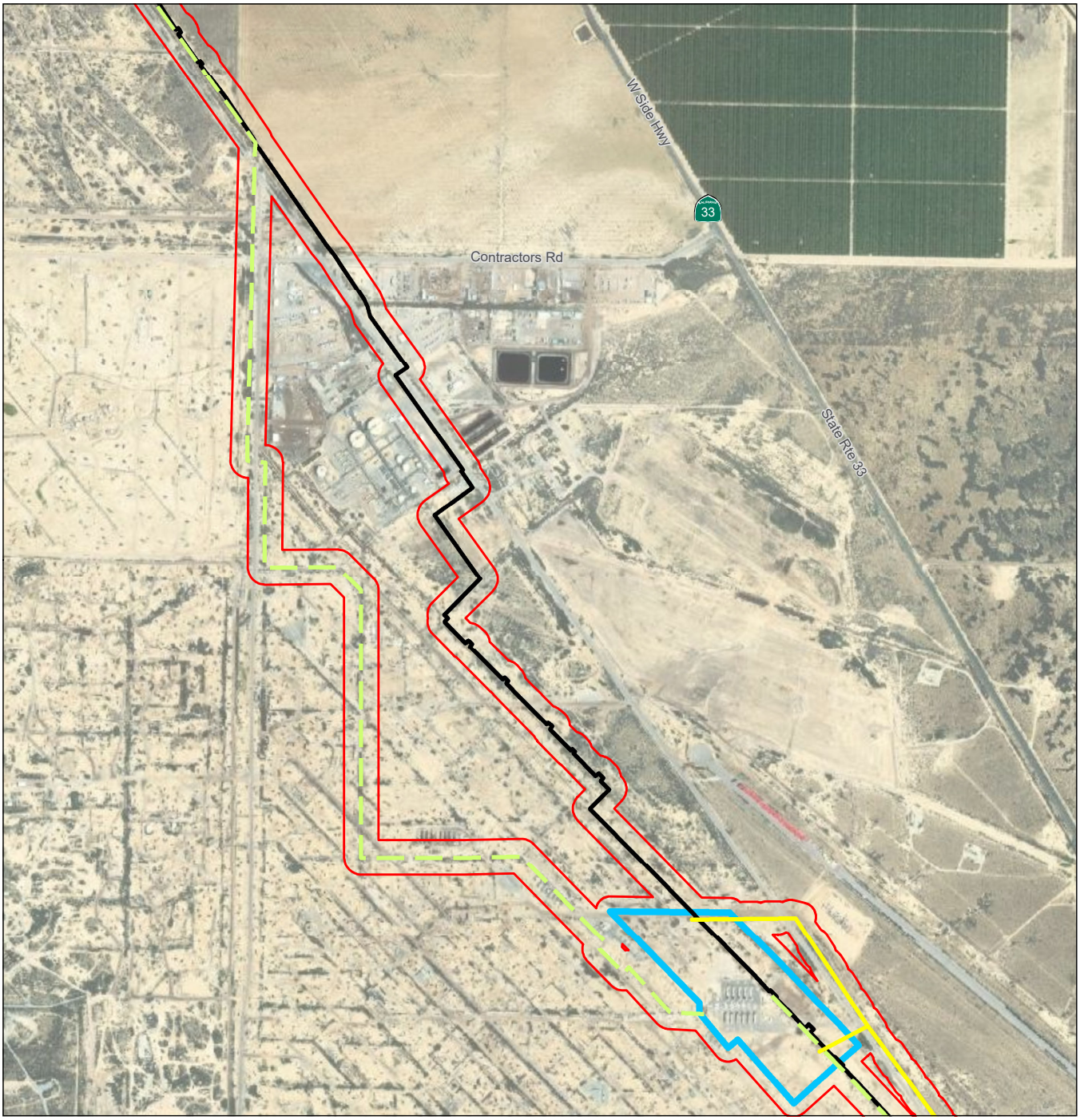
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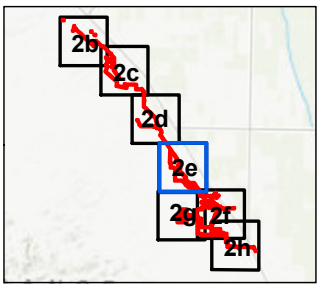
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Study Area

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0 750 1,500 Feet

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N

Stantec AERA

Project Location
Kern County,
California

Prepared by DL on 2023-05-17
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IR by BK on 2023-05-17

Client/Project
185805407

Aera Energy LLC
Aera CarbonFrontier Project

Figure No.
2e

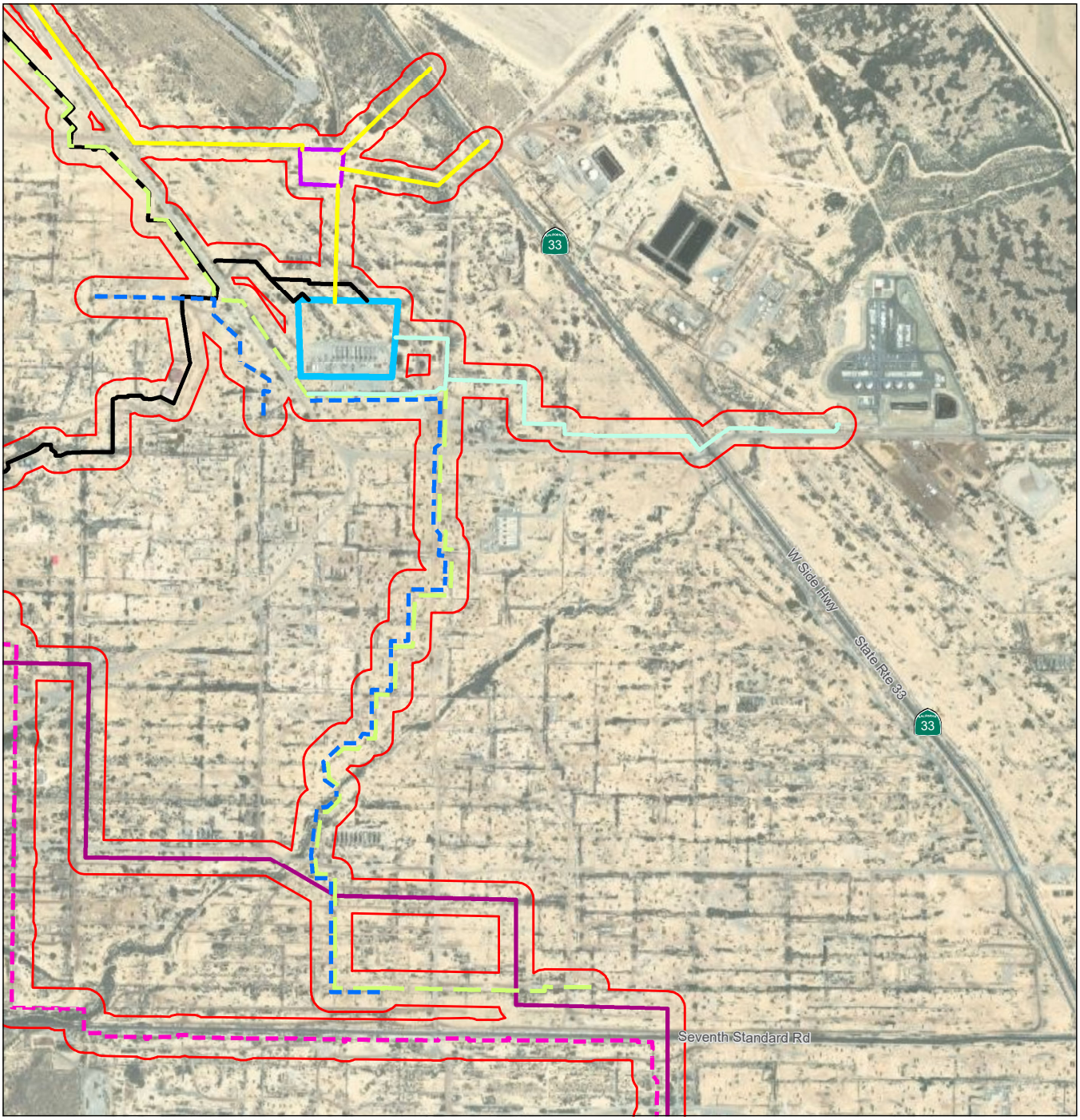
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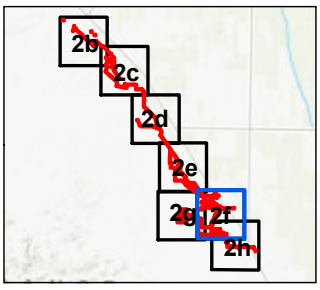
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- Study Area

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0 750 1,500 Feet

(At original document size of 8.5x11)
1:16,000

N

Stantec AERA

Project Location
Kern County,
California

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Client/Project
185805407

Aera Energy LLC
Aera CarbonFrontier Project

Figure No.
2f

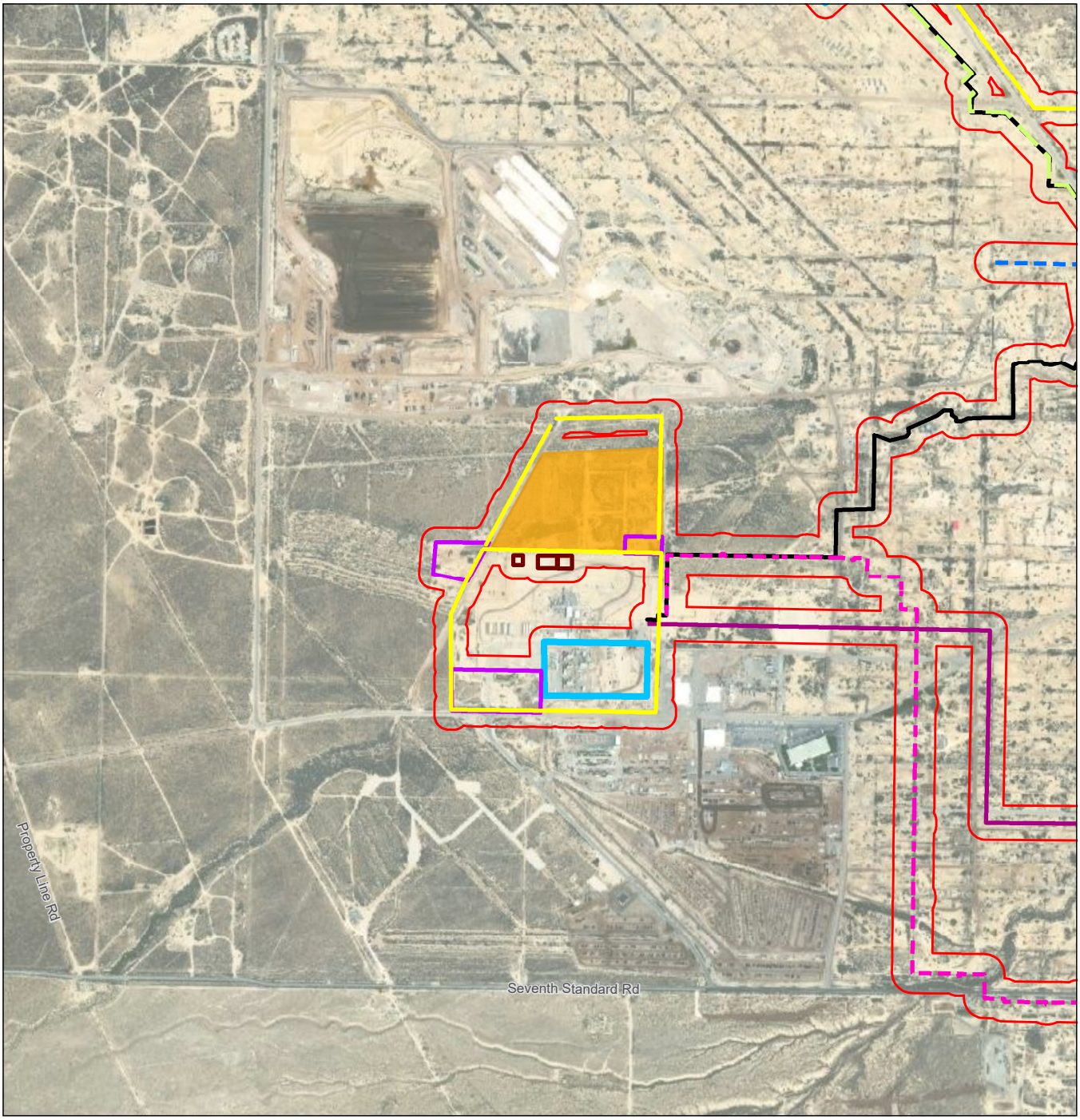
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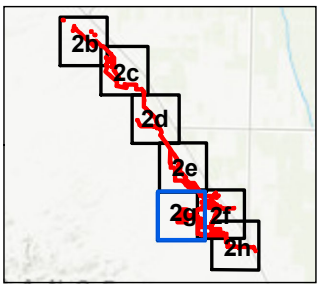
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0 750 1,500 Feet

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N

Stantec AERA

Project Location
Kern County,
California

Prepared by DL on 2023-05-17
TR by SET on 2023-05-17
IR by BK on 2023-05-17

Client/Project 185805407

Aera Energy LLC
Aera CarbonFrontier Project

Figure No.
2g

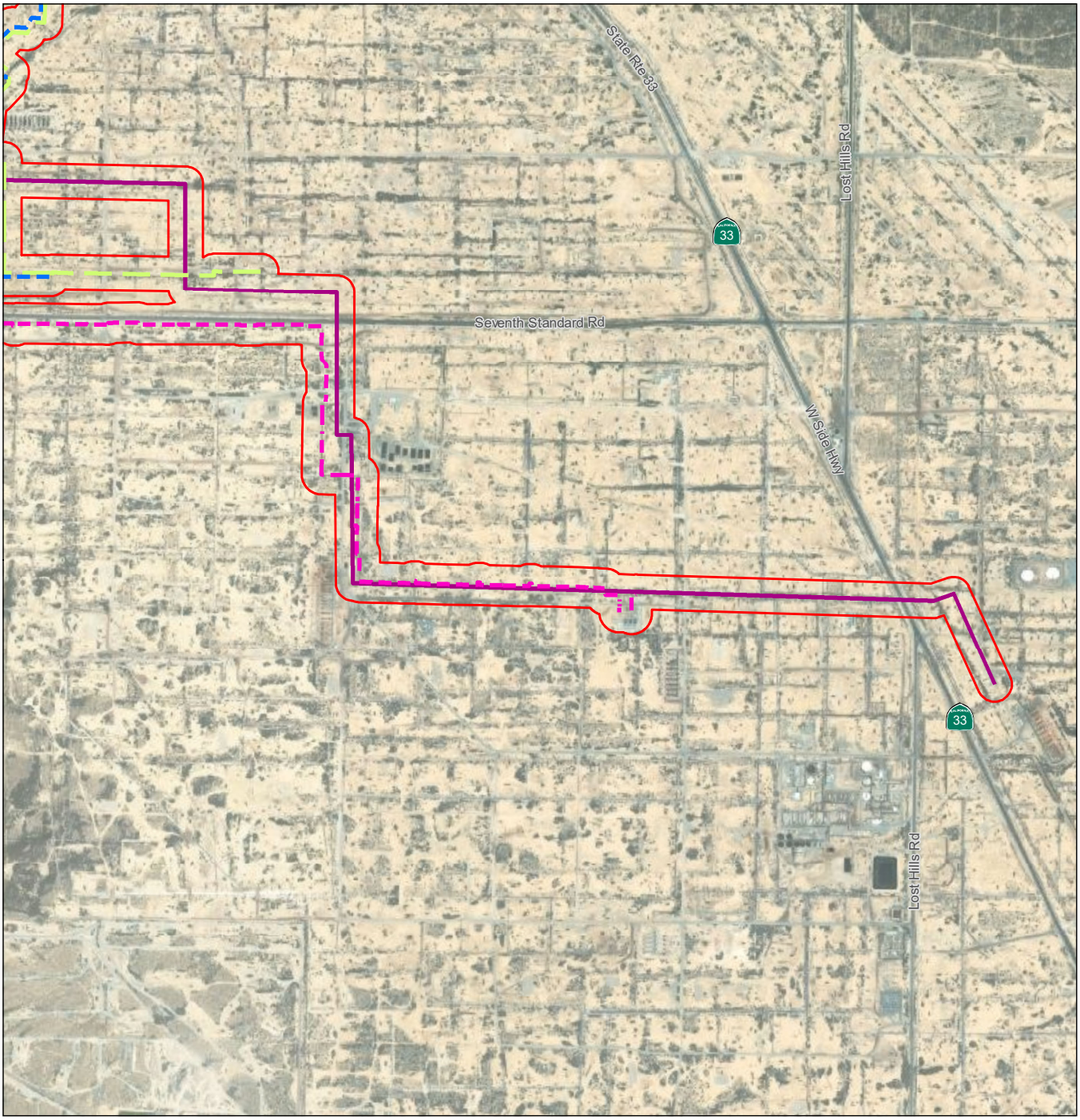
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Project Location

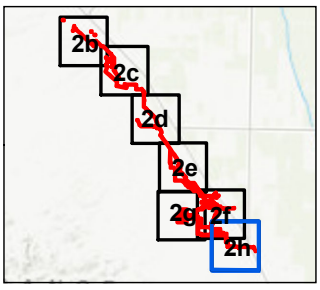
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1. Coordinate System: NAD 1983 StatePlane California V FIPS 0405 Feet
2. Data Sources:CalGEM 2019, Stantec 2022, 2023.
3. Background: Sources: Esri, HERE, Garmin, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), (c) OpenStreetMap contributors, and the GIS User Community
Source: Esri, Maxar, Earthstar Geographics, and the GIS User Community

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Study Area

Project Components

- Proposed CO_2 Injection Wells
- Existing Oil Wells to be Converted to CO_2 Injection Wells
- Proposed Monitoring Wells
- Existing Del Sur Gas Line to Gas Plant 32
- Existing Steam Line Routes
- Proposed CO_2 Pipelines
- Potential Produced Water Lines Routes
- Potential Power Line Routes
- Potential Steam Line Routes
- Tulare CVR to GP32 (Optional)
- Proposed Compressor Booster Station
- Potential Substation Locations
- Pre-Combustion Facilities
- Proposed CO_2 Capture Facility
- Proposed Staging Area Adjacent to Gas Plant 32

0 750 1,500 Feet

(At original document size of 8.5x11)
1:16,000

N

Stantec AERA

Project Location
Kern County,
California

Prepared by DL on 2023-05-17
TR by SET on 2023-05-17
IR by BK on 2023-05-17

Client/Project 185805407

Aera Energy LLC
Aera CarbonFrontier Project

Figure No.
2h

Title
Project Location

Notes

1. Coordinate System: NAD 1983 StatePlane California V FIPS 0405 Feet
2. Data Sources:CalGEM 2019, Stantec 2022, 2023.
3. Background: Sources: Esri, HERE, Garmin, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), (c) OpenStreetMap contributors, and the GIS User Community
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2.0 RESULTS

The following sections detail the findings of this Desktop Geohazards and Geotechnical Assessment.

2.1 REGIONAL GEOLOGY

The Project Site is located in the San Joaquin Valley, within the southern half of the Great Valley Geomorphic Province of California. The Great Valley is characterized by a broad alluvial plain extending over 400 miles through Central California and reaching up to 50 miles wide. The San Joaquin Valley is approximately 200 miles long and up to 70 miles wide. The northern portion of the San Joaquin Valley is drained by the San Joaquin River, which flows from east-central California to the San Francisco Bay before reaching the Pacific Ocean. The southern portion of the San Joaquin Valley drains into two terminal lake beds, Tulare Lake and Buena Vista Lake. Geologically, the San Joaquin Valley structural trough is characterized by marine and continental sedimentary deposits reaching thicknesses of up to 32,000 feet.

The surficial geology of the Project Site consists of Quaternary-age alluvial deposits ranging from gravel to sand, silt, and clay units. The Tulare Formation underlies the Quaternary alluvium and consists of weakly indurated gravel, pebble, sand, and clay. Clay units vary in permeability (Aera Energy & Geosyntec Consultants, 2022). The Tulare Formation is underlain by the San Joaquin formation, the Etchegoin formation, and the Monterey Shale. The San Joaquin formation is characterized as a Pliocene aged sandstone, silty sand, and siltstone containing mostly marine fossils. The Etchegoin formation is a marine sandstone. The Monterey Shale is a marine biogenic deposit characterized by clayey to siliceous shales with varying degrees of bedding, weathering, and lithification (Dibblee & Minch, 2006). The geologic map of the Project Site is provided in Figures 3a through 3i.

Structurally, the Project Site is located along the western margin of the San Joaquin fold belt. The fold belt is characterized by fault-bend and fault-propagated folds associated with complex faulting in the area and resulting in a series of anticlines and synclines along the southern and western boundaries of the San Joaquin Valley (Namson & Davis, 1988).

The U.S. Geological Survey (USGS) has mapped Quaternary active faults within 35-miles of the Project Site. The nearest Quaternary active faults mapped by the USGS are the San Andreas fault zone, a right-lateral fault zone located approximately 10 miles west of the Project Site and the Poso Creek fault, approximately 25 miles east of the Project Site. Other named and unnamed Quaternary active faults have also been mapped within a 35-mile radius of the Project Site (USGS, 2023).





- Study Area

Project Components

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- Existing Oil Wells to be Converted to CO_2 Injection Wells
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- Existing Steam Line Routes
- Proposed CO_2 Pipelines
- Potential Produced Water Lines Routes
- Potential Power Line Routes
- Potential Steam Line Routes
- Tulare CVR to GP32 (Optional)
- Proposed Compressor Booster Station
- Potential Substation Locations
- Pre-Combustion Facilities
- Proposed CO_2 Capture Facility
- Proposed Staging Area Adjacent to Gas Plant 32

0 0.65 1.3 Miles

(At original document size of 8.5x11)
1:80,760

N

Notes

1. Coordinate System: NAD 1983 StatePlane California V FIPS 0405 Feet
2. Data Sources:CalGEM 2019, Stantec 2022.
3. Background: Sources: Esri, GEBCO, NOAA, National Geographic, Garmin, HERE, Geonames.org, and other contributors
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Esri, Garmin, GEBCO, NOAA NGDC, and other contributors

Stantec AERA

Project Location
Kern County,
California

Prepared by DL on 2023-05-17
TR by SET on 2023-05-17
IR by BK on 2023-05-17

Client/Project 185805407

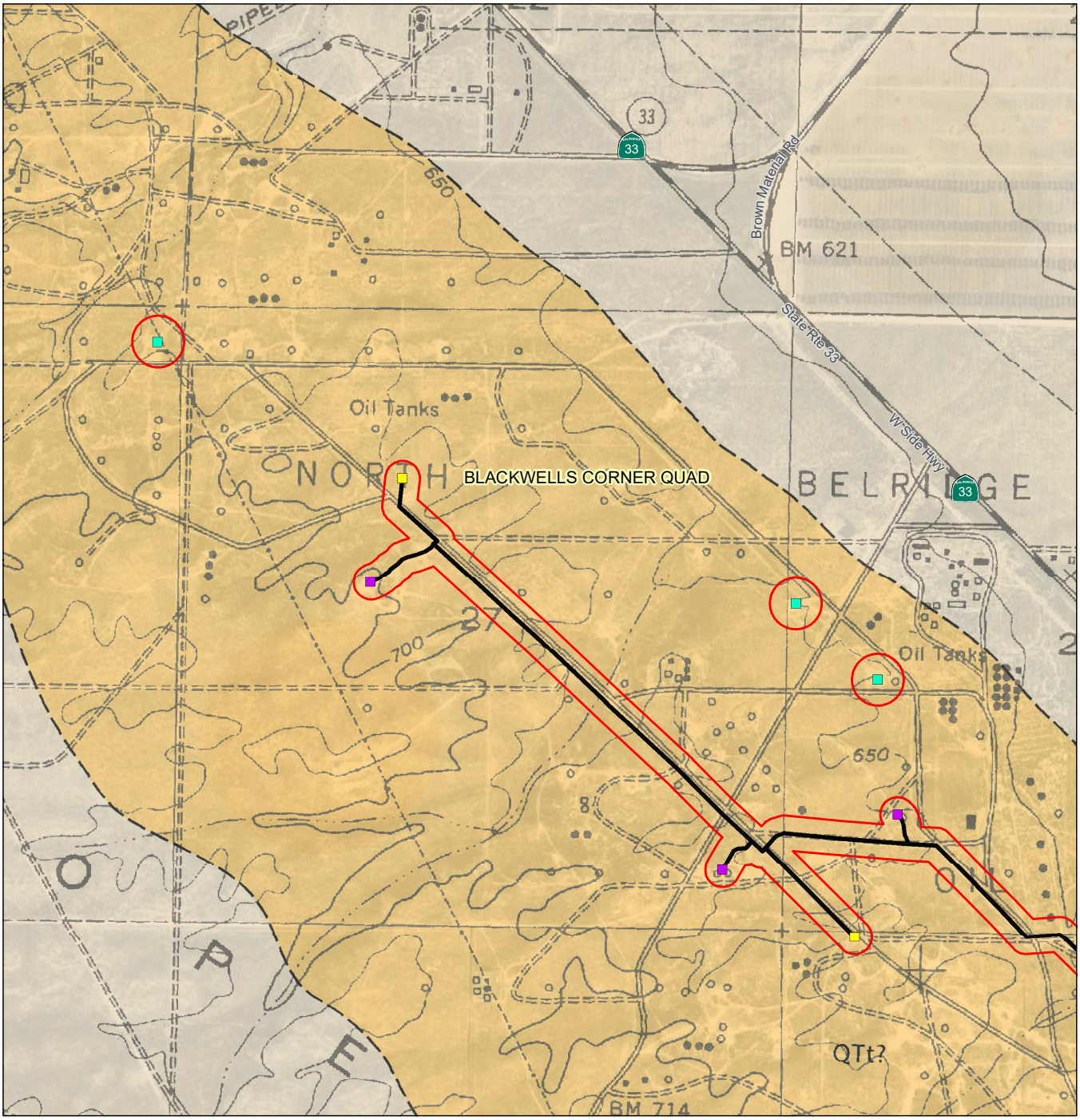
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Aera CarbonFrontier Project

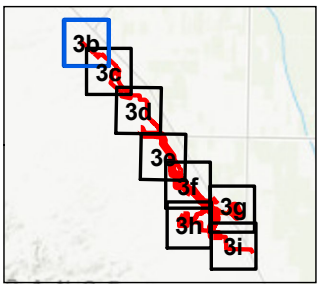
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Title
Project Geology

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- Study Area
- Proposed CO_2 Injection Wells
- Existing Oil Wells to be Converted to CO_2 Injection Wells
- Proposed Monitoring Wells
- Proposed CO_2 Pipelines

Geology Description

- Qa: Alluvium (Holocene)
- QTt: Tulare Formation (Pliocene to Pleistocene)

0 750 1,500 Feet

(At original document size of 8.5x11)
1:16,000

N

Stantec AERA

Project Location	Prepared by DL on 2023-05-17
Kern County,	TR by SET on 2023-05-17
California	IR by BK on 2023-05-17
Client/Project	185805407

Aera Energy LLC
Aera CarbonFrontier Project

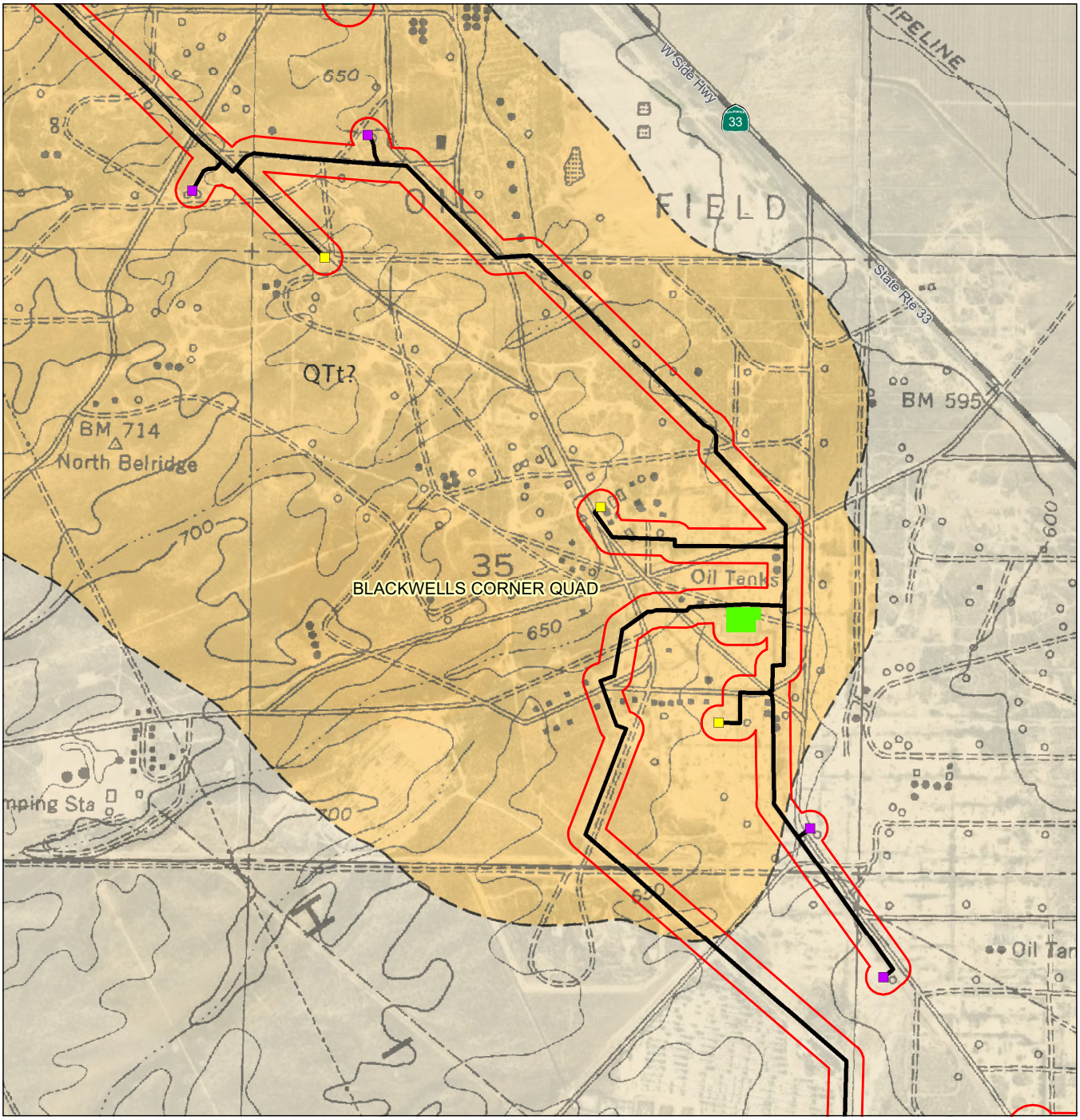
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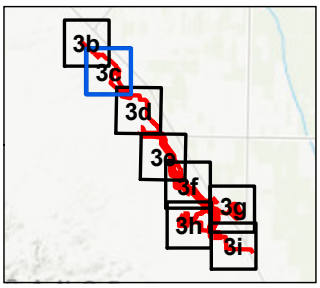
Title
Project Geology

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1. Coordinate System: NAD 1983 StatePlane California V FIPS 0405 Feet
2. Data Sources: CalGEM 2019, Stantec 2022, 2023..
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- Study Area
- Proposed CO_2 Injection Wells
- Existing Oil Wells to be Converted to CO_2 Injection Wells
- Proposed Monitoring Wells
- Proposed CO_2 Pipelines
- Proposed Compressor Booster Station

Geology Description

- Qa: Alluvium (Holocene)
- QTt: Tulare Formation (Pliocene to Pleistocene)

0 750 1,500 Feet

(At original document size of 8.5x11)
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N

Stantec AERA

Project Location	Prepared by DL on 2023-05-17
Kern County,	TR by SET on 2023-05-17
California	IR by BK on 2023-05-17
Client/Project	185805407

Aera Energy LLC
Aera CarbonFrontier Project

Figure No.
3c

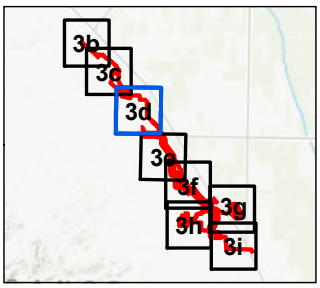
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Project Geology

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Source: Esri, Maxar, Earthstar Geographics, and the GIS User Community

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- Study Area
- Existing Oil Wells to be Converted to CO_2 Injection Wells
- Proposed Monitoring Wells
- Proposed CO_2 Pipelines
- Potential Steam Line Routes

Geology Description

- Qa: Alluvium (Holocene)

0 750 1,500 Feet

(At original document size of 8.5x11)
1:16,000

N

Stantec AERA

Project Location	Prepared by DL on 2023-05-17
Kern County,	TR by SET on 2023-05-17
California	IR by BK on 2023-05-17
Client/Project	185805407

Aera Energy LLC
Aera CarbonFrontier Project

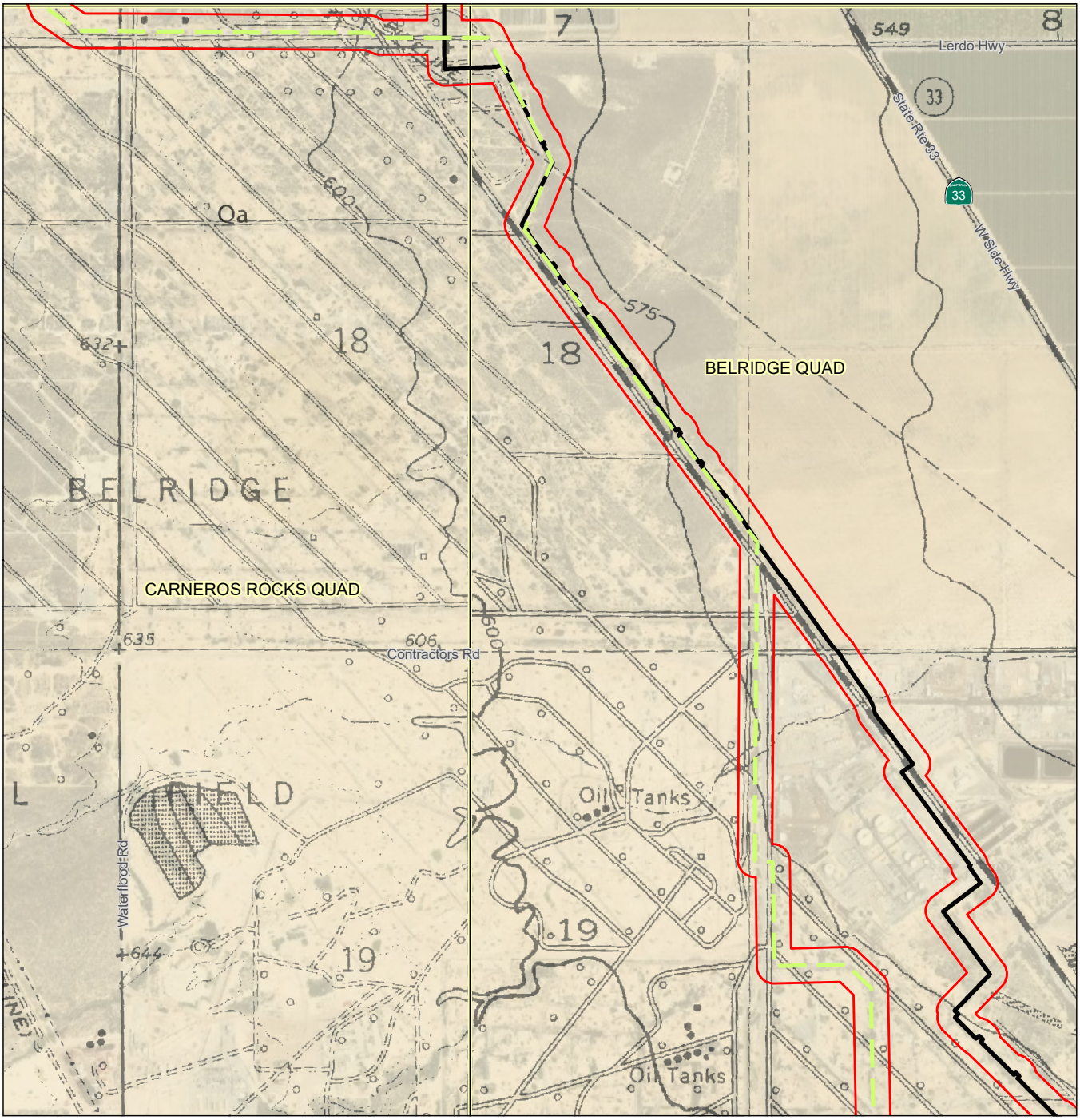
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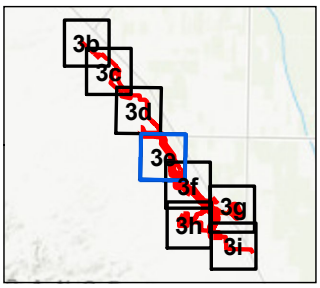
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Study Area

Proposed CO_2 Pipelines

Potential Steam Line Routes

Geology Description

Qa: Alluvium (Holocene)

0 750 1,500 Feet

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1:16,000

N

Stantec AERA

Project Location
Kern County,
California

Prepared by DL on 2023-05-17
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Client/Project
185805407

Aera Energy LLC
Aera CarbonFrontier Project

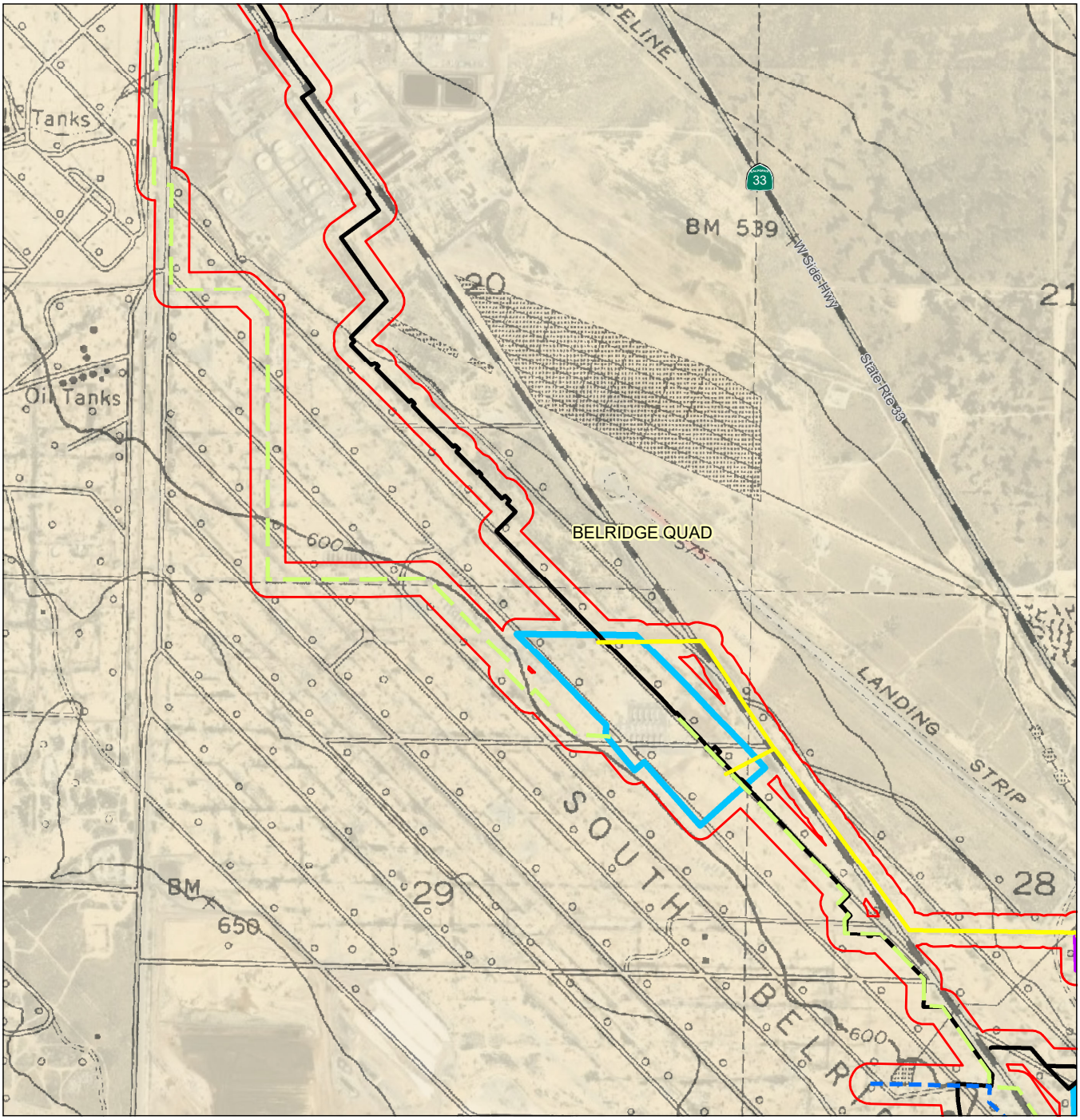
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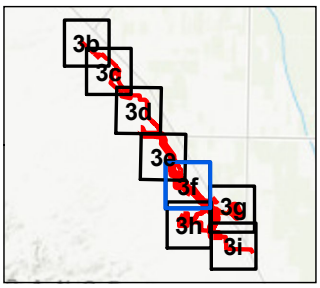
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- Study Area
- Proposed CO_2 Pipelines
- Existing Steam Line Routes
- Potential Power Line Routes
- Potential Steam Line Routes
- Potential Substation Locations
- Proposed CO_2 Capture Facility

Geology Description

- Qa: Alluvium (Holocene)

0 750 1,500 Feet

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N

Stantec AERA

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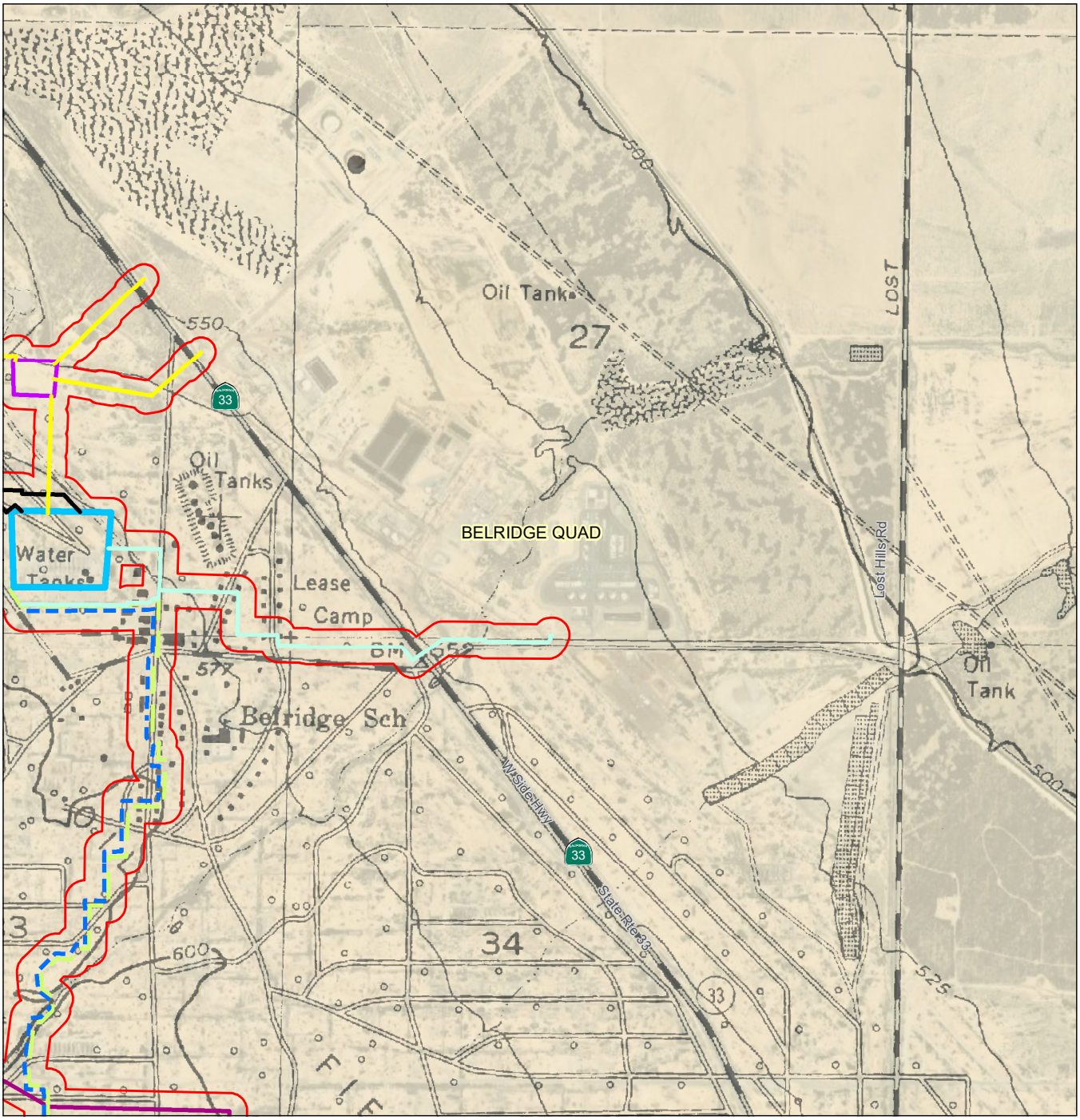
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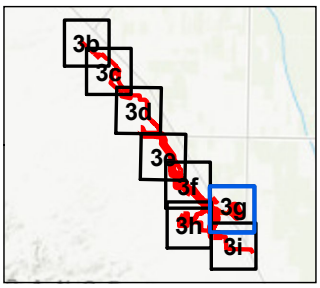
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- Study Area
- Proposed CO_2 Pipelines
- Existing Steam Line Routes
- Potential Produced Water Lines Routes
- Potential Power Line Routes
- Potential Steam Line Routes
- Tulare CVR to GP32 (Optional)
- Potential Substation Locations
- Proposed CO_2 Capture Facility

Geology Description

- Qa: Alluvium (Holocene)

0 750 1,500 Feet

(At original document size of 8.5x11)
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Notes

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Stantec AERA

Project Location
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Client/Project 185805407

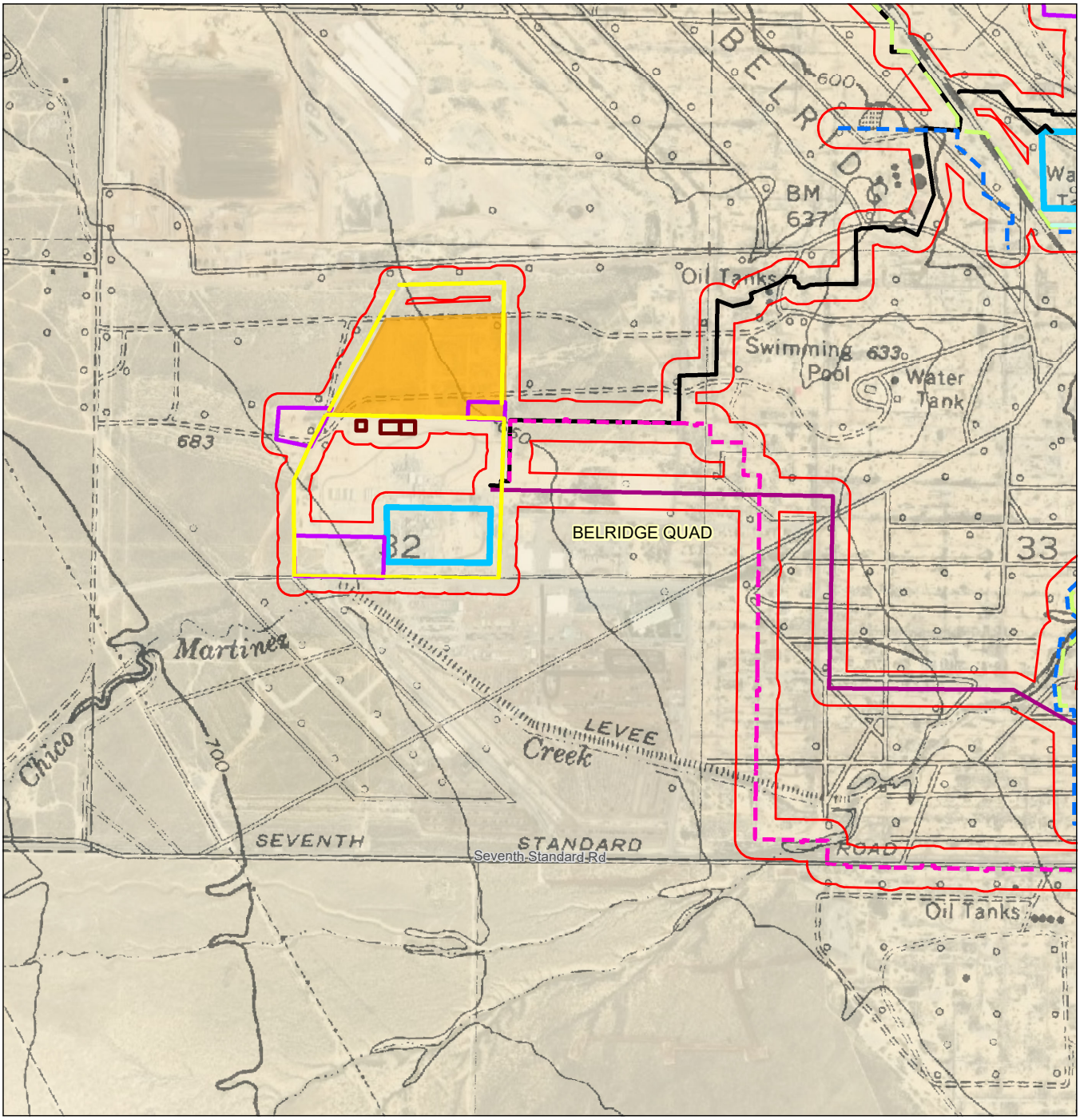
Aera Energy LLC
Aera CarbonFrontier Project

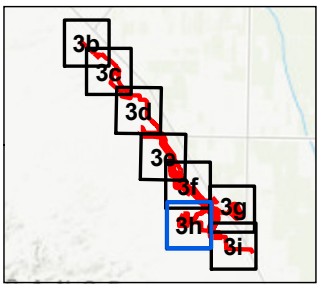
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Title
Project Geology

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- Study Area
- Existing Del Sur Gas Line to Gas Plant 32
- Proposed CO_2 Pipelines
- Existing Steam Line Routes
- Potential Produced Water Lines Routes
- Potential Power Line Routes
- Potential Steam Line Routes
- Tulare CVR to GP32 (Optional)
- Potential Substation Locations
- Pre-Combustion Facilities
- Proposed CO_2 Capture Facility
- Proposed Staging Area Adjacent to Gas Plant 32

Geology Description

- Qa: Alluvium (Holocene)

0 750 1,500 Feet

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N

Stantec AERA

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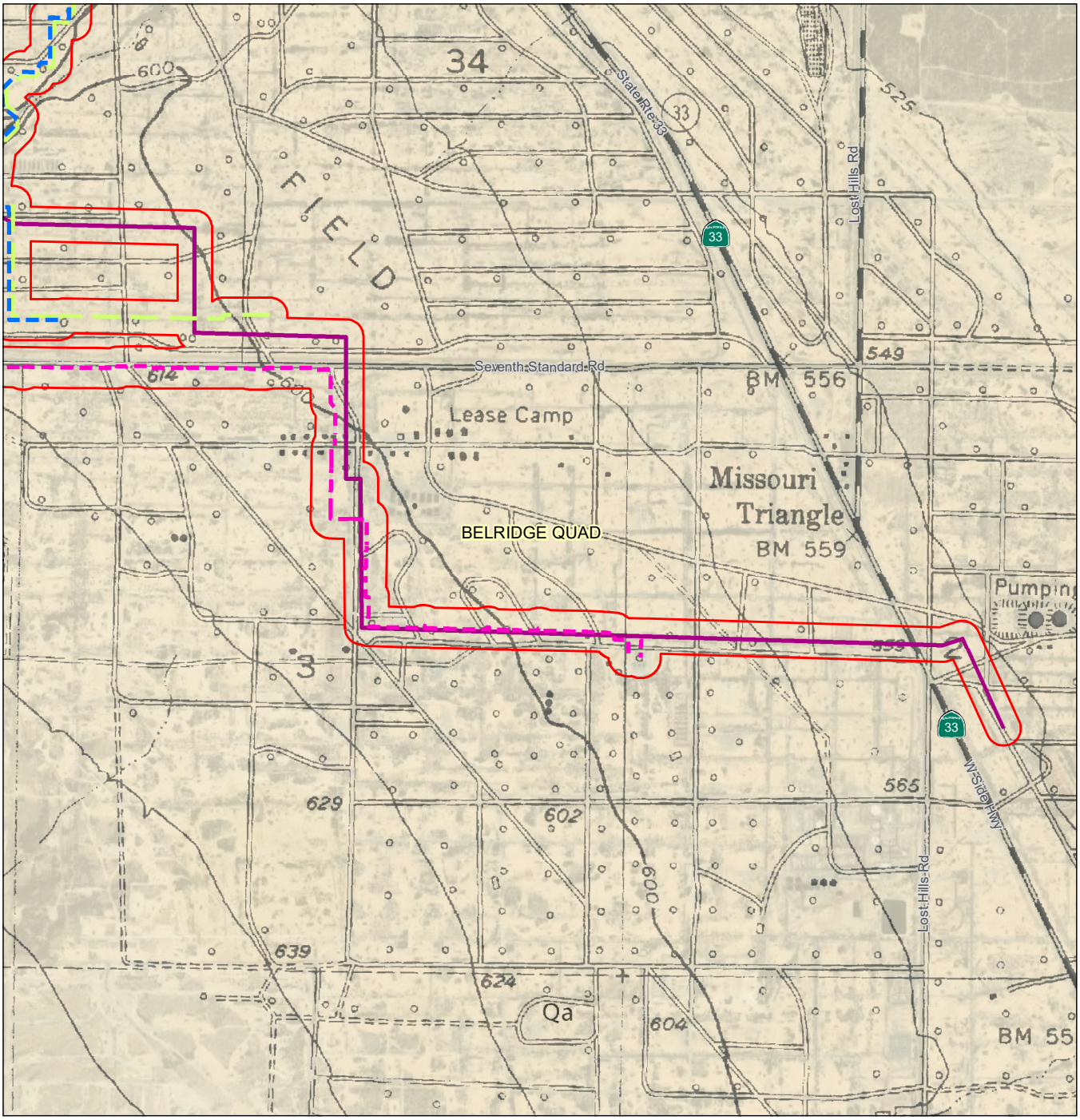
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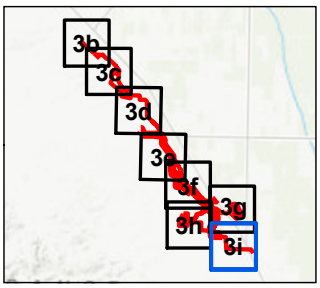
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- Study Area
- Existing Del Sur Gas Line to Gas Plant 32
- Existing Steam Line Routes
- Potential Steam Line Routes
- Tulare CVR to GP32 (Optional)

Geology Description

- Qa: Alluvium (Holocene)

0 750 1,500 Feet

(At original document size of 8.5x11)
1:16,000

N

Stantec AERA

Project Location	Prepared by DL on 2023-05-17
Kern County,	TR by SET on 2023-05-17
California	IR by BK on 2023-05-17
Client/Project	185805407

Aera Energy LLC
Aera CarbonFrontier Project

Figure No.
3i

Title
Project Geology

Notes
1. Coordinate System: NAD 1983 StatePlane California V FIPS 0405 Feet
2. Data Sources: CalGEM 2019, Stantec 2022, 2023..
3. Background: Sources: Esri, HERE, Garmin, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), (c) OpenStreetMap contributors, and the GIS User Community
Source: Esri, Maxar, Earthstar Geographics, and the GIS User Community

V:\1858\Active\185805xxxx Aera\03 data\gis cad\gis\185805372 BelridgeCCSPaleo Figure3 BelridgeCCS Geology DDP 20221229.mxd Revised: 2023-05-17 By: Dalaw

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2.2 REGIONAL GROUNDWATER

The Project Site is located within the Central Valley Groundwater Basin, San Joaquin Basin, and Kern County subbasin (CDWR, 2023; CDWR, 2020). Broadly speaking, groundwater flow is to the east and toward the main valley floor. Potentiometric surface analysis for the alluvial deposits indicates the groundwater flow in the North Belridge Oil Field area is to the north-northeast, and in the South Belridge Oil Field area groundwater flows to the east-northeast (Aera Energy & Geosyntec Consultants, 2022).

The California Department of Water Resources (CDWR) and USGS periodically monitor groundwater levels in water wells surrounding the Project Site. The groundwater level at an observation well (Site Code 355137N1195985W0001) located approximately 8.9 miles east of the Project Site is reported as 34.3 ft below ground surface (bgs) on October 17, 2022. The groundwater level at an observation well (Site Code 354021N1195011W001), located approximately 9 miles southeast of the Project Site is reported as 124.2 ft bgs on October 12, 2022 (CDWR, 2023).

The Belridge multiple-well monitoring site (Belridge Water Storage District, BWSD) is located approximately 1.3 miles east and downgradient from the northeast corner of the South Belridge Oil Field. Table 1 provides the most recent depth to water data from this group of groundwater monitoring wells (USGS, 2023).

Table 1. Summary of groundwater monitoring well data for the Belridge multiple-well monitoring site (USGS, 2023).

Well No.	USGS Site ID	Location (lat/long)	Well Depth (ft)	Depth to Water (ft bgs)	Date Collected
BWSD #5	353049119434105 028S021E08A005M	35°30'49.07", 119°43'41.96"	280	156.04	1/18/2023
BWSD #4	353049119434104 028S021E08A004M	35°30'49.07", 119°43'41.96"	530	178.96	1/18/2023
BWSD #3	353049119434103 028S021E08A003M	35°30'49.07", 119°43'41.96"	890	518.08	1/18/2023
BWSD #2	353049119434102 028S021E08A002M	35°30'49.07", 119°43'41.96"	1190	519.01	1/18/2023
BWSD #1	353049119434101 028S021E08A001M	35°30'49.07", 119°43'41.96"	1515	681.65	1/18/2023

The approximate surface elevation of the Project Site is 546 feet above mean sea level (amsl). Based on the above groundwater level data, the estimated depth to groundwater at the Project Site is 150 to 500 ft bgs.



2.3 REGIONAL SEISMICITY

2.3.1 Fault Rupture Hazard

The USGS has mapped Quaternary active faults within 35-miles of the Project Site. The nearest Quaternary active fault mapped by the USGS is the San Andreas fault zone, a right-lateral fault zone, located approximately 10 miles west of the Project Site. The Poso Creek fault is located approximately 25 miles east of the Project Site. Other named and unnamed Quaternary active faults have also been mapped within a 35-mile radius of the Project Site (USGS, 2023),though none occur at the Project Site. Although the possibility of a new fault forming cannot be entirely precluded, the regular occurrence of low magnitude seismic events on the existing active [illegible] [illegible] [illegible]

- A relative shallow groundwater table (within approximately 50 feet below ground surface) or completely saturated soil conditions that would allow positive pore pressure generation.

The Project Site is not within any currently mapped Liquefaction Zones established by the California Geological Survey (CGS) as the area has not been evaluated for liquefaction or landslide hazards (CGS, 2019). Additionally, the Project Site is outside of Earthquake Zones of Required Investigation, as mapped by CGS (CGS, 2022).

Based on the near surface soil conditions, anticipated subsurface soil conditions, depth to groundwater, and proximity to seismically active faults, it is Stantec's opinion that the potential for seismically induced settlement, including liquefaction, is low to moderate at the Project Site (less than 50% probability within the next 100-years).

2.3.4 Lateral Spreading

Lateral spreading typically occurs as a form of horizontal displacement of relatively flat-lying alluvial material toward an open or "free" face such as an open body of water, channel, or excavation. This movement is generally due to failure along a weak plane and is often associated with liquefaction. As cracks develop within the weakened material, blocks of soil displace laterally toward the open face. Cracking and lateral movement may gradually propagate away from the face as blocks continue to break free.

The Project Site has a low to moderate liquefaction potential as discussed above and is located at least one-half to one mile from a free face (abrupt changes in surface topography). Given the relatively flat topography of the Project Site, soil conditions, depth to groundwater, depth to bedrock, and the low potential for liquefaction in the area, the potential for lateral spreading is considered low.

2.4 LOCAL FAULTS AND FRACTURES

Twelve subsurface faults with measurable vertical offset were interpreted from a three-dimensional (3D) seismic survey of the Project Site and correlated with well log data. These fault interpretations were incorporated into a static 3D geologic model to support the project's UIC Class VI application (Aera Energy, 2022b). Four of the identified faults form the boundaries of the Area of Review (AoR) in which the CO_2 plume will be contained, an additional □□□ are contained within the AoR bounding faults□□□d □□ □ □r□ □□□□□d □□□□d□ □□□□□ □□R. None of the faults identified offset Quaternary strata or have ground surface expressions and were consequently interpreted to be inactive.

Each fault transects the injection zone. Furthermore, fault stability analysis indicates that these faults are stable and not susceptible to movement (Aera Energy, 2022b).

2.5 SUBSIDENCE

Land subsidence is a gradual settling or sudden sinking of the Earth's surface due to several factors. Underground mining operations can lead to surface subsidence as subsurface material settles where fluids and/or material have been removed from below. Soil types also play a role in land subsidence since some types of soil expand when wet and contract when dry.

In California's San Joaquin Valley, the primary cause of land subsidence is groundwater pumping in unconsolidated aquifers (CDWR, 2020). Surface subsidence due to groundwater withdrawal is well documented within the San Joaquin Valley Groundwater Basin and Kern County Subbasin (CDWR, 2020; USGS, 2022b). Approximately 900 square miles within the San Joaquin River Hydrologic Region have subsided, with subsidence reaching up to 2.25 feet in some areas (CDWR, 2020).

Surface subsidence due to oil extraction has been documented at the Project Site. Subsidence at the Project Site has been attributed to withdrawal of oil and gas from diatomaceous reservoirs at depths of approximately 1,000 to 2,000 feet below ground level. Monitoring data from radar satellite synthetic aperture radar (RADARSAT SAR) surveys collected every 24-days from February through December, 2001, were used to determine subsidence within the Project Area. The maximum ground surface vertical displacement detected during this time occurred from June 25 to July 19 (30 millimeter [mm]), and from August 12 to September 5 (60 mm).

Additional SAR data from the European ERS-1 and ERS-2 satellites were used to derive subsidence estimates for the period 1992 to 2000. During this time, the maximum subsidence detected within the North Belridge Oil Field area was 1,850 mm, or an average of 15 mm per day over a 24-day period (Youden, et al., 2002). Aera began using interferometric synthetic aperture radar (InSAR) data in 1999 to monitor subsidence rates on an approximately monthly basis. As a result of these data, measures were employed to balance fluid withdrawal and injection in these reservoirs to mitigate subsidence rates. InSAR data indicate that in 2021, vertical movement of the surface ranged from -10 cm to +10 cm, suggesting that only minor amounts of subsidence and inflation have occurred within the monitored area (Aera, 2022a).

Although unconsolidated alluvial soils are present over portions of the Project Site, these soils are largely unsaturated and are not used as a source of groundwater. Therefore, the risk of subsidence in these soils is low. Subsidence has been historically documented at the Project Site and attributed to oil and gas withdrawal from diatomaceous reservoirs within the Monterey Formation at depths of 1,000 to 2,000 feet. Monitoring data indicate that subsidence mitigation efforts have been successful and little-to-no subsidence occurs today. For this reason, the risk of subsidence at the Project Site due to oil and gas extraction is considered moderate. Lastly, the proposed Project will be exclusively used for CO_2 sequestration and no fluids, aside from small-volume samples for monitoring, will be withdrawn from the sequestration zone, eliminating the possibility for subsidence caused by the Project.



2.6 SITE CONDITIONS

2.6.1 Expansive Soil Potential

Soil volume changes can occur when expansive soils undergo alternating cycles of wetting (swelling) and drying (shrinking). Soils mapped on the Project Site are primarily alluvial and include Kimberlina fine sandy loam with 0 to 9 percent slopes, Milham sandy loam with 0 to 5 percent slopes, and Panoche clay loam with 0 to 5 percent slopes. These soils are not considered hydric soils (NRCS, 2023).

The design level geotechnical investigation will determine the expansive potential of the underlying soil at the Project Site and any mitigation measures required.

2.6.2 Corrosive Soil Potential

Sand in direct contact with concrete typically has a lower corrosion potential than clay soils in direct contact with concrete. Corrosive soils can typically be mitigated with corrosion resistant concrete. Natural Resources Conservation Service (NRCS) mapped soils on the Project Site have the following risks of corrosion:

Table 2. Corrosive potential of soils mapped on the Project Site (NRCS, 2023).

Soil Type	Potential Corrosion of Concrete	Potential Corrosion of Steel
Kimberlina fine sandy loam, 0 to 2 percent slopes MLRA 17	Moderate	Moderate
Kimberlina sandy loam, 2 to 9 percent slopes	Moderate	High
Milham sandy loam, 0 to 2 percent slopes MLRA 17	Moderate	Moderate
Milham sandy loam, 2 to 5 percent slopes	Moderate	High
Panoche clay loam, 0 to 5 percent slopes	Low	Moderate

The design level geotechnical investigation will determine the corrosion potential of the underlying soil at the Project Site and any mitigation measures required.

2.6.3 Near-surface Obstructions or Restrictive Soil Layers

If surface organics are identified, they will be removed prior to grading the Project Site. The approximate depth of subsurface organic material and soils will be characterized in the design level geotechnical investigation. Near-surface obstructions or restrictive soil layers will be assessed by the design-level geotechnical investigation.



2.6.4 Frost Depth

California Extreme Frost Line Penetration at the Project Site is an average of 5 inches per the US Department of Commerce (Department of Commerce, 2023). Proposed minimum foundation depths will be required below the frost depth and will be included in the design-level geotechnical investigation report.

2.6.5 Slopes

The Project Site is relatively flat, with a topographic gradient less than 5 percent. Permanent slopes steeper than 5:1 (horizontal to vertical) or higher than 5 feet are not anticipated to be constructed or built upon for the Project. Due to the existing topography and the proposed grading, landslides are not considered a potential hazard for the Project Site. The stability of slopes, if any, should be verified when design-grading information becomes available.

2.6.6 Erosion

The predominantly fine-grained soils underlying the Project Site are potentially susceptible to erosion or the loss of topsoil due to surface water flows and wind-driven movement. The on-site soils have a very low to medium runoff potential (the potential for water to runoff into drainage channels vs. infiltrate directly into the soil. The erosion potential for each on-site soil was also determined using the K-Factor. The soil-erodibility factor (K) represents: (1) the susceptibility of soil or surface material to erosion, (2) the transportability of the sediment, and (3) the amount and rate of runoff given a particular rainfall input, as measured under a standard condition. Fine-textured soils that are high in clay have low K values (about 0.05 to 0.15) because the particles are resistant to detachment. Coarse-textured soils, such as sandy soils, also have low K values (about 0.05 to 0.2) because of high infiltration resulting in low runoff, although these particles are easily detached. Medium-textured soils, such as a silt loam, have moderate K values (about 0.25 to 0.45) because they are moderately susceptible to particle detachment and they produce runoff at moderate rates. Soils having a high silt content are especially susceptible to erosion and have high K values, which can exceed 0.45 and can be as large as 0.65. Silt-size particles are easily detached and tend to crust, producing high runoff rates and large runoff volumes (Caltrans, 2023). Refer to Table 3 below.



Table 3. Erosive Potential for Soils Mapped on the Project Site (NRCS, 2023).

Soil Type	Runoff Class	Erosion Potential (K-Factor)
Kimberlina fine sandy loam, 0 to 2 percent slopes MLRA 17	Very Low	0.32
Kimberlina sandy loam, 2 to 9 percent slopes	Low	0.43
Milham sandy loam, 0 to 2 percent slopes MLRA 17	Low	0.43
Milham sandy loam, 2 to 5 percent slopes	Medium	0.43
Panoche clay loam, 0 to 5 percent slopes	Low	0.43

The erosion potential for soils increased when the soils are disturbed, the existing vegetation removed, and the soil is exposed to wind and rain drop impact. Additionally, steeper slopes will tend to erode faster if not protected with erosion and sediment control best management practices (BMPs). Mitigation of soil erosion may include selective grading, establishment of anchoring vegetation, design of runoff control features such as drainage ditches, and construction of erosion control features such as pavements and surface mats. These mitigation options will be addressed in the design-level evaluations for the Project.

2.6.7 Landforms that Could Develop Sinkholes or Other Hazards

Sinkholes and karst topography (limestone formations susceptible to formation of underground caverns) are known to exist in California (USGS, 2000). However, the Project Site is covered by Quaternary alluvial material and underlain by loosely-consolidated bedrock of the Tulare Formation. Therefore, the potential for sinkhole development at the Project Site is considered relatively low. Existing landforms are not consistent with landforms that could develop into sinkholes or other geologic hazards but should be addressed in the design level geotechnical investigation when site specific conditions are understood.

2.7 REVIEW OF AERIAL PHOTOGRAPHS

Historical aerial imagery from 1937, 1942, 1956, 1974, 1976, 1984, 1994, 2005, 2009, 2012, and 2016 reveal that the Project Site and adjacent properties were developed for oil and production since prior to 1937 (EDR, 2022).



3.0 CONCLUSIONS

Based on the currently planned development, it is Stantec's opinion that the Project Site has a low likelihood of surface fault rupture due to the distance from active faults. The Project Site may be subject to strong ground shaking due to seismic events. The anticipated depth to groundwater ranges from 150 feet bgs to 500 feet bgs at the Site. Based on the near surface soil conditions, anticipated subsurface soil conditions, and the low to moderate PGA, it is Stantec's opinion that the potential for liquefaction-related ground failure, including liquefaction, is low to moderate. The potential for lateral spreading is low, and the likelihood of surface subsidence is moderate on the Project Site.

Although expansive soils have not specifically been identified on the Project Site, the design-level geotechnical investigation will establish the types and depths of soils at the Project Site and recommend corrosion mitigation and minimum foundation depths to mitigate against the potential effects of frost.

The design-level geotechnical investigation will further assess the depth to groundwater below the Project Site, if needed. Due to the relatively flat topography of the Project Site, landslides are not considered a potential hazard. The development of sinkholes is unlikely but will be further assessed during the design level geotechnical investigation.



4.0 LIMITATIONS AND ASSUMPTIONS

Analyses performed at the desktop level rely on available, pre-existing data. The intent of the desktop approach is to provide practical results that guide our client as an exploratory, cost-saving measure before field work is considered and conducted. No field investigation was performed as part of this Assessment. Limitations and assumptions relevant to this Assessment include, but are not limited to, the following:

- The data analyzed herein is correct and adequate for this analysis.
- Data provided by the Client, including reports and maps, are correct and up to date.
- The activity state (e.g., active, inactive) of faults identified in this Assessment is not addressed herein.
- Slope stability within the Study Area or surroundings is not addressed herein.



5.0 REFERENCES

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E.2 U.S. Environmental Protection Agency Class VI Underground Injection Control (UIC) Permit Application (application available at the time of public review)

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ATTACHMENT E

TESTING AND MONITORING PLAN [40 CFR 146.90]

1. FACILITY INFORMATION

Facility Name: CarbonFrontier

Facility Contact: Randy Hoyle, Chief Carbon Solutions Officer
10000 Ming Ave., Bakersfield, CA 93311
(661) 665-5000, RWHoyle@aeraenergy.com

Well Information:

Well Number	County, State	Latitude	Longitude
CI1-64Z-27N	Kern County, CA	35°33'9.4877"N	119°48'26.3702"W
CI2-64Z-35N	Kern County, CA	35°32'32.6713"N	119°47'37.0682"W
CI3-64Z-35N	Kern County, CA	35°32'11.6457"N	119°47'7.5912"W
CI4-64Z-35N	Kern County, CA	35°31'55.4154"N	119°46'51.7864"W
27R-27N	Kern County, CA	35°33'2.4280"N	119°48'28.6103"W
55-26N	Kern County, CA	35°32'43.2520"N	119°47'32.7755"W
64-35N	Kern County, CA	35°31'44.3600"N	119°46'44.9788"W
9-1N	Kern County, CA	35°31'31.6480"N	119°46'37.0154"W
64-27N	Kern County, CA	35°32'38.0979"N	119°47'54.6576"W

Version History

File Name	Version	Date	Description of Change
Attachment E – Aera CCS Testing and Monitoring Plan.pdf	1	January 19, 2023	Original document
Attachment E – CarbonFrontier Testing and Monitoring Plan V2 04182024	2	April 18, 2024	Revisions made based on additional monitoring well and design of seismicity monitoring network

This Testing and Monitoring Plan (TMP) describes how Aera Energy LLC (Aera) will monitor the CarbonFrontier site pursuant to Title 40 of the Code of Federal Regulations (CFR) 146.90. In addition, the TMP will be used to confirm that that the wells are operating as planned, the carbon dioxide (CO_2) plume and pressure front are moving as predicted, and that there is no endangerment to Underground Sources of Drinking Water (USDWs). Monitoring data will also be used to validate and update the geological and reservoir models used to predict the CO_2 plume extent and to support Area of Review (AoR) reevaluations and non-endangerment demonstrations.

Aera will review and submit any amendments to the TMP no less than every 5 years in order to incorporate monitoring data, operational data, and AoR reevaluations, in accordance with 40 CFR

146.90(j). Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan (ERRP, **Attachment I**).

2. OVERALL STRATEGY AND APPROACH FOR TESTING AND MONITORING

The CarbonFrontier TMP and the monitoring, verification, and accounting (MVA) program detailed in the Quality Assurance and Surveillance Plan (QASP) will be used to demonstrate safe underground storage of injected CO_2 and USDW non-endangerment.

An AoR delineation model was constructed using a comprehensive data set as further described in **Section 2** of the Application Narrative and **Attachment B**. The proposed injection site is characterized by a porous and permeable injection zone, the 64 Zone Sandstones, overlain by a laterally continuous and impermeable confining layer, the Santos Shale Member, both of which are folded to form a broad anticline. The Santos Shale Member has an average true vertical thickness of approximately 200 feet (ft) and extends far beyond the AoR. The confining zone fractures are very limited and do not affect the macroscopic sealing capacity of the layer. Faults exist but available data suggests that these faults do not transmit fluids or pressure. Log and core analysis data display a difference of at least two orders magnitude in permeability between the 64 Zone Sandstones and the Upper Santos and Lower Santos shales. Overall, the site data indicate that the fluids will be confined to the 64 Zone Sandstones.

The Alluvium and Tulare formation (Fm) are potential USDWs over a portion of the area within the AoR that is outside the aquifer exemption boundary (for the Tulare Fm), and/or where groundwater with total dissolved solids (TDS) concentrations less than 10,000 milligrams per liter (mg/L) may exist (for the Alluvium and outside of the Tulare Fm exempt area). The injection zone is separated from these potential USDWs by numerous confining layers at depth. The injection zone is on average 7,250 ft true vertical depth (TVD) below the Tulare Fm across the North Belridge oil field anticline; whereas, the Alluvium, where present, is separated from the injection zone by a vertical distance of approximately 8,000 ft. The potential risks of CO_2 injection on groundwater quality in the potential USDWs are minimal due to: the limited aerial extent of the potential USDWs; numerous confining units (at the base of the Alluvium, within the Tulare Fm, and in deeper formations); the structural geometry of the North Belridge oil field anticline and injection zone; and the vertical distance separating the potential USDWs from the injection zone.

The injection wells will have continuous monitoring through pressure and temperature gauges. Pressure and temperature monitoring will enable immediate detection of deviations outside the operational limits. The injectate will be analyzed for fluid composition to verify geochemical composition and potential reaction with reservoir constituents. Each injection well will be tested annually for external mechanical integrity and undergo a pressure fall-off test every five years.

Subsurface monitoring will consist of CO_2 plume and pressure front monitoring, groundwater monitoring, and seismicity monitoring. Monitoring wells 1-28N, 39-26N, and 27-1N will be used to monitor the CO_2 plume through direct and indirect methods, including fluid sampling of the injection zone, pulsed neutron logging, and distributed temperature sensing (DTS). The pressure front will be monitored directly at wells 1-28N, 39-26N, and 27-1N. Monitoring wells 1-28N and

25-26N will be monitored for potential changes in fluid geochemistry above the injection zone in the Agua Sandstone, which is the first permeable interval above the injection zone, directly overlying the primary confining layer. These wells will also be analyzed by pulsed neutron logging in the Agua Sandstone for potential CO_2 leakage. Monitoring well 35X-27N will be used for fluid sampling and pressure monitoring in the Lower Carneros Sandstone, which overlies the secondary confining layer.

A microseismic monitoring network, in conjunction with the California Integrated Seismic Network, will be used to monitor for microseismic events at or above magnitude 1.0. Estimates of earthquake shaking potential prepared by the California Geological Survey (CGS) and United States Geological Survey (USGS) indicate that the AoR is located in an area of moderate seismic risk; however, while there are active faults within the region that have the potential to produce significant sharking, none are expected to induce subsurface ruptures within the AoR. All of the faults that are present within the AOI are interpreted to be inactive. The ERRP (**Attachment I**) provides details on the appropriate response actions.

This TMP and the **QASP** details the continuous pressure and temperature monitoring of the injection and monitoring wells in addition to periodic well logging, mechanical integrity testing, and subsurface fluid and CO_2 stream analysis used to demonstrate safe operation and storage of the injected CO_2. This TMP and **QASP** will provide early detection of operational or well integrity issues and demonstrate USDW non-endangerment. A summary of the testing and monitoring strategies to be conducted is given in **Table 1**.

2.1 Quality Assurance Procedures

A **QASP** for the testing and monitoring activities, required pursuant to 146.90(k), is provided as **Appendix A** to this TMP.

2.2 Reporting Procedures

Aera will report the results of testing and monitoring activities to the U.S. Environmental Protection Agency (EPA) in compliance with the requirements under 40 CFR 146.91.

Table 1: Summary of Testing and Monitoring Activities

Activity	Location(s)	Method	Pre-Injection Frequency	Injection Frequency	PISC Frequency	Analytical Technique	Lab/Custody	Purpose
CO_2 stream analysis	After compression and processing and before injection wellheads	Direct sampling	Once	Quarterly	N/A	Chemical analysis	California certified lab	Monitor injectate
Injection rate and volume	Before wellhead	Flow meter	N/A	Continuous	N/A	Direct measurement	N/A	Monitor injectate rate and volume
Injection temperature/ pressure	Before wellhead	Temperature/ pressure gauge	N/A	Continuous	N/A	Direct measurement	N/A	Monitor injectate temperature, pressure, and well integrity
Annular pressure	Wellhead	Pressure gauge	N/A	Continuous	None	Direct measurement	N/A	Monitor annular pressure and well integrity
Downhole pressure/ temperature	Injection wells	Downhole gauge and DTS	Continuous	Continuous	None	Direct measurement	N/A	Monitor reservoir pressure/injection temperature/well integrity
	Monitoring wells	Downhole gauge and DTS	Continuous	Continuous	Quarterly	Direct measurement	N/A	Monitor reservoir pressure/injection temperature/well integrity
Internal mechanical integrity	Injection wells and Monitoring wells	Annulus pressure test via annulus pressure gauge	Once	Every five years	None	Direct measurement	N/A	Monitor internal mechanical integrity of wellbore
External mechanical integrity	Injection wells	Temperature log/DTS, acoustic log, or oxygen activation log	Once	Annual	Once, prior to plugging	Physical analysis	N/A	Monitor external mechanical integrity
	Monitoring wells	Temperature log/DTS, acoustic log, or oxygen activation log	Once	As needed	As needed	Physical analysis	N/A	Monitor external mechanical integrity
	Injection wells	Ultrasonic casing/ cement log	Once	As needed	None	Physical analysis	N/A	Monitor well integrity
Corrosion monitoring	After compression	Coupon	Once	Quarterly	None	Physical analysis	N/A	Monitor well integrity
Pressure fall-off testing	Injection wells	Pressure gauge	Once	Every 5 years	None	Direct Measurement	N/A	Monitor well and reservoir integrity

Activity	Location(s)	Method	Pre-Injection Frequency	Injection Frequency	PISC Frequency	Analytical Technique	Lab/Custody	Purpose
Geochemistry monitoring	Monitoring wells: Agua Sandstone (I-28N, 25-26N); Lower Carneros Sandstone (35X-27N)	Fluid sampling	Once	Annually	Every two years	Chemical analysis	California certified lab	Monitor for CO_2 leakage
CO_2 plume tracking	Monitoring wells: 64 Zone (I-28N, 39-26N, 27-1N)	Fluid sampling	Once	Annually	Every two years	Direct Measurement	California certified lab	Directly monitor CO_2 plume migration
	Monitoring wells: 64 Zone (I-28N, 39-26N, 27-1N)	Pulsed neutron wireline log	Once	Annually	Every two years	Indirect measurement	N/A	Indirectly monitor CO_2 plume migration
	Monitoring wells: Agua Sandstone (I-28N, 25-26N)	Pulsed neutron wireline log	Once	Annually	Every two years	Indirect measurement	N/A	Monitor for CO_2 leakage
Pressure front tracking	Monitoring wells: 64 zone (I-28N, 39-26N, 27-1N); Agua Sandstone (I-28N, 25-26N); Lower Carneros Sandstone (35X-27N)	Pressure gauge	Continuously	Continuously	Continuously	Direct Measurement	N/A	Monitor pressure front migration
Seismic activity monitoring	AoR and within 1 mile radius of injection wells	Borehole DAS (38-35N) and public surface seismic stations	Continuous	Continuous	None	Indirect measurement	N/A	Monitor natural and induced seismic activity of 1.0 for reservoir, well, facility, and pipeline integrity
	Within 1 mile radius of injection wells	California Integrated Seismic Network	Continuous	Continuous	Continuous	Indirect measurement	N/A	Monitor seismic activity of magnitude 2.7 or greater for reservoir, well, facility, and pipeline integrity

3D: three dimensional
DAS: distributed acoustic sensing
DTS: distributed temperature sensing
N/A: not applicable
PISC: post-injection site care

3. CARBON DIOXIDE STREAM ANALYSIS [40 CFR 146.90(A)]

Aera will analyze the CO_2 stream during the operation period to yield data representative of its chemical and physical characteristics and meet the requirements of 40 CFR 146.90(a).

3.1 Sampling Location and Frequency

Sampling will take place quarterly each year starting from 3 months, 6 months, 9 months, and 12 months after the date of commencement/injection. The collected samples will be analyzed by an analytical laboratory.

Prior to the commencement of injection, Aera will conduct a pre-injection analysis of the CO_2 injection stream with samples collected from monitoring points upstream of CO_2 injection wellheads. Aera will submit these data to EPA as part of the permit application requirements [146.82(a)(7)(iv)].

The proposed CO_2 stream will be sourced from a mixture of Aera's planned CO_2 capture facilities, located in the adjacent South Belridge oil field, and from third-party suppliers, received by pipeline or truck. These streams will be tested and reported to EPA according to the requirements of 40 CFR 146.82(a)(7)(iv). The proposed CO_2 streams are discussed in more detail in **Sections 1 and 7** of the Application Narrative.

3.2 Analytical Parameters

Aera will analyze the CO_2 stream for the constituents identified in **Table 2** using the methods listed.

Table 2: Summary of Analytical Parameters for CO_2 Stream

Parameter	Analytical Method(s)
Carbon dioxide (CO_2)	ASTM D1945-14 (2019). Gas Chromatography (GC) with thermal conductivity detector (TCD)
Moisture (water vapor, H_2O)	ISBT 3.0. Electrometric moisture analyzer
Oxygen (O_2), Nitrogen (N_2)	ASTM D1945-14 (2019). GC/TCD
Argon (Ar)	ISBT 4.0. GC with discharge ionization detector (DID) for Ar
Hydrogen (H_2)	ASTM D1945-14 (2019). GC/TCD
Carbon monoxide (CO)	ISBT 5.0. GC with pulsed discharge ionization detector (PDID)
Oxides of nitrogen (NO_x)	ISBT 7.0. Colorimetric tubes, able to detect NO and NO_2
Ammonia (NH_3)	ISBT 6.0. Ammonia-specific colorimetric detector tube
Total hydrocarbons (THC)	ISBT 10.0. GC with flame ionization detector (FID)
Methane (CH_4)	ASTM D1945-14 (2019). GC/TCD
Aromatic hydrocarbons	ISBT 12.0. GC with photoionization detector (PID)
Total sulfur (TS)	ISBT 13.0. GC with sulfur chemiluminescent detector (SCD) Apply ISBT 14.0 if SO_2 level is expected to exceed 1 ppm
Sulfur dioxide	ISBT 14.0. GC/SCD
Hydrogen sulfide (H_2S)	ASTM D1945-14 (2019). GC/TCD
Ethanol (C_2H_6O)	EPA Method 8260B. GC with mass spectroscopy (MS)
^{13}C isotope	USGS Techniques and Methods 5-D4. GC with dual-inlet isotope ratio mass spectrometry (GC-IRMS)

3.3 Sampling Methods

Samples will be collected and prepared based on recommendations of the analytical methods included in **Table 2**.

Sample containers will be labeled with durable labels and indelible markings. A unique sample identification number, sample description, sampling date, location, personnel, and their signatures will be recorded on each sample container. Please refer to **Section 2.3** of the **QASP**. for further details.

3.4 Laboratory to be Used / Chain of Custody and Analysis Procedures

Samples will be analyzed by California-certified laboratories using standard method-specific procedures. Selected laboratories, methods, and detection limits are listed in the **QASP**, along with the required chain of custody procedures.

Chain of custody information will include sampling date, sample description, type of sample, sampler name, location of sampling, methods for analysis, preservatives in the sample container, requested turnaround time for sample results, and the names and signatures of the people relinquishing and receiving the sample(s). A separate laboratory will be contracted to perform the carbon ^{13} isotope analysis. Details of the sample chain of custody and the analysis procedures are included in the **QASP** document.

4. CONTINUOUS RECORDING OF OPERATIONAL PARAMETERS [40 CFR 146.88(E)(1), 146.89(B) AND 146.90(B)]

Aera will install and use continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added; and the temperature of the CO_2 stream, as required by 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

Safety valves and system equipment will be installed and operated following American Petroleum Institute Recommended Practice 14B. Biannual testing of surface and subsurface safety valves will be conducted to document their ability to hold pressure. Aera has standard operating procedures to function-test surface safety valves in existing facilities. The surface safety valves, also known as emergency shutdown valves, will be calibrated every 6 months to document their ability to hold pressure. Aera will conduct a function test of the master valve and associated wellhead pipeline isolation valves by fully opening and closing the valves on an annual basis. In addition, Aera will demonstrate valves can hold pressure by conducting an annual leak test using pressure gauges installed on either side of the valves.

Aera will use its existing supervisory control and data acquisition (SCADA) system to monitor equipment, rapidly identify issues that require repairs, and automatically initiate shut-in by a fail-safe actuated gate valve if a critical parameter is exceeded. In addition, Aera's Integrated Operating Control Center (IOCC) is staffed continuously by trained operators to monitor alarms and wells. If there is a triggered alarm, the IOCC will be able to shut-in injection immediately. An operator can then be dispatched to the well site to troubleshoot the alarm and perform needed repairs. If Aera finds a surface or subsurface safety valve inoperable, injection will be shut-in and repairs will be made within 90 days. If an extension of 90 days is needed, a request for approval will be sent to the Underground Injection Control (UIC) Program Director.

In compliance with 40 CFR 146.89(b), Aera will begin continuous monitoring of operational parameters by conducting an initial annulus pressure test on each injection and monitoring well to establish internal mechanical integrity prior to the start of CO_2 injection. Although exact procedures for specific wells will vary based on conditions and equipment at the location and below surface, in general, Aera will use the procedure below for conducting each annulus pressure test:

- Notify the UIC Program Director in writing 30 days in advance of the annulus pressure test, in compliance with 40 CFR 146.91(d)(3).
- Fill the tubing/casing annulus to surface with corrosion inhibited packer fluid.
- Rig up the pump truck and connect to the tubing/casing annulus at surface.
- Increase pressure on the tubing/casing annulus to the injection maximum allowable surface injection pressure and mechanically isolate the annulus.
- Hold pressure for 30 minutes. Capture test data on a pressure recording chart and in a data file with a reading at least once/minute.

- Less than a 3% drop or 3% build in pressure from the initial pressure shall constitute a successful annulus pressure test.
- Bleed off pressure, shut in the tubing/casing annulus. Rig down the pump truck.
- If the test is successful, report the results to the UIC Program Director within 30 days, as per 40 CFR 146.91(b)(1).
- If the test is unsuccessful, report the results to the UIC Program Director within 24 hours, as per 40 CFR 146.91(c)(4) and commence an investigation to evaluate the cause of the test failure.
    - In the event that a loss of mechanical integrity is discovered, as per 40 CFR 146.88(f), Aera will:
        - Cease injection.
        - Take the steps reasonably necessary to determine whether there may have been a release of the injected CO_2 stream or formation fluids into any unauthorized zone.
        - Notify the UIC Program Director within 24 hours.
        - Restore and demonstrate mechanical integrity to the satisfaction of the UIC Program Director prior to resuming injection.

4.1 Monitoring Location and Frequency

Following the initial annulus pressure test, as required under 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b), Aera will continuously monitor and record operational parameters at each injection well including surface and downhole injection pressure, injection rate and volume, surface and downhole temperature, surface and downhole pressure on the annulus between the tubing and long string casing, and the annulus fluid volume as detailed in **Table 3**.

Table 3: Sampling Devices, Locations, and Frequencies for Continuous Monitoring

Test Description	Device(s)	Location	Minimum Sampling Frequency[a]	Min. Recording Frequency[b]
Injection Pressure	Direct Measurement by Pressure Gauge	Surface and downhole	Continuous	Continuous [c]
Injection Rate	Flowmeter	Surface	Continuous	Continuous [c]
Injection Volume	Calculated	Surface	Continuous	Continuous [c]
Annulus Pressure	Direct Measurement by Pressure Gauge	Surface and Above Packer	Continuous	Continuous [c]
Annulus Fluid Volume	Direct Measurement of Fluid Added	Surface	As Required [d]	As Required [d]
CO_2 Stream Temperature	Temperature Gauge	Surface	Continuous	Continuous [c]
Temperature	DTS	Surface and Downhole	Continuous	Continuous [c]
Acoustic	DAS	Surface and Downhole	Continuous	Continuous [c]

Notes:
[a] Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every 2 seconds and save this value in memory.
[b] Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.
[c] This can be the average of the sampled readings over the period, or maximum or minimum, as appropriate.
[d] Fluid volume added or removed to maintain annular pressure will be recorded on the date performed and submitted to the regulatory authority.

4.2 Monitoring Details

Calibration standards, precision, and tolerances for the instruments in **Table 3** will meet or exceed accepted industry standards. Formulas used for calculation of parameters and conversion factors will be provided by the equipment supplier and will comply with accepted industry standards for the specific equipment and be appropriately adjusted for the CO_2 stream and composition parameters.

Data collected from the activities detailed in **Table 3** will be stored in Aera's surveillance system starting prior to the beginning of CO_2 injection so that baseline values, averages, and trends can be established for the parameters at each well. After the start of CO_2 injection, trends will be continuously monitored on each well and compared to prior trends so that changes can be quickly recognized. Total injection rates and volumes into injection wells will be analyzed relative to total CO_2 supplied for injection from surface facilities.

Well by well data trends that are steady and predictable, and in accordance with both CO_2 volumes supplied for injection and expected reservoir pressure increases from injection, will suggest the presence of satisfactory mechanical integrity. Rapid changes in parameters such as annulus

pressure, fluid added to the annulus, and injection rate, or unexpected trends in these data, may provide cause for an investigation of mechanical integrity.

In the event that a loss of mechanical integrity is discovered, as per 40 CFR 146.88(f), Aera will:

1. Cease injection.
2. Take the steps reasonably necessary to determine whether there may have been a release of the injected CO_2 stream or formation fluids into any unauthorized zone.
3. Notify the UIC Program Director within 24 hours.
4. Restore and demonstrate mechanical integrity to the satisfaction of the UIC Program Director prior to resuming injection.

5. CORROSION MONITORING

In compliance with 40 CFR 146.90(c), Aera will monitor well materials during the injection operation period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance. Aera will use the corrosion coupon method, as per 40 CFR 146.90(c)(1) and collect and evaluate samples according to the description below.

5.1 Monitoring Location and Frequency

Coupon samples will be attached to individual holders and inserted into a corrosion monitoring flow-through loop that is connected to the main CO_2 transport pipeline. Aera will place the loop in a location downstream of the process compression/dehydration/pumping equipment and upstream of wellheads. A parallel stream of high-pressure CO_2 will be routed from the main CO_2 transport pipeline through this corrosion monitoring loop and then back into a lower pressure point upstream in the system. The corrosion monitoring loop will operate when injection is active. No other equipment will act on the CO_2 past this point; therefore, this location will provide representative exposure of the coupon samples to the CO_2 composition, temperature, and pressure that will be incurred at wellheads and below surface. The holders and location of the system will be included in the pipeline design and will allow for continual injection during sample removal.

Aera will conduct initial baseline evaluations of corrosion coupon samples upon authorization to inject, and then quarterly following the start of injection, as per 40 CFR 146.90(c). An additional evaluation of coupons will occur within 30 days after any stop in injection, followed by a return to the quarterly monitoring schedule. If the CO_2 injection rate changes significantly, Aera will adjust the monitoring frequency to demonstrate sufficient characterization of well construction materials.

5.2 Sample Description

Corrosion coupon samples will consist of the same materials used in injection well construction that are expected to be in contact with the CO_2 stream. The materials are listed in **Table 4** below. Each coupon will be weighed, measured, and photographed prior to initial exposure.

Table 4: List of Equipment Coupons with Materials of Construction

Equipment Coupon	Material of Construction
Long-String Casing (6000ft – 8000 ft)	Modified 13Cr110
Liner (7700ft – 8500ft)	Modified 13Cr95
Injection Tubing	Modified 13Cr80
Wellhead	Flow wetted surfaces are expected to consist of F6NM in CO_2 Injection wells and F22 with Alloy 625 Clad in monitoring wells.
Packer	Alloy 718 or equivalent for packers and EPDM Elastomers

5.3 Monitoring Details

The coupons will be handled and assessed for corrosion using the ASTM International (ASTM) G1-03 1999 standard for preparing, cleaning, and evaluating corrosion test specimens. The coupons will be photographed, visually inspected with a minimum of 10× power, dimensionally measured (to within 0.0001 in.) and weighed (to within 0.0001 gm). An ongoing record of the appearance, dimension, and weight, of each respective coupon sample will be maintained showing changes from previous evaluations. Rates and trends of corrosion will be determined for each respective sample, and changes in rates and trends will be noted. As warranted based on observed coupon corrosion rates, Aera may conduct additional downhole tests in wells, only as needed, for comparison and to demonstrate continual mechanical integrity.

5.3.1 Additional Downhole Corrosion Tests

An initial casing inspection log will be run prior to commencing injection operations as per 40 CFR 146.87(a)(4)(iv) and will provide baseline casing wall thickness measurements to which future logs will be compared. Subsequent casing inspection logs will be run as warranted based on observed coupon corrosion rates and trends or as required by the UIC Program Director, as per CFR 146.89(d) and 146.90(e). Aera will provide written notification to the UIC Program Director at least 30 days of prior to running these logs, as per 40 CFR 146.87(f). Casing inspection log measurement showing a wall thickness reduction greater than 20 percent from the initial log will be evaluated and may warrant corrective action.

6. ABOVE CONFINING ZONE MONITORING

Aera will monitor groundwater quality for potential geochemical changes above the confining zone during the operation period to meet the requirements of 40 CFR 146.90(d).

Aera will conduct pressure, temperature, and pulsed neutron logging along with fluid composition monitoring in the sandstone units directly overlying the primary confining unit and the secondary confining unit. This testing will allow for early detection of potential leakage from the injection zone. The monitoring wells will be located on Aera property.

The two sandstone units in which monitoring will be conducted are as follows:

- Agua Sandstone, approximately 7,500 to 7,800 ft TVD: permeable zone immediately above the primary confining layer (Lower Santos Shale)

- Lower Carneros Sandstone, approximately 6,550 to 7,150 ft TVD: permeable zone directly above the secondary confining layer (Upper Santos Shale)

A generalized stratigraphic column for the North Belridge oil field is depicted in **Figure 1**.

6.1 Monitoring Location and Frequency

Table 5 shows the planned monitoring methods, locations, and frequencies for groundwater quality and geochemical monitoring above the confining zone. The locations of the project monitoring wells are shown in **Figure 2**. These wells are located to allow for early detection of potential leakage from the injection zone into the permeable Agua or Lower Carneros Sandstones, which directly overlie the primary and secondary confining layers, respectively.

Pulsed neutron logging will be used to understand the porosity of different sections of the monitoring zone and to monitor for the presence of fluids and potential CO_2 leakage. The saturation will be used to quantify the amount of CO_2 leaking through the primary confining layer, with the location used to identify a potential pathway of the leakage and what corrective actions may be necessary.

Pressure and temperature will be monitored continuously to identify indicators of potential leakage from the injection zone to the monitoring zone. An increase in pressure and decrease of temperature in the monitoring zone may indicate leakage of CO_2 or other displaced gases and/or reservoir fluids from the injection zone into the Agua or Lower Carneros Sandstones. Because pressures in the monitoring zone are expected to be generally stable, variations from baseline identified through fluid sampling and analysis may provide an additional indicator of potential leakage of CO_2 or displacement of reservoir fluids into the monitoring zones.

Fluid will be analyzed for geochemical properties (CO_2 concentrations, pH, and metal ions) to detect potential leakage from the injection zone as evidenced by increases in CO_2 or metals concentrations due to increased acidity during injection. While changes are not anticipated, as the project progresses and the CO_2 plume migrates within the AoR, data will be analyzed to evaluate if additional monitoring is warranted.

Baseline monitoring will be conducted prior to injection to establish conditions against which to compare future monitoring data. A numerical database will be used to establish statistical bounds of each analytical parameter for comparison of the baseline to injection period data. Significant abnormalities or changes will be used to evaluate sequestration efficacy and if additional sampling events may be warranted. Abnormalities suggestive of leakage could include increased TDS, change in cation and/or anion signature(s), increase in CO_2 concentrations, pH changes, or changes in dissolved metal concentrations.

Table 5: Monitoring of Fluid Composition and Geochemical Changes Above the Confining Zone

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency[1,2]
Agua Sandstone (approximately 7,500-7,800 ft TVD)	Fluid sampling	Monitoring wells 1-28N and 25-26N	Northern half of injection area	Baseline: Once prior to first injection. During injection: annually
	Temperature and Pressure Monitoring	Monitoring wells 1-28N and 25-26N	Vertical distribution within well casings (based upon geophysical data indicating most transmissive interval within the perforation)	Continuous
	Pulsed neutron logging	Monitoring wells 1-28N and 25-26N	Along wellbore	Baseline: Once prior to first injection During injection: annually
Lower Carneros Sandstone (approximately 6,550–7,150 ft MD)	Pressure	Monitoring well 35X-27N	Above injection zone	Continuous
	Fluid sampling	Monitoring well 35X-27N	Above injection zone	Baseline: Once prior to first injection During injection: annually

Notes:
1. Annual sampling will occur up to 45 days before the anniversary date of authorization of injection each year.
2. Logging will take place up to 45 days before the anniversary date of authorization of injection each year.

MD: measured depth

6.2 Analytical Parameters

Table 6 identifies the parameters to be monitored and the analytical methods. Fluid sampling is planned to include an extensive set of chemical parameters to establish aqueous geochemical data. Parameters will include selected constituents that:

- Have primary and secondary EPA drinking water maximum contaminant levels;
- Are the most responsive to interaction with CO_2 or brine;
- Are needed for quality control; and
- May be needed for geochemical modeling.

If new information or updates to the geochemical modeling based on pre-operational testing identifies additional subsurface geochemical processes (e.g., potential changes in subsurface properties or potential contaminant mobilization), the list of subsurface fluid analytical parameters may be updated.

Table 6: Summary of Analytical and Field Parameters for Fluid Sampling

Parameters	Analytical Methods
Cations/metals (aluminum, barium, calcium, manganese, sodium, potassium, iron, arsenic, magnesium, silica, cadmium, chromium, copper, lead, selenium, titanium, zinc)	EPA Method 200.7/200.8 or similar
Anions (chloride, sulfate, sulfide, bromide, fluoride, nitrate)	EPA Method 300.0/300.1 or similar; SM 4500 for sulfide
Dissolved gases - CO_2 - CH_4 - O_2 - H_2S (field)	 RSK-175M RSK-175M SM 4500 OG or RSK-175M Field
Total dissolved solids	EPA Method 160.1/SM 2540 C
Alkalinity	SM 2320 B/EPA Method 310.1
Field measurements: - pH - Specific conductance - Temperature	 EPA Method 150.1/SM4500-H+B EPA Method 120.1 Thermocouple
Hardness	SM 2340C
Turbidity	SM 2130B
Specific gravity	SM2710F
Water density	SM2710F
Dissolved inorganic carbon isotopes ($\delta^{13}C$)	Mass spectrometry

6.3 Sampling Methods

Sampling will be performed in accordance with the **QASP**. Samples will be handled and shipped to the selected analytical laboratory under standard chain-of-custody procedures, detailed in the **QASP** and in the following section.

6.4 Laboratory to be Used/Chain of Custody Procedures

Samples will be analyzed by California-certified laboratories using standard method-specific procedures. Selected laboratories, methods, and detection limits are listed in the **QASP**, along with required chain of custody procedures.

Chain of custody information will include sampling date, sample description, type of sample, sampler name, location of sampling, methods for analysis, preservatives in the sample container, requested turnaround time for sample results, and the names and signatures of the people relinquishing and receiving the sample(s).

6.5 Surface Air and/or Soil Gas Monitoring

Pursuant to 40 CFR 146.90 (h)(1) through (3), surface air monitoring and/or soil gas monitoring may be required by the EPA for Class VI wells based on potential endangerment to USDWs within the AoR. There is little potential for USDW endangerment within the AoR for numerous reasons (**Section 2.7** of the Application Narrative) which include an aquifer exemption for portions of the North Belridge oil field [EPA, 2019], groundwater TDS concentrations exceeding the 10,000 mg/L threshold to be considered a USDW in parts of the Alluvium [Wood Environmental and Infrastructure Solutions, Inc., 2021], and where there is groundwater within the Alluvium with

TDS potentially less than 10,000 mg/L, there are multiple confining layers and low risk for communication with the injection zone. In the portions of the AoR where there is no aquifer exemption and TDS concentrations in groundwater are unknown, if groundwater occurs within the Tulare Fm and/or Alluvium, it is considered a potential USDW; however, the potential for endangerment caused by CO_2 injection is still low due to the anticlinal geometry, presence of multiple confining units, and the limited extent of these potential USDWs.

If the results of planned pre-operational testing identify significant uncertainties about the geologic setting, EPA may mandate surface air and/or soil gas monitoring be conducted under 40 CFR 146.90; if this occurs, Aera will comply with these requirements. Class VI injection wells are also subject to Subpart RR of the EPA Greenhouse Gas (GHG) Reporting Program. This rule requires facilities to develop and implement an MRV plan that is site specific and details the maximum monitoring area (MMA), active monitoring area (AMA), potential leakage pathways, strategies for detecting and quantifying leakage, and general information on CO_2 received for injection. Aera will comply with these requirements by developing and implementing an EPA-approved MRV plan.

7. EXTERNAL MECHANICAL INTEGRITY TESTING

Aera will conduct at least one of the tests presented in **Table 7** periodically during the injection phase to demonstrate external mechanical integrity as required at 146.89(c) and 146.90.

7.1 Testing Location and Frequency

To demonstrate the external mechanical integrity of the CO_2 injection wells, Aera will conduct at least one of the tests presented in **Table 7** annually during the injection phase, as required in 146.89(c) and 146.90(e). External mechanical integrity tests will be also performed on monitoring wells if irregularities are observed in continuous measurements of the surface tubing and annulus pressure or during routine logging, testing, and sampling programs.

Table 7: Annual External Mechanical Integrity Tests (MITs)

Test Description	Location
Temperature	Conventional wireline well log or DTS
Acoustic	Conventional wireline noise log
Oxygen Activation	Conventional wireline well log

7.2 Testing Details

Aera will run at least one of the tests in **Table 7** every year, within 45 days of the respective anniversary date of the start of injection on each CO_2 injection well, and as warranted on monitoring wells.

DTS allows for continuous temperature profiles over the installed depth rather than measurements at fixed points. DTS fiber optic cable will be cemented in the annulus and will be utilized from the surface to top of the confining layer in the injection wells to continuously provide accurate temperatures profiles of the injection stream. The continuous temperature data can be analyzed to

provide information about the specific depths that the CO_2 enters the formation. Abnormal temperature profiles may indicate mechanical integrity concerns or unexpected leakage of CO_2. DTS will be installed in monitoring wells, 1-28N, 39-26N, 25-26N and 27-1N.

The following general procedure will be followed for logging:

- Notify the UIC Program Director of the logging schedule at least 30 days prior to logging, per 40 CFR 146.87(f).
- Move in and rig up wireline logging unit. Assemble the temperature, oxygen activation, or noise logging tools.
- Rig up wireline pressure control equipment and test for leaks.
- Run in the hole with tools to plug back total depth and log to surface per industry-cased hole logging standards.
- Recover tools and rig down.
- Interpret log results.
- As required in 40 CFR 146.88(f), if there is an indication of a loss of mechanical integrity:
    - Cease injection;
    - Take the steps reasonably necessary to determine whether there may have been a release of the injected CO_2 stream or formation fluids into any unauthorized zone;
    - Notify the UIC Program Director within 24 hours;
    - Restore and demonstrate mechanical integrity to the satisfaction of the UIC Program Director prior to resuming; and
    - Notify the UIC Program Director when injection can be expected to resume.
- If mechanical integrity is confirmed, prepare and submit a report on the interpreted logging results to the UIC Program Director within 30 days, as required in 40 CFR 146.91(b).

8. PRESSURE FALL-OFF TESTING

Aera will perform pressure fall-off tests during the injection phase as described below to meet the requirements of 40 CFR 146.90(f).

8.1 Testing Location and Frequency

A pressure fall-off test will be conducted on each operational Class VI injection well, at least once every 5 years throughout the injection phase of the project. Results of pressure fall-off tests will be submitted to UIC Program Director electronically within 30 days of the test [40 CFR 146.91(e) and 146.91(b)(3)].

Aera will conduct pressure fall-off testing according to the procedure below.

8.2 Testing Details

A pressure fall-off test is composed of a period of injection followed by a period of shut-in. Aera will hold and record a constant injection rate while maintaining as stable operating conditions as practically possible prior to the test shut-in period. The injection will then be shut in instantaneously at the wellhead or as near the wellhead as feasible. One or more pressure gauges will record the pressure either downhole, at or near the wellhead or both downhole and at the wellhead. Each gauge will be of type that meets or exceeds American Society of Mechanical Engineers B 40.1 Class 1A (1% accuracy across full range). The surface pressure gauge will cover the 0 to 3,000-psi range while the downhole gauge will cover the 0 to 8,000 psi range. Exact gauges specifications will be included in each test report.

Overall, measures will be taken to acquire test data of sufficient quality, over sufficient time periods, to enable clear interpretation of the test results and an evaluation of the near-wellbore formation properties.

9. CARBON DIOXIDE PLUME AND PRESSURE FRONT TRACKING

Aera will employ direct and indirect methods to track the extent of the CO_2 plume and the presence or absence of elevated pressure during the operation period to meet the requirements of 40 CFR 146.90(g). As shown below, the plan and schedule are designed to monitor the free-phase CO_2 plume location, thickness, and saturation; track the pressure development within the AoR over time; validate computational modeling results; and demonstrate the operations are not leading to elevated CO_2 or brine leakage or seismic risks.

Annual fluid sampling, pulsed neutron logging, and continuous measurements of injection zone temperature and pressure within four monitoring wells will provide a robust mechanism for tracking the extent of the CO_2 plume and the presence or absence of elevated pressures.

Monitoring well locations were selected based on simulated plume and pressure front migration and are in locations to validate the simulation results with the monitoring plan outlined below. **Figures 3 and 4** show the predicted evolution of the CO_2 plume and pressure front, respectively, during and following injection.

9.1 Plume Monitoring Location and Frequency

Table 8 presents the methods that Aera will use to monitor the position of the CO_2 plume, including the activities, locations, and frequencies Aera will employ. The parameters to be analyzed as part of fluid sampling in the injection zone and associated analytical methods are the same as for above confining zone monitoring and are presented in **Table 6**.

Quality assurance procedures for these methods are presented in **Section 1.4** of the **QASP**.

Table 8: CO_2 Plume Monitoring Activities

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Direct Plume Monitoring				
64 Zone	Fluid sampling	1-28N	1 Point Location: ~8,029 - 8,358 ft MD	Annual
64 Zone	Fluid sampling	39-26N	1 Point Location: ~7,975 - 8,243 ft MD	Annual
64 Zone	Fluid sampling	27-1N	1 Point Location: ~8,001 - 8,302 ft MD	Annual
Indirect Plume Monitoring				
64 Zone	Pulsed neutron logging	1-28N	Survey log: ~7,505 - 8,450 ft MD	Quarterly until plume identified, then annual
64 Zone	Pulsed neutron logging	39-26N	Survey log: ~7,667–8,300 ft MD	Quarterly until plume identified, then annual
64 Zone	Pulsed neutron logging	27-1N	Survey log: ~7,594 - 8,278 ft MD	Quarterly until plume identified, then annual
64 Zone	DTS	1-28N	Entire Wellbore	Continuous
64 Zone	DTS	39-26N	Entire Wellbore	Continuous
64 Zone	DTS	27-1N	Entire Wellbore	Continuous

9.2 Plume Monitoring Details

9.2.1 Direct Methods

Fluid Sampling

The primary method for direct plume monitoring will be fluid sampling from the injection zone to detect changes from baseline values, indicative of the CO2 plume's presence. Samples will be collected annually, up to 45 days before the anniversary date of authorization of injection each year. The parameters to be analyzed as part of the fluid sampling in the target injection zone and the analytical methods are presented in Table 6.

9.2.2 Indirect Methods

Distributed Temperature Sensing

Distributed temperature sensing allows for continuous temperature profiles over the installed depth rather than measurements at fixed points The continuous temperature data can be analyzed to provide information about the specific depths that the CO_2 enters the formation. Abnormal temperature profiles may indicate mechanical integrity concerns or unexpected leakage of CO_2. DTS will be installed in the 64 Zone monitoring wells, 1-28N, 39-26N, and 27-1N, to identify temperature changes that may indicate the CO_2 plume's arrival at that location. DTS will also be installed in the Agua sandstone monitoring well 26-25N to evaluate temperature changes above the injection zone.

Pulsed Neutron Logging

The CO_2 plume location will be tracked using pulsed neutron logging that will provide high-resolution vertical data around the wellbore of each monitoring well. The saturation of CO_2 in the target formation will be estimated by measuring the die-away time of a short neutron pulse. The die-away time is a function of the porosity and the fluid types in the rock. Pulsed neutron log accuracy and calibration are discussed in the **QASP** (**Section 1.4.7**)

An initial pulsed neutron log will be performed before the CO_2 plume reaches the monitoring well and will serve as a baseline that future measurements will be compared against. Increases in CO_2 saturation relative to baseline may indicate that the plume has reached the monitoring well. These data will be used in reevaluations of the AoR (**Attachment B**).

9.3 Pressure-Front Monitoring Location and Frequency

9.3.1 Distributed Pressure Sensing

Aera will deploy pressure gauges in each monitoring well to continuously monitor reservoir pressure and detect the position of the pressure front. **Table 9** presents the methods that Aera will use to monitor the position of the pressure front, including the activities, locations, and their frequencies.

Quality assurance procedures for these methods are presented in **Section 1.4.7** of the **QASP**.

Table 9: Pressure Front Monitoring Activities

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Direct Pressure-Front Monitoring				
64 Zone	DTS/Pressure Gauge	1-28N	Distributed measurement to ~8,450 ft MD	Continuous
64 Zone	DTS/Pressure Gauge	39-26N	Distributed measurement to ~8,243 ft MD	Continuous
64 Zone	DTS/Pressure Gauge	27-1N	Distributed measurement to ~8,278 ft MD	Continuous

9.4 Seismicity Monitoring

A microseismic monitoring network will be utilized to detect microseismic events at or above magnitude 1.0 in real time. Events with an event magnitude of at least 1.0 will be detectable across the entirety of the AoR from surface to at least 2,000 ft below the injection zone and at least 1 mile radius of the injection wells. Future technologies may be added to the seismic monitoring network pending evaluation and the approval of the UIC Program Director. Additionally, the California Integrated Seismic Network will be monitored continuously for indication of an earthquake of magnitude 2.7 or greater occurring within a radius of one mile of injection operations from commencement of injection activity to its completion. Aera will respond to seismic events with an epicenter in the AoR in accordance with the Seismic Response System for seismic events >M1.0 established in the Emergency and Remedial Response Plan (**Attachment I).** A summary of the seismic monitoring locations and frequencies is given in **Table 10**.

9.4.1 Network Design

A continuously recording distributed acoustic sensing (DAS) fiber optic cable will be deployed from approximately surface–8,000 ft within a plugged and abandoned well, 38-35N, located in the capproximate center of the AoR. DAS is a system using fiber optic cables to provide distributed strain sensing along the length of the cable. The combined downhole DAS in addition to public seismic monitoring stations will be capable of accurately detecting a magnitude event of at least 1.0 (or higher) within, and surrounding, the AoR.

9.4.2 Network Operation

After design, the microseismic network will be installed and tested. After testing is completed, the network will be operational to monitor for microseismic events in real time through the injection phase and into the post-injection period. Monitoring will begin at least one month prior to injection to establish the microseismic baseline.

Table 10: Summary of Passive Seismic Monitoring System

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
AoR	Seismic events over magnitude 1.0	Borehole DAS (38-35N) and public surface seismic stations	Within 1-mile radius of injection wells	Continuous
AoR	Seismic events over magnitude 2.7	California Integrated Seismic Network	Within 1-mile radius of injection wells	Continuous

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Figures

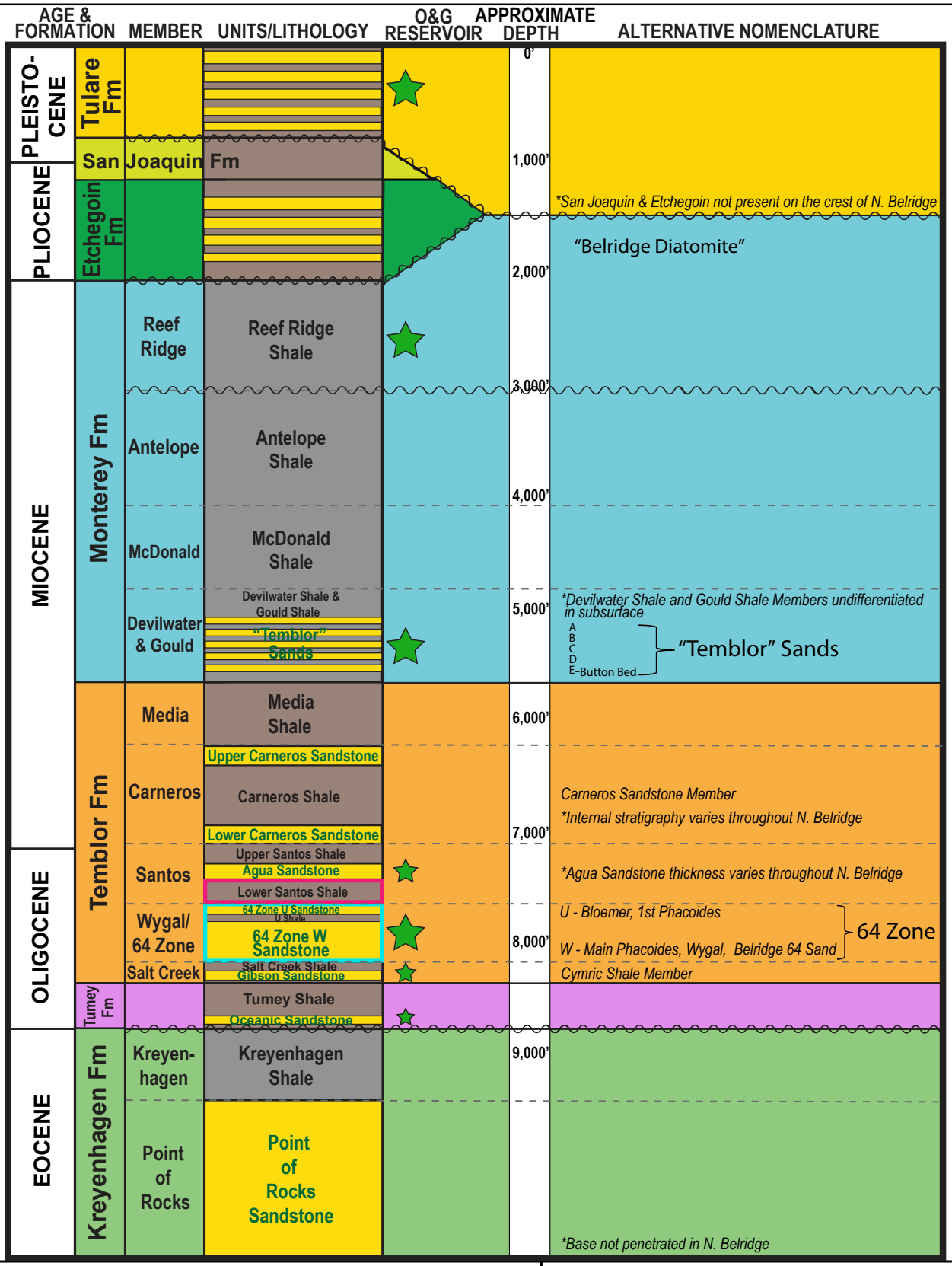
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Figure 2. Location Map of Repurposed and New Wells

Figure 3. Evolution of CO_2 Plume Map View

Figure 4. Evolution of Pressure Differential Map View



Legend

- Significant Oil and Gas Producing Unit
- Injection Zone
- Primary Confining Zone
- Unconformity
- Formation Boundary
- Member Boundary

Lithology

- Mudstone
- Sandstone
- Siliceous Mudstone

Explanation

O&G - Oil and Gas
Fm - Formation
N. - North

North Belridge Stratigraphic Column

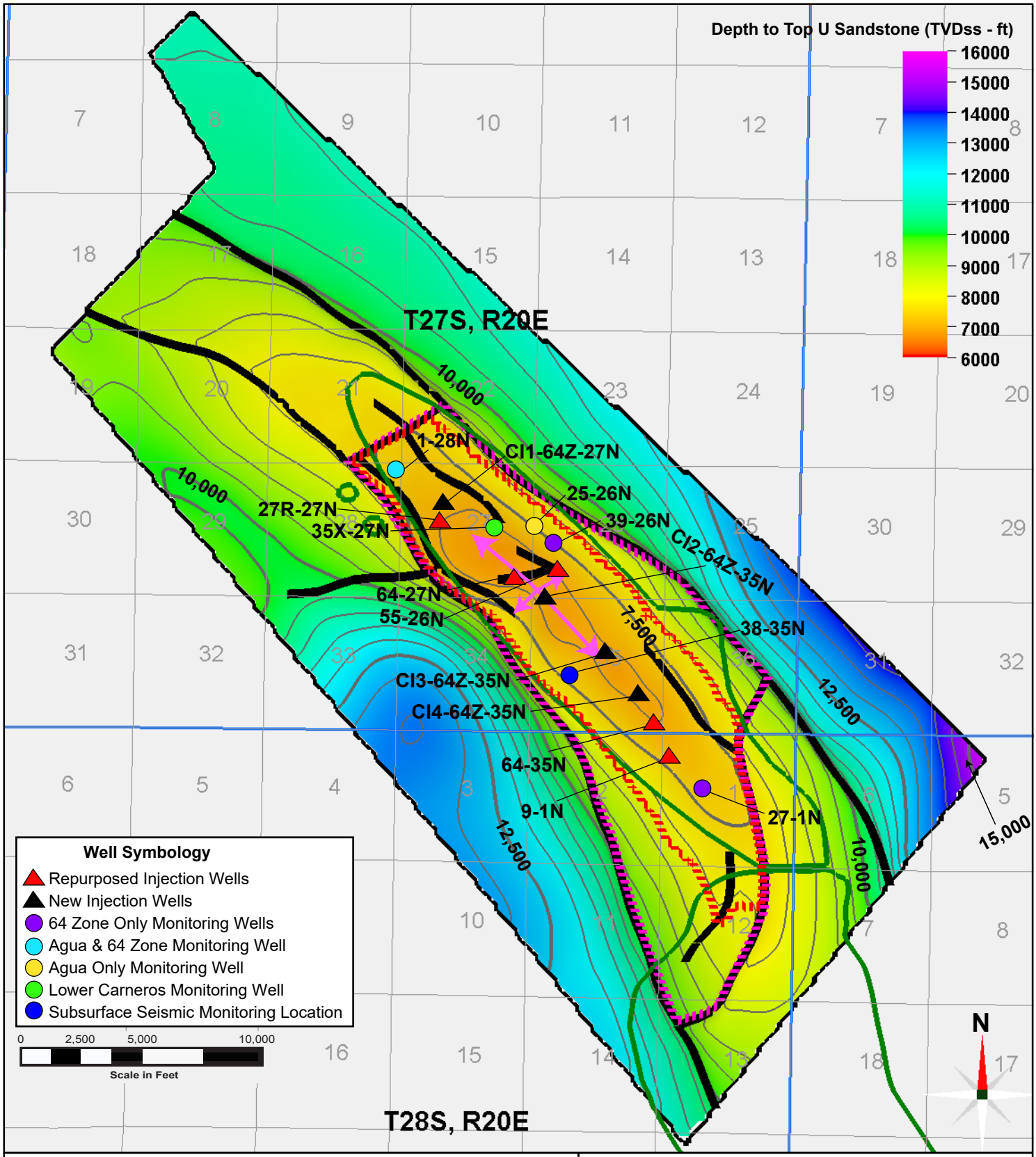
North Belridge Oil Field
Western Kern County
California

Geosyntec consultants

CarbonFrontier | April 2024

Figure 1

Geosyntec\Aera Belridge CCUS Project - General\EPA VI\A. Technical\01_Figures_EPAProactive2024\i_Illustrator\Attachment E\E_ Fig-1 North Belridge Strat Column.ai



Legend:

- Area of Interest
- Township/Range Boundaries
- Section Boundaries
- 1973/74 Oil Field Boundaries
- Fault Traces
- Elevation Contours (500 ft CI)
- Area of Review
- Modeled CO_2 Plume Extent
- Anticline Axis

Explanation:

ft - feet
TVDss - true vertical depth sub sea (ft)
CI - contour interval
CO_2 - carbon dioxide

Notes:

Surface artifacts due to interpolation across faults and structural model grid.

Location Map of Repurposed and New Wells

North Belridge Oil Field
Western Kern County
California

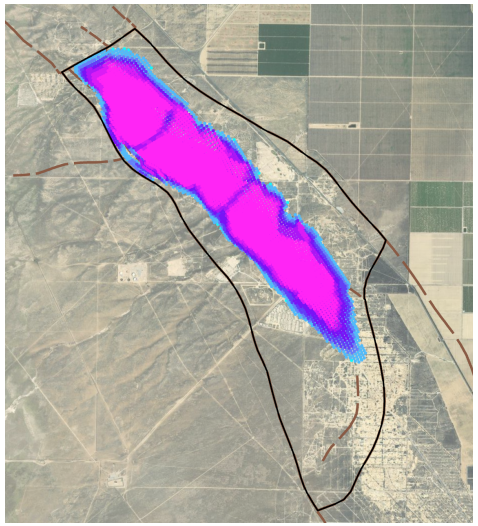
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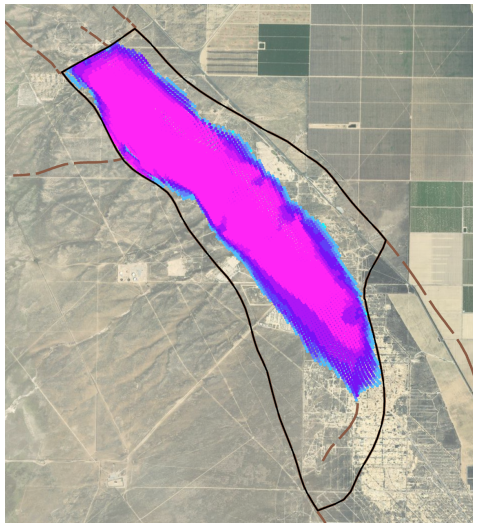
Figure 2

Geosyntec\Aera Belridge CCUS Project - General\EPA VI\A. Technical\01_Figures_EPAProactive2024\i_Illustrator\Attachment E\E_ Fig-2 Location of New & Repurposed well.ai

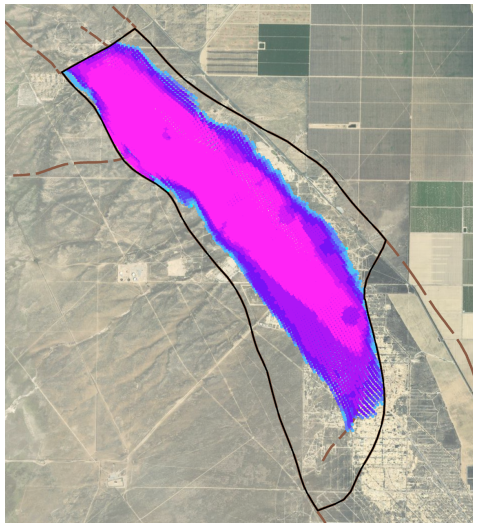
1 year during injection (2027)



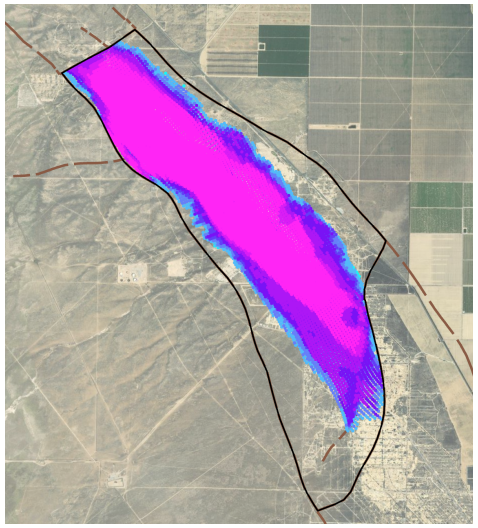
5 years during injection (2031)



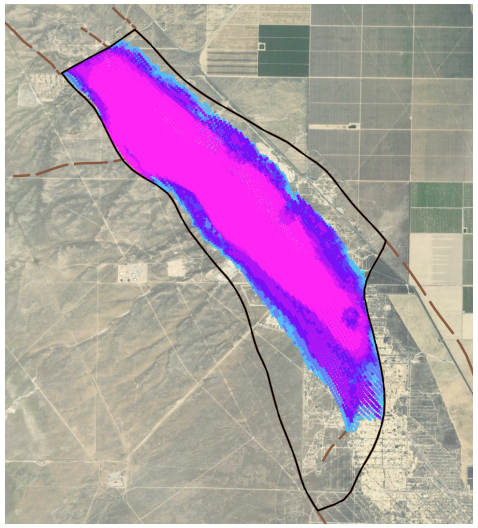
End of injection (9.5 years, 2035)



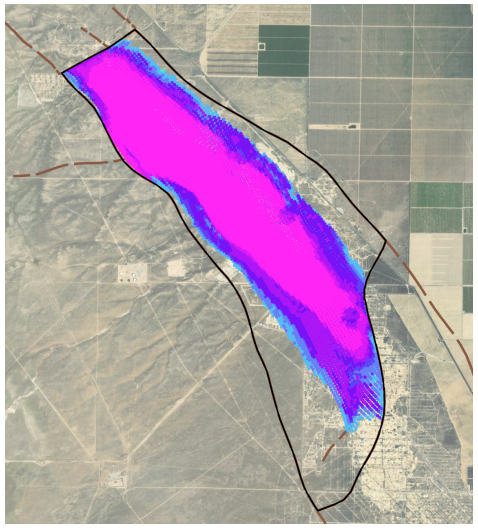
15 years post-injection (2050)



70 years post-injection (2105)



100 years post-injection (2135)



Legend:

- Area of Review Boundary
- Faults are projected from Top U-Sandstone

N

Explanation:

CO_2 - Carbon Dioxide

1 10 20 30 40 50 60 68

CO_2 Saturation (%)

Notes:

The CO_2 plume is shown as a percent value of CO_2 saturation in the pore space, which is the sum of all phases (free-phase, dissolved phase in water, dissolved phase in oil, and residual) for all cells in the model at the respective time. The saturations are shown in map view by presenting the maximum value for all depths of the Area of Review. The Area of Review Boundary is defined as the maximum extent of the CO_2 plume and the pressure front.

0 10,000 Feet

Evolution of CO_2 Plume
Map View

North Belridge Oil Field
Western Kern County
California

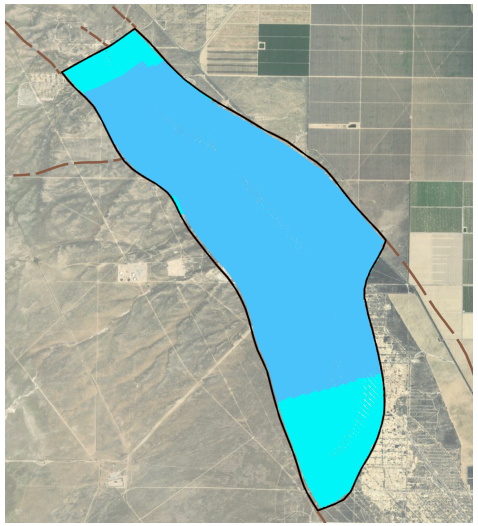
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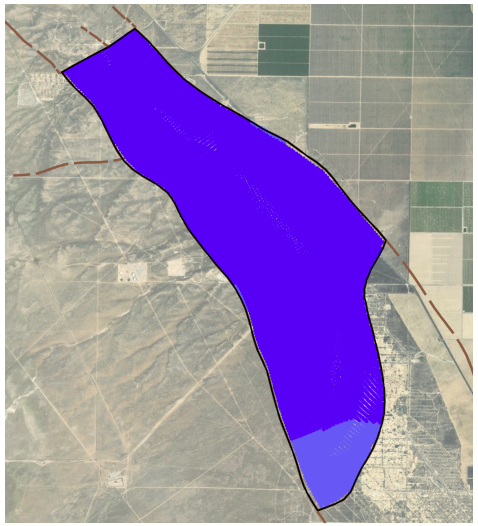
Figure 3

Geosyntec\Aera Belridge CCUS Project - General\EPA VI\A. Technical\01_Figures_EPAProactive2024\i_Illustrator\Attachment E\E_ Fig-3 Map View CO_2 Saturation Distribution.ai

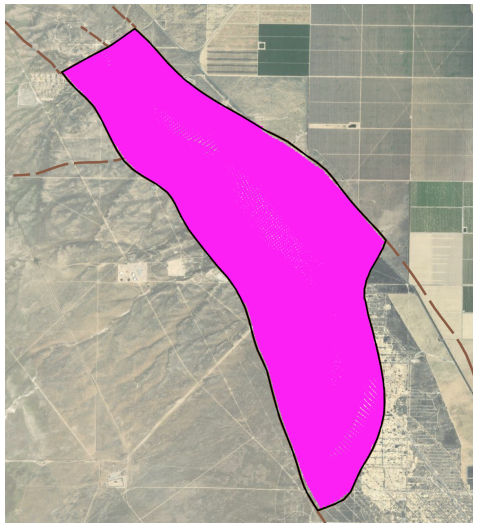
1 year during injection (2027)



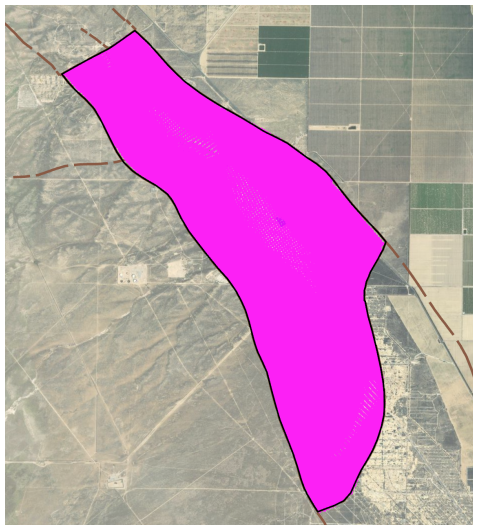
5 years during injection (2031)



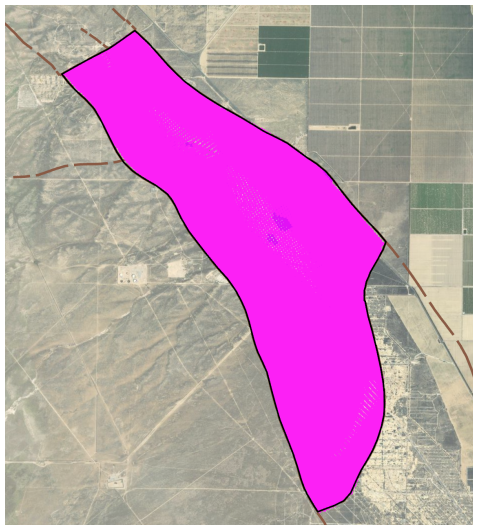
End of injection (9.5 years, 2035)



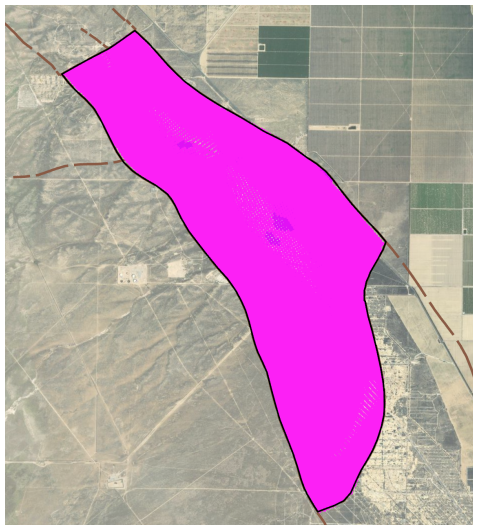
15 years post-injection (2050)



70 years post-injection (2105)



100 years post-injection (2135)



Legend:

Area of Review Boundary

Faults projected from Top U-Sandstone

25 1,000 1,500 2,000 2,500 3,000 3,500 4,000 4,350

Pressure Differential (psi)

Notes:

Showing maximum pressure Increment at each X/Y cell for all depths.

0 10,000 Feet

N

Evolution of Pressure Differential
Map View

North Belridge Oil Field
Western Kern County
California

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Figure 4

Geosyntec\Aera Belridge CCUS Project - General\EPA VI\A. Technical\01_Figures_EPAProactive2024\i_Illustrator\Attachment E\E_ Fig-4 Map View Modeled Pressure Differential.ai

Appendix A

Quality Assurance and Surveillance Plan

The Quality Assurance and Surveillance Plan (QASP) is attached separately.

CLASS VI INJECTION WELL:
QUALITY ASSURANCE AND SURVEILLANCE PLAN

April 2024

Prepared by:

Aera Energy LLC

File Name	Version	Date	Description of Change
Aera CCS Quality Assurance and Surveillance Plan.pdf	1	January 19, 2023	Original document
Attachment E – Appendix A – Quality Assurance and Surveillance Plan V2 04182024.pdf	2	April 18, 2023	Revisions made based on additional monitoring well and design of seismicity monitoring network

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TITLE AND APPROVAL SHEET

This Quality Assurance and Surveillance Plan (QASP) is approved for use and implementation at CarbonFrontier. The signatures below denote the approval of this document and intent to abide by the procedures outlined within it.

Name Title	Date
Name Title	Date
Name Title	Date

DISTRIBUTION LIST

The following project participants will receive the completed Quality Assurance and Surveillance Plan (QASP) and all future updates for the duration of the project.

1. PROJECT MANAGEMENT

1.1 Project/Task Organization

1.1.1 Key Individuals and Responsibilities

The project, led by Aera Energy LLC (Aera), includes participation from several subcontractors. The testing and monitoring activities responsibilities will be shared between Aera and their designated subcontractors and the program will be broken in six subcategories:

1. Subsurface Fluid Sampling
2. Well Logging
3. Mechanical Integrity Testing (MIT)
4. Pressure/Temperature Monitoring
5. Carbon Dioxide (CO_2) Stream Analysis
6. Geophysical Monitoring

1.1.2 Independence from Project QA Manager and Data Gathering

The majority of the physical samples collected and data gathered as part of the monitoring, verification, and accounting (MVA) program will be analyzed, processed, or witnessed by third parties independent and outside of the project management structure.

1.1.3 QA Project Plan Responsibility

Aera will be responsible for maintaining and distributing the official, approved Quality Assurance and Surveillance Plan (QASP). Aera will periodically review this QASP and consult with U.S. Environmental Protection Agency (EPA) if/when changes to the plan are warranted.

1.2 Problem Definition/Background

1.2.1 Reasoning

The Aera CarbonFrontier Carbon Capture and Sequestration (CCS) Project's MVA program has operational monitoring, verification, and environmental monitoring components. Operational monitoring is used to ensure safety with the procedures associated with fluid injection, determine the response of the injection zone, and the movement of the CO_2 plume. Aera will use its existing Supervisory Control and Data Acquisition (SCADA) system to monitor injection. Key monitoring parameters include the pressure of injection well tubing and annulus, injection zone geochemistry, above confining zone geochemistry, and seismicity. Other monitoring parameters include injection rate, total mass and volume injected, injection well temperature profile, and pressure front tracking.

The verification component will provide information to evaluate if leakage of CO_2 through the confining zone is occurring. This includes pulsed neutron logging, subsurface fluid monitoring, and pressure and temperature monitoring.

The environmental monitoring components will determine if the injectate were potentially released into the shallow subsurface. This monitoring includes pulsed neutron logging, subsurface fluid monitoring, and seismicity monitoring.

The primary goal of the CarbonFrontier MVA program is to demonstrate that project activities are protective of human health and the environment. To help achieve this goal, this QASP was developed to establish the quality standards of the testing and monitoring program to meet the requirements of the EPA's Underground Injection Control (UIC) Program for Class VI wells.

1.2.2 Reasons for Initiating the Project

The goal of the CarbonFrontier CCS Project is to inject and retain CO_2 for permanent geologic sequestration. In order to demonstrate that this can be done safely, a rigorous MVA plan is proposed to demonstrate that the injected CO_2 is retained within the intended storage reservoir.

1.2.3 Regulatory Information, Applicable Criteria, Action Limits

The Class VI Rule requires owners or operators of Class VI wells to perform several types of activities during the lifetime of the project in order to demonstrate that the injection wells maintain their mechanical integrity, that fluid migration and the extent of pressure elevation are within the limits described in the permit application, and that underground sources of drinking water (USDWs) are not endangered. These monitoring activities include mechanical integrity tests (MITs), injection well testing during operation, monitoring of subsurface fluid quality, and tracking of the CO_2 plume and associated pressure front. This document details both the measurements that will be taken as well as the steps to demonstrate that the quality of the data is such that the data can be used with confidence in making decisions during the life of the project.

1.3 Project/Task Description

1.3.1 Summary of Work to be Performed

Table 1 describes the testing and monitoring activities, reasoning, responsible parties, locations, methods, techniques, and purpose. **Tables 2** and **3** summarize the instrumentation and geophysical surveys, respectively.

The Testing and Monitoring Plan (**Attachment E**) contains the schedule for the activities listed in the tables mentioned above.

Table 1: Summary of Testing and Monitoring

Activity	Location(s)	Method	Pre-Injection Frequency	Injection Frequency	PISC Frequency	Analytical Technique	Lab/Custody	Purpose
CO_2 stream analysis	After compression and processing and before injection wellheads	Direct sampling	Once	Quarterly	N/A	Chemical analysis	California certified lab	Monitor injectate
Injection rate and volume	Before wellhead	Flow meter	N/A	Continuous	N/A	Direct measurement	N/A	Monitor injectate rate and volume
Injection temperature/ pressure	Before wellhead	Temperature/ pressure gauge	N/A	Continuous	N/A	Direct measurement	N/A	Monitor injectate temperature, pressure, and well integrity
Annular pressure	Wellhead	Pressure gauge	N/A	Continuous	None	Direct measurement	N/A	Monitor annular pressure and well integrity
Downhole pressure/ temperature	Injection wells	Downhole gauge and DTS	Continuous	Continuous	None	Direct measurement	N/A	Monitor reservoir pressure/injection temperature/well integrity
	Monitoring wells	Downhole gauge and DTS	Continuous	Continuous	Quarterly	Direct measurement	N/A	Monitor reservoir pressure/injection temperature/well integrity
Internal mechanical integrity	Injection wells and Monitoring wells	Annulus pressure test via annulus pressure gauge	Once	Every five years	None	Direct measurement	N/A	Monitor internal mechanical integrity of wellbore
External mechanical integrity	Injection wells	Temperature log/DTS, acoustic log, or oxygen activation log	Once	Annual	Once, prior to plugging	Physical analysis	N/A	Monitor external mechanical integrity
	Monitoring wells	Temperature log/DTS, acoustic log, or oxygen activation log	Once	As needed	As needed	Physical analysis	N/A	Monitor external mechanical integrity
	Injection wells	Ultrasonic casing/ cement log	Once	As needed	None	Physical analysis	N/A	Monitor well integrity
Corrosion monitoring	After compression	Coupon	Once	Quarterly	None	Physical analysis	N/A	Monitor well integrity
Pressure fall-off testing	Injection wells	Pressure gauge	Once	Every 5 years	None	Direct Measurement	N/A	Monitor well and reservoir integrity

Activity	Location(s)	Method	Pre-Injection Frequency	Injection Frequency	PISC Frequency	Analytical Technique	Lab/Custody	Purpose
Geochemistry monitoring	Monitoring wells: Agua Sandstone (I-28N, 25-26N); Lower Carneros Sandstone (35X-27N)	Fluid sampling	Once	Annually	Every two years	Chemical analysis	California certified lab	Monitor for CO_2 leakage
CO_2 plume tracking	Monitoring wells: 64 Zone (I-28N, 39-26N, 27-1N)	Fluid sampling	Once	Annually	Every two years	Direct Measurement	California certified lab	Directly monitor CO_2 plume migration
	Monitoring wells: 64 Zone (I-28N, 39-26N, 27-1N)	Pulsed neutron wireline log	Once	Annually	Every two years	Indirect measurement	N/A	Indirectly monitor CO_2 plume migration
	Monitoring wells: Agua Sandstone (I-28N, 25-26N)	Pulsed neutron wireline log	Once	Annually	Every two years	Indirect measurement	N/A	Monitor for CO_2 leakage
Pressure front tracking	Monitoring wells: 64 zone (I-28N, 39-26N, 27-1N); Agua Sandstone (I-28N, 25-26N); Lower Carneros Sandstone (35X-27N)	Pressure gauge	Continuously	Continuously	Continuously	Direct Measurement	N/A	Monitor pressure front migration
Seismic activity monitoring	AoR and within 1 mile radius of injection wells	Borehole DAS (38-35N)	Continuous	Continuous	None	Indirect measurement	N/A	Monitor natural and induced seismic activity of 1.0 for reservoir, well, facility, and pipeline integrity
	Within 1 mile radius of injection wells	California Integrated Seismic Network	Continuous	Continuous	Continuous	Indirect measurement	N/A	Monitor seismic activity of magnitude 2.7 or greater for reservoir, well, facility, and pipeline integrity

3D: three dimensional
DAS: distributed acoustic sensing
DTS: distributed temperature sensing
N/A: not applicable
PISC: post-injection site care

Table 2: Instrumentation Summary

Monitoring Location	Instrument Type	Monitoring Target (Formation or Other)	Data Collection Location(s)	Purpose
CO_2 facility	Pressure/temperature gauge	CO_2 stream	Plant, after compression	Monitor operation, equipment, and permit parameters
	Flowmeter	CO_2 stream	Plant, after compression	Monitor operation, equipment, and permit parameters
Monitoring wells	Pressure gauge	AOR	Wellbore (all wells)	Pressure front tracking and dissipation zone pressure monitoring
	Pulsed neutron logging tool		Logged interval total depth (TD) to surface casing	Well integrity and CO_2 plume migration
	DTS fiber optic		Wellbore (1-28N, 39-26N, 27-1N)	Well integrity and CO_2 plume migration
	DAS fiber optic		Wellbore (38-35N)	Downhole seismic activity monitoring
Injection wells	Pressure/temperature gauge	Injectate	Wellhead	Monitor operation, equipment, and permit parameters
	Pressure/temperature gauge	64 Zone	1 point location, below injection packer	Monitor operation, equipment, and permit parameters
	Pressure gauge	Injection well annular pressure	Wellhead	Monitor operation, equipment, and permit parameters, integrity of casing, tubing and packer
	Fluid level acoustic sensor	Injection well annular fluid level	Wellhead	Monitor equipment, integrity of casing, tubing and packer
	DTS fiber optic	AoR	Wellbore	Monitor the operation, equipment, and permit parameters; well integrity

AoR: area of review
DAS: distributed acoustic sensing
DTS: distributed temperature sensing

Table 3: Geophysical Surveys Summary

Monitoring Activity	Tool or Survey Description	Monitoring Location	Monitoring Target (Formation or Other)	Purpose
Well logs	Triple Combo	New injection wells	Surface to TD	Reservoir and fluid properties, correlations
	Pulsed neutron	monitoring wells	Injection zone, primary confining layer, and first permeable layer above primary confining layer	Well integrity and CO_2 plume saturation
	Cement bond log/ultrasonic casing cement inspection log	Injection wells	All casing strings	Well integrity

TD: total depth

1.3.2 Geographic Locations

The planned location of injection and monitoring wells are provided in **Table 4** and are shown in **Figure 1.**

Table 4: Location of Injection and Monitoring Wells

Injection Wells	Latitude	Longitude
CI1-64Z-27N	35°33'9.4877"N	119°48'26.3702"W
CI2-64Z-35N	35°32'32.6713"N	119°47'37.0682"W
CI3-64Z-35N	35°32'11.6457"N	119°47'7.5912"W
CI4-64Z-35N	35°31'55.4154"N	119°46'51.7864"W
27R-27N	35°33'2.4280"N	119°48'28.6103"W
55-26N	35°32'43.2520"N	119°47'32.7755"W
64-35N	35°31'44.3600"N	119°46'44.9788"W
9-1N	35°31'31.6480"N	119°46'37.0154"W
64-27N	35°32'38.0979"N	119°47'54.6576"W
Monitoring Wells		
39-26N	35°32'54.8149"N	119°47'35.1082"W
1-28N	35°33'22.7757"N	119°48'51.4527"W
25-26N	35°33'1.2506"N	119°47'43.8785"W
27-1N	35°31'18.6498"N	119°46'21.0202"W
35X-27N	35°32'59.1538"N	119°48'06.3812"W
Subsurface Seismic Monitoring Location		
38-35N	35°32'3.6420"N	119°47'29.6741"W

1.3.3 Resource and Time Constraints

No resource or time constraints have been identified during the pre-construction phase.

1.4 Quality Objectives and Criteria

1.4.1 Performance/Measurement Criteria

The overall objective of quality assurance for monitoring is to develop and implement procedures to provide results that meet the site characterization and non-endangerment requirements set for the Class VI permit.

Table 5 summarizes parameters for analytical and field monitoring of subsurface fluid quality. Subsurface fluid monitoring will be conducted during the pre-injection, injection, and post-injection phases of the project. Monitoring wells will be used to gather water-quality samples and pressure data. **Tables 6** and **7** summarize the analytical parameters for CO_2 stream monitoring and corrosion coupon assessment. The list of analytes may be reassessed periodically and adjusted to

include or exclude compounds based on their effectiveness to the overall monitoring program goals. **Table 8** summarizes the specifications for field gauges.

Table 9 summarizes the typical outcome of testing and monitoring results, including activity levels of each parameter, project action limits, detection limits, and anticipated readings. This will serve as a reference for data review, validation, and taking corrective actions.

Key testing and monitoring areas include:

- Subsurface fluid sampling
    - Aqueous chemical concentrations
- Well logging
    - Pulsed neutron logging
- Corrosion monitoring
- Mechanical integrity testing (MIT)
    - Pressure, temperature and acoustic logging
    - Pulsed neutron logging
    - Cement and casing evaluation logging
- Pressure/temperature monitoring
    - Pressure/temperature from in-situ gauges
    - Pressure/temperature from surface gauges
    - Temperature from distributed temperature sensing
- CO_2 stream analysis
    - Carbon dioxide (CO_2, volume per volume [v/v])
    - Moisture (H_2O, parts per million [ppm] v/v)
    - Oxygen (O_2, ppm v/v)
    - Nitrogen (N_2, ppm v/v)
    - Argon (Ar, ppm v/v)
    - Hydrogen (H_2, ppm v/v)
    - Carbon monoxide (CO, ppm v/v)
    - Nitrogen oxides (NOx, ppm v/v)
    - Ammonia (NH_3, ppm v/v)
    - Total hydrocarbons (THC, ppm v/v as CH_4)
    - Methane (CH_4, ppm v/v)

  - aromatic hydrocarbons (ppm v/v)
  - Total sulfur (TS, ppm v/v)
  - Sulfur dioxide (SO_2, ppm v/v)
  - Hydrogen sulfide (H_2S, ppm v/v)
  - Isotope δ13C (per mil, ‰)
  - Ethanol (ppm v/v)
- Seismicity monitoring
  - Distributed acoustic sensing (DAS) fiber optic

Table 5: Summary of Analytical and Field Parameters for Fluid Sampling

Parameters	Analytical Methods[1]	Detection Limit/Range[2]	Typical Precisions (Laboratory Control Limit) [2]	Typical Quality Control (QC) Requirements
Cations/metals (aluminum, barium, manganese, arsenic, cadmium, chromium, copper, lead, selenium, titanium, zinc)	EPA Method 200.7/200.8 or similar by inductively coupled plasma optical emission spectroscopy (ICP-OES) or mass spectroscopy (ICP-MS)	0.01 to 2 mg/L (analyte, dilution, and matrix dependent; scanning or selective ion monitoring mode dependent)	85-115%	Daily calibration; blanks, duplicates, QC check std, and matrix spikes at 10% or greater frequency
Cations/metals (calcium, sodium, potassium, iron, magnesium, silica)				Daily calibration; blanks, duplicates, QC check std, and matrix spikes at 10% or greater frequency
Anions (chloride, sulfate, sulfide, bromide, fluoride, nitrate)	EPA Method 300.0/300.1 or similar by ion chromatography; SM 4500 for sulfide by colorimetry	0.1 to 1 mg/L for 300.0/300.1; 0.05 mg/L for SM 4500 (sulfide) (analyte, dilution, and matrix dependent)	90-110%; 70-130% for sulfide	Daily calibration; blanks, duplicates, QC check std, and matrix spikes at 10% or greater frequency
Dissolved CO_2	Coulometric titration or RSK-175M by gas chromatography/flame ionization detector (GC/FID)	5 µg/L	80-120%	Daily calibration; blanks, duplicates, QC check std, and matrix spikes at 10% or greater frequency
Dissolved CH_4	RSK-175M by GC/FID	1 µg/L	80-120%	Daily calibration; blanks, duplicates, QC check std, and matrix spikes at 10% or greater frequency
Dissolved O_2	SM 4500 OG by Membrane Electrode Method or RSK-175M by GC/FID	0.01 mg/L	80-120%	Daily calibration; blanks, duplicates, QC check std, and matrix spikes at 10% or greater frequency
Dissolved H_2S (field)	Field Test Kit	Dependent on selected field test kit	Dependent on selected field test kit	Dependent on selected field test kit
Total dissolved solids	EPA Method 160.1/SM 2540 C by gravimetry	1 mg/L	84-108 %	Balance calibration, duplicate analysis, QC check std
Alkalinity	SM 2320 B/EPA Method 310.1 by titration	5 mg/L	80-120%	Daily calibration of pH, blanks, duplicates, QC check std

Parameters	Analytical Methods[1]	Detection Limit/Range[2]	Typical Precisions (Laboratory Control Limit) [2]	Typical Quality Control (QC) Requirements
pH (field)	EPA Method 150.1/SM4500-H+B electrometrically	Dependent on field meter selected	Dependent on field meter selected	User calibration per manufacturer recommendation, QC check std
Specific conductance (field)	EPA Method 120.1 by conductivity meter	Dependent on field meter selected	Dependent on field meter selected	User calibration per manufacturer recommendation, QC check std
Temperature (field)	Thermocouple	Dependent on field meter selected	Dependent on field meter selected	Factory calibration
Hardness	SM 2340C by titration	7.05 mg/L	Dependent on selected laboratory	Daily calibration; blanks, duplicates, QC check std, and matrix spikes at 10% or greater frequency
Turbidity	SM 2130B by nephelometry	0.05 NTU	90-110%	Daily calibration; blanks, duplicates, QC check std, and matrix spikes at 10% or greater frequency
Specific gravity	SM 2710F by calculation	0.05	Dependent on selected laboratory	Daily calibration; blanks, duplicates, QC check std, and matrix spikes at 10% or greater frequency
Water density	SM 2710F by calculation	0.05g/cc	Dependent on selected laboratory	Daily calibration; blanks, duplicates, QC check std, and matrix spikes at 10% or greater frequency
Dissolved inorganic carbon isotopes ($\delta^{13}C$)	Mass spectrometry	Dependent on selected laboratory	Dependent on selected laboratory	Dependent on selected laboratory

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.
Note 2: Detection limits and precision (laboratory control limits) are typical for these analytical methods and were provided by Eurofins Environment Testing.
µg/L: microgram per liter
g/cc: gram per cubic centimeter
mg/L: milligrams per liter
NTU: Nephelometric turbidity unit

Table 6: Summary of Analytical Parameters for CO_2 Stream

Parameters	Analytical Methods[(1)]	Detection Limit/Range	Typical Precisions	QC Requirements[(2)]
Carbon dioxide (CO_2)	ASTM D1945-14 (2019). Gas Chromatography (GC) with thermal conductivity detector (TCD).	0.01-20 mol.%	0.01-0.10% repeatability and 0.02-0.15% duplicability between 0-20 mol.%	Routine calibrations per ASTM standards; blanks, duplicates, QC check standards by the contracted laboratory
Moisture (H_2O)	ISBT 3.0. electrometric moisture analyzer.	0-100 ppm. v/v	5-10% @ 10 ppm v/v	Routine calibrations per ISBT standards; blanks, duplicates, QC check standards by the contracted laboratory
Oxygen (O_2)	ASTM D1945-14 (2019). GC/TCD.	0.01-20 mol.%	0.01-0.10% repeatability and 0.02-0.15% reproducibility between 0-20 mol.%	Routine calibrations per ASTM standards; blanks, duplicates, QC check standards by the contracted laboratory
Nitrogen (N_2)	ASTM D1945-14 (2019). GC/TCD.	0.01-100 mol.%	0.01-0.10% repeatability and 0.02-0.15% reproducibility between 0 – 100 mol.%	Routine calibrations per ISBT standards; blanks, duplicates, QC check standards by the contracted laboratory
Argon (Ar)	ISBT 4.0. GC with discharge ionization detector (DID).	0-100 ppm. v/v	5-10% @ 30 ppm v/v	Routine calibrations per ISBT standards; blanks, duplicates, QC check standards by the contracted laboratory
Hydrogen (H_2)	ASTM D1945-14 (2019). GC/TCD.	0.01-10 mol.%.	0.01-0.08% repeatability and 0.02-0.12% reproducibility between 0 – 10 mol.%	Routine calibrations per ASTM standards; blanks, duplicates, QC check standards by the contracted laboratory
Carbon monoxide (CO)	ISBT 5.0. GC with pulsed discharge ionization detector (PDID).	0-50 ppm. v/v	5-10% @ 10 ppm v/v	Routine calibrations per ISBT standards; blanks, duplicates, QC check standards by the contracted laboratory
Nitrogen oxides (NO_x)	ISBT 7.0. colorimetric tubes to detect NO and NO_2.	0.2-10 ppm. v/v	5-30% of full scale	Routine calibrations per ISBT standards; blanks, duplicates, QC check standards by the contracted laboratory
Ammonia (NH_3)	ISBT 6.0. ammonia-specific colorimetric detector tube.	0.5-5 ppm. v/v	5-30% of full scale	Routine calibrations per ISBT standards; blanks, duplicates, QC check standards by the contracted laboratory
Total hydrocarbons (THCs)	ISBT 10.0. GC with flame ionization detector (FID).	0-100 ppm. v/v	1-2% @ 20 ppm v/v	Routine calibrations per ISBT standards; blanks, duplicates, QC check standards by the contracted laboratory
Methane (CH_4)	ASTM D1945-14 (2019). GC/TCD.	0-100 mol.%	0.01-0.10% repeatability and 0.02-0.15% reproducibility between 0 – 100 mol.%	Routine calibrations per ISBT standards; blanks, duplicates, QC check standards by the contracted laboratory

Parameters	Analytical Methods[(1)]	Detection Limit/Range	Typical Precisions	QC Requirements[(2)]
Aromatic hydrocarbons	ISBT 12.0. GC with photoionization detector (PID). 0-5 ppm	0-0.20 ppm	5-10% @ 0.020 ppm v/v	Routine calibrations per ISBT standards; blanks, duplicates, QC check std, and matrix spikes at 10% or greater frequency
Total sulfur	ISBT 13.0. GC with sulfur chemiluminescent detector (SCD).	0-5 ppm. v/v	5-10% @ 0.10 ppm	Routine calibrations per ISBT standards; blanks, duplicates, QC check standards by the contracted laboratory
Sulfur dioxide (SO_2)	ISBT 14.0. GC/SCD.	0-5 ppm. v/v.	5-10% @ 0.10 ppm v/v	Routine calibrations per ISBT standards; blanks, duplicates, QC check standards by the contracted laboratory
Hydrogen sulfide (H_2S)	ASTM D1945-14 (2019), GC/TCD.	0.3 - 30 mol.%	0.04-0.10% repeatability and 0.07-0.15% reproducibility between 0.3 – 30 mol.%	Routine calibrations per ASTM standards; blanks, duplicates, QC check standards by the contracted laboratory
Ethanol EtOH	EPA Method 8260B. GC with mass spectroscopy (MS).	25-500 ppb, v/v	10-13% between 25-500 ppb v/v	Routine calibrations per EPA recommendations; blanks, duplicates, QC check standards by the contracted laboratory
^{13}C isotope	USGS techniques and methods 5-D4. GC with dual-inlet isotope ratio mass spectrometry (GC-IRMS)	–50 to 3 ‰	±0.1 ‰	Quality assurance information to be provided by the contracted laboratory

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.
Note 2: Key elements for quality assurance (QA) include: employing knowledgeable and responsible personnel to perform sample analysis, documentation, and reporting, establishing a QA team with experienced and dedicated reviewers to review results, and appropriate maintenance and calibration of equipment involved.

Table 7: Summary of Analytical Parameters for Corrosion Coupons

Parameters	Analytical Methods[(1)]	Detection Limit/Range	Typical Precisions	QC Requirements
Mass	NACE RP0775-2005	0.005 mg	+/- 2%	Annual calibration of scale
Thickness	NACE RP0775-2005	0.001 mm	+/- 0.005 mm	Factory calibration

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.
mm: millimeter

Table 8: Summary of Measurement Parameters for Field Gauges

Parameters	Methods	Detection Limit/Range	Typical Precisions	QC Requirements
Booster pump discharge pressure	ANSI Z540-1-1994	+/- 0.001 psi / 0-3000 psi	+/- 0.01 psi	Annual calibration of scale
Injection tubing temperature	ANSI Z540-1-1994	+/- 0.001 °F / 0-500 °F	+/- 0.01 °F	Annual calibration of scale
Annulus pressure	ANSI Z540-1-1994	+/- 0.001 psi / 0-3000 psi	+/- 0.01 psi	Annual calibration of scale
Injection tubing pressure	ANSI Z540-1-1994	+/- 0.001 psi / 0-3000 psi	+/- 0.01 psi	Annual calibration of scale
Wellhead pressure	ANSI Z540-1-1994	+/- 0.001 psi / 0-3000 psi	+/- 0.01 psi	Annual calibration of scale
Downhole temperature	ANSI Z540-1-1994	+/- 0.001 °F / 0-500 °F	+/- 0.01 °F	Annual calibration of scale
Injection mass flow rate	Unknown	Dependent on selected meter	Depended on selected meter	Based on manufacturer specifications

psi: pounds per square inch

Table 9: Actionable Testing and Monitoring Outputs

Activity or Parameter	Project Action Limit	Anticipated Reading
Seismic Activity	Action taken based on magnitude and felt report or local observation as per Seismic Response System established in Emergency and Remedial Response Plan (**Attachment I**)	No seismic event greater than M2.5 within 1 mile of injection wells
Mechanical integrity (pulsed neutron log)	Action taken when pulsed neutron measurements indicate CO_2 outside of expected range / zone	No measurement change from baseline caused by CO_2 in annular space, above injection zone, or in formation above confining zone
Surface pressure / temperature	Action taken when pressures and temperatures are well outside of modeled / expected range	Pressures/temperatures within proposed operational ranges
Downhole pressure / temperature	Action taken when pressures and temperatures are well outside of modeled / expected range	Pressures/temperatures within proposed operational ranges
Subsurface fluid quality	Action taken when changes in fluid constituent concentrations indicate movement of CO_2 or brines into or above the confining zone	No statistically significant difference between observed and baseline geochemical parameter patterns in Agua Sandstone or Lower Carneros Sandstone formation
Above confining zone pressure	Action taken when pressures are well outside of modeled / expected range	Pressures within proposed operational range
Injection well annular volume	Action taken when annular volume is well outside of modeled / expected range	No expected annular volume change not related to temperature

1.4.2 Precision

Assessment of analytical precision can be made through the use of field generated duplicate samples as well as laboratory generated duplicate samples.

1.4.3 Accuracy and Bias

Data accuracy and bias will be assessed by analyzing standards of known concentrations and measuring its actual recovery in analysis versus the expected recovery. Laboratory assessment of analytical accuracy and bias will be the responsibility of the individual laboratories per their standard operating procedures (SOPs) and analytical methodologies and will be evaluated through the use of laboratory control samples, matrix spikes, and surrogates (where applicable). Assessment of bias in the field can be ascertained through collection of field blanks. Field blanks will be collected no less than one per sampling event to screen for sample bottle contamination. For direct pressure or logging measurements, there is no potential for bias with the instruments used to collect data.

1.4.4 Representativeness

Data representativeness expresses the degree to which data accurately and precisely represents a characteristic of a population, parameter variations at a sampling point, a process condition, or an environmental condition. The sampling network has been designed to provide data representative of site conditions. For analytical results of individual subsurface fluid samples, representativeness will be estimated by ion and mass balances. Ion balances with ±10% error or less will be considered valid. Mass balance assessment will be used in cases where the ion balance is greater than ±10% to help determine the source of error. For a sample and its duplicate, if the relative percent difference is greater than 10%, the sample may be considered non-representative.

1.4.5 Completeness

Data completeness is a measure of the amount of valid data obtained from a measurement system compared to the amount that was expected to be obtained under normal conditions. It is anticipated that data completeness of 90% for liquid sampling will be acceptable to meet monitoring goals. For direct pressure and temperature measurements, it is expected that data will be recorded no less than 90% of the time.

1.4.6 Comparability

Data comparability expresses the confidence with which one data set can be compared to another. The data sets to be generated by this project will be comparable to future data sets because of the use of standard sample collection and analytical methods and the level of QA/QC effort. If historical subsurface fluid data become available from other sources, their applicability to the project and level of quality will be assessed prior to use with data gathered on this project. Direct pressure, temperature, and logging measurements will be directly comparable to previously obtained data.

1.4.7 Method Sensitivity

Tables 10 through **15** provide additional details on gauge specifications and sensitivities. Values may change depending on vendor, service provider, and specific item chosen at time of operation.

Table 10: Pressure and Temperature – Downhole Gauge Specifications.

Parameter	Value
Calibrated working pressure range	Atmospheric to 10,000 psi
Initial pressure accuracy	<+/- 2 psi over full scale
Pressure resolution	0.005 psi at 1-s sample rate
Pressure drift stability	<+/- 1 psi per year over full scale
Calibrated working temperature range	77–266 °F
Initial temperature accuracy	<+/- 0.9°F per +/-0.27 °F
Temperature resolution	0.009 °F at 1-s sample rate
Temperature drift stability	<+/- 0.1 °F per year at 302 °F
Max temperature	302 °F

Table 11: Representative Logging Tool Specifications

Parameter	Pulsed Neutron	Cement Bond Log	Ultrasonic casing / cement inspection
Logging speed	Up to 3,600 ft/hr	Up to 3,600 ft/hr	400 to 4,500 ft/hr
Vertical resolution	15 in	3 ft	0.6 to 6.0 in
Investigation	Formation fluid saturation, annular space, mechanical integrity	Cement bond (cement-casing, cement-formation)	Casing and cement (cement-casing, cement-formation and annular coverage)
Temperature rating	350 °F	350 °F	350 °F
Pressure rating	15,000 psi	20,000 psi	20,000 psi

Table 12: Pressure Field Gauge—Injection Tubing Pressure

Parameter	Value
Calibrated working pressure range	0 to 3,000 psi
Initial pressure accuracy	< 0.04375 %
Pressure resolution	0.001 psi
Pressure drift stability	To be determined after first year

Table 13: Pressure Field Gauge—Annulus Pressure

Parameter	Value
Calibrated working pressure range	0 to 3000 psi
Initial pressure accuracy	< 0.04375 %
Pressure resolution	0.001 psi
Pressure drift stability	To be determined after first year

Table 14: Temperature Field Gauge—Injection Tubing Temperature

Parameter	Value
Calibrated working temperature range	0 to 500 °F
Initial temperature accuracy	< 0.0055 %
Temperature resolution	0.001 °F
Temperature drift stability	To be determined after first year

Table 15: Mass Flow Rate Field Gauge—CO_2 Mass Flow Rate

Parameter	Value
Calibrated working flow rate range	50,522 to 303,133 lb/hr
Initial mass flow rate accuracy	< 0.18 %
Mass flow rate resolution	0.0001 lb/hr
Mass flow rate drift stability	To be determined after first year

lb/hr: pounds per hour

1.5 Special Training/Certifications

1.5.1 Specialized Training and Certifications

The geophysical survey equipment and wireline logging tools will be operated by trained, qualified, and certified personnel, according to the service company that provides the equipment. The subsequent data will be processed and analyzed according to industry standards. No specialized certifications are required for personnel conducting subsurface fluid sampling, but field sampling will be conducted by personnel trained to understand and follow the project specific sampling procedures. Upon request, Aera will provide the agency with the laboratory SOPs developed for the specific parameter using the appropriate standard method. Each laboratory technician conducting the analysis on the samples will be trained on the SOP developed for each standard method. Aera will include the technician's training certification with the annual report.

1.5.2 Training Provider and Responsibility

Training for personnel will be provided by the operator or by the subcontractor responsible for the data collection activity.

1.6 Documentation and Records

1.6.1 Report Format and Package Information

Aera will submit an annual report containing the required project data, including testing and monitoring information as specified by the Class VI permit. Data will be provided in electronic or other formats as required by the UIC Program Director.

1.6.2 Other Project Documents, Records, and Electronic Files

Other documents, records, and electronic files such as well logs, test results, or other data will be provided as required by the UIC Program Director.

1.6.3 Data Storage and Duration

Aera or a designated contractor will maintain the required project data as specified in the Class VI permit.

1.6.4 QASP Distribution Responsibility

The Aera Plant Manager will be responsible for ensuring that those included on the distribution list will receive the most current copy of the approved QASP.

2. DATA GENERATION AND ACQUISITION

2.1 Sampling Process Design

Discussion in this section is focused on subsurface fluid sampling and does not address monitoring methods that do not gather physical samples (e.g., logging, seismic monitoring, and pressure/temperature monitoring). During the pre-injection and injection phases, subsurface fluid sampling is planned to include an extensive set of chemical parameters to establish aqueous geochemical baseline data. Parameters will include selected constituents that: (1) have primary and secondary EPA drinking water maximum contaminant levels, (2) are the most responsive to interaction with CO_2 or brine, (3) are needed for quality control, and (4) may be needed for geochemical modeling. The full set of parameters is presented in **Table 5**. After a sufficient baseline is established, monitoring scope may shift to a subset of indicator parameters that are (1) the most responsive to interaction with CO_2 or brine and (2) are needed for quality control.

Implementation of a reduced set of parameters would be done in consultation with the EPA. Isotopic analyses will be performed on baseline samples to the degree that the information helps verify a condition or establish an understanding of non-project related variations. For non-baseline samples, isotopic analyses may be reduced in the monitoring wells if a review of the historical project results or other data determines that further sampling for isotopes is not needed. During a period where a reduced set of analytes is used, if statistically significant trends are observed that are the result of unintended CO_2 or brine migration, then the analytical list would be expanded to the full set of monitoring parameters. The fluid samples will be analyzed using a laboratory meeting the requirements under the EPA National Environmental Laboratory Accreditation Program (NELAP). The other samples will be analyzed by the operator or a third-party laboratory.

Dissolved CO_2 will be analyzed by methods consistent with Test Method B of ASTM D 513-11 or equivalent. Isotopic analysis will be conducted using established methods.

2.1.1 Design Strategy

2.1.1.1 CO_2 Stream Monitoring Strategy

The primary purpose of analyzing the CO_2 stream is to evaluate the potential interactions of CO_2 and/or other constituents of the injectate with formation solids and fluids. This analysis can also identify (or rule out) potential interactions with well materials. Establishing the chemical composition of the injectate also supports the determination of whether the injectate meets the qualifications of hazardous waste under the Resource Conservation and Recovery Act (RCRA), 42 U.S.C. 6901 et seq. (1976), and/or the Comprehensive Environmental Response, Compensation, and Liability Act, (CERCLA) 42 U.S.C. 9601 et seq. (1980). Additionally, monitoring the chemical and physical characteristics of the CO_2 (e.g., isotopic signature, other constituents) may help distinguish the injectate from the native fluids and gases if unintended leakage from the storage reservoir occurred. Injectate monitoring is required at a sufficient frequency to detect changes to any physical and chemical properties that may result in a deviation from the permitted specifications.

Calibration of transmitters used to monitor pressures, temperatures, and flow rates of CO_2 into the injection well shall be conducted annually. Reports will contain test equipment used to calibrate the transmitters, including test equipment manufacturers, model and serial numbers, calibration dates, and expiration dates.

2.1.1.2 Corrosion Monitoring Strategy

Corrosion coupon analyses will be conducted quarterly to aid in demonstrating the mechanical integrity of the equipment in contact with the CO_2. Coupons shall be sent quarterly to a qualified company for analysis and an analysis conducted in accordance with NACE Standard RP-0775 (or similar) to determine and document corrosion wear rates based on mass loss.

2.1.1.3 Above Confining Zone Monitoring Strategy

Aera will monitor subsurface fluid composition for potential geochemical changes above the confining zone during the operation period to meet the requirements of 40 CFR 146.90(d).

Monitoring will be conducted in the following zones:

- Agua Sandstone, approximately 7,500 to 7,800 ft true vertical depth (TVD): zone immediately above the primary confining layer (Lower Santos Shale)
- Lower Carneros Sandstone, approximately 6,550 to 7,150 ft TVD: zone directly above the secondary confining layer (Upper Santos Shale)

The monitoring wells 1-28N and 25-26N will be used for fluid sampling of the groundwater in the Agua Sandstone at prescribed frequencies in **Attachment E**. Monitoring well 35X-27N will be used for fluid sampling of the groundwater in the Lower Carneros Sandstone. These wells are selected to allow for early detection of potential leakage from the injection zone into the permeable

Agua or Lower Carneros Sandstones, which directly overlie the primary and secondary confining layers, respectively.

Samples will be analyzed for constituents listed in **Table 5** to document baseline fluid chemistry and to detect changes in fluid chemistry that could result from the movement of brine or CO_2 from the storage interval through the seal formation.

2.1.1.4 Injection Zone Fluid Monitoring Strategy

The primary method for direct plume monitoring will be fluid sampling from the injection zone to detect changes from baseline values, indicative of the CO_2 plume's presence. Monitoring wells 1-28N, 39-26N, and 27-1N will be used for fluid sampling of the reservoir fluid in the injection zone. The parameters to be analyzed and the analytical methods are presented in **Table 5**.

2.1.2 Type and Number of Samples/Test Runs

Subsurface fluid sampling plans are detailed in **Attachment E** and summarized in **Tables 16** and **17**. CO_2 stream analysis plans are also detailed in **Attachment E**.

2.1.3 Site/Sampling Locations

Table 16 shows the planned monitoring methods and locations for subsurface fluid composition and geochemical monitoring above the confining zone. **Table 17** shows the planned monitoring methods and locations for subsurface fluid composition and geochemical monitoring in the injection zone. The locations of the monitoring wells are shown in **Figure 1**. Wells are located based on the AoR modeling to allow for tracking of the CO_2 plume and pressure front and early warning of leakage from the injection zone into the Agua Sandstone or Lower Carneros sandstone.

CO_2 stream sampling will occur after the pre-combustion and post-combustion sources have compressed and comingled so that the sample will be representative of the composition of the injectate.

Table 16: Monitoring of Fluid Composition and Geochemical Changes Above the Confining Zone

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage
Agua Sandstone (approximately 7,500-7,800 ft TVD)	Fluid sampling	Monitoring wells 1-28N and 25-26N	Northern half of injection area
	Temperature and Pressure Monitoring	Monitoring wells 1-28N and 25-26N	Vertical distribution within well casings (based upon geophysical data indicating most transmissive interval within the perforation)
	Pulsed neutron logging	Monitoring wells 1-28N and 25-26N	Along wellbore
Lower Carneros Sandstone	Pressure	Monitoring well 35X-27N	Above injection zone

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage
(approximately 6,550–7,150 ft MD)	Fluid sampling	Monitoring well 35X-27N	Above injection zone

Table 17: Monitoring of Fluid Composition and Geochemical Changes in the Injection Zone

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage
64 Zone	Fluid sampling	1-28N	1 Point Location: ~8,029 - 8,358 ft MD
		39-26N	1 Point Location: ~7,975 - 8,243 ft MD
		27-1N	1 Point Location: ~8,001 - 8,302 ft MD
	Pulsed neutron logging	1-28N	Survey log: ~7,505 - 8,450 ft MD
		39-26N	Survey log: ~7,667–8,300 ft MD
		27-1N	Survey log: ~7,594 - 8,278 ft MD
	DTS	1-28N, 39-26N, and 27-1N	Entire Wellbore

2.1.4 Sampling Site Contingency

The proposed monitoring wells are located on property owned by Aera and access permissions have already been granted. No problems with site accessibility are anticipated. If inclement weather makes site access difficult, sampling schedules will be reviewed, and alternative dates may be selected that would still meet permit-related conditions.

No problems of site inaccessibility are anticipated for CO_2 stream sampling. If inclement weather makes site access difficult, sampling schedules will be reviewed, and alternative dates may be selected that would still meet permit related conditions.

2.1.5 Activity Schedule

The subsurface fluid sampling activities are summarized in **Table 5** with schedules in **Tables 16** and **17**. The CO_2 stream sampling activities are summarized in **Table 6**. CO_2 stream sampling will be conducted quarterly.

2.1.6 Critical/Informational Data

During both sampling and analytical efforts, detailed field and laboratory documentation will be taken. Documentation will be recorded in field and laboratory forms and notebooks. Critical information will include time and date of activity, person/s performing activity, location of activity (well or field sampling location), method (instrument or lab analysis), field or laboratory

instrument calibration data, and field parameter values. For laboratory analyses, the laboratory will provide a report containing critical data generated during the analysis and provide to end users in digital and printed formats. Noncritical field data may include appearance and odor of the sample, problems with well or sampling equipment, and weather conditions.

2.1.7 Sources of Variability

Potential sources of variability related to monitoring activities include (1) natural variation in fluid quality, formation pressure and temperature and seismic activity; (2) variation in fluid quality, formation pressure and temperature, and seismic activity due to project operations; (3) changes in recharge due to rainfall, drought, and snowfall; (4) changes in instrument calibration during sampling or analytical activity; (5) different staff collecting or analyzing samples; (6) differences in environmental conditions during field sampling activities; (7) changes in analytical data quality during life of project; and (8) data entry errors related to maintaining project database.

Activities to eliminate, reduce, or reconcile variability related to monitoring activities include (1) collecting long-term baseline data to observe and document natural variation in monitoring parameters, (2) evaluating data in timely manner after collection to observe anomalies in data that can be addressed, be resampled or reanalyzed, (3) conducting statistical analysis of monitoring data to determine whether variability in a data set is the result of project activities or natural variation, (4) maintaining weather-related data using on-site weather monitoring data or data collected near project site (such as from local airports), (5) checking instrument calibration before, during and after sampling or sample analysis, (6) thoroughly training staff, (7) conducting laboratory quality assurance checks using third party reference materials, and/or blind and/or replicate sample checks, and (8) developing a systematic review process of data that can include sample-specific data quality checks (i.e., cation/anion balance for aqueous samples).

2.2 Sampling Methods

2.2.1 Sampling SOPs

2.2.1.1 Analytical Parameters

Table 5 identifies the parameters to be monitored and the analytical methods Aera will use for subsurface fluid sampling. If new information or updates to the geochemical modeling based on pre-operational testing raises additional concerns about subsurface geochemical processes (e.g., potential changes in subsurface properties or potential contaminant mobilization), the list of analytical parameters may need to be updated to ensure that the applicable parameters are included.

Subsurface fluid sampling data will be compared to baseline data to identify changing conditions in the subsurface, including fluid leakage. Abnormalities suggestive of leakage could include increased total dissolved solids (TDS), change in cation and/or anion signature(s), increase in CO_2 concentrations, pH changes, or changes in dissolved metal concentrations that indicate leaching of the geological formation.

Table 6 identifies the parameters to be monitored and the analytical methods Aera will use for CO_2 stream sampling. Revisions to the methods may be made in consultation with the UIC Program Director.

2.2.1.2 Sampling Methods

Fluid sampling will likely be performed using a U-tube sampling system to collect large volume samples recovered at the surface at reservoir pressure using a positive gas displacement pump driven with nitrogen gas. A downhole check valve allows fluid to flow into a loop of stainless-steel tubing, after which fluid is driven to the surface with compressed ultra-pure nitrogen gas. The sample is then collected at formation pressure at a volume of up to 100 liters. This sampling method prevents off-gassing and isolates the sample from ambient air. Samples will be depressurized for collection and submitted for laboratory analysis according to standard shallow groundwater analysis methods, described below, with temperature and pressure corrections calculated. Pressurized samples may become degassed, with gas analyzed, pending development of a project-specific SOP, as no EPA standard analytical methods are known for deep subsurface fluid. If U-tube sampling is determined to be infeasible in the monitoring well (which can occur if fines or precipitates accumulate in the system, for example), alternate sampling methods will be evaluated.

Depending on the developed laboratory project-specific SOP for analysis of pressurized samples, Aera will follow traditional groundwater sampling SOPs as needed. Samples requiring filtration will be filtered through 0.45-micrometer flow-through filter cartridges as appropriate and consistent with ASTM D6564-00. Before sample collection, filters will be purged with a minimum of 100 mL of well water (or more if required by the filter manufacturer). For field parameters, additional efforts will be made to minimize exposure time to the atmosphere during filtration, collection, and analysis.

Sample holding times will be consistent with those described in EPA (1974), American Public Health Association (APHA [2005]), Wood (1976), and ASTM Method D6517-00 (2005). After collection, samples will be placed in ice chests in the field and maintained thereafter at $\leq$6 °C, but not frozen, until analysis. The samples will be maintained at their preservation temperature and hand-delivered or shipped via overnight carrier to the designated laboratory within 24 hours. The sample bottles will have waterproof labels with information denoting project, sampling date and time, sampling location, sample identification number, sample type (fresh water or brine), analyte, volume, filtration used (if any), and preservative used (if any).

2.2.2 In-situ Monitoring

In-situ monitoring of subsurface fluid chemistry parameters is not currently planned.

2.2.3 Continuous Monitoring

Pressure data will be collected from monitoring wells on a continuous basis (e.g., hourly to daily) using dedicated pressure transducers with data loggers to characterize pressure trends.

2.2.4 Sample Homogenization, Composition, Filtration

Described above in **Section 2.2.1**.

2.2.5 Sample Containers and Volumes

For subsurface fluid samples, new sample bottles will be used. Sample bottles and bags for analytes will be used as received (ready for use) from the vendor or contract analytical laboratory for the analyte of interest. A summary of sample containers is presented in **Table 18**.

For CO_2 stream monitoring, samples will be collected in a clean sample container rated for the appropriate collection pressure (i.e., mini cylinders or polybags). Details are summarized in **Table 19**.

2.2.6 Sample Preservation

For subsurface fluid samples, the preservation methods in **Table 18** will be used. No preservation is required or used for CO_2 stream, and additional details of sampling requirements are shown in **Table 19**.

Corrosion coupon sampling only requires that the coupons be physically separated (e.g., sleeves, baggies) during transportation to prevent physical abrasion.

2.2.7 Cleaning/Decontamination of Sampling Equipment

Pumps and related equipment and materials necessary for subsurface fluid sampling will be selected based on site needs and cleaned and decontaminated according to standard guidelines.

The field glassware (pipets, beakers, filter holders, etc.) will be cleaned with tap water to remove any loose dirt, washed in a dilute nitric acid solution, and rinsed three times with deionized water before use.

CO_2 stream sampling containers will be either disposed of or decontaminated by the analytical laboratory.

2.2.8 Support Facilities

For subsurface fluid sampling, the following are required: air compressor, vacuum pump, generator, multi-electrode water quality sonde, analytical meters (pH, specific conductance, etc.). Field activities are usually completed in field vehicles and portable laboratory trailers located on site.

Sampling tubing, connectors and valves required to sample the CO_2 stream will be supplied by the analytical lab providing the sampling containers. Sampling will occur within the CO_2 compression unit.

Field gauges will be removed from injection and monitoring wells utilizing existing standard industry tools and equipment. Deployment and retrieval of verification well gauges will be done using procedures and equipment recommended by the vendor, subcontractor, or per standard industry practice.

2.2.9 Corrective Action, Personnel, and Documentation

Field staff will be responsible for properly testing equipment and performing corrective actions on broken or malfunctioning field equipment. If corrective action cannot be taken in the field, then

equipment will be returned to the manufacturer for repair or replacement. Significant corrective actions affecting analytical results will be documented in field notes.

2.3 Sample Handling and Custody

Logging, geophysical monitoring, and pressure/temperature monitoring does not apply to this section and is omitted.

Sample holding times will be consistent with those described in EPA (1974), APHA (2005), Wood (1976), and ASTM Method D6517-00 (2005). After collection, samples will be placed in ice chests in the field and maintained thereafter at $\leq$6 °C but not frozen until analysis. The samples will be maintained at their preservation temperature and hand-delivered or shipped via overnight carrier to the designated laboratory within 24 hours. Analysis of the samples will be completed within the holding time listed in **Tables 18** and **19**. As appropriate, alternative sample containers and preservation techniques approved by the UIC Program Director will be used to meet analytical requirements.

CO_2 stream sampling occurs under high pressure. Impurities in CO_2 may be improperly measured due to partitioning coefficient of CO_2 when in sampling system. It is a significant factor for consistently obtaining accurate analytical results. The point in the system where vaporization occurs must be well managed to prevent impurity partitioning and avoid over or under-reporting of impurities. ISBT 2.0 standard recommends that the vaporization devices including the pressure regulators remain heated during sample collection and analysis. Precautions should be taken to prevent icing at the vaporization point. Samples should be analyzed as soon as practically possible after collection to minimize potential sample adulteration.

2.3.1 Maximum Hold Time/Time Before Retrieval

See **Tables 18** and **19** for maximum sample holding time for subsurface fluid samples and CO_2 stream samples.

2.3.2 Sample Transportation

See description at the beginning of this section.

2.3.3 Sampling Documentation

Field notes will be collected for the subsurface fluid samples collected. These forms will be retained and archived as reference. The sample documentation is the responsibility of sampling personnel.

An analysis authorization form will be provided with each CO_2 stream sample provided for analysis.

2.3.4 Sample Identification

The sample bottles will have waterproof labels with information denoting project, sampling date and time, sampling location, sample identification number, sample type (fresh water or brine), analyte, volume, filtration used (if any), and preservative used (if any).

Table 18: Summary of Anticipated Sample Containers, Preservation Treatments, and Holding Times for Subsurface Fluid Samples

Target Parameters	Volume/Container Material	Preservation Technique	Sample Holding Time
Cations/metals (aluminum, barium, calcium, manganese, sodium, potassium, iron, arsenic, magnesium, silica, cadmium, chromium, copper, lead, selenium, titanium, zinc)	250 ml/HDPE	Filtered, nitric acid, 4 °C	180 days
Anions (chloride, sulfate, sulfide, bromide, fluoride, nitrate)	125 ml/ HDPE	4 °C	28 days (48 hours for nitrate)
Dissolved gases CO_2 CH_4 O_2	 2 X 40-mL VOA vials 2 X 40-mL VOA vials 500 mL amber glass	 4 °C, no headspace HCl, 4 °C, no headspace 4 °C, no headspace	 7 days 14 days 15 minutes
TDS	1-liter HDPE	4 °C	7 days
Alkalinity	250 ml/HDPE	4 °C	14 days
Hardness	250 ml/HDPE	Nitric acid	180 days
Turbidity	125 ml/ HDPE	4 °C	48 hours
Specific gravity	250 ml/HDPE	4 °C	28 days
Water density	250 ml/HDPE	4 °C	28 days
Dissolved inorganic carbon isotopes ($\delta^{13}C$)	Dependent on selected analytical laboratory		

Table 19: Summary of Sample Containers, Preservation Treatments, and Holding Times for CO_2 Stream Analysis

Sample	Volume/Container Material	Preservation Technique	Sample Holding time (max)
CO_2 stream	(2) 2L MLB Polybags (1) 75 cc Mini Cylinder	Sample Storage Cabinets	5 days

2.3.5 Sample Chain-of-Custody

For fluid samples, chain-of-custody will be documented using a standardized form. Copies of the form will be provided to the person/lab receiving the samples as well as the person/lab transferring the samples. These forms will be retained and archived to allow simplified tracking of sample status. The chain-of -custody form and record keeping is the responsibility of sampling personnel.

For CO_2 stream analysis, an analysis authorization will accompany the sample to the laboratory at which point a chain-of-custody accompanies the sample through their processes.

2.4 Analytical Methods

Logging, geophysical monitoring, and pressure/temperature monitoring does not apply to this section and is omitted.

2.4.1 Analytical SOPs

Analytical SOPs are referenced in the laboratory methods provided in **Tables 5 and 6**. Other laboratory specific SOPs utilized by the laboratory will be determined after a contract laboratory has been selected. Upon request, Aera will provide the agency with the laboratory SOPs developed for the specific parameter using the appropriate standard method. Each laboratory technician conducting the analysis on the samples will be trained on the SOP developed for each standard method. Aera will include each technician's training certification with the annual report.

2.4.2 Equipment/Instrumentation Needed

Equipment and instrumentation are specified in **Tables 5 and 6** for the individual analytical methods.

2.4.3 Method Performance Criteria

Tables 5 through **7** list the analytes specific to each method along with the associated performance criteria, including reporting limits, method detection limits, and accuracy and precision limits. Nonstandard method performance criteria are not anticipated for this project.

2.4.4 Analytical Failure

Each laboratory conducting the analyses in **Tables 5** through **7** will be responsible for appropriately addressing analytical failure according to their individual SOPs.

2.4.5 Sample Disposal

Each laboratory conducting the analyses in **Tables 5** through **7** will be responsible for appropriate sample disposal according to their individual SOPs.

2.4.6 Laboratory Turnaround

Laboratory turnaround will vary by laboratory, but generally turnaround of verified analytical results within one month will be suitable for project needs.

2.4.7 Method Validation for Nonstandard Methods

Nonstandard methods are not anticipated for this project. If nonstandard methods are needed or proposed in the future, the EPA will be consulted on additional appropriate actions to be taken.

2.5 Quality Control

Geophysical monitoring and pressure/temperature monitoring does not apply to this section and is omitted. For log quality control, please refer to specific vendors at time of logging, following industry standard practices.

2.5.1 Field Quality Control Samples

2.5.1.1 Blanks

For subsurface fluid sampling, a field blank will be collected and analyzed for the inorganic analytes in **Table 5** at a frequency of 10% or greater. Field blank samples consist of laboratory supplied, reagent-free water that are collected in the field. Field blanks will be exposed to the same field and transport conditions as the subsurface fluid samples. Field blanks will be used to detect contamination resulting from the collection process. Trip blanks will be included with each set of samples being transported to analytical laboratories to detect contamination resulting from the transportation process.

2.5.1.2 Duplicates

For each subsurface fluid sampling event, a duplicate subsurface fluid sample will be collected from a well from a rotating schedule at 10% or greater frequency. Duplicate samples will be collected from the same source immediately after the original sample in different sample containers and processed as the other samples. Duplicate samples will be used to assess sample heterogeneity and analytical precision.

2.5.2 Exceeding Control Limits

If the sample analytical results exceed control limits (i.e., ion balances > ±10%), further examination of the analytical results will be done by evaluating the ratio of the measured TDS to the calculated TDS (i.e., mass balance) per the American Public Health Association (APHA) method. The method indicates which ion analyses should be considered suspect based on the mass balance ratio. Suspect ion analyses will then be reviewed in the context of historical data and interlaboratory results, if available. Suspect ion analyses will then be brought to the attention of the analytical laboratory for confirmation and/or reanalysis. The ion balance will be recalculated, and if the error is still not resolved, suspect data will be identified during data validation and may be given less importance in data interpretations.

2.5.3 Calculating Applicable QC Statistics

2.5.3.1 Charge Balance

The analytical results will be evaluated to determine correctness of analyses based on anion-cation charge balance calculation. Because the potable waters are electrically neutral, the chemical analyses should yield equally negative and positive ionic activity. The anion-cation charge balance will be calculated using the formula:

$$\%\ difference = 100 \text{ x } \frac{\sum cations - \sum anions}{\sum cations + \sum anions},$$

where the sums of the ions are represented in milliequivalents (meq) per liter and the criteria for acceptable charge balance is ±10%.

2.5.3.2 Mass Balance

The ratio of the measured TDS to the calculated TDS will be calculated in instances where the charge balance acceptance criteria are exceeded using the formula:

$$1.0 < \frac{measured\ TDS}{calculated\ TDS} < 1.2,$$

where the anticipated values are between 1.0 and 1.2.

2.5.3.3 Outliers

Identification of statistical outliers is essential prior to the statistical evaluation of fluid chemistry. This project will use the EPA's Unified Guidance (March 2009) as a basis for selection of recommended statistical methods to identify outliers in subsurface fluid chemistry data sets as appropriate. These techniques include probability plots, box plots, Dixon's test, and Rosner's test. The EPA-1989 outlier test may also be used as another screening tool to identify potential outliers.

2.6 Instrument/Equipment Testing, Inspection, and Maintenance

Logging tool equipment will be maintained as per wireline industry best practices and standards.

For subsurface fluid sampling, field equipment will be maintained, factory serviced, and factory calibrated per manufacturer's recommendations. Spare parts that may be needed during sampling will be included in supplies on-hand during field sampling.

For the laboratory equipment, testing, inspection, and maintenance will be the responsibility of the analytical laboratory per standard practice, method-specific protocol, or NELAP requirement.

2.7 Instrument/Equipment Calibration and Frequency

2.7.1 Calibration and Frequency of Calibration

Pressure/temperature gauge calibration information is located in **Tables 10** through **15**. Logging tool calibration will be performed at the discretion of the service company providing the equipment, following standard industry practices. Calibration frequency will be determined by standard industry practices.

For subsurface fluid sampling and CO_2 stream sampling, calibration requirements are specific to each method and given in **Tables 5** and **6**, respectively.

2.7.2 Calibration Methodology

Logging tool calibration methodology will follow standard industry practices.

For subsurface fluid sampling and CO_2 stream sampling, calibration methodology is given in **Tables 5** and **6**, respectively.

2.7.3 Calibration Resolution and Documentation

Logging tool calibration resolution and documentation will follow standard industry practices.

For subsurface fluid sampling and CO_2 stream sampling, calibration resolution and documentation requirements are specific to each method and given in **Tables 5** and **6**, respectively.

2.8 Inspection/Acceptance for Supplies and Consumables

2.8.1 Supplies, Consumables, and Responsibilities

Supplies and consumables for field and laboratory operations will be procured, inspected, and accepted as required from vendors approved by Aera or the respective subcontractor responsible

for the data collection activity. Acquisition of supplies and consumables related to fluid analyses will be the responsibility of the laboratory per established standard methodology or operating procedures.

2.9 Non-Direct Measurements

Aera will employ direct and indirect methods to track the extent of the CO_2 plume and the presence or absence of elevated pressure. Non-direct methods include pulsed neutron logging, DTS, and seismicity monitoring by DAS.

2.9.1 Pulsed Neutron Logging

The CO_2 plume location will be tracked using pulsed neutron logging that will provide high-resolution vertical data around the wellbore of the Agua Sandstone (I-28N, 25-26N) and 64 Zone (1-28N, 39-26N, and 27-1N) monitoring wells. The saturation of CO_2 in the target formation will be estimated by measuring the die-away time of a short neutron pulse. The die-away time is a function of the porosity and the fluid types in the rock. The exact precision and accuracy of the data will depend on the selected tool and the logging environment of each well, but representative pulsed neutron logging tool specifications are given in **Table 21**.

An initial pulsed neutron log will be created before the CO_2 plume reaches the monitoring well and will serve as a baseline that future measurements will be compared against. Increases in CO_2 saturation relative to baseline will indicate when and where the plume has reached the monitoring well. These data will also be used in reevaluations of the AoR.

2.9.2 Distributed Temperature Sensing

DTS allows for continuous temperature profiles over the installed depth rather than measurements at fixed points. The continuous temperature data can be analyzed to provide information about the specific depths that the CO_2 enters the formation. Abnormal temperature profiles may indicate mechanical integrity concerns or unexpected leakage of CO_2. DTS fiber optic cable will be installed in the 64 Zone monitoring wells, 1-28N, 39-26N, and 27-1N, to identify temperature changes that may indicate the CO_2 plume's arrival at that location. DTS fiber optic will also be installed in the Agua sandstone monitoring well 26-25N to evaluate temperature fluctuation above the injection zone.

2.9.3 Seismicity Monitoring

A microseismic monitoring network will be utilized to detect microseismic events at or above magnitude 1.0 in real time. Events with an event magnitude of at least 1.0 will be detectable across the entirety of the AoR from surface to at least 2,000 ft below the injection zone and at least 1 mile radius of the injection wells. Future technologies may be added to the seismic monitoring network pending evaluation and the approval of the UIC Program Director. Additionally, the California Integrated Seismic Network will be monitored continuously for indication of an earthquake of magnitude 2.7 or greater occurring within a radius of one mile of injection operations from commencement of injection activity to its completion. Aera will respond to seismic events with an epicenter in the AoR in accordance with the Seismic Response System for seismic events >M1.0

established in the Emergency and Remedial Response Plan (**Attachment I).** A summary of the seismic monitoring locations and frequencies is given in **Table 20**.

2.9.3.1 Network Design

A continuously recording DAS fiber optic array will be deployed from approximately surface–8,000 ft within a plugged and abandoned well, 38-35N, located in the approximate center of the AoR. DAS is a system using fiber optic cables to provide distributed strain sensing along the length of the cable. The combined downhole DAS in addition to public seismic monitoring stations will be capable of accurately detecting a magnitude event of at least 1.0 (or higher) within, and surrounding, the AoR.

2.9.3.2 Network Operation

After design, the microseismic network will be installed and tested. After testing is completed, the network will be operational to monitor for microseismic events in real time through the injection phase and into the post-injection period. Monitoring will begin at least 1 month prior to injection to establish the microseismic baseline.

Automatic event detection shall include 24-hour/day seismic event tracking and detection, with event location processing completed within 24–48 hours for larger events. Responses to events of a range of low to high magnitudes will be set up according to a traffic light system, with descriptions provided in the Emergency and Remedial Response Plan (**Attachment I**). Maintenance of seismometer, datalogger and communications equipment shall be conducted periodically according to the manufacturer's specifications. Processed data of recorded events will be catalogued and summarized monthly. Monitoring and maintenance will be conducted by trained personnel.

Table 20: Summary of Passive Seismic Monitoring System

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
AoR	Seismic events over magnitude 1.0	Borehole DAS (38-35N) and public surface seismic stations	Within 1-mile radius of injection wells	Continuous
AoR	Seismic events over magnitude 2.7	California Integrated Seismic Network	Within 1-mile radius of injection wells	Continuous

2.10 Data Management

2.10.1 Data Management Scheme

Aera or a designated contractor will maintain the required project data as provided elsewhere in the permit. Data will be backed up on tape or held on secure servers.

2.10.2 Recordkeeping and Tracking Practices

The records of gathered data will be securely held and properly labeled for auditing purposes.

2.10.3 Data Handling Equipment/Procedures

The equipment used to store data will be properly maintained and operated according to proper industry techniques. Aera's supervisory control and data acquisition (SCADA) and vendor data acquisition systems will interface with one another, and all subsequent data will be held on a secure server.

2.10.4 Responsibility

The primary project managers will be responsible for ensuring proper data management is maintained.

2.10.5 Data Archival and Retrieval

The data will be held by Aera. These data will be maintained and stored for auditing purposes as described in **Section 2.10.1**.

2.10.6 Hardware and Software Configurations

Aera and vendor hardware and software configurations will be appropriately interfaced.

2.10.7 Checklists and Forms

Checklists and forms will be procured and generated as necessary.

3. ASSESSMENT AND OVERSIGHT

3.1 Assessments and Response Actions

3.1.1 Activities to be Conducted

Subsurface fluid data will be collected at the frequency outlined in **Table 1**. After completion of sample analysis, results will be reviewed for QC criteria as noted in **Section 2.5**. If the data quality fails to meet criteria set in **Section 2.5.**, samples will be reanalyzed, if still within holding time criteria. If outside of holding time criteria, additional samples may be collected, or sample results may be excluded from data evaluations and interpretations. Evaluation for data consistency will be performed according to procedures described in the EPA 2009 Unified Guidance (EPA, 2009).

3.1.2 Responsibility for Conducting Assessments

Organizations gathering data will be responsible for conducting internal assessments. Stop-work orders will be handled internally within individual organizations.

3.1.3 Assessment Reporting

The assessment information will be reported to the individual organizations' project manager outlined in **Section 1.1**.

3.1.4 Corrective Action

The corrective action affecting only an individual organization's data collection responsibility will be addressed, verified, and documented by the individual project managers and communicated to the other project managers as necessary. Corrective actions affecting multiple organizations will be addressed by the members of the project leadership and communicated to other members on the distribution list for the QASP. Assessments may require integration of information from multiple monitoring sources across organizations (operational, in-zone monitoring, above-zone monitoring) to determine whether correction actions are required and/or the most cost-efficient and effective action to implement. Aera will coordinate multiorganization assessments and corrective actions as warranted.

3.2 Reports to Management

3.2.1 QA Status Reports

QA status reports are not expected to be required. If any testing or monitoring techniques are changed, the QASP will be reviewed and updated as appropriate in consultation with EPA. Revised QASPs will be distributed by Aera to the full distribution list at the beginning of this document.

4. DATA VALIDATION AND USABILITY

4.1 Data Review, Verification, and Validation

4.1.1 Criteria for Accepting, Rejecting, or Qualifying Data

Subsurface fluid data validation will include the review of the concentration units, sample holding times, and the review of duplicate, blank, and other appropriate QA/QC results. The results will be entered into a database or spreadsheet with periodic data review and analysis. Aera will retain copies of the laboratory analytical test results and/or reports. Analytical results will be reported on a frequency based on the approved Class VI permit conditions. In the periodic reports, data will be presented in graphical and tabular formats as appropriate to characterize general subsurface fluid quality and identify intrawell variability with time. After sufficient data have been collected, additional methods, such as those described in the EPA 2009 Unified Guidance (EPA, 2009), will be used to evaluate intrawell variations for subsurface fluid constituents, to evaluate if significant changes have occurred that could be the result of CO_2 or brine seepage beyond the storage reservoir.

4.2 Verification and Validation Methods

4.2.1 Data Verification and Validation Processes

See **Sections 2.5** and **4.1.1**. Appropriate statistical software will be used to determine data consistency.

4.2.2 Data Verification and Validation Responsibility

Aera or its designated subcontractor will verify and validate subsurface fluid sampling data.

4.2.3 Issue Resolution Process and Responsibility

Aera or its designated representative will oversee the subsurface fluid data handling, management, and assessment process. Staff involved in these processes will consult with Aera or its designated representative to determine actions required to resolve issues.

4.2.4 Checklist, Forms, and Calculations

Checklists and forms will be developed specifically to meet Class VI permit requirements.

4.3 Reconciliation with User Requirements

4.3.1 Evaluation of Data Uncertainty

Statistical software will be used to determine subsurface fluid data consistency using methods consistent with EPA 2009 Unified Guidance (EPA, 2009).

4.3.2 Data Limitations Reporting

The organization-level project managers will be responsible for ensuring that data developed by their respective organizations is presented with the appropriate data-use limitations.

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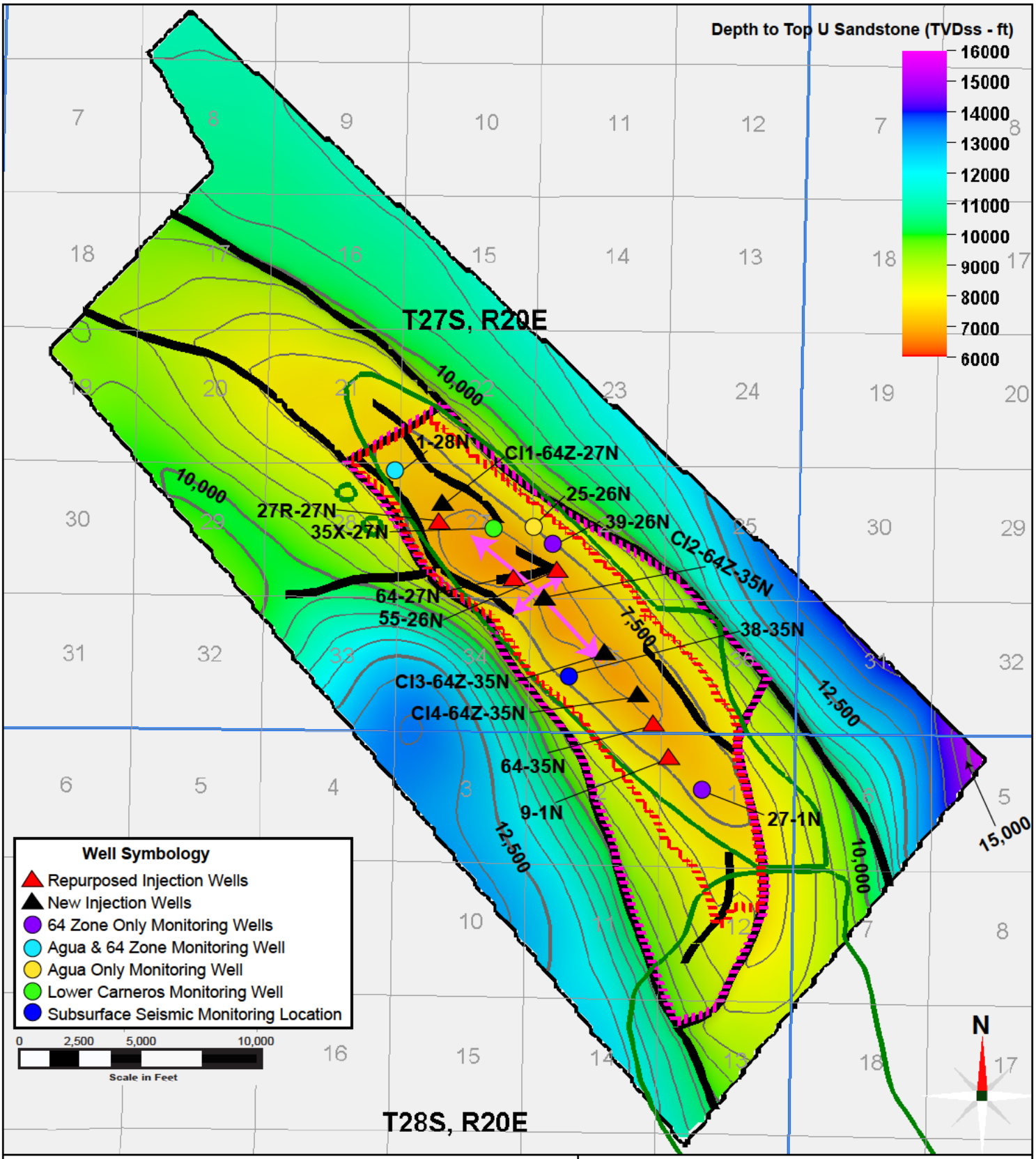
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Figures



Legend:

- Area of Interest
- Township/Range Boundaries
- Section Boundaries
- 1973/74 Oil Field Boundaries
- Fault Traces
- Elevation Contours (500 ft CI)
- Area of Review
- Modeled CO_2 Plume Extent
- Anticline Axis

Explanation:

ft - feet
TVDss - true vertical depth sub sea (ft)
CI - contour interval
CO_2 - carbon dioxide

Notes:

Surface artifacts due to interpolation across faults and structural model grid.

Location Map of Repurposed and New Wells

North Belridge Oil Field
Western Kern County
California

Geosyntec consultants

CarbonFrontier	April 2024	Figure 1

Geosyntec\Aera Belridge CCUS Project - General\EPA VI\A. Technical\01_Figures_EPAProactive2024\i_Illustrator\Attachment E\Appendix A - QASP\Appendix A Figure 1 Location of New & Repurposed well.ai

E.3 Paleontological Records Search

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Appendix F

Hazards and Hazardous Materials

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F-1 Phase I ESA

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AERA CARBONFRONTIER PROJECT

Phase 1 Environmental Site Assessment

June 26, 2023

Prepared for:
Aera Energy LLC
10000 Ming Avenue
Bakersfield, CA 93311-1302

Prepared by:
Stantec Consulting Services Inc.
2646 Santa Maria Way, Suite 107
Santa Maria CA 93455-1776

Project No.: 185805372

Sign-off Sheet and Signatures of Environmental Professionals

This document entitled *Aera CarbonFrontier Project), Phase I Environmental Site Assessment* was prepared by Stantec Consulting Services Inc. ("Stantec") for the account of Aera Energy LLC (the "Client"). The conclusions in the Report are Stantec's professional opinion, as of the time of the Report, and concerning the scope described in the Report. The opinions in the document are based on conditions and information existing at the time the scope of work was conducted and do not take into account any subsequent changes. The Report relates solely to the specific project for which Stantec was retained and the stated purpose for which the Report was prepared. The Report is not to be used or relied on for any variation or extension of the project, or for any other project or purpose, and any unauthorized use or reliance is at the recipient's own risk.

Stantec has assumed all information received from the "Client" and third parties in the preparation of the Report to be correct. While Stantec has exercised a customary level of judgment or due diligence in the use of such information, Stantec assumes no responsibility for the consequences of any error or omission contained therein.

This Report is intended solely for use by the Client in accordance with Stantec's contract with the Client. While the Report may be provided to applicable authorities having jurisdiction and others for whom the Client is responsible, Stantec does not warrant the services to any third party. The report may not be relied upon by any other party without the express written consent of Stantec, which may be withheld at Stantec's discretion.

Author: _____

Thomas Stanley
Geologic Staff

I declare that, to the best of my professional knowledge and belief, I meet the definition of Environmental Professional as defined in § 312.10 of Title 40 of the Code of Federal Regulations, Part 312, (40 CFR 312). I have the specific qualifications based on education, training, and experience to assess a property of the nature, history, and setting of the property. I have developed and performed all the appropriate inquiries in conformance with the standards and practices set forth in 40 CFR Part 312.

Quality Reviewer: _____

Kirk Henning
Senior Scientist

Independent Reviewer: _____

Eric K. Snelling, R.E.P.A.
Principal Environmental Planner

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Abbreviations

AAI	All Appropriate Inquiry
ACM	Asbestos-containing material
Aera	Aera Energy LLC
AST	Aboveground Storage Tank
ASTM	ASTM International
AUL	Activity Use Limitation
BBLS	Barrels
BER	Business Environmental Risk
bgs	Below Ground Surface
Breitburn	Breitburn Operating LP
CalGEM	Department of Conservation Division of Oil, Gas and Geothermal Resources
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CFR	Code of Federal Regulation
CO_2	Carbon Dioxide
CREC	Controlled Recognized Environmental Conditions
CUP	Conditional Use Permit
CUPA	Certified Unified Program Agency
DOGGR	Department of Conservation Division of Oil, Gas and Geothermal Resources
DTSC	Department of Toxic Substances
EP	Environmental Professional
EPA	Environmental Protection Agency
ESA	Environmental Site Assessment
GES	Groundwater and Environmental Services, Inc.
HREC	Historical Recognized Environmental Conditions
HUC	Hydrologic Unit Code
HUD	Housing and Urban Development
KCEHS	Kern County Environmental Health Services

KCFD	Kern County Fire Department
LBP	Lead-based paint
LUST	Leaking Underground Storage Tank
mg/L	Milligrams per Liter
Mmt	Million Metric Tonnes
NESHAP	National Emissions Standard for Hazardous Air Pollutants
NRCS	Natural Resource Conservation Service
NWI	National Wetlands Inventory
OES	California Office of Emergency Services
PCBs	Polychlorinated Biphenyls
PIC	Person-In-Charge
RCRA	Resource Conservation and Recovery Act
REC	Recognized Environmental Conditions
RWQCB	Regional Water Quality Control Board
SR	State Route
SJVAPCD	San Joaquin Valley Air Pollution Control District
SWRCB	State Water Resources Control Board
TDS	Total Dissolved Solids
USDA	United States Department of Agriculture
USDW	Underground Sources of Drinking Water
USGS	United States Geological Survey
UST	Underground Storage Tank
VEC	Vapor Encroachment Condition
WGS	World Geodetic System
Wood	Wood Environmental & Infrastructure Solutions, Inc.



1.0 EXECUTIVE SUMMARY

Stantec Consulting Services Inc. (Stantec) has completed a Phase I Environmental Site Assessment (ESA) report of the property located within the North and South Belridge oil fields, located from an area to the west of the intersection of State Route (SR) 33 and Brown Material Road, southeast to the approximate location of the intersection of SR-33 and Lost Hills Road (the "Subject Property"), on behalf of Aera Energy LLC (Aera) (the "Client"). The work was performed according to Stantec's proposal and terms and conditions dated August 9, 2022, and accepted by the Client on August 30, 2022. Aera Energy LLC (Aera) (the "User") has been designated as the User of this report. The intended use of this Phase I ESA is to identify potential risks associated with the proposed construction of a carbon dioxide transfer pipeline, to be used in a carbon capture and sequestration system.

The Phase I ESA was conducted in conformance with the requirements of ASTM International (ASTM) Designation E1527-21 and E1527-13, and All Appropriate Inquiry (AAI) as defined by the United States Environmental Protection Agency (EPA) in Title 40 of the Code of Federal Regulations (CFR), Part 312 (40 CFR 312), except as may have been modified by the scope of work, and terms and conditions, requested by the Client. Any exceptions to, or deletions from, the ASTM or AAI practice are described in Section 2.3.

The Subject Property is located within the North and South Belridge Oil Fields, in an unincorporated area of western Kern County, approximately 14 miles west of the town of Buttonwillow, seven miles southwest of the town Lost Hills, and eleven miles north of the town of McKittrick, California. From the south, the Subject Property spans an area in the vicinity of the intersection of Lost Hills Road and SR-33 (also known as the West Side Highway), northwestward through Seventh Standard Road, northward through the South Belridge Oil Field variously paralleling or oriented east of Pole Line Road through Lerdo Highway, then continuing along the vicinity of Pole Line Road to the North Belridge Oil Field. A Subject Property Location Map is provided as Figure 1. A Subject Property Vicinity Overview Map is provided as Figure 2 and Subject Property Vicinity Maps illustrating the main features of the Subject Property and vicinity are provided as Figures 3A through 3F. Subject Property Vicinity Maps Photographs taken during the site reconnaissance visit are provided in Appendix A.

We have performed a Phase I ESA in conformance with the scope and limitations of ASTM Practice E1527-21 of the "Subject Property", an approximately 13-mile long corridor that encompasses all Project features and a one-eighth mile buffer, centered on 35.501525°, 119.751895° (World Geodetic System of 1984 [WGS 84]). Any exceptions to, or deletions from, this practice are described in Section 2.3 of this report. This assessment has revealed the following recognized environmental conditions (RECs), Controlled RECs (CRECs), and/or significant data gaps in connection with the Subject Property:

- The current and historical use of the Subject Property and surrounding land for petroleum hydrocarbon extraction activities, from 1911 to the present, is considered a REC.
- Regulatory records indicate that an area of land to the west of the Subject Property, but likely incorporating the Subject Property, was used as a Class III solid waste landfill until 2007. The

area of fill is listed as over 27 acres, to a depth of 10 feet below ground surface (bgs), and it is considered likely that portions of the Subject Property occur within this area of fill. In addition, historical aerial photography indicate worker residences were demolished in the 1970s and 1980s. Houses constructed prior to this period often contained asbestos-containing materials (ACM) and lead-based paint (LBP) within the building materials. The potential for ACM and LBP to be contained within various areas of fill at the Subject Property, as well as the potential for the fill to be uncompacted and/or uncontrolled, is considered a REC.

- Kern County Environmental Health Services records indicated that a historical waste disposal site is located in the South Belridge Oil Field east of the Oasis office building. Refer to Figure 3 for the approximate location of the waste disposal site. No additional information was available for this REC.
- A total of 41 wastewater pits used for disposal of 'produced water' or for other uses are currently or were historically located within 0.5 miles of the Subject Property. Of these, the majority are either closed former percolation ponds, secondary containment basins, emergency overflow basins, or process basins. Based on the distance, direction, and regulatory status, these sites are not anticipated to represent an environmental concern to the Subject Property.

The preceding summary is intended for informational purposes only. Reading of the full body of this report is recommended.

Site Location



Project Location

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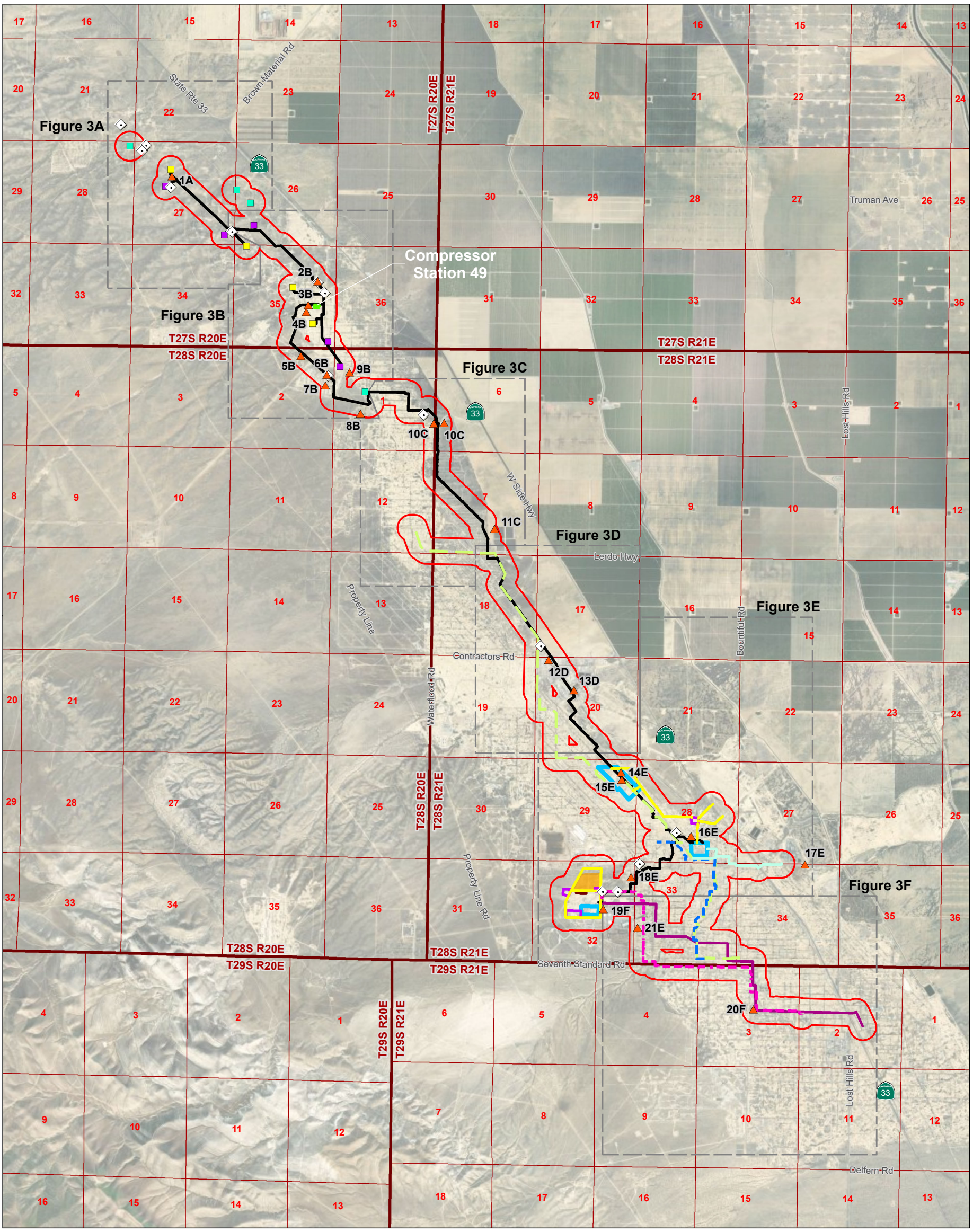
Stantec AERA

Project Location Kern County, California	Prepared by DL on 2023-05-17 TR by SET on 2023-05-17 IR by TS on 2023-05-17
Client/Project Aera Energy Belridge Carbon Capture and Sequestration (CCS) Project Phase I Environmental Site Assessment	185805407
Figure No. **1**	
Title **Subject Property Location Map**	

Notes
1. Coordinate System: NAD 1983 StatePlane California V FIPS 0405 Feet
2. Data Sources: CalGEM, 2019, Stantec 2022, 2023.
3. Background: Sources: Esri, HERE, Garmin, USGS, Intermap, INCREMENT P, NRCan, Esri Japan, METI, Esri China (Hong Kong), Esri Korea, Esri (Thailand), NGCC, (c) OpenStreetMap contributors, and the GIS User Community

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- 8th Mile Buffer
- Township and Range
- Section
- Site Features
- Photo Points
- Proposed CO_2 Injection Wells
- Existing Oil Wells to be Converted to CO_2 Injection Wells
- Proposed Monitoring Wells
- Existing Del Sur Gas Line to Gas Plant 32
- Existing Steam Line Routes
- Proposed CO_2 Pipelines
- Potential Produced Water Lines Routes
- Potential Power Line Routes
- Potential Steam Line Routes
- Tulare CVR to GP32 (Optional)
- Proposed Compressor Booster Station
- Potential Substation Locations
- Pre-Combustion Facilities
- Proposed CO_2 Capture Facility
- Proposed Staging Area Adjacent to Gas Plant 32

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Stantec AERA

Project Location
Kern County, California

Prepared by DL on 2023-05-17
TR by SET on 2023-05-17
IR by TS on 2023-05-17

Client/Project
185805407
Aera Energy LLC
Aera CarbonFrontier Project
Phase I Environmental Site Assessment

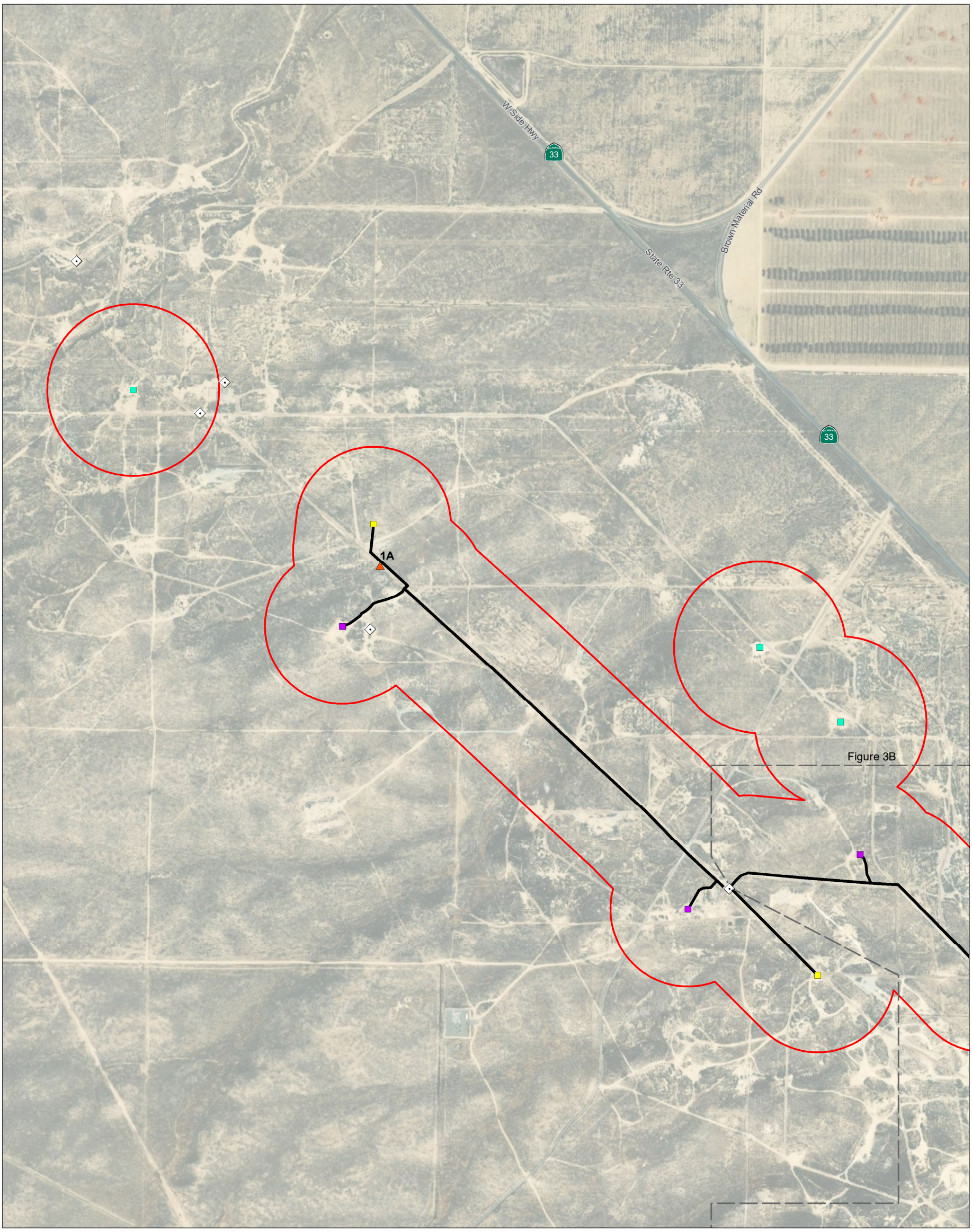
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Title
Subject Property Vicinity Overview Map

Notes
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2. Data Sources: CalGEM, 2019, Stantec 2022,2023.
3. Background: Source: Esri, Maxar, Earthstar Geographics, and the GIS User Community

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- 8th Mile Buffer
- Site Features
- Photo Points
- Proposed CO_2 Injection Wells
- Existing Oil Wells to be Converted to CO_2 Injection Wells
- Proposed Monitoring Wells
- Proposed CO_2 Pipelines

0 900 1,800 Feet

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Stantec AERA

Project Location
Kern County,
California

Prepared by DL on 2023-05-17
TR by SET on 2023-05-17
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Client/Project
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Phase I Environmental Site Assessment

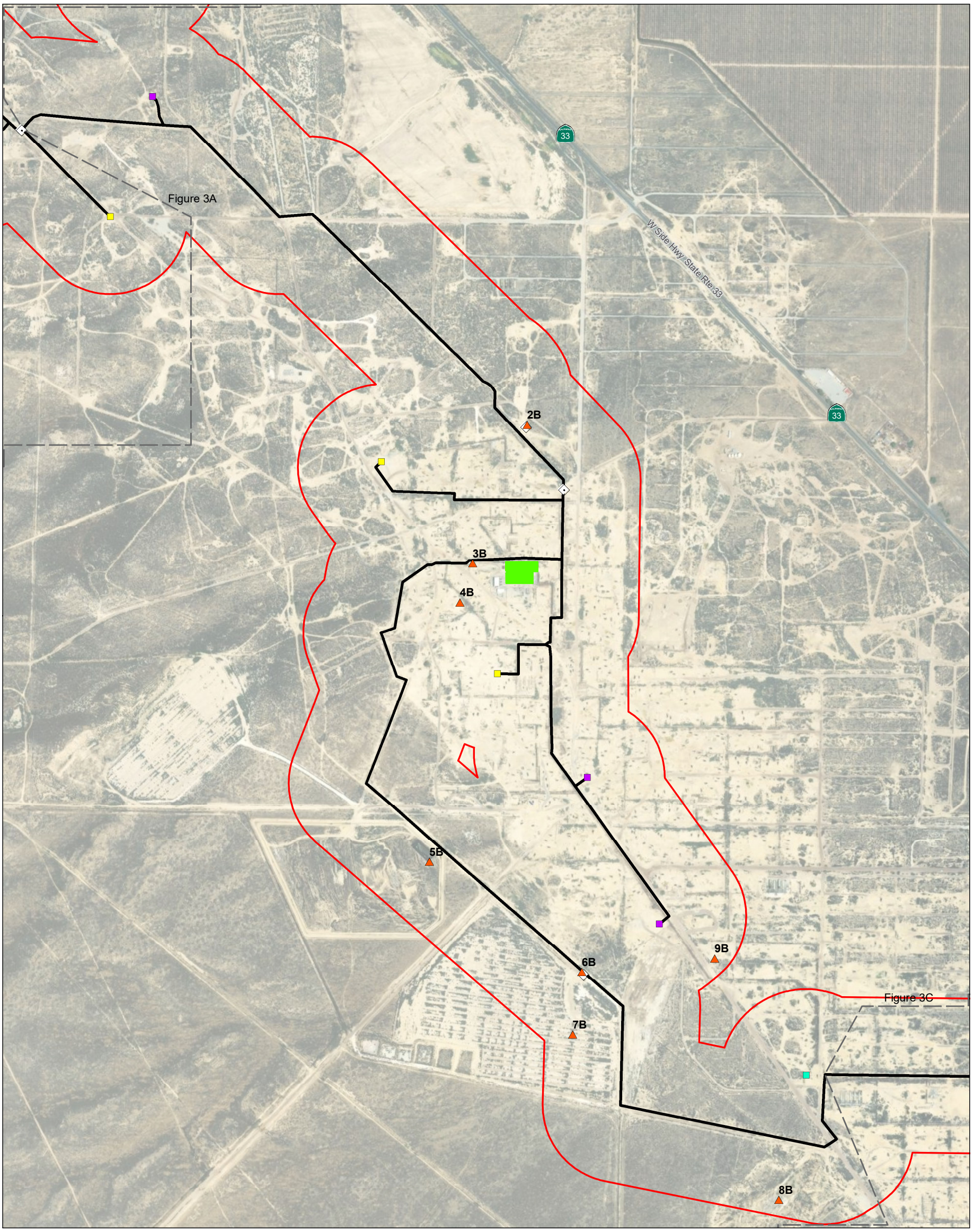
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Title
Subject Property Vicinity Maps

Notes
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2. Data Sources: CalGEM, 2019, Stantec 2022, 2023.
3. Background: Source: Esri, Maxar, Earthstar Geographics, and the GIS User Community

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- 8th Mile Buffer
- Site Features
- Photo Points
- Proposed CO_2 Injection Wells
- Existing Oil Wells to be Converted to CO_2 Injection Wells
- Proposed Monitoring Wells
- Proposed CO_2 Pipelines
- Proposed Compressor Booster Station

0 900 1,800 Feet

(At original document size of 11x17)
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Stantec AERA

Project Location
Kern County, California

Prepared by DL on 2023-05-17
TR by SET on 2023-05-17
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Client/Project
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Phase I Environmental Site Assessment

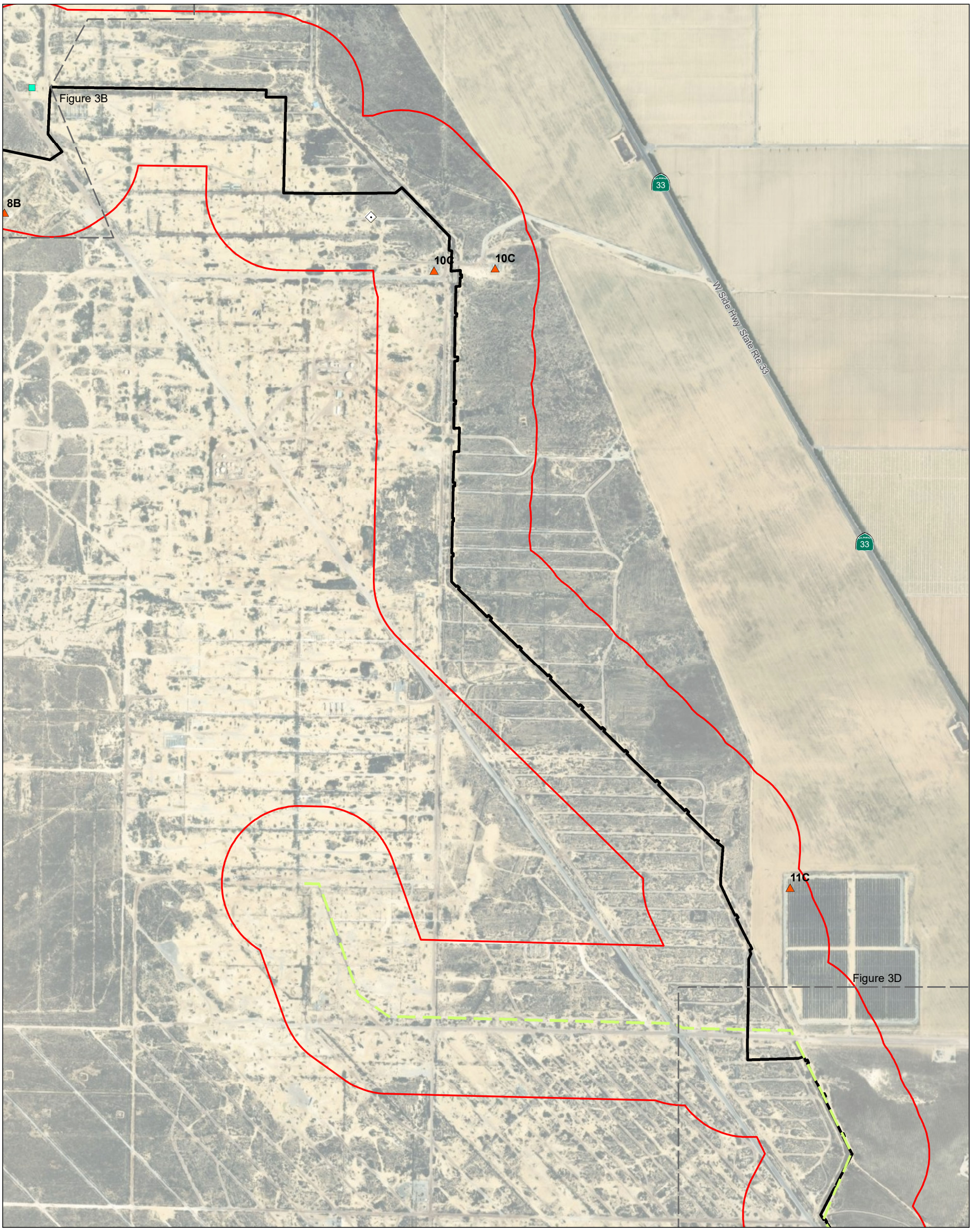
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Title
Subject Property Vicinity Maps

Notes
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2. Data Sources: CalGEM, 2019, Stantec 2022, 2023.
3. Background: Source: Esri, Maxar, Earthstar Geographics, and the GIS User Community

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8th Mile Buffer
Site Features
Photo Points
Proposed Monitoring Wells
Proposed CO_2 Pipelines
Potential Steam Line Routes

0 900 1,800 Feet

(At original document size of 11x17)
1:10,800

N

Stantec AERA

Project Location
Kern County,
California

Prepared by DL on 2023-05-17
TR by SET on 2023-05-17
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Client/Project
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Aera Energy LLC
Aera CarbonFrontier Project
Phase I Environmental Site Assessment

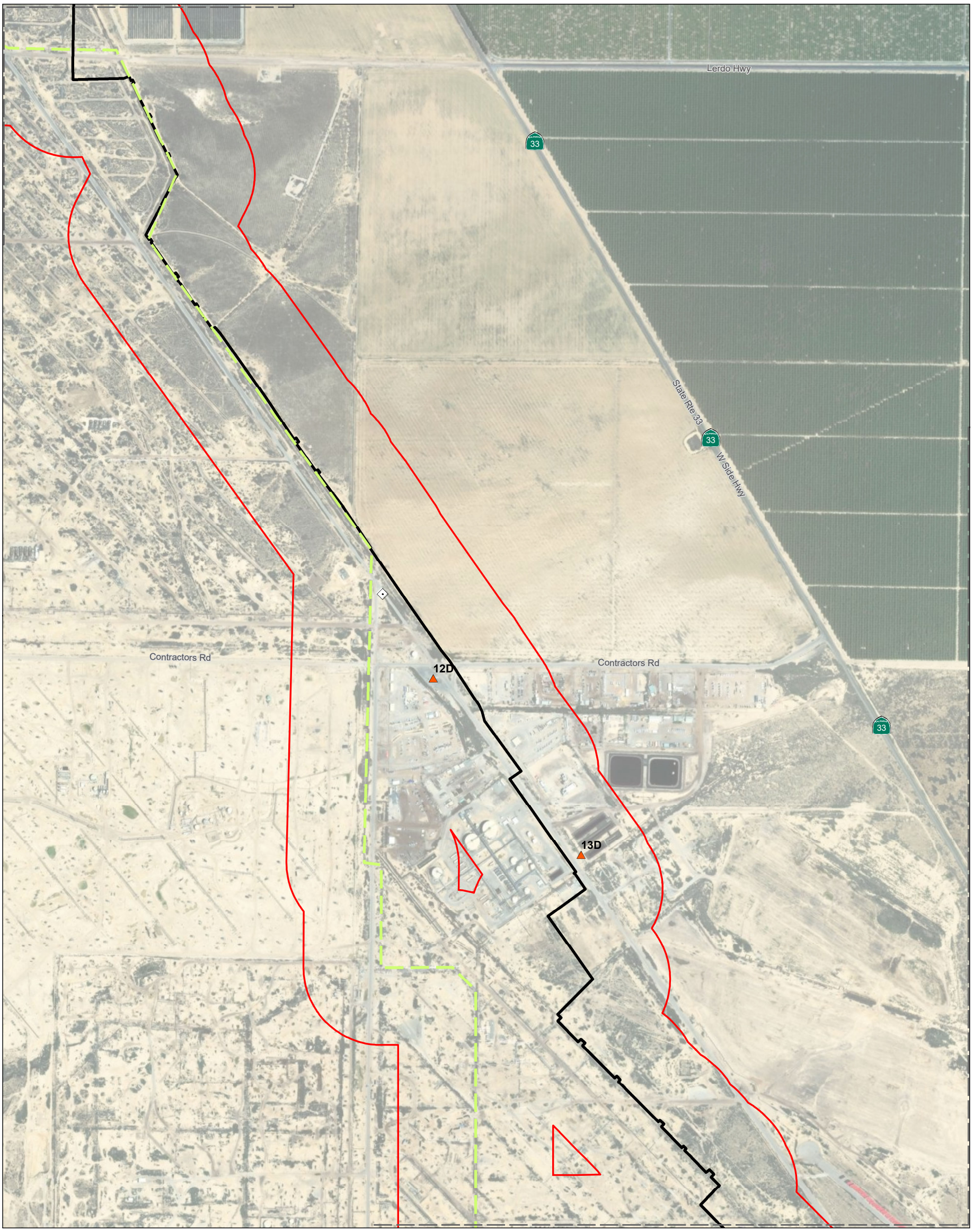
Figure No.
3C

Title
Subject Property Vicinity Maps

Notes
1. Coordinate System: NAD 1983 StatePlane California V FIPS 0405 Feet
2. Data Sources: CalGEM, 2019, Stantec 2022, 2023.
3. Background: Source: Esri, Maxar, Earthstar Geographics, and the GIS User Community

V:\185805\Active\185805xxxxx_Aera\03_data\gis_cad\gis\185805372_BelridgeCCS\Phase1_data\AeraBelridge_Phase1_SiteVicinity_20221114.mxd Revised: 2023-06-27 By: Dalaw

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8th Mile Buffer
Site Features
Photo Points
Proposed CO_2 Pipelines
Potential Steam Line Routes

0 900 1,800 Feet

(At original document size of 11x17)
1:10,800

N

Stantec AERA

Project Location
Kern County,
California

Prepared by DL on 2023-05-17
TR by SET on 2023-05-17
IR by TS on 2023-05-17

Client/Project
185805407
Aera Energy LLC
Aera CarbonFrontier Project
Phase I Environmental Site Assessment

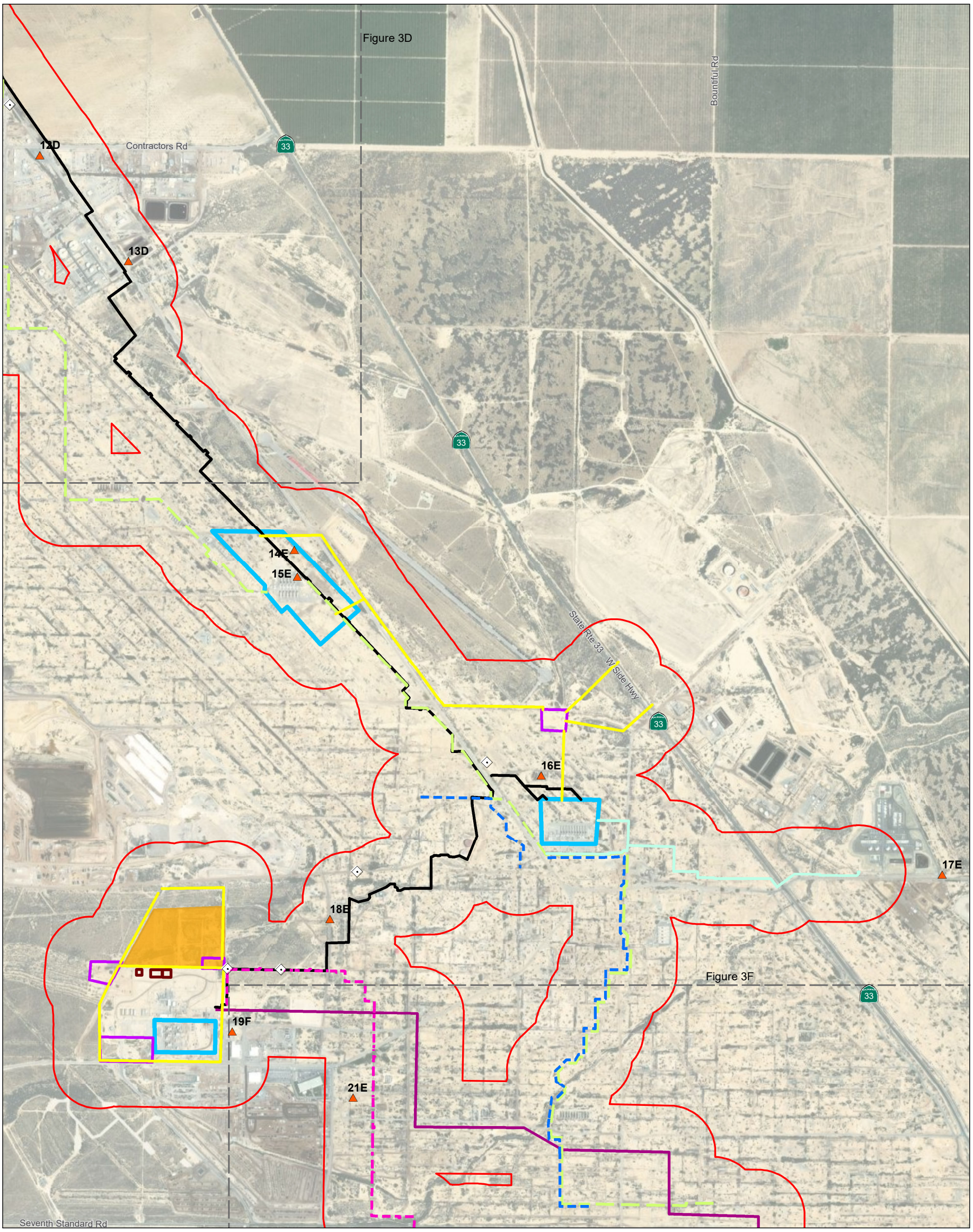
Figure No.
3D

Title
Subject Property Vicinity Maps

Notes
1. Coordinate System: NAD 1983 StatePlane California V FIPS 0405 Feet
2. Data Sources: CalGEM, 2019, Stantec 2022, 2023.
3. Background: Source: Esri, Maxar, Earthstar Geographics, and the GIS User Community

V:\1858\Active\1858xxxx_Aera\03_data\gis_cad\gis\185805372_BelridgeCCS\Phase1_data\AeraBelridge_Phase1_SiteVicinity_20221114.mxd Revised: 2023-06-27 By: Dalaw

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- 8th Mile Buffer
- Site Features
- Photo Points
- Existing Del Sur Gas Line to Gas Plant 32
- Existing Steam Line Routes
- Proposed CO_2 Pipelines
- Potential Produced Water Lines Routes
- Potential Power Line Routes
- Potential Steam Line Routes
- Tulare CVR to GP32 (Optional)
- Potential Substation Locations
- Pre-Combustion Facilities
- Proposed CO_2 Capture Facility
- Proposed Staging Area Adjacent to Gas Plant 32

0 1,500 3,000 Feet

(At original document size of 11x17)
1:18,000

N

Stantec AERA

Project Location
Kern County,
California

Prepared by DL on 2023-05-17
TR by SET on 2023-05-17
IR by TS on 2023-05-17

Client/Project
185805407
Aera Energy LLC
Aera CarbonFrontier Project
Phase I Environmental Site Assessment

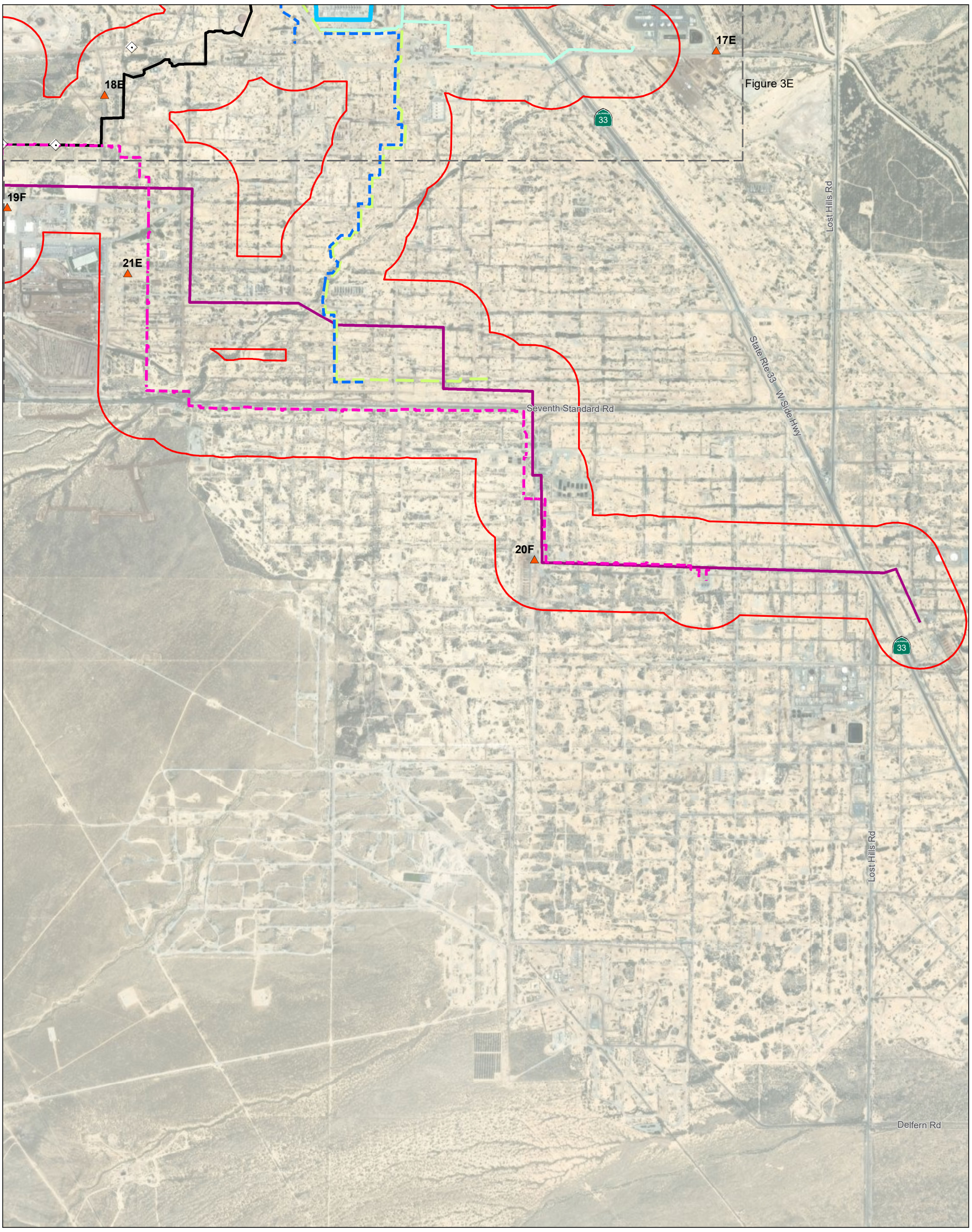
Figure No.
3E

Title
Subject Property Vicinity Maps

Notes
1. Coordinate System: NAD 1983 StatePlane California V FIPS 0405 Feet
2. Data Sources: CalGEM, 2019, Stantec 2022, 2023.
3. Background: Source: Esri, Maxar, Earthstar Geographics, and the GIS User Community

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- 8th Mile Buffer
- Site Features
- Photo Points
- Existing Del Sur Gas Line to Gas Plant 32
- Existing Steam Line Routes
- Proposed CO_2 Pipelines
- Potential Produced Water Lines Routes
- Potential Steam Line Routes
- Tulare CVR to GP32 (Optional)
- Proposed CO_2 Capture Facility

0 1,500 3,000 Feet

(At original document size of 11x17)
1:18,000

N

Stantec AERA

Project Location
Kern County,
California

Prepared by DL on 2023-05-17
TR by SET on 2023-05-17
IR by TS on 2023-05-17

Client/Project
185805407
Aera Energy LLC
Aera CarbonFrontier Project
Phase I Environmental Site Assessment

Figure No.
3F

Title
Subject Property Vicinity Maps

Notes
1. Coordinate System: NAD 1983 StatePlane California V FIPS 0405 Feet
2. Data Sources: CalGEM, 2019, Stantec 2022, 2023.
3. Background: Source: Esri, Maxar, Earthstar Geographics, and the GIS User Community

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2.0 INTRODUCTION

The objective of this Phase I Environmental Site Assessment (ESA) was to perform All Appropriate Inquiry (AAI) into the past ownership and uses of the Subject Property consistent with good commercial or customary practice as outlined by ASTM International (ASTM) in "Standard Practice for Environmental Site Assessments: Phase I Environmental Site Assessment Process", Designation E1527-21 and E1527-13. "All Appropriate Inquiry" is the process for evaluating a property's environmental conditions for the purpose of qualifying for landowner liability protections under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) following final rule of Part 312 of Title 40, Code of Federal Regulations (40 CFR Part 312). The purpose of this Phase I ESA was to identify, to the extent feasible, adverse environmental conditions including recognized environmental conditions ("RECs") of the Subject Property. While the AAI Rule still references the ASTM E1527-13 standard until fully adopted by the EPA, this report incorporates procedures as prescribed in ASTM E1527-21, which is the current published ASTM standard for Phase I ESAs.

The ASTM E1527-21 standard indicates that the goal of the Phase I ESA is to identify RECs, as well as historical recognized environmental conditions (HRECs) and controlled recognized environmental conditions (CRECs) that may exist at a property. The term "recognized environmental conditions" is defined as:

1) the presence of hazardous substances or petroleum products in, on, or at the Subject Property due to a release to the environment;

2) the likely presence of hazardous substances or petroleum products in, on, or at the Subject Property due to a release or likely release to the environment; or

3) the presence of hazardous substances or petroleum products in, on, or at the Subject Property under conditions that pose a material threat of a future release to the environment.

ASTM defines a "HREC" as a previous release of hazardous substances or petroleum products affecting the Subject Property that has been addressed to the satisfaction of the applicable regulatory authority and meets current unrestricted use criteria established by a regulatory authority, without subjecting the property to any required controls (e.g., activity and use limitations or other property use limitations). A HREC is not considered a REC.

ASTM defines a "CREC" as a REC resulting from a past release of hazardous substances or petroleum products that has been addressed to the satisfaction of the applicable regulatory authority (e.g., as evidenced by the issuance of a no further action letter or equivalent, or meeting risk-based criteria established by regulatory authority), but with hazardous substances or petroleum products allowed to remain in place subject to the implementation of required controls (e.g., property use restrictions, activity and use limitations, institutional controls, or engineering controls).

As defined by ASTM, RECs can include hazardous substances or petroleum products present under conditions in compliance with laws if that presence represents a material threat of future release. The release of hazardous substances or petroleum products is, however, not a REC if that presence is a *de minimis* condition. *De minimis* conditions are minor releases that generally do not present a material risk to human health and would not likely be subject to enforcement action if brought to the attention of governmental agencies. ASTM also considers the potential for a business environmental risk (BER), defined as a risk which can have a material environmental or environmentally driven impact on the business associated with the current or planned use of the Subject Property, not necessarily limited to those environmental issues required to be investigated by the ASTM standard. Consideration of BERs may involve addressing one or more ASTM non-scope considerations.

This Phase I ESA was conducted in accordance with our proposal to Aera Energy LLC (Aera) dated August 9, 2022, and Client's authorization on August 30, 2022. The scope of work conducted during this Phase I ESA consisted of a visual reconnaissance of the Subject Property, interviews with key individuals, and review of reasonably ascertainable documents. The scope of work did not include an assessment for environmental regulatory compliance of any facility ever operated at the Subject Property (past or present), or sampling and analyzing of environmental media. Stantec was not contracted to perform an independent evaluation of the purchase or lease price of the Subject Property and its relationship to current fair market value. The conclusions presented in this Phase I ESA report are professional opinions based on data described herein. The opinions are subject to the limitations described in Section 2.3.

ASTM E1527-21 notes that the availability of record information varies from source to source. The User or Environmental Professional (EP) is not obligated to identify, obtain, or review every possible source that might exist with respect to a property. Instead, ASTM identifies record information that is reasonably ascertainable from standard sources. "Reasonably ascertainable" means:

1. Information that is publicly available;
2. Information that is obtainable from its source within reasonable time and cost constraints; and
3. Information that is practicably reviewable.

2.1 SUBJECT PROPERTY DESCRIPTION

The Subject Property is located within the North and South Belridge oil fields, in an unincorporated area of western Kern County, approximately 14 miles west of the town of Buttonwillow, seven miles southwest of the town of Lost Hills, and eleven miles north of the town of McKittrick, California. From the south, the Subject Property spans an area in the vicinity of the intersection of Lost Hills Road and State Route (SR) 33 (also known as the West Side Highway), northwestward through Seventh Standard Road, northward through the South Belridge Oil Field variously paralleling or oriented east of Pole Line Road through Lerdo Highway, then continuing along the vicinity of Pole Line Road to the North Belridge Oil Field. A Subject Property Location Map is illustrated on Figure 1. A Subject Property Vicinity Overview Map is provided as Figure 2 and Subject Property Vicinity Maps illustrating the main features of the Subject

Property and vicinity is provided as Figures 3A through 3F. Photographs taken during the site reconnaissance visit are provided in Appendix A.

The Subject Property is approximately 11.7 miles long and is approximately 1,000 feet (0.19 mile) wide. The approximate centroid of the Subject Property is located at the following coordinates: 35.501525°, -119.751895° (WGS 84). The Subject Property is within the Subject Property and encompasses approximately 3,252 acres mainly within the Belridge and Blackwells Corner (1988) 7.5-minute U.S. Geological Survey (USGS) quadrangles, with small portions of the Subject Property falling within the Lost Hills and Carneros Rocks USGS quadrangles.

To access the Subject Property from Interstate 5, take the Buttonwillow SR-58 / McKittrick Highway exit and travel west on SR-58 for approximately eight miles; turn right onto Lokern Road and travel west approximately 7.3 miles; turn right on SR-33 and travel northwest approximately 2.5 miles to arrive at the southern end of the Subject Property.

Aera has submitted an application to the Kern County Planning and Natural Resources Department to request approval of a Zone Change and Conditional Use Permit (CUP) (deemed complete on September 26, 2022) and any other required approvals, if any, for the construction and operation of a carbon capture and sequestration (CCS) project in the South and North Belridge oil fields. The proposed Project would require approvals for additions and improvements to the existing oil field facilities (gas separation, compression, and pumping equipment), new carbon dioxide (CO_2) pipelines located primarily aboveground utilizing existing pipeline corridors, Underground Injection Control (UIC) Class VI geologic sequestration injection wells, CO_2 monitoring wells, and an underground carbon sequestration field for the storage of CO_2 in accordance with appropriate financial assurance mechanisms that ensure permanence in compliance with applicable regulatory standards.

The proposed Project would capture CO_2 from existing produced gas streams (pre-combustion) and emissions from existing stationary sources (post-combustion) within the South Belridge Oil Field and transport the CO_2 through pipelines to the North Belridge Oil Field for injection at dedicated Class VI injection wells. The proposed underground CO_2 sequestration field, approximately 2,636 acres in size, would be located within the North Belridge Oil Field with surface and mineral rights held by Aera and other private owners. Oil and gas production activities within the proposed sequestration zone within the North Belridge Oil Field, known as the 64 zone, would cease as a result of the implementation of the proposed Project.

It is anticipated that the proposed Project would capture and sequester up to 1.6 million metric tonnes (MMt) of CO_2 per year beginning in 2026 and will contribute to the goal of California for carbon neutrality by 2045 (Executive Order B-55-18) by reducing industrial CO_2 emissions.

Implementation of the Project would require permits from the EPA for up to nine Class VI injection wells in compliance with the UIC program Class VI geologic sequestration regulations. The proposed CO_2 related facilities, pipelines, Class VI injection wells and associated CO_2 monitoring wells will be located within the CUP boundary. The proposed Project would not exceed 1,223 afy (26,000 barrels or 1.09 million gallons

per day) and Aera would need to acquire and/or develop additional sources of water to support the Project during the operational phase.

The Belridge oil fields were discovered in the early 1900s, as oil naturally surfaced due to pressure in the geologic reservoir, with the first well spudded along the Chico Martinez Creek in April 1911 (Allan and Lalicata 2012). Since then, the Belridge oil fields developed into North and South Belridge oil fields. The Subject Property lies along the North and South Belridge oil fields on the Antelope Plain, an alluvial piedmont consisting of coalescing alluvial fans from the Temblor Range to the west. The region slopes to the east towards the San Joaquin Valley. The Subject Property is heavily disturbed with oil wells and well pads, oil and gas infrastructure, gas and steam pipelines, and multiple unnamed dirt or graveled access roads along with a few paved roads.

2.2 SPECIAL TERMS, CONDITIONS, AND ADDITIONAL ASSUMPTIONS

The exceptionally large size of the Subject Property introduced limitations to Stantec's site reconnaissance visit conducted on October 13, 2022; chiefly, access to all building interiors and some portions of the Subject Property and adjacent land was not granted due to time and security clearance constraints. This is considered a data gap but is not considered to significantly affect the EP's ability to identify RECs at the Subject Property and is unlikely to affect the overall conclusions of this report.

2.3 EXCEPTIONS AND LIMITING CONDITIONS

This report documents work that was performed in accordance with generally accepted professional standards at the time and location in which the services were provided and given the schedule and budget constraints established by the client. No other representations, warranties, or guarantees are made concerning the accuracy or completeness of the data or conclusions contained within this report, including no assurance that this work has uncovered all potential and actual liabilities and conditions associated with the Subject Property.

This report provides an evaluation of selected environmental conditions associated with the Subject Property that was assessed at the time the work was conducted and is based on information obtained by and/or provided to Stantec at that time. There are no assurances regarding the accuracy and completeness of this information received from others.

Conclusions made within this report consist of Stantec's professional opinion as of the time of the writing of this report and are based solely on the scope of work described in the report, the limited data available, and the results of the work. They are not a certification of the Subject Property's environmental condition.

The client did not provide or contract Stantec to provide recorded title records or search results for environmental liens or activity and use limitations encumbering the property or in connection with the Subject Property. Stantec did not obtain historical records that document the property history in 5-year intervals, and this resulted in data gaps. Although this represents data gaps, these data gaps are not

considered to impact the EPs ability to identify RECs unless stated as such. Based on the information obtained during the course of this ESA and general knowledge of development at and near the Subject Property, the absence of this information did not affect the ability of the EPs to identify RECs, HRECs, CRECs, or *de minimis* conditions.

This report has been prepared for the exclusive use of the client identified herein and any use of or reliance on this report by any third party is prohibited, except as may be consented to in writing by Stantec or as required by law. The provision of any such consent is at Stantec's sole and unfettered discretion and will only be authorized pursuant to the conditions of Stantec's standard form reliance letter. Stantec assumes no responsibility for losses, damages, liabilities, or claims, howsoever arising, from third party use of this report.

Project Specific limiting conditions are provided in Section 2.2.

The conclusions are based on the conditions encountered at the Subject Property by Stantec at the time the work was conducted.

As the purpose of this report is to identify Subject Property conditions which may pose an environmental risk; the identification of non-environmental risks to structures or people on the Subject Property is beyond the scope of this assessment.

The findings, observations, and conclusions expressed by Stantec in this report are not an opinion concerning the compliance of any past or present owner or operator of the Subject Property which is the subject of this report with any Federal, state, provincial or local law or regulation.

This report presents professional opinions and findings of a scientific and technical nature. It does not and shall not be construed to offer a legal opinion or representations as to the requirements of, nor compliance with, environmental laws, rules, regulations, or policies of Federal, state, provincial or local governmental agencies. It is recommended that issues raised by the report should be reviewed for the client by its legal counsel.

Stantec specifically disclaims any responsibility to update the conclusions in this report if new or different information later becomes available or if the conditions or activities on the property subsequently change.

2.4 PERSONNEL QUALIFICATIONS

This Phase I ESA was conducted by, or under the supervision of, an individual that meets the ASTM definition of an EP. The credentials of the EP and other key Stantec personnel involved in conducting this Phase I ESA are provided in Appendix B.

3.0 USER-PROVIDED INFORMATION

ASTM E1527-13 and ASTM E1527-21 describe responsibilities of the User to complete certain tasks in connection with the performance of "All Appropriate Inquiries" into the Subject Property. The ASTM standard requires that the EP request information from the User on the results of those tasks because that information can assist in the identification of RECs, CRECs, HRECs, or *de minimis* conditions in connection with the Subject Property. Towards that end, Stantec requested that the User provide the following documents and information:

Description of Information	Provided (Yes / No)	Description and/or Key Findings
User Questionnaire and/or Interview	Y	Historical oil field operations identified.
Environmental Liens or Activity and Use Limitations (AUL)	Y	Chain of title information reviewed identified use limitations at closed landfill area.
Previous Environmental Permits or Reports Provided by User	Y	If none, the user reportedly does not possess any of these documents.
Purpose of the Phase I ESA	Y	The intended use of the Phase I is to identify potential areas of concern that may affect the construction of the proposed CCS project.

The User provided information is included in Appendix C.

4.0 RECORDS REVIEW

The objective of consulting historical sources of information is to develop the history of the Subject Property and surrounding area and evaluate if past uses may have resulted in RECs. Physical setting records are evaluated to determine if the physical setting may have contributed to adverse environmental conditions in connection with the Subject Property. During the review of historical records, Stantec attempted to identify uses of the Subject Property from the present to the first developed use of the Subject Property. Stantec's research included the reasonably ascertainable and useful records described in this section.

4.1 PHYSICAL SETTING

A summary of the physical setting of the Subject Property is provided in the table below with additional details in the following subsections:

Topography:	Relatively flat with an overall gradual slope from west to east towards the San Joaquin Valley, in keeping with the surrounding topography.
Soil/Bedrock Data:	The Subject Property is underlain by alluvium and the Tulare formation, an unconsolidated formation of silts, sands, and gravel. The Tulare formation overlies the Etchegoin formation, which consists of sandstone and mudstone sedimentary marine deposits.
Estimated Depth to Groundwater/ Estimated Direction of Gradient:	Shallow groundwater may occur beneath the North Belridge Oil Field in the form of perched water. Within the central portion of the South Belridge Oil Field, groundwater is typically co-mingled with oil. Within the eastern flank of the South Belridge Oil Field, groundwater generally flows to the east. Depth to groundwater within the main portion of the oil field is typically greater than 150 feet below ground surface.
NOTE: Site-specific groundwater flow direction and depth can only be determined by conducting site-specific testing, which Stantec has not conducted.	

4.1.1 Subject Property Topography and Surface Water Flow

The topography of the Subject Property is relatively flat, interrupted only by oil and gas construction, and slopes gradually from west to east towards the San Joaquin Valley. The Subject Property ranges from 675 feet above mean sea level (amsl) on the western edge down to 550 feet amsl on the eastern edge.

4.1.2 Regional and Subject Property Geology

According to the U.S. Department of Agriculture (USDA) Natural Resource Conservation Service (NRCS), four soil map units occur in the Subject Property. The soils are described in the *Soil Survey of Kern County, California* (USDA NRCS 2022a). The map units are summarized in Table 1 and shown in Appendix A, Figure A-1.

Table 1: Historic Soil Map Units within the Subject Property.

Map Unit Symbol	Map Unit Name	Description	Hydric	Acreage in Subject Property
174	Kimberlina fine sandy loam, 0-2% slopes	The Kimberlina series consists of very deep, well drained soils on flood plains and recent alluvial fans. These soils formed in mixed alluvium derived dominantly from igneous and/or sedimentary rock sources.	No	1,295.40
175	Kimberlina fine sandy loam, 2-5% slopes	The Kimberlina series consists of very deep, well drained soils on flood plains and recent alluvial fans. These soils formed in mixed alluvium derived dominantly from igneous and/or sedimentary rock sources.	No	232.05
176	Kimberlina fine sandy loam, 5-9% slopes	The Kimberlina series consists of very deep, well drained soils on flood plains and recent alluvial fans. These soils formed in mixed alluvium derived dominantly from igneous and/or sedimentary rock sources.	No	7.87
196	Milham sandy loam, 0 to 2 percent slopes Major Land Resource Area 17	The Milham series consists of very deep, well drained soils on alluvial fans, plains, low terraces, and fan remnants. These soils formed in mixed calcareous alluvium weathered from granitic and sedimentary rock.	No	546.13
197	Milham sandy loam, 2 to 5 percent slopes	The Milham series consists of very deep, well drained soils on alluvial fans, plains, low terraces, and fan remnants. These soils formed in mixed calcareous alluvium weathered from granitic and sedimentary rock.	No	383.16
211	Panoche clay loam, 0 to 2 percent slopes	The Panoche series consists of very deep, well drained soils on alluvial fans and flood plains. These soils formed in loamy calcareous alluvium from sedimentary rock.	No	442.39
212	Panoche clay loam, 2 to 5 percent slopes	The Panoche series consists of very deep, well drained soils on alluvial fans and flood plains. These soils formed in loamy calcareous alluvium from sedimentary rock.	No	344.96
Total				**3,251.96**

The Subject Property is located in the Great Valley Geomorphic Province, within the southwestern portion of the San Joaquin Valley. The southwestern margin of the valley is renowned for its oil fields trapped within anticlinal uplifts (CGS, 2002). Soil types mapped across the Subject Property, as reported by the EDR Area Corridor Report, predominantly comprise the Kimberlina fine sandy loam, with minor amounts of Milham sandy loam and Panoche clay loam. The California Geological Survey maps bedrock beneath the Subject Property as comprising Pleistocene to Holocene (Recent) alluvium, lake, playa, and terrace deposits, often unconsolidated or semi-consolidated.

4.1.3 Regional and Subject Property Hydrogeology

The Subject Property is within Hydrologic Unit Code (HUC)-8 18030012 - Tulare-Buena Vista Lakes. This area is also mainly within the Lower Kern River Flood Canal HUC-10 Watershed 1803001216, with a section of the southern portion of the Subject Property within the Upper Kern River Flood Canal HUC-10 Watershed 1803001212. The Subject Property also includes the following HUC-12 Watersheds from north to south: unnamed-180300121502, Town of Lost Hills-180300121504, unnamed-180300121603, Kern River Flood Canal-Kern River Channel-180300121604, Kern River Flood Canal-180300121602, Chico Martinez Creek-180300121206, and Kern River Flood Canal-180300121207.

The southwestern San Joaquin Basin regional groundwater flow direction is generally to the east towards the San Joaquin Valley [Burton et al., 2012; Kern County Planning and Natural Resources Department, 2020a]. Within the Subject Property, however, the local hydraulic gradient is typically affected by local geologic structures, such as the anticlines and synclines that typify the western San Joaquin fold belt [Harding, 1976; Aera, 2014; Kern County Planning and Natural Resources Department, 2020b].

The EPA, under the Safe Drinking Water Act, requires protection of underground sources of drinking water (USDW) that have total dissolved solids (TDS) concentrations less than 10,000 milligrams per liter (mg/L). If the TDS concentration is greater than 10,000 mg/L, the formation can be considered a non-USDW. Oil-bearing formations include a mixture of typically poor-quality to saline groundwater and hydrocarbons [Kern County Planning and Natural Resources Department, 2020a]. Within the North Belridge Oil Field, groundwater is typically intermingled with oil.

The UIC program administered by the EPA granted California Department of Conservation Division of Oil, Gas and Geothermal Resources (CalGEM, formerly DOGGR) primacy to administer the UIC program in 1982, the oil and gas producing aquifers identified in 1973 and 1974 California Oil and Gas Fields Volumes I, II, and III submitted in accordance with Section 1425 (a) of the Safe Drinking Water Act dated April 20, 1981 were exempt as a USDW (EPA, 1982). In the North Belridge Oil Field, this includes the Tulare Formation, Etchegoin Formation, Monterey Formation, Temblor Formation, and Tumey Formation; whereas in the South Belridge Oil Field, this includes the Tulare Formation, Etchegoin Formation, and Monterey Formation.

In accordance with the EPA groundwater exemption criteria specified in Title 40, CFR, Part 146.4, Aera Energy, LLC and Greka Oil & Gas, Inc. submitted an Underground Injection Control Aquifer Exemption Application for the Tulare Formation, North Belridge Oil Field (Revision 1) [Aera and Greka, 2018] and Aera Energy, LLC, Belridge Energy Resources, California Resources Corporation, E&B Natural Resource



Management, Freeport-McMoran Oil & Gas, Linn Operating Inc., Vaquero Energy Inc., and West American Energy submitted an Underground Injection Control Aquifer Exemption Application for the Tulare Formation, South Belridge Oil Field [Aera et al., 2018], to DOGGR and the California State Water Resources Control Board (SWRCB) on November 7, 2018 and July 26, 2018, respectively, to expand the existing USDW exempt areas. These documents were intended to demonstrate the groundwater within the Tulare Formation met the following EPA exemption criteria specified in Title 40, CFR, Part 146.4:

- It does not currently serve as a source of drinking water; and
- It cannot now and will not in the future serve as a source of drinking water because:
    - It is mineral-, hydrocarbon-, or geothermal-energy producing, or can be demonstrated by a permit applicant as part of a permit application for a Class II or Class III operation to contain minerals or hydrocarbons that considering their quantity and location are expected to be commercially producible, or
- TDS content of the groundwater is more than 3,000 mg/L and less than 10,000 mg/L and is not reasonably expected to supply a public water system or to have any other beneficial uses.

The applications were approved by the EPA June 7, 2019 [EPA, 2019] and March 13, 2020 [EPA, 2020], respectively.

Within the eastern and southern-most portion of the Subject Property, including the northern portion of the South Belridge Oil Field, groundwater within the Alluvium occurs as a perched zone atop the unconformity at the base of the Alluvium and/or upper clay layer within the Tulare Fm. In this area, alluvial groundwater consists of produced water from former produced water percolation ponds (see Figure 2.7-1 for former disposal pond locations) [Aera, 2017; Aera Energy, LLC, and Greka Oil & Gas, Inc. (Aera and Greka), 2018; USEPA, 2019; Wood Environmental & Infrastructure Solutions, Inc. (Wood), 2021].

This produced groundwater transitions into native groundwater to the east and northeast, with a mixed zone occurring between these two groundwater types [Aera, 2017; Wood, 2021, 2022]. Native alluvial groundwater occurs to the east of the North Belridge Oil Field as wells as within and to the east of the South Belridge Oil Field, where the western extent of native alluvial groundwater is controlled by the North and South Belridge oil fields anticline structures [Wood, 2019, 2021, 2022] (Figure 2.7-4). There is no native alluvial groundwater within the southern portion of the North Belridge Oil Field (Figure 2.7-5) [Aera, 2014, 2017; SWRCB, 2014; Wood, 2022].

Publicly available groundwater elevation data and groundwater quality data from monitoring wells within portions of the Alluvium were compiled from the North and South Belridge oil fields [Breitburn Operating LP. (Breitburn), 2018a; Wood, 2021, 2022; Groundwater and Environmental Services, Inc. (GES), 2022]. The potentiometric surface map for the Alluvium indicates groundwater flow in the North Belridge Oil Field area to the north-northeast, and in the South Belridge Oil Field area to the east-northeast. There are no groundwater elevation data for the Alluvium in the northern half of the Subject Property, likely because the Alluvium is less than 150 ft thick and the depth to groundwater, where available, is mostly greater

than 150 ft. Therefore, the Alluvium in the northern portion of the Subject Property is believed to be dry due to the structural elevation.

4.1.4 Surface Hydrology

Chico Martinez Creek, an ephemeral stream toward the southern end of the Subject Property, is the most prominent remaining regional stream draining from the southwest to the northeast through the South Belridge Oil Field toward the Central Valley. The source of historic Chico Martinez Creek is located on the eastern slope of the Temblor Range (35.4188542, -119.8623563 WGS84) and it generally flows east where it terminates approximately 0.55 mile southwest of Lost Hills Highway Kern County, California (35.4610736, -119.6990172 WGS84). While the terminus of historic Chico Martinez Creek is located west of Lost Hills Highway based on historical data (USGS and National Wetlands Inventory [NWI]); a review of available aerial imagery (dating back to 1994) indicates it flows further east to approximately 1.10 miles east of Lost Hills Highway where it terminates at a north-south traversing agricultural canal/aqueduct. The Subject Property includes two sections of historical Chico Martinez Creek:

1) Section of Chico Martinez Creek located approximately 0.45 mile southeast of the Aera Oasis Building (i.e., the main Aera office building at Belridge) and beginning approximately 700 feet north of Seventh Standard Road, then continuing for approximately 0.40 mile toward the northeast; and

2) Section of Chico Martinez Creek beginning just south of the intersection of SR-33 and Treeline Road/Roustabout Road, crossing under SR-33, then continuing to the northeast for approximately 0.65 mile.

Considered as a whole, sections of Chico Martinez Creek still appear to be channelized but these sections are interspersed with areas with no defined channel bed and bank. The system has been altered and segmented due to oil field development.

4.2 FEDERAL, STATE AND TRIBAL ENVIRONMENTAL RECORDS

A regulatory agency database search report was obtained from Environmental Database Resources, Inc., a third-party environmental database search firm. A complete copy of the database search report, including the date the report was prepared, the date the information was last updated, and the definition of databases searched, is provided in Appendix D.

Stantec evaluated the information listed within the database relative to potential impact to the Subject Property, assessing the potential for impacts based in part on the physical setting. As part of this process, inferences have been made regarding the likely groundwater flow direction at or near the Subject Property. As described in 4.1.3, shallow groundwater flows to the east. Observations about the Subject Property and adjoining properties made during the Subject Property reconnaissance are provided in more detail in Section 5.

4.2.1 Listings for Subject Property

The Subject Property was identified in the environmental database report in the following databases with the associated entries listed below:

Local Lists of Hazardous Waste/Contaminated Sites: CERS HAZ WASTE

- Phillips 66 – 17251 Pole Line Road. This entity is listed as a hazardous waste generator, though additional information regarding the specific waste(s) produced is not listed.

Records of Emergency Release Reports: CHMIRS (California Hazardous Material Incident Report System)

- Phillips 66 Pipeline – 17251 Pole Line Road. This entry is associated with California Office of Emergency Services (OES) Incident Number 4-6216. The incident occurred on November 30, 2004, and comprised a release of approximately 50 BBLS of crude oil due to a portable tank overfill. The release was reportedly contained to a bermed containment area.

Other Databases

The Subject Property was also positively identified in the following databases, though the positive identification does not necessarily constitute an elevated risk of impact.

- Facility Index System
    - Phillips 66 – “Middle”, associated with an address of 17251 Pole Line Road and registry identification number 110065253969.
- Certified Unified Program Agency (CUPA)
    - Phillips 66 – Middle, associated an address of 17251 Pole Line Road, listed within Kern County CUPA database. The entry is dated May 6, 2022.
- Emissions Inventory Data
    - Unocal California PI, associated with an address of 17251 Pole Line Road and a facility ID of 1520
    - Phillips 66 Pipeline, associated with an address of 17251 Pole Line Road and a facility ID of 1520
- UIC – There are 119 UIC sites listed associated with the Subject Area, all of which are associated with Aera Energy LLC.

4.2.2 Listings for Adjoining and Nearby Sites with Potential to Impact Subject Property

Stantec assessed data presented in the environmental agency database search report to evaluate the potential for conditions on adjoining and nearby sites to pose a REC, CREC, or HREC for the Subject Property. The evaluation included an opinion of the potential for contamination by hazardous substances or petroleum products to migrate to the Subject Property from an adjoining or nearby site, including by vapor migration or encroachment (i.e., potential for a vapor encroachment condition [VEC]).

Based on this evaluation, the following individual facilities were identified as the most likely potential sources of impact to the Subject Property. The basis for why each of the following listed databases creates a REC for the Subject Property is also provided.

Listed Facility Name/Address	Database Listing(s)	Distance/Direction from Subject Property
Multiple wastewater pits located across the North and South Belridge oilfield	EDR Wastewater Pits	18 pits <1/8 mile (660 feet) from the Subject Property 8 pits between 1/8 mile and 1/4 mile (1,320 feet) from the Subject Property 15 pits located between 1/4 mile and 1/2 mile (2,640 feet) from the Subject Property (a total of 41 pits).
Subject Property. The listed pits are a combination of closed percolation ponds, secondary containment basis, process basins, discharge ponds, and emergency overflow basins. Refer to Appendix C for a listing of each pit identified, its purpose, and status.		
Closed North Belridge Landfill 1 mile NE Belridge Oil Co	SWF/LF, FINANCIAL ASSURANCE, CERS	590 feet west of the Subject Property.
The landfill is listed as a 210,000 cubic yard capacity Class III landfill that ceased operation in 2007, and was operated by Aera Energy LLC. The dimensions are listed as 10 feet deep and with an area of 28.7 acres. The landfill was closed under Cal Recycle Permit SWIS/WDID/Global ID Number 15-AA-0067. The site was capped and has been maintained/inspected by WSP and Aera. The potential for uncontrolled fill and solid waste disposal over such a large area in close proximity to the Subject Property is considered a REC.		
South Belridge Disposal Site	Kern County Environmental Health Services landfill database	Within Subject Property along existing Del Sur to GP 32 pipeline. No excavation is currently proposed.
The landfill was legacy owned by Shell Oil Co. The dimensions are listed with an area of 15 acres and an unknown depth. The potential for uncontrolled fill and solid waste disposal over an area within the buffer for a pipeline in the Subject Property is considered a REC.		

The remaining listings in the database search report, including listings of Orphan Sites, provided in Appendix D do not constitute a potential REC for the Subject Property.

4.3 LOCAL/REGIONAL ENVIRONMENTAL RECORDS

Stantec checked the following sources to obtain information pertaining to Subject Property use and/or indications of RECs in connection with the Subject Property:

4.3.1 Local Health Department

Agency Name, Contact Information, Date	Finding
Kern County Environmental Health Services Contacted via website form October 7, 2022	The Kern County Environmental Health Services (KCEHS) department has provided information in response to a Public Records Act request. The information provided by KCEHS has been incorporated into this report.

4.3.2 Fire Department

Agency Name, Contact Information, Date	Finding
Kern County Fire Department Contacted via website form October 11, 2022	The Kern County Fire Department (KCFD) responded to Stantec's initial request for information pertaining to parcels that comprise the Subject Property on October 14, 2022. The KCFD identified records pertaining to the following addresses: • 19651 Highway 33 – An Occupancy Detail Report identifying Aera Energy as the current tenant. • 19091 Highway 33 – A Fire Protection System Permit (ref. 2012-FPS-047) registered to Aera Energy. The system is described as an Ansul I-101 system installed within a spray booth. • 18271 Highway 33 – A Fire Alarm Permit (ref. 2006-FA-022) registered to Exxon Mobile in 2006, Linn Energy in 2015 (2015-FA-052). • 16435 Highway 33 – Occupancy Detail Reports for Shell Pipeline Co-Carneras. The inspection records (spanning from 2011 to 2019) indicate an automated pump station is present at this address.

4.3.3 Local Building and/or Planning Department Records

Agency Name, Contact Information, Date	Findings
Kern County Planning and Natural Resources Department planning@kerncounty.com October 7, 2022	The Kern County Planning and Natural Resources Department did not respond to Stantec's request for information within the timescales of this report. While this is

Agency Name, Contact Information, Date	Findings
	considered a data gap, it is not considered to significantly affect the EP's conclusions.

4.3.4 Local/Regional Pollution Control Agency Department Records

Agency Name, Contact Information, Date	Findings
San Joaquin Valley Air Pollution Control District sjvapcd@valleyair.org October 11, 2022	In a response dated October 13, 2022, the San Joaquin Valley Air Pollution Control District (SJVAPCD) indicated that the District holds records responsive to Stantec's information request (identified by request number C-2022-10-50); however, due to the volume of records requested from the SJVAPCD, an extension to the response deadline was requested. The SJVAPCD indicated that records would be released to Stantec as and when they were identified. Stantec will collate, interpret, and relay any subsequent pertinent findings to the Client as these responses are received.
California Department of Toxic Substances Control: Chatsworth Office 9211 Oakdale Avenue Chatsworth, CA 91311 October 10, 2022	In a response dated October 13, 2022, the California Department of Toxic Substances Control (DTSC) acknowledged Stantec's request for information regarding parcels identified as comprising the Subject Property. The DTSC Chatsworth office did not identify records pertaining to those parcels, but instead referred Stantec to the online Envirostor database maintained by the DTSC. The Envirostor database does not show any cases at the Subject Property surrounding facility, within a one-mile radius of the Subject Property. The nearest case is associated with Clean Harbors Buttonwillow LLC, located at 2500 West Lokern Road approximately 4.1 miles southeast of the Subject Area.

4.3.5 Local/Regional Water Quality Agency Records

Agency Name, Contact Information, Date	Findings
State Water Resources Control Board GeoTracker Database Accessed October 10, 2022	The State Water Resources Control Board (SWRCB) maintains its records within the online GeoTracker database. Stantec reviewed the database and did not identify any cases located within the Subject Property. The nearest case is located approximately 50 feet west of the Subject Property (see Figure 3 in Section F) and is associated with a Leaking Underground Storage Tank (LUST) case that was granted case closure in 1991. The media of concern is listed as soil impacted by gasoline.

Agency Name, Contact Information, Date	Findings
	There are no other cases within a one-mile radius of the Subject Property.

4.3.6 Federal/State/Local Natural Resource Records

Agency Name, Contact Information, Date	Findings
California Department of Conservation Geologic Energy Management Division Well Finder Online Application Accessed October 11, 2022	Stantec reviewed the Well Finder application maintained by CalGEM. The Subject Property is located within the North Belridge and South Belridge oil fields and is surrounded by thousands of plugged wells and hundreds of active, idle, and canceled wells. The density of oil wells along the Subject Area is greatest in the South Belridge Oil Field. The path of the Subject Property skirts to the north of the majority of the wells in the North Belridge Oil Field.

4.4 HISTORICAL RECORDS REVIEW

4.4.1 Land Title Records/Deeds

Land title records, deeds, environmental liens, and activity and use limitation documentation was not provided by the User, and public records were not searched by Stantec.

4.4.2 Aerial Photographs

Stantec reviewed historical aerial photographs provided by Environmental Data Resources, Inc. (EDR). The general type of activity on a property and land use changes can often be discerned from the type and layout of structures visible in the photographs. However, specific elements of a facility's operation usually cannot be discerned from aerial photographs alone. The following table summarizes Stantec's observations of the reviewed historical aerial photographs. Copies of the historical aerial photographs are included in Appendix E.

Year	Scale	Observations of Subject Property and Adjoining/Nearby Properties
1937, 1942	1"=1,000'	On the earliest reviewed mapping from 1937, the Subject Property is predominantly comprising undeveloped land. Moderate amounts of petroleum extraction-related development (roads, tanks, oil derricks) are visible in Sections A and F, and significant development (buildings, ponds, greater concentrations of oil derricks) is visible in Sections B and E. The southeastern portion of Section E appears to be developed with a residential complex for site workers, complete with houses with gardens, soft landscaping, and suspected school or communal building.

Year	Scale	Observations of Subject Property and Adjoining/Nearby Properties
1956	1”=1,000’	Significant development is evident in Section A by 1956, including the construction of roads, parking lots, tanks, and oil well platforms. An airstrip was constructed to the southeast of Section D. Additional derricks have been constructed in the southern and western portions of Section F. Section F –Tank battery constructed adjacent to the southeast by 1994
1974, 1976	1”=1,000’	Percolation ponds are evident approximately 550 feet northeast of the Subject Property in Section B, with addition and expansion of the ponds evident through later years to until 1984. Additional smaller percolation ponds are visible throughout Section D, with further additions in 1976 and 1984. The formerly undeveloped land to the northeast of the Subject Property has been cultivated for agricultural use. Some of the residential dwellings in the southeastern portion of Section E appear to have been demolished by 1976, and all remaining units are fully removed by 1984.
1984	1”=1,000’	Proliferation of oil extraction platforms is visible in the southwest of Section C by 1984. Percolation ponds are visible in the surrounding area, with the closest located approximately 350 feet west of the Subject Property. Tank farms have been constructed to the northeast and southwest of the Subject Property in Section D by 1984. A facility or complex has been constructed in the formerly-undeveloped southwestern portion of Section E, with several buildings, tanks, and associated roads and parking lots visible.
1994	1”=1,000’	A battery of tanks has been constructed adjacent to the southeast of the Subject Property in Section F.
2005	1”=1,000’	Pipelines tracing the proposed path of the Subject Property are visible in photography from 2005.
2009, 2012	1”=1,000’	The percolation ponds to the northeast of Section B have been drained by 2009.

Name of aerial photograph source: EDR Aerial Photo Decade Package.

The use of the Subject Property and surrounding lands for hydrocarbon extraction use and the inherent risks of surface spills and observed percolation of impacted process water into the subsurface is considered a REC.

The demolition of residential structures in the vicinity of the Subject Property is considered an item of note, given the potential for asbestos containing materials to be present within the former building fabrics which may now be present in surface soils, assuming the demolition materials were not thoroughly removed from the Subject Property.

4.4.3 City Directories

Stantec retained a third party to research available city directories for the Subject Property and adjoining and nearby properties, in approximately five-year intervals. Copies of the city directory listings are included in Appendix E.

The City Directory report did not identify any addresses listed to Ducon Road or Pole Line Road, located within and adjacent to the Subject Property.

Name of city directories and source: EDR City Directory Image Report.

Given the absence of entries, no RECs were noted during the review of the City Directories.

4.4.4 Historical Fire Insurance Maps

Fire insurance maps were developed for use by insurance companies to depict facilities, properties, and their uses for many locations throughout the United States. These maps provide information on the history of prior land use and are useful in assessing whether there may be potential environmental contamination on or near the Subject Property. These maps, which have been periodically updated since the late 19th century, often provide valuable insight into historical Subject Property and adjoining and nearby property uses.

Stantec requested fire insurance maps from EDR; however, no coverage exists for the Subject Property. The Sanborn® Map Search Report indicating “no coverage” is presented in Appendix E.

4.4.5 Historical Topographic Maps

Stantec reviewed historical USGS Topographic Maps of multiple quadrangles to help identify past Subject Property and adjoining and nearby property usage and areas of potential environmental concern. Copies of the historical maps are provided in Appendix E. The topographic map quadrangles and scales are listed below:

Scale	Quadrangle	Year
30-minute, 1:125,000	McKittrick Lost Hills	1912 1914
15-minute, 1:50,000	McKittrick	1979
7.5-minute, 1:31,680	Belridge Blackwell	1943 1943
7.5-minute, 1:24,000	Belridge Blackwells Corner	1947 1947
7.5-minute, 1:24,000	West of Goose Lake Lost Hills Blackwells Corner Belridge Carneros Rocks	1950 1953, 1973, 2012, 2015, 2018 1953, 1973, 1982, 2012, 2015, 2018 1953, 1973, 2012, 2015, 2018 1959, 1973, 1982, 2012, 2015, 2018

The following table summarizes the maps reviewed and our observations.

Year	Scale	Observations of Subject Property and Adjoining/Nearby Properties
1912, 1914	1:125,000	On the earliest reviewed map editions from 1912 and 1914, the Subject Property comprises undeveloped land. The central portion of the Subject Property is crossed by two creeks flowing from the southwest to the northeast.
1943, 1947	1:31,680, 1:25,000	By 1943, the Subject Property and surrounding land has been partially developed with multiple tracks and minor roads providing access to the oil field with associated pump stations. Highway 33 has been constructed to the east of the Subject Property. Numerous oil exploration structures (derricks and/or pumpjacks) are visible in cluster around the South Belridge Lease Camp in the southern portion of the Subject Property. The area remains largely unchanged by 1947.
1950, 1953, 1959, 1973, 1979, 1982, 2012, 2015, 2018	1:24,000	By 1953, the South Belridge Lease Camp has expanded with labeled features including a school, swimming pool, landing strip, water tanks, and oil tanks. Additional oil derricks and/or pumpjacks are mapped throughout the oilfield to the northwest and south/southeast. Additional access roads have been constructed in a uniform distribution across the oilfield, providing access to the oil wells. At least six batteries of oil tanks are mapped in the northern portion of the Subject Property. Further expansion to the oilfield extraction activities is evidence to the southwest of the South Belridge Lease Camp by 1979. No significant changes in the configuration of the Subject Property and surrounding land are evident from subsequent map editions through to the most recent mapping from 2018.

Name of maps and source: EDR Historical Topo Map Report.

The historical use of the Subject Property and surrounding land for hydrocarbon extraction activities is considered a REC to the entire Subject Property.

4.4.6 Other Historical Sources

No other historical sources were researched.

5.0 SITE RECONNAISSANCE

A visit to the Subject Property and its vicinity was conducted by Ms. Emily Medler on October 13, 2022. Ms. Medler was accompanied by Mr. Jared Pratt, of Stantec, as an Aera-designated Person-In-Charge (PIC). Ms. Medler and Mr. Pratt were not accompanied by other Aera personnel during the Subject Property visit. Figure 2 provides information about the Subject Property and adjoining sites and the location of potential areas of environmental concern. Photographs collected during the site reconnaissance are included in Appendix A.

5.1 SITE RECONNAISSANCE METHODOLOGY

The site reconnaissance focused on observation of current conditions and observable indications of past uses and conditions of the Subject Property that may indicate the presence of RECs. The reconnaissance of the Property was conducted on foot and Stantec utilized the following methodology to observe the Property:

- Traverse the outer Subject Property boundary
- Traverse transects across the Subject Property
- Traverse the periphery of all structures on the Subject Property

Weather conditions during the visit to the Subject Property were clear and sunny. There were no weather-related Subject Property access restrictions encountered during the reconnaissance visit. The reconnaissance of the Property was conducted by way of accessible oil roads and adjacent highways. All buildings and interior areas were not accessible due to security clearances.

5.2 GENERAL DESCRIPTION

Subject Property and Area Description:	The Subject Property is located within the North and South Belridge oil fields. The Subject Property is active oil production and processing facilities in Kern County, CA.
Subject Property Operations:	The Subject Property is used for oil and gas production, including heavy oil production from the Tulare formation and light oil production from the Diatomite formation. Crude oil is sold on the Property and is transported to markets in California for processing into gasoline and other fuels.
Structures, Roads, Other Improvements:	The Subject Property is approximately 13 miles long. There are abundant structures, roads, and other petroleum industry infrastructure located on the Subject Property, including but are not limited to: separators, well heads, pumping stations, transportation lines, pipelines, and steam generators.
Subject Property Size:	Approximately 3,252 acres
Estimated % of Subject Property Covered by	~35-50%

Buildings and/or Pavement:	
Observed Current Subject Property Use/Operations:	Oil Production and Processing
Observed Evidence of Past Subject Property Use(s):	The Belridge Oil Field has consistently been used as an oil field since 1911.The Subject Property remained undeveloped until 1943 (See 4.4.5 Historical Topographic Maps) and has since been consistently used for oil production.
Sewage Disposal Method (and age):	Could not be determined
Potable Water Source:	Belridge Water Storage District
Electric and Natural Gas Utilities:	Pacific Gas & Electric

5.3 HAZARDOUS SUBSTANCES AND PETROLEUM PRODUCTS

The following table summarizes Stantec's observations during the Subject Property reconnaissance.

Observations	Description/Location
Hazardous Substances and Petroleum Products as Defined by CERCLA 42 U.S.C. § 9601(14) with identified uses:	None observed.
Drums/Totes/Intermediate Bulk Containers (≥ 5 gallons):	None observed.
Strong, Pungent, or Noxious Odors:	Yes, throughout the Subject Property hydrocarbon odors were noted, associated with active petroleum production activities.
Pools of Liquid:	Five large separation ponds were observed in the southeast portion of Section D along Pole Line Road. Specific contents could not be determined but appeared to be a slurry mix of produced water, and oil.
Unidentified Substance Containers:	None observed.
Polychlorinated biphenyl (PCB)-Containing Equipment:	None observed.
Other Observed Evidence of Hazardous Substances or Petroleum Products:	None observed.

5.4 INTERIOR OBSERVATIONS

Due to security clearance and safety reasons, Stantec was not able to observe interior spaces of buildings and structures within the Subject Property.

5.5 EXTERIOR OBSERVATIONS

Stantec made the following observations during the site reconnaissance of exterior areas of the Subject Property and/or identified the following information during the interview or records review portions of the assessment:

Observations	Description
On-site Pits, Ponds, or Lagoons:	Due to the size and active production of the Subject Property, not all pits, ponds, or lagoons were not able to be documented. The following was observed during the site reconnaissance: • Four separation ponds were observed in the southeast portion of Section D along Pole Line Road. • 0.08-square mile area of decommissioned percolation ponds in the central portion of Section B.
Stained Soil or Pavement:	Limited staining was observed on the ground surface around active oil wells within the Subject Property.
Stressed Vegetation:	No stressed vegetation was observed in the Subject Property.
Waste Streams and Waste Collection Areas:	No waste collection areas were observed on or adjacent to the Subject Property.
Solid Waste Disposal:	No solid waste disposal areas were observed.
Potential Areas of Fill Placement:	In the southeast corner of Section B, a sink hole area was observed within the Subject Property. This area was fenced off and was only able to be observed from Pole Line Road. Additionally minor stockpiling was observed in the southern corner of Section B associated with some pipeline maintenance crews.
Wastewater:	No wastewater discharge was observed during the site reconnaissance.
Stormwater:	Due to the predominantly unpaved nature of the Subject Property, stormwater generally infiltrates the surface of the Subject Property or flows down-gradient. In paved portions of the Subject Property, stormwater flows into surface drains and is allowed to discharge onto unpaved portions of the facility.
Wells:	Oil wells were observed throughout the entirety of the Subject Property. Stantec observed a representative number of oil wells to determine likely existing conditions at the typical well pads within the Subject Property
Septic Systems:	Existing Aera office facilities are served by active septic systems
Other Exterior Observations:	None

5.6 UNDERGROUND STORAGE TANKS/STRUCTURES

Existing USTs:	An abundance of above ground infrastructure was observed during the site reconnaissance that have the potential to lead to underground storage tanks (USTs). In Section D, an active fuel station owned by Schwebel Petroleum Co. was observed that would indicate the presence of USTs. USTs at the fueling station are in compliance and operating with active Kern County Environmental Health (KCEHS) permits. Given the size and active production of the Subject Property, there is potential that several USTs are present within the Subject Property.
Former USTs:	Given the size, active production, and historical use of the Subject Property, there is potential that several former USTs are present within the Subject Property.
Other Underground Structures:	An abundance of underground structures was observed during the site reconnaissance. Due to the size, active production of the Subject Property, and the constraints of this report, all underground structures were not able to be observed and documented. Refer to the Photo Log included in Appendix A for examples of aboveground infrastructure that would indicate the presence of underground structures.

5.7 ABOVEGROUND STORAGE TANKS

Existing ASTs:	Several large crude oil and water Aboveground Storage Tanks (ASTs) were observed during the site reconnaissance. The ASTs observed were not accessible due to fencing and security clearances. No evidence of leaks or surface staining were observed around the ASTs. Refer to the Photo Log included in Appendix A for some ASTs that were observed during the site reconnaissance.
Former ASTs:	Several ASTs were observed during the site reconnaissance, many of which are likely former ASTs. Due to the size, active production of the Subject Property, and the constraints of this report, all aboveground structures were not able to be observed and documented. Refer to the Photo Log included in Appendix A for some former ASTs that were observed during the site reconnaissance.

5.8 ADJOINING PROPERTIES

5.8.1 Current Uses of Adjoining Properties

As viewed from the Subject Property and/or from public rights-of-way, Stantec made the following observations about use and activities on adjoining sites:

NORTH	Petroleum extraction and pipeline stations.
EAST	Used for petroleum extraction purposes.
SOUTH	Used for petroleum extraction purposes.
WEST	Petroleum extraction and grazing land.

5.8.2 Observed Evidence of Past Uses of Adjoining Properties

Observations of adjoining sites providing indications of past use and activities, if any, are described below.

NORTH	Due to the former and abandoned infrastructure that is present, this site appears to have been used for oil production use.
EAST	Due to the former and abandoned infrastructure that is present, this site appears to have been used for oil production use.
SOUTH	Due to the former and abandoned infrastructure that is present, this site appears to have been used for oil production use.
WEST	Due to the former and abandoned infrastructure that is present, this site appears to have been used for oil production use.

5.8.3 Pits, Ponds, or Lagoons on Adjoining Properties

As viewed from the Subject Property and/or from public rights-of-way, Stantec made the following observations about the presence of pits, ponds, and lagoons on adjoining sites:

NORTH	None observed.
EAST	None observed during the site reconnaissance. Historical aerials indicate the presence of separation or percolation ponds.
SOUTH	None observed.
WEST	A sinkhole/area of subsidence was observed in the along the southwestern portion of Section B.

5.9 OBSERVED PHYSICAL SETTING

Topography of the Subject Property and Surrounding Area:	The Subject Property is relatively flat with gentle slope from west to east.

6.0 INTERVIEWS

The results of various interviews with property owner representatives have been incorporated into the report findings.

7.0 EVALUATION

This section provides a summary overview of or Findings, Opinions, and Conclusions.

7.1 FINDINGS AND OPINIONS

Information gathered from interviews, reviews of existing data, and an inspection was evaluated to determine if RECs are present in connection with the Subject Property. Based on this information, Stantec made the following findings and developed the following opinions.

- The Subject Property comprises multiple parcels of land currently and historically used by the petroleum hydrocarbon extraction industry. Sources of potential impacted on and within close proximity to the Subject Property have included oil derricks and pumpjacks, pipelines, ASTs, and percolation ponds. Records indicate a LUST case and recorded release of oil have occurred on or within close proximity to the Subject Property. Multiple wastewater pits have been observed in proximity to the Subject Property during a site reconnaissance visit and historical aerial photography. CalGEM records show hundreds of active, plugged, and abandoned wells are present within the vicinity of the length of the Subject Property.

  The Subject Property and adjacent land has been in use for petroleum hydrocarbon extraction activities from 1911 to the present day. Multiple current and historical information sources indicate releases of petroleum hydrocarbons have occurred on or close to the Subject Property. Based on the long history of petroleum production activities at the Subject Property, there is a potential for additional areas of petroleum hydrocarbon containing soil to exist in the vicinity of proposed project features.

- Regulatory records indicate an area to the west of the Subject Property comprised a Class III landfill. The entry is listed 590 feet west of the Subject Property but is recorded as up to 28.7 acres in area, filled to a depth of approximately 10 feet. Given the dimensions, Stantec believes the oil field facility was designated as a landfill to allow historical operators to fill and dispose of soil and/or waste on-site. In addition, historical aerial photography shows a worker housing area in the southern portion of the Subject Property was demolished in the 1970s and 1980s. Buildings constructed prior to this time were likely constructed with materials including ACM and LBP.

  Relatively uncontrolled solid-waste disposal practices of mixed fill type, which may include demolition material, ACM, and LBP, if present beneath the Subject Property, would require special handling and disposal, and represents a potential BER. Additional safety measures for construction workers may also be required, if the fill is to be disturbed during construction phase activities. Heterogeneous or uncompacted fill also presents a settlement risk, should structures of significant weight be proposed across areas of fill.

- An environmental records search was performed and identified sites within their respective ASTM E1527-21 search radii of the Subject Property that may represent RECs, CRECs, HRECs, or *de minimis* conditions.
- A total of 41 wastewater pits are located within 0.5 miles of the Subject Property, with 18 located within 0.125 miles (660 feet) of the Subject Property. Of these, the majority are either closed former percolation ponds, secondary containment basins, emergency overflow basins, or process basins.

Based on the distance, direction, and regulatory status, these sites are not anticipated to represent an environmental concern to the Subject Property.

Based on one or more of the following reasons: distance from the Subject Property, position of sites with respect to assumed groundwater flow direction, the type of native soils, and regulatory status, none of the other sites identified in the environmental records search report are expected to impact soil or groundwater quality at the Subject Property. The environmental records search identified no additional RECs, CRECs, HRECs or *de minimis* conditions at or near the Subject Property.

7.2 DATA GAPS

The federal AAI final rule [40 CFR 312.10(a)], ASTM E1527-13, and ASTM E1527-21 identify a "data gap" as the lack or inability to obtain information required by the standards and practices of the rule despite good faith efforts by the EP or the User.

Any data gaps resulting from the Phase I ESA described in this report are listed and discussed below.

Gap	Discussion
Deletions or Exceptions from Scope of Work Referenced in Section 1.4:	None.
Weather-Related Restrictions to Site Reconnaissance:	None
Facility Access Restrictions to Site Reconnaissance:	The interiors of all the buildings and structures present onsite were not able to be observed due to restrictions and security clearance. These restrictions are not considered to significantly limit the EP's ability to recognize RECs at the Subject Property and are not considered to affect the overall conclusions of this Report.
Other Site Reconnaissance Restrictions:	Due to the size of the Subject Property and the time restrictions of this report, every surface and area within the Subject Property was not able to be observed. This restriction is not considered to significantly limit the EP's ability to recognize RECs at the Subject Property and is not considered to affect the overall conclusions of this Report.
Data Gaps from Environmental Records Review:	Responses were not received from multiple regulatory agencies contacted as part of the information request process. While these absent responses are considered to represent data gaps, they are not considered to significantly limit the EP's ability to recognize RECs at the Subject Property and are not considered to affect the overall conclusions of this Report.
Data Gaps from Historical Records Review:	Historical aerial photographs and topographic maps were not able to be obtained in 5-year intervals. This is considered a data gap but given the relatively small changes noted between map and photograph editions, it is not considered to significantly limit the EP's ability to recognize RECs at the Subject Property and is not considered to affect the overall conclusions of this Report.



Gap	Discussion
Data Gaps from Interviews:	None
Other Data Gaps:	None.

7.3 CONCLUSIONS

We have performed a Phase I ESA in conformance with the scope and limitations of ASTM Practice E1527-21 of the Subject Property, an approximately 11.7-mile long area centered on 35.501525°, -119.751895° (WGS 84). Any exceptions to, or deletions from, this practice are described in Section 2.3 of this report. This assessment has revealed the following evidence of RECs in connection with the Subject Property:

- The current and historical use of the Subject Property and surrounding land, from 1911 to present, for petroleum hydrocarbon extraction activities is considered a REC.
- Regulatory records indicate an area of land to the west of the Subject Property, but likely incorporating the Subject Property, was used as a Class III landfill until 2007. The area of fill is listed as over 27 acres, to a depth of 10 feet bgs, and it is considered likely that portions of the Subject Property are incorporated within this area of fill. In addition, historical aerial photography indicate worker residences were demolished in the 1970s and 1980s. Houses constructed prior to this period often contained ACM and LBP within the building fabric. The potential for ACM and LBP to be contained within various areas of fill at the Subject Property, as well as the potential for the fill to be uncompacted and/or uncontrolled, is considered a REC.
- Kern County Environmental Health Services records indicated that a historical waste disposal site is located in the South Belridge Oil Field east of the Oasis office building. Refer to Figure 3 for the approximate location of the waste disposal site. No additional information was available for this REC.
- A total of 41 wastewater pits are currently or were historically located within 0.5 miles of the Subject Property. Of these, the majority are either closed former percolation ponds, secondary containment basins, emergency overflow basins, or process basins. Based on the distance, direction, and regulatory status, these sites are not anticipated to represent an environmental concern to the proposed project.

7.4 RECOMMENDATIONS

Stantec recommends the following additional activities to further characterize the soil conditions at the Subject Property and to assist in planning for construction of the proposed Project:

- Complete Phase II ESA activities within selected areas of potential environmental concern within the Subject Property that may be affected by the proposed Project, such as historical

drilling/production sump locations, and the closed Class III solid waste landfill, and a suspect waste disposalarea.

- Develop a Soil Management Plan for implementation during Project construction activities to properly manage affected soils/wastes that are encountered during ground disturbing activities.

8.0 NON-SCOPE CONSIDERATIONS

The following ASTM E1527-21 Non-Scope Considerations were performed as part of this Phase I ESA:

- Lead-Based Paint
- Asbestos-Containing Materials
- PCBs in Caulk

8.1 LEAD-BASED PAINT

Concern for LBP is primarily related to residential structures. The EPA's Final Rule on Disclosure of Lead-Based Paint in Housing (40 CFR Part 745) defines LBP as paint or other surface coatings that contain lead equal to or in excess of 1.0 milligram per square centimeter or 0.5 percent by weight.

The risk of lead toxicity in LBP varies based upon the condition of the paint and the year of its application. The U.S. Department of Housing and Urban Development (HUD) has identified the following risk factors:

- The age of the structure as follows: maximum risk is from paint applied before 1950.
- There is severe risk from paint applied before 1960.
- There is moderate risk from deteriorated paint applied before 1970.
- There is slight risk from the paint that is intact but applied before 1977.
- The condition of the painted surfaces.
- The presence of children and certain types of households in the building.
- Previously reported cases of lead poisoning in the building or area.

Construction Date	Residential (Yes/No)	Observed Condition of Painted Surfaces
Variable	No	Painted surfaces observed on-site were of various states of condition, with peeling, cracking, and flaking paint observed on painted exterior surfaces of ASTs, pipelines, and stairways.

8.2 ASBESTOS

Asbestos can be found in many applications, including sprayed-on or blanket-type insulation, pipe wraps, mastics, floor and ceiling tiles, wallboard, mortar, roofing materials, and a variety of other materials commonly used in construction. The greatest asbestos-related human health risks are associated with friable asbestos, which is ACM that can be reduced to powder by hand pressure. Friable asbestos can

become airborne and inhaled, which has been associated with specific types of respiratory disease. The manufacturing and use of asbestos in most building products was curtailed during the late 1970s. Presumed ACMs in the form of flange gasket material, AST gaskets, and pipe insulation were observed throughout the Subject Property.

Stantec makes no warranty as to the possible existence or absence of inaccessible materials or to their evaluation with respect to asbestos content. Samples of suspect ACM should be collected for laboratory analysis of asbestos prior to any renovation or building demolition to be compliant with, EPA National Emission Standard for Hazardous Air Pollutants (NESHAP) regulations.

8.3 PCBS IN CAULK

PCBs belong to a broad family of man-made organic chemicals known as chlorinated hydrocarbons. The commercial production of PCBs started in the late 1920s until their manufacture was banned in 1979 because of the possible carcinogenic risk to human health and to the environment. PCBs have a range of toxicity and vary in consistency from thin, light-colored liquids to yellow or black waxy solids. Due to their non-flammability, chemical stability, high boiling point, and electrical insulating properties, PCBs were used in hundreds of industrial and commercial applications including electrical, heat transfer, and hydraulic equipment; as plasticizers in paints, plastics, and rubber products; in pigments, dyes, and carbonless copy paper; and many other industrial applications. The PCBs used in these products were chemical mixtures made up of a variety of individual chlorinated biphenyl components, known as congeners. Most commercial PCB mixtures are known in the United States by their industrial trade names. The most common trade name is Aroclor.

Prior to the 1979 ban, PCBs entered the environment during their manufacture and use in the United States. Although no longer commercially produced in the United States, PCBs may be present in products and materials such as caulk produced before the 1979 PCB ban. Today PCBs associated with building demolition or renovation projects can still be released into the environment from illegal or improper dumping of PCB wastes; disposal of PCB-containing consumer products into municipal or other landfills not designed to handle hazardous waste and through improper containment during removal.

Further assessment of PCBs in caulk appears to be warranted based upon the date of construction of on-site facilities.

9.0 REFERENCES

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Aera Energy, LLC and Greka Oil & Gas, Inc. (Aera and Greka), 2018, UIC Aquifer Exemption Application, Tulare Formation, North Belridge Oil Field, Kern County, California. November 7

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Wood Environmental & Infrastructure Solutions, Inc., 2022, Revised Second Semiannual 2021 SB4 Groundwater Monitoring Report – Section 12, 13, and 18 Leases, South Belridge Oil Field, Kern County, California, GeoTracker Site Global ID: GAOG10009277. February 28.

APPENDICES

APPENDIX A
SITE PHOTOGRAPHS AND GEOLOGIC MAP

Client: Aera Energy LLC	**Project: Aera CarbonFrontier Project**
Site Name: Belridge	**Site Location: Belridge, CA**

Photograph ID: 1 **Direction:** North **Survey Date:** 10/13/2022 **Comments:** View of northern portion of the Study Area in Section A. This section of the Study Area is mostly undeveloped with some remaining decommissioned infrastructure and equipment.	
Photograph ID: 2 **Direction:** Southeast **Survey Date:** 10/13/2022 **Comments:** View southeast of the Study Area in Section A. This section of the Study Area is mostly undeveloped with some remaining decommissioned infrastructure and equipment.	

Client: Aera Energy LLC	**Project: Aera CarbonFrontier Project**
Site Name: Belridge	**Site Location: Belridge, CA**

Photograph ID: 3 **Direction:** Northwest/North **Survey Date:** 10/13/2022 **Comments:** View northwest/north of the Study Area in Section A. Decommissioned pipelines, pumping units, and other equipment is visible. This portion of the Study Area is most undeveloped and vegetated.	
Photograph ID: 4 **Direction:** Northeast **Survey Date:** 10/13/2022 **Comments:** View northeast within Section A. This photograph demonstrates some of the varying road conditions present within the Study Area.	

Client: Aera Energy LLC	**Project: Aera CarbonFrontier Project**
Site Name: Belridge	**Site Location: Belridge, CA**

Photograph ID: 5 **Direction:** South **Survey Date:** 10/13/2022 **Comments:** View south of the Study Area in Section A. Decomissioned AST and transfer station observed. Mesh netting observed on the port valve openings to prevent wildlife from entering the AST.	
Photograph ID: 6 **Direction:** Southwest **Survey Date:** 10/13/2022 **Comments:** View southwest of the Study Area in Section A. View of some decommissioned electrical equipment.	

Client: Aera Energy LLC	**Project: Aera CarbonFrontier Project**
Site Name: Belridge	**Site Location: Belridge, CA**

Photograph ID: 7 **Direction:** West **Survey Date:** 10/13/2022 **Comments:** View west of a Light Oil Gathering System.	
Photograph ID: 8 **Direction:** West **Survey Date:** 10/13/2022 **Comments:** View west at same Light Oil Gathering System. Three electrical transformers are visible in photograph. Numerous electrical transformers were observed throughout the site.	

Client: Aera Energy LLC	**Project: Aera CarbonFrontier Project**
Site Name: Belridge	**Site Location: Belridge, CA**

Photograph ID: 9

Direction:
Southeast

Survey Date:
10/13/2022

Comments:
View southeast in Section B. Photograph showing the boundary between the developed and actively used portions compared to the undeveloped habitat to the north.



Photograph ID: 10

Direction:
Northwest

Survey Date:
10/13/2022

Comments:
View northwest in Section B. Photograph showing the boundary between the developed and actively used portions.



Client: Aera Energy LLC	**Project: Aera CarbonFrontier Project**
Site Name: Belridge	**Site Location: Belridge, CA**

Photograph ID: 11 **Direction:** East **Survey Date:** 10/13/2022 **Comments:** View east in Section B. View of open/abandoned, wood plank lined pit. See Photograph ID 12.	
Photograph ID: 12 **Direction:** Southeast **Survey Date:** 10/13/2022 **Comments:** View of open/abandoned, wood plank lined pit in the central portion of Section B	

Client: Aera Energy LLC	**Project: Aera CarbonFrontier Project**
Site Name: Belridge	**Site Location: Belridge, CA**

Photograph ID: 13 **Direction:** Southwest **Survey Date:** 10/13/2022 **Comments:** View of pipeline the proposed Project has the potential to follow. View southwest in Section B. Comparing with Photograph ID 14, demonstrates the boundary between the developed and actively used portions of the Study Area with the undeveloped habitat areas.	
Photograph ID: 14 **Direction:** North **Survey Date:** 10/13/2022 **Comments:** View of pipeline the proposed Project has the potential to follow. View north in Section B. Comparing with Photograph ID 13, demonstrates the boundary between the developed and actively used portions of the Study Area with the undeveloped habitat areas.	

Client: Aera Energy LLC	**Project: Aera CarbonFrontier Project**
Site Name: Belridge	**Site Location: Belridge, CA**

Photograph ID: 15 **Direction:** East **Survey Date:** 10/13/2022 **Comments:** View of east in Section B of the Study Area. View of a	
Photograph ID: 16 **Direction:** Northeast **Survey Date:** 10/13/2022 **Comments:** View northeast in Section B of the Study Area. View of Oil/Water seperator station with other infrastructure in the surrounding areas (pumping stations, well heads, pipelines).	

Client: Aera Energy LLC	**Project: Aera CarbonFrontier Project**
Site Name: Belridge	**Site Location: Belridge, CA**

Photograph ID: 17 **Direction:** Southwest **Survey Date:** 10/13/2022 **Comments:** View southwest in southern portion of Section B. View of dry collection or overflow area.	
Photograph ID: 18 **Direction:** North **Survey Date:** 10/13/2022 **Comments:** View of rusted drum in the southern portion of Section B adjacent to dry former percolation ponds. No staining was observed and original contents could not be determined.	

Client: Aera Energy LLC	**Project: Aera CarbonFrontier Project**
Site Name: Belridge	**Site Location: Belridge, CA**

Photograph ID: 19 **Direction:** East **Survey Date:** 10/13/2022 **Comments:** View east in northern portion of Section C of the Study Are. View to the east of the Study Area showing the boundary between the undeveloped, habitat with the developed and actively used areas. Compare to Photograph ID 20.	
Photograph ID: 20 **Direction:** West **Survey Date:** 10/13/2022 **Comments:** View west in northern portion of Section C of the Study Are. View to the west within the Study Area showing the boundary between the undeveloped, habitat with the developed and actively used areas. Compare to Photograph ID 19.	

Client: Aera Energy LLC	**Project: Aera CarbonFrontier Project**
Site Name: Belridge	**Site Location: Belridge, CA**

Photograph ID: 21 **Direction:** Northeast **Survey Date:** 10/13/2022 **Comments:** View northeast in Section D of the Study Area. View of 3 large collection or seperation pools. Liquid was present in these pools, potentially oil or slurry mix. Pools were covered with a protective mesh netting.	
Photograph ID: 22 **Direction:** East **Survey Date:** 10/13/2022 **Comments:** View east in Section D of the Study Area. View of close-up of large collection or seperation pool. Liquid was present in these pools, potentially oil or slurry mix. Pools were covered with a protective mesh netting.	

Client: Aera Energy LLC	**Project: Aera CarbonFrontier Project**
Site Name: Belridge	**Site Location: Belridge, CA**

Photograph ID: 23 **Direction:** East **Survey Date:** 10/13/2022 **Comments:** View east in Section E of the Study Area. View of abandoned and decommissioned steam generator systems located adjacent to the footprint of the potential carbon capture facility.	
Photograph ID: 24 **Direction:** West **Survey Date:** 10/13/2022 **Comments:** View west in Section E of the Study Area. View of active steam generators systems located within the footprint of the potential carbon capture facility.	

Client: Aera Energy LLC	**Project: Aera CarbonFrontier Project**
Site Name: Belridge	**Site Location: Belridge, CA**

Photograph ID: 25 **Direction:** Northeast **Survey Date:** 10/13/2022 **Comments:** View northeast/east in Section E of the Study Area. View of undeveloped portions of the Study Area to the east. Decommissioned and former infrastructure remains in these areas.	
Photograph ID: 26 **Direction:** Northwest **Survey Date:** 10/13/2022 **Comments:** View northwest in Section E of the Study Area. View of active BSWP facility in the southeastern portion of the Study Area, location for proposed Water Treatment Plant.	

Client: Aera Energy LLC	**Project: Aera CarbonFrontier Project**
Site Name: Belridge	**Site Location: Belridge, CA**

Photograph ID: 27 **Direction:** Northeast **Survey Date:** 10/13/2022 **Comments:** View northeast in Section E of the Study Area. View of Diatomite Thermal Recovery (DTR) restricted area along Hill Road.	
Photograph ID: 28 **Direction:** Southeast **Survey Date:** 10/13/2022 **Comments:** View southeast in Section E of the Study Area. View of pumping station located adjacent to the DTR area, south of Hill Road. Two ASTs are visible in the background, contents were unable to be determined.	

Client: Aera Energy LLC	**Project: Aera CarbonFrontier Project**
Site Name: Belridge	**Site Location: Belridge, CA**

Photograph ID: 29

Direction:
West

Survey Date:
10/13/2022

Comments:
View west in Section E of the Study Area. View of active Sulferox Terminal Facility in the western portion of the Study Area. Same location is for potential Cogen 32 Carbon Capture Facility.



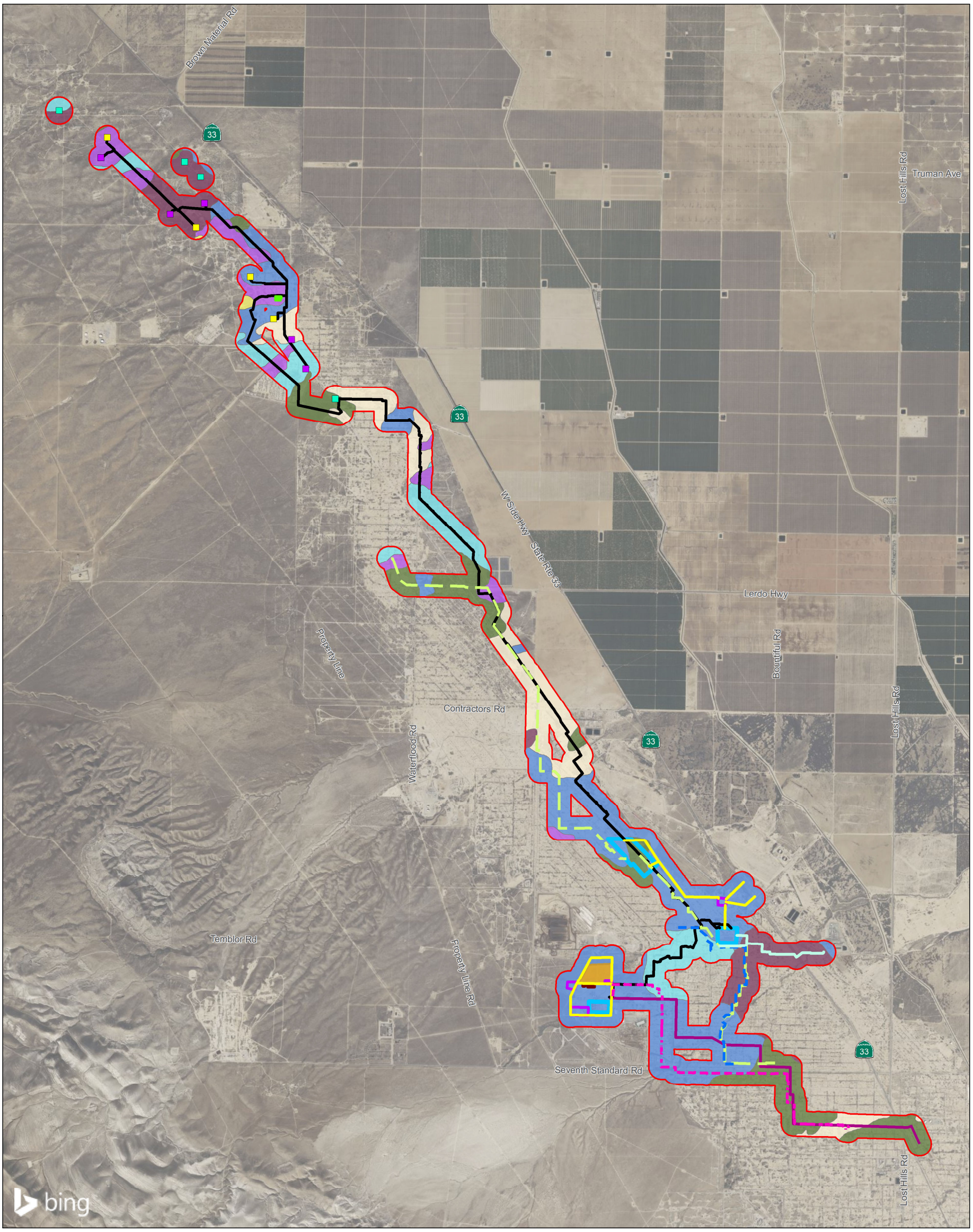
Photograph ID: 30

Direction:
South

Survey Date:
10/13/2022

Comments:
View south in Section E of the Study Area. View of active Sulferox Terminal Facility from its northern gate. In the left hand of the photo is the existing pipeline the proposed project has the potential to follow.





- Study area
- Proposed CO_2 Injection Wells
- Existing Oil Wells to be Converted to CO_2 Injection Wells
- Proposed Monitoring Wells
- Existing Del Sur Gas Line to Gas Plant 32
- Existing Steam Line Routes
- Proposed CO_2 Pipelines
- Potential Produced Water Lines Routes
- Potential Power Line Routes
- Potential Steam Line Routes
- Tulare CVR to GP32 (Optional)
- Proposed Compressor Booster Station
- Potential Substation Locations
- Pre-Combustion Facilities
- Proposed CO_2 Capture Facility
- Proposed Staging Area Adjacent to Gas Plant 32

Soils Map Unit Symbol

- 174; Kimberlina fine sandy loam, 0 to 2 percent slopes MLRA 17
- 175; Kimberlina sandy loam, 2 to 5 percent slopes
- 176; Kimberlina sandy loam, 5 to 9 percent slopes
- 196; Milham sandy loam, 0 to 2 percent slopes MLRA 17
- 197; Milham sandy loam, 2 to 5 percent slopes
- 211; Panoche clay loam, 0 to 2 percent slopes
- 212; Panoche clay loam, 2 to 5 percent slopes

0 4,500 9,000 Feet

(At original document size of 11x17)
1:54,000

N

Stantec AERA

Project Location
Kern County,
California

Prepared by DL on 2023-06-06
TR by SET on 2023-06-06
IR by GH on 2023-06-06

Client/Project
185805407
Aera Energy LLC
Aera CarbonFrontier Project
Biological Resources Technical Report

Figure No.
A-1

Title
Historic Soil Map Units

Notes
1. Coordinate System: NAD 1983 StatePlane California V FIPS 0405 Feet
2. Data Sources: CalGEM, 2019, Stantec 2022,2023. Soils from NRCS 2023.
3. Background: © 2023 Microsoft Corporation © 2023 Maxar ©CNES (2023) Distribution Airbus DS

V:\185805\Active\185805xxxxx_Aera\03_data\gis_cad\gis\185805372_BelridgeCCS\BRTR_Figure5_HistoricSoilTypes_20221025.mxd Revised: 2023-06-08 By: Dalaw

Disclaimer: This document has been prepared based on information provided by others as cited in the Notes section. Stantec has not verified the accuracy and/or completeness of this information and shall not be responsible for any errors or omissions which may be incorporated herein as a result. Stantec assumes no responsibility for data supplied in electronic format, and the recipient accepts full responsibility for verifying the accuracy and completeness of the data.

APPENDIX B
STANTEC RESUMES

Eric Snelling QSD/P, CPESC, REPA

Principal Environmental Planner · 30 Years of Experience · Santa Maria, California

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[illegible]

EDUCATION

[illegible]

[illegible]

CERTIFICATIONS & TRAINING

[illegible]

[illegible]

REGISTRATIONS

[illegible]

[illegible]

MEMBERSHIPS

[illegible]

PROJECT EXPERIENCE

Environmental Assessments – Oil and Gas

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

** denotes projects completed with other firms*

Eric Snelling QSD/P, CPESC, REPA

Principal Environmental Planner · 30 Years of Experience · Santa Maria, California

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Assessment, Permitting and Compliance

Eric Snelling QSD/P, CPESC, REPA

Principal Environmental Planner · 30 Years of Experience · Santa Maria, California

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[illegible]

[illegible]

[illegible]

Eric Snelling QSD/P, CPESC, REPA

Principal Environmental Planner · 30 Years of Experience · Santa Maria, California

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[illegible]

[illegible]

[illegible]

Eric Snelling QSD/P, CPESC, REPA

Principal Environmental Planner · 30 Years of Experience · Santa Maria, California

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PRESENTATIONS

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Kirk Henning

Senior Scientist
28 years of experience · Santa Maria, California

[illegible]

EDUCATION

[illegible]

MEMBERSHIPS

[illegible]

[illegible]

PROJECT EXPERIENCE

AQUIFER DELINEATION AND CHARACTERIZATION

[illegible]

[illegible]

ENVIRONMENTAL SITE ASSESSMENTS PHASE I, II, III

[illegible]

[illegible]

[illegible]

[illegible]

M[illegible]

[illegible]

M[illegible]

[illegible]

ENVIRONMENTAL SITE REMEDIATION

M[illegible]

[illegible]

M[illegible]

[illegible]

** denotes projects completed with other firms*

GROUNDWATER MONITORING AND REPORTING

NATURAL RESOURCE DAMAGE ASSESSMENT AND OIL SPILL RESPONSE

PROJECT MANAGEMENT

** denotes projects completed with other firms*

QUALITY ASSURANCE / QUALITY CONTROL

[illegible]

[illegible]

[illegible]

SITE ASSESSMENT

[illegible]

[illegible]

[illegible]

** denotes projects completed with other firms*

Tom Stanley

Geologic Staff
5 years of experience · Thousand Oaks, California

EDUCATION

BSc/MGeol Geological Sciences, University of Leeds, Leeds, United Kingdom, 2016

CERTIFICATIONS & TRAINING

40-Hour OSHA Health & Safety Certification, HAZWOPER, United States, 2020

8-Hour OSHA Supervisor's Certification, United States, 2020

PROJECT EXPERIENCE

SOIL AND GROUNDWATER REMEDIATION SYSTEMS

Former Ultramar #77 | Yorba Linda, California, United States | Geologic Staff

For more than 20 years, Stantec has provided support to the ongoing remediation project comprising the monitoring and decommission of remedial wells and groundwater monitoring wells surrounding a former hydrocarbon release site. Responsibilities have included oversight of drilling contractors to destroy on-site and off-site wells, co-ordination with subcontractors, and liaison with regulatory agencies and the general public. Dates involved: 01/2020-06/2020

Azusa Landfill Soil Disposal | Azusa, California, United States | Geologic Staff

Stantec was approached to assist with the delineation of and removal of non-conforming soils that had been mistakenly sent to a landfill with an inappropriate classification for the waste. An investigation was prepared to locate and define the extent of the non-conforming soils, comprising soil sampling and in-situ analysis with an x-ray fluorescence tool. Responsibilities included on-site sampling and record-keeping, sample preparation, and reporting. Role: Geologic Staff | Dates involved: 03/2020-04/2020

Willett Tank Farm | Ventura, California, United States | Geologic Staff

Stantec is providing ongoing support to a land developing Client interested in the purchase of a former crude oil storage facility comprising four former above-ground storage tanks with ancillary infrastructure. A Phase I identified contamination beneath the site, potentially extending to a nearby stream. Thomas coordinated subcontractors to delineate and assess vertical and lateral extents of hydrocarbon-impacted soils beneath the former crude oil storage facility. Responsibilities included collection of soil and soil vapor samples, scheduling of laboratory analysis, real-time adjustments to proposed sampling locations based on field observations, and preparation of draft figures indicating the volume of impacted soils requiring remediation and/or removal. Role: Geologic Staff | Dates involved: 06/2020

Former NASA Industrial Plant | Downey, California, United States | Geologic Staff

Stantec assisted in the potential acquisition of a property located on a former NASA rocket and materials testing facility. Thomas supported Phase I ESA to identify potential sources of contamination located on the property and to assess the potential for known off-site contamination to impact the subsurface media at the property. In order to meet the deadlines of an escrow period, he also assisted in scoping, preparing for, and undertaking a limited Phase II ESA. Soil vapor probes were installed to assess the presence and extent of solvent plumes in soil vapor. Soil and groundwater samples were also taken to assess the potential source of the observed vapor phase plumes beneath the property. Further analysis of the data led to the identification of two discrete plumes at the property. One derived from an off-site source and the second was identified to be associated with a localized source located on the property.

Based on the findings of the Phase II ESA, recommendations of the likely mitigation measures were made based on the identified soil vapor contamination. In addition, the investigation identified that should the acquisition proceed, the Client could be required to accept partial responsibility for potential future litigation or remediation of the regional soil vapor phase contamination plume.

BROWNFIELD REMEDIATION AND REDEVELOPMENT

Centre 27 Business Park * | Birstall, England, United Kingdom | Geo-Environmental Consultant

Provided support in the redevelopment of a business park suffering from subsidence attributed to either the compression of a historical landfill known to lie beneath the site, or due to collapsing former coal workings known to encroach upon the site, or a combination of the two. An intrusive investigation was undertaken to assess the extents of the former landfill and assess the extent and condition of historical coal workings beneath the site, as well as undertake a ground gas assessment and structural assessment to inform redevelopment design. Site works comprised drilling and rock coring. Responsibilities included co-ordination with subcontractors, soil and rock logging, and soil sampling, report writing, preliminary founding pile design Role: Geo-Environmental Consultant | Dates involved: 05/2018

Former INEOS Plastic Works* | Helsby, Cheshire, United Kingdom | Geo-Environmental Consultant

Provided oversight of a brownfield remediation project to support the redevelopment of a former plastics factory to a site suitable for residential use. The site, highly impacted with chemicals from its former use, required the oversight of a qualified environmental consultant to ensure remediation was undertaken in line with regulatory guidelines. Responsibilities included oversight of excavation and sump-pump removal of free product, soil, groundwater and surface water sampling, analysis of chemical testing results, preparation and refinement of Conceptual Site Models and Material Reuse Models, and liaison with the UK Environment Agency. Role: Geo-Environmental Consultant | Dates involved: 03/2018-01/2019

VAPOR INTRUSION / METHANE SITE ASSESSMENT & MITIGATION-RELATED PROJECTS

Western Avenue | Los Angeles, California, United States | Geologic Staff

Scoped and managed a soil vapor investigation along the proposed route of a water trunk line in central Los Angeles. The five-mile stretch of proposed pipeline passed through methane zones mapped by the Los Angeles Department of Building and Safety. In order to assess potential health and safety risks to construction workers during construction of the pipeline, Thomas coordinated and led a six-week field investigation involving the drilling, installation, and sampling of soil vapor probes.

Playa Vista | Los Angeles, California, United States | Geologic Staff

Assisted in the assessment and mitigation of vapor intrusion conditions (to include methane) identified at a commercial office building that was being remodeled into a medical office building. The scope of services provided included the completion of vapor intrusion investigations to evaluate the presence of volatile organic compounds and methane within the subsurface of the building. The results of the methane testing were used to establish the methane design basis in accordance with LADBS site testing standards and city ordinance for methane mitigation systems. Stantec assisted the general contractor on behalf of the client to provide additional architectural design considerations and implementation of the mitigation systems as a retrofit of the existing building. Air monitoring was provided during the installation of the sub-slab passive methane mitigation piping system based on the detection of up to 100% methane beneath the building slab during the assessment phase of the project.

Thomas provided additional air monitoring during the remodel to confirm that the installed methane mitigation measures were performing adequately in limiting the intrusion of methane and VOCs into the building. In addition, water quality testing was completed by Stantec to evaluate the existing water supply quality and enable decisions to be made on equipment that may be needed to meet the client's healthcare standards and existing state and federal water quality standards for occupancy by its personnel and visitors for use as a medical office building.

EMPLOYMENT HISTORY

Delta-Simons Environmental Consultants

Geo-Environmental Consultant
2016 - 2020 · 3 years

Preparation of Phase I Environmental Site Assessments, Phase II Site Investigations, Remediation Statements and Remediation Verification Reports. Experienced in scoping and overseeing drilling and excavation programs, scheduling and interpreting chemical analysis of soil and groundwater samples, and collecting and interpreting geotechnical data.

** denotes projects completed with other firms*

APPENDIX C
USER PROVIDED RECORDS

AERA CARBONFRONTIER PROJECT

WASTEWATER PITS REPORTED BY EDR WITH CURRENT STATUS AND FUNCTION

EDR Map ID	Feature	Lat	Long	Geotracker Global ID	Status	Category
124	Wastewater Pits	35.53405	-119.78276	T10000006758	Active	Secondary Containment
125	Wastewater Pits	35.45568	-119.70469	T10000008078	Inactive	Steam Blowdown Pit
126	Wastewater Pits	35.45673	-119.71796	T10000008078	Inactive	Condensation Pit
127	Wastewater Pits	35.55681	-119.81161	T10000006757	Inactive	EOB (Emergency Overflow Basin)
128	Wastewater Pits	35.45701	-119.71243	T10000008078	Active	Steam Blowdown Pit
129	Wastewater Pits	35.53503	-119.78417	T10000006758	Inactive	EOB
131	Wastewater Pits	35.54360	-119.79724	T10000006757	Inactive	EOB
135	Wastewater Pits	35.48000	-119.73579	T10000011582	Active	EOB
136	Wastewater Pits	35.45598	-119.70603	T10000008078	Inactive	Air Compressor Setting
137	Wastewater Pits	35.48057	-119.73597	T10000011582	Active	Waste Discharge Pond
138	Wastewater Pits	35.48039	-119.73578	T10000011582	Active	Waste Discharge Pond
139	Wastewater Pits	35.46253	-119.72356	T10000008078	Inactive	Steam Blowdown Pit
140	Wastewater Pits	35.56058	-119.81293	L10002981694	Inactive	Secondary Containment
141	Wastewater Pits	35.48031	-119.73526	T10000011582	Active	Waste Discharge Pond
142	Wastewater Pits	35.51511	-119.76256	L10005630246	Inactive	Waste Discharge Pond
143	Wastewater Pits	35.51477	-119.76261	L10005630246	Inactive	Waste Discharge Pond
144	Wastewater Pits	35.51420	-119.76262	L10005630246	Inactive	Waste Discharge Pond
145	Wastewater Pits	35.51390	-119.76266	L10005630246	Inactive	Waste Discharge Pond
147	Wastewater Pits	35.47501	-119.73242	T10000008078	Inactive	Waste Discharge Pond
148	Wastewater Pits	35.48194	-119.73492	T10000011582	Active	Waste Discharge Pond
149	Wastewater Pits	35.51547	-119.76430	L10005630246	Inactive	Secondary Containment
150	Wastewater Pits	35.53865	-119.78887	T10000006758	Inactive	EOB
151	Wastewater Pits	35.46179	-119.70642	T10000011585	Active	Waste Discharge Pond
152	Wastewater Pits	35.51546	-119.76440	L10005630246	Inactive	Waste Discharge Pond
153	Wastewater Pits	35.48193	-119.73377	T10000011582	Active	Waste Discharge Pond
154	Wastewater Pits	35.54459	-119.78530	Not Listed	Closed	North Surface Imoundments
155	Wastewater Pits	35.46762	-119.71103	WDR100026926	Closed	Wastewater Disposal Facility
156	Wastewater Pits	35.47520	-119.72921	WDR100026929	Closed	Wastewater Disposal Facility
157	Wastewater Pits	35.45919	-119.70432	T10000011585	Active	Waste Discharge Pond
158	Wastewater Pits	35.53634	-119.77581	L10005431189	Inactive	Waste Discharge Pond
159	Wastewater Pits	35.45964	-119.70513	T10000011585	Active	Waste Discharge Pond
160	Wastewater Pits	35.45993	-119.70384	T10000011585	Active	Waste Discharge Pond
161	Wastewater Pits	35.46013	-119.70279	T10000011585	Active	Relief Pit
162	Wastewater Pits	35.46027	-119.70267	T10000011585	Active	Relief Pit
163	Wastewater Pits	35.46028	-119.70287	T10000011585	Active	Relief Pit
164	Wastewater Pits	35.51215	-119.76673	L10005630246	Inactive	Waste Discharge Pond
165	Wastewater Pits	35.46022	-119.70450	T10000011585	Active	Waste Discharge Pond
166	Wastewater Pits	35.46048	-119.70233	T10000011585	Active	EOB
167	Wastewater Pits	35.51499	-119.77075	L10005630246	Closed	Waste Discharge Pond
168	Wastewater Pits	35.53528	-119.77388	L10005431189	Inactive	EOB
169	Wastewater Pits	35.48017	-119.74713	Not Listed	Berry Property Not Aera Pit	

APPENDIX D
ENVIRONMENTAL AGENCY DATABASE SEARCH REPORT

Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249

Inquiry Number: 7133623.8s
September 30, 2022

EDR Area / Corridor Report

6 Armstrong Road, 4th floor
Shelton, CT 06484
Toll Free: 800.352.0050
www.edrnet.com

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Government Records Searched/Data Currency Tracking	GR-1

Thank you for your business.
Please contact EDR at 1-800-352-0050
with any questions or comments.

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EXECUTIVE SUMMARY

A search of available environmental records was conducted by Environmental Data Resources, Inc (EDR). The report was designed to assist parties seeking to meet the search requirements of EPA's Standards and Practices for All Appropriate Inquiries (40 CFR Part 312), the ASTM Standard Practice for Environmental Site Assessments (E1527-21), the ASTM Standard Practice for Environmental Site Assessments for Forestland or Rural Property (E 2247-16), the ASTM Standard Practice for Limited Environmental Due Diligence: Transaction Screen Process (E 1528-14) or custom requirements developed for the evaluation of environmental risk associated with a parcel of real estate.

SUBJECT PROPERTY INFORMATION

ADDRESS

AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

TARGET PROPERTY SEARCH RESULTS

The Target Property was identified in the following databases.

Page Numbers and Map Identifcations refer to the EDR Area/Corridor Report where detailed data on individual sites can be reviewed.

Sites listed in ***bold italics*** are in multiple databases.

ADDITIONAL ENVIRONMENTAL RECORDS

Local Lists of Hazardous waste / Contaminated Sites

CERS HAZ WASTE: CERS HAZ WASTE

A review of the CERS HAZ WASTE list, as provided by EDR, and dated 04/18/2022 has revealed that there is 1 CERS HAZ WASTE site within the requested target property.

Site	Address	Map ID / Focus Map(s)	Page
PHILLIPS 66 - MIDDLE	***17251 POLE LINE RD***	***J41 / 8***	***84***

Records of Emergency Release Reports

CHMIRS: California Hazardous Material Incident Report System

A review of the CHMIRS list, as provided by EDR, and dated 04/03/2022 has revealed that there is 1 CHMIRS site within the requested target property.

Site	Address	Map ID / Focus Map(s)	Page
PHILLIPS 66 PIPELINE OES Incident Number: 4-6216	***17251 POLE LINE RD***	***J42 / 8***	***88***

EXECUTIVE SUMMARY

Other Ascertainable Records

FINDS: Facility Index System/Facility Registry System

A review of the FINDS list, as provided by EDR, and dated 05/13/2022 has revealed that there is 1 FINDS site within the requested target property.

Site	Address	Map ID / Focus Map(s)	Page
PHILLIPS 66 - MIDDLE Registry ID:: 110065253969	17251 POLE LINE RD	J38 / 8	82

CUPA Listings: CUPA Resources List

A review of the CUPA Listings list, as provided by EDR, has revealed that there is 1 CUPA Listings site within the requested target property.

Site	Address	Map ID / Focus Map(s)	Page
PHILLIPS 66 - MIDDLE Database: KERN CO CUPA, Date of Government Version: 05/06/2022	***17251 POLE LINE RD***	***J41 / 8***	***84***

EMI: Emissions Inventory Data

A review of the EMI list, as provided by EDR, and dated 12/31/2020 has revealed that there are 2 EMI sites within the requested target property.

Site	Address	Map ID / Focus Map(s)	Page
UNOCAL CALIFORNIA PI Facility Id: 1520	17251 POLE LINE ROAD	J37 / 8	80
PHILLIPS 66 PIPELINE Facility Id: 1520	***17251 POLE LINE RD***	***J42 / 8***	***88***

UIC: UIC Listing

A review of the UIC list, as provided by EDR, and dated 06/06/2022 has revealed that there are 119 UIC sites within the requested target property.

Site	Address	Map ID / Focus Map(s)	Page
AERA ENERGY LLC		A1 / 8	59
AERA ENERGY LLC		2 / 8	59
AERA ENERGY LLC		B3 / 8	60
AERA ENERGY LLC		B4 / 8	60
AERA ENERGY LLC		B5 / 8	61
AERA ENERGY LLC		A6 / 8	62
AERA ENERGY LLC		7 / 8	62
AERA ENERGY LLC		8 / 8	63
AERA ENERGY LLC		C9 / 8	63
AERA ENERGY LLC		D10 / 8	64
AERA ENERGY LLC		11 / 8	65
AERA ENERGY LLC		D12 / 8	65
AERA ENERGY LLC		D13 / 8	66
AERA ENERGY LLC		14 / 8	66

EXECUTIVE SUMMARY

Site	Address	Map ID / Focus Map(s)	Page
AERA ENERGY LLC		C15 / 8	67
AERA ENERGY LLC		16 / 8	68
AERA ENERGY LLC		E17 / 8	68
AERA ENERGY LLC		E18 / 8	69
AERA ENERGY LLC		E19 / 8	69
AERA ENERGY LLC		E20 / 8	70
AERA ENERGY LLC		F21 / 8	71
AERA ENERGY LLC		F22 / 8	71
AERA ENERGY LLC		F23 / 8	72
AERA ENERGY LLC		F24 / 8	72
AERA ENERGY LLC		F25 / 8	73
AERA ENERGY LLC		F26 / 8	74
AERA ENERGY LLC		G27 / 8	74
AERA ENERGY LLC		G28 / 8	75
AERA ENERGY LLC		H29 / 8	75
AERA ENERGY LLC		H30 / 8	76
AERA ENERGY LLC		31 / 8	77
AERA ENERGY LLC		I32 / 8	77
AERA ENERGY LLC		I33 / 8	78
AERA ENERGY LLC		34 / 8	78
AERA ENERGY LLC		J35 / 8	79
AERA ENERGY LLC		K36 / 8	80
AERA ENERGY LLC		J39 / 8	83
AERA ENERGY LLC		K40 / 8	83
AERA ENERGY LLC		43 / 8	93
AERA ENERGY LLC		44 / 8	93
AERA ENERGY LLC		45 / 8	94
AERA ENERGY LLC		L46 / 8	94
AERA ENERGY LLC		L47 / 8	95
AERA ENERGY LLC		M48 / 8	96
AERA ENERGY LLC		M49 / 8	96
AERA ENERGY LLC		50 / 12	97
AERA ENERGY LLC		51 / 15	98
AERA ENERGY LLC		52 / 15	98
AERA ENERGY LLC		53 / 15	99
AERA ENERGY LLC		N54 / 15	99
AERA ENERGY LLC		N55 / 15	100
AERA ENERGY LLC		N56 / 15	101
AERA ENERGY LLC		O57 / 16	101
AERA ENERGY LLC		O58 / 16	102
AERA ENERGY LLC		P59 / 19	102
AERA ENERGY LLC		P60 / 19	103
AERA ENERGY LLC		P61 / 19	104
AERA ENERGY LLC		Q62 / 19	104
AERA ENERGY LLC		Q63 / 19	105
AERA ENERGY LLC		R64 / 19	105
AERA ENERGY LLC		R65 / 19	106
AERA ENERGY LLC		66 / 19	107
AERA ENERGY LLC		S67 / 19	107
AERA ENERGY LLC		S68 / 19	108
AERA ENERGY LLC		69 / 19	108
AERA ENERGY LLC		70 / 19	109
AERA ENERGY LLC		T71 / 19	110
AERA ENERGY LLC		T72 / 19	110
AERA ENERGY LLC		73 / 19	111
AERA ENERGY LLC		U74 / 19	111

EXECUTIVE SUMMARY

Site	Address	Map ID / Focus Map(s)	Page
AERA ENERGY LLC		U75 / 19	112
AERA ENERGY LLC		V76 / 19	113
AERA ENERGY LLC		V77 / 19	113
AERA ENERGY LLC		V78 / 19	114
AERA ENERGY LLC		79 / 19	114
AERA ENERGY LLC		W80 / 19	115
AERA ENERGY LLC		W81 / 19	116
AERA ENERGY LLC		82 / 19	116
AERA ENERGY LLC		83 / 19	117
AERA ENERGY LLC		X84 / 19	117
AERA ENERGY LLC		X85 / 19	118
AERA ENERGY LLC		Y86 / 19	119
AERA ENERGY LLC		Y87 / 19	119
AERA ENERGY LLC		Z88 / 19	120
AERA ENERGY LLC		Z89 / 19	120
AERA ENERGY LLC		Y90 / 19	121
AERA ENERGY LLC		Y91 / 19	122
AERA ENERGY LLC		AA92 / 19	122
AERA ENERGY LLC		93 / 19	123
AERA ENERGY LLC		AA94 / 19	123
AERA ENERGY LLC		AB95 / 19	124
AERA ENERGY LLC		AB96 / 19	125
AERA ENERGY LLC		97 / 19	125
AERA ENERGY LLC		AC98 / 19	126
AERA ENERGY LLC		AB99 / 19	126
AERA ENERGY LLC		AC100 / 19	127
AERA ENERGY LLC		101 / 19	128
AERA ENERGY LLC		AD102 / 19	128
AERA ENERGY LLC		AD103 / 19	129
AERA ENERGY LLC		104 / 19	129
AERA ENERGY LLC		AE105 / 19	130
AERA ENERGY LLC		AF106 / 19	131
AERA ENERGY LLC		AF107 / 19	131
AERA ENERGY LLC		AG108 / 19	132
AERA ENERGY LLC		AE109 / 19	132
AERA ENERGY LLC		AG110 / 19	133
AERA ENERGY LLC		AG111 / 19	134
AERA ENERGY LLC		AH112 / 19	134
AERA ENERGY LLC		AH113 / 19	135
AERA ENERGY LLC		AI114 / 19	135
AERA ENERGY LLC		115 / 19	136
AERA ENERGY LLC		AI116 / 19	137
AERA ENERGY LLC		117 / 19	137
AERA ENERGY LLC		AI118 / 19	138
AERA ENERGY LLC		119 / 20	138
AERA ENERGY LLC		AJ120 / 19	139
AERA ENERGY LLC		121 / 19	140
AERA ENERGY LLC		122 / 19	140
AERA ENERGY LLC		AJ123 / 19	141

EXECUTIVE SUMMARY

CERS: CERS

A review of the CERS list, as provided by EDR, and dated 04/18/2022 has revealed that there are 2 CERS sites within the requested target property.

Site	Address	Map ID / Focus Map(s)	Page
PHILLIPS 66 - MIDDLE	***17251 POLE LINE RD***	***J41 / 8***	***84***
PHILLIPS 66 PIPELINE	***17251 POLE LINE RD***	***J42 / 8***	***88***

SURROUNDING SITES: SEARCH RESULTS

Surrounding sites were identified in the following databases.

Page Numbers and Map Identifcations refer to the EDR Area/Corridor Report where detailed data on individual sites can be reviewed.

Sites listed in ***bold italics*** are in multiple databases.

Unmappable (orphan) sites are not considered in the foregoing analysis.

STANDARD ENVIRONMENTAL RECORDS

Lists of state and tribal landfills and solid waste disposal facilities

SWF/LF: Solid Waste Information System

A review of the SWF/LF list, as provided by EDR, has revealed that there is 1 SWF/LF site within approximately 0.5 miles of the requested target property.

Site	Address	Direction / Distance	Map ID / Focus Map(s)	Page
NORTH BELRIDGE LANDF	***1 MI NE BELRIDGE OIL***	***SW 0 - 1/8 (0.112 mi.)***	***146 / 7***	***167***

Database: SWF/LF (SWIS), Date of Government Version: 05/09/2022
Facility ID: 15-AA-0067
Operational Status: Closed
Regulation Status: Permitted

ADDITIONAL ENVIRONMENTAL RECORDS

Other Ascertainable Records

RCRA NonGen / NLR: RCRA - Non Generators / No Longer Regulated

A review of the RCRA NonGen / NLR list, as provided by EDR, and dated 06/20/2022 has revealed that there are 2 RCRA NonGen / NLR sites within approximately 0.25 miles of the requested target property.

Site	Address	Direction / Distance	Map ID / Focus Map(s)	Page
CLARIANT OIL SERVICE	18426 POLE LINE RD	SE 0 - 1/8 (0.048 mi.)	AL133 / 15	159

EPA ID:: CAL000357095				
KS INDUSTRIES LP EPA ID:: CAL000419769	18426 POLE LINE RD	SE 0 - 1/8 (0.048 mi.)	AL134 / 15	161

Cortese: "Cortese" Hazardous Waste & Substances Sites List

A review of the Cortese list, as provided by EDR, and dated 06/21/2022 has revealed that there is 1 Cortese site within approximately 0.5 miles of the requested target property.

Site	Address	Direction / Distance	Map ID / Focus Map(s)	Page
NORTH BELRIDGE OIL F	***NORTH BELRIDGE OIL F***	***S 0 - 1/8 (0.042 mi.)***	***AK130 / 8***	***143***

CUPA Listings: CUPA Resources List

A review of the CUPA Listings list, as provided by EDR, has revealed that there is 1 CUPA Listings site within approximately 0.25 miles of the requested target property.

Site	Address	Direction / Distance	Map ID / Focus Map(s)	Page
CLARIANT OIL SERVICE	***18426 POLE LINE RD***	***SE 0 - 1/8 (0.048 mi.)***	***AL132 / 15***	***150***
Database: KERN CO CUPA, Date of Government Version: 05/06/2022				

WASTEWATER PITS: Oil Wastewater Pits Listing

A review of the WASTEWATER PITS list, as provided by EDR, and dated 02/11/2021 has revealed that there are 41 WASTEWATER PITS sites within approximately 0.5 miles of the requested target property.

Site	Address	Direction / Distance	Map ID / Focus Map(s)	Page
Not reported		S 0 - 1/8 (0.014 mi.)	C124 / 8	141
Not reported		N 0 - 1/8 (0.028 mi.)	AI125 / 19	142
Not reported		ESE 0 - 1/8 (0.031 mi.)	126 / 19	142
Not reported		NW 0 - 1/8 (0.032 mi.)	127 / 4	142
Not reported		S 0 - 1/8 (0.036 mi.)	128 / 19	143
Not reported		S 0 - 1/8 (0.042 mi.)	AK129 / 8	143
Not reported		SW 0 - 1/8 (0.044 mi.)	131 / 4	150
Not reported		NE 0 - 1/8 (0.049 mi.)	AM135 / 15	164
Not reported		N 0 - 1/8 (0.050 mi.)	136 / 19	164
Not reported		NE 0 - 1/8 (0.064 mi.)	137 / 15	164
Not reported		NE 0 - 1/8 (0.065 mi.)	AM138 / 15	165
Not reported		W 0 - 1/8 (0.072 mi.)	139 / 19	165
Not reported		NE 0 - 1/8 (0.078 mi.)	140 / 3	165
Not reported		NE 0 - 1/8 (0.085 mi.)	AM141 / 15	166
Not reported		W 0 - 1/8 (0.100 mi.)	AN142 / 8	166
Not reported		W 0 - 1/8 (0.103 mi.)	AN143 / 11	166
Not reported		W 0 - 1/8 (0.104 mi.)	AO144 / 11	167
Not reported		W 0 - 1/8 (0.106 mi.)	AO145 / 11	167
Not reported		NE 1/8 - 1/4 (0.131 mi.)	147 / 15	172
Not reported		NE 1/8 - 1/4 (0.168 mi.)	148 / 15	172
Not reported		W 1/8 - 1/4 (0.198 mi.)	AP149 / 8	173
Not reported		NW 1/8 - 1/4 (0.200 mi.)	150 / 4	173
Not reported		E 1/8 - 1/4 (0.201 mi.)	151 / 19	173
Not reported		W 1/8 - 1/4 (0.204 mi.)	AP152 / 8	174
Not reported		NE 1/8 - 1/4 (0.220 mi.)	153 / 15	174

EXECUTIVE SUMMARY

Site	Address	Direction / Distance	Map ID / Focus Map(s)	Page
Not reported		NE 1/8 - 1/4 (0.231 mi.)	154 / 5	174
Not reported		N 1/4 - 1/2 (0.254 mi.)	155 / 19	175
Not reported		NE 1/4 - 1/2 (0.265 mi.)	156 / 16	175
Not reported		N 1/4 - 1/2 (0.269 mi.)	157 / 19	175
Not reported		E 1/4 - 1/2 (0.285 mi.)	158 / 8	176
Not reported		NE 1/4 - 1/2 (0.296 mi.)	159 / 19	176
Not reported		NNW 1/4 - 1/2 (0.312 mi.)	160 / 20	176
Not reported		N 1/4 - 1/2 (0.320 mi.)	AQ161 / 20	177
Not reported		N 1/4 - 1/2 (0.329 mi.)	AQ162 / 20	177
Not reported		N 1/4 - 1/2 (0.330 mi.)	AQ163 / 20	177
Not reported		W 1/4 - 1/2 (0.337 mi.)	164 / 11	178
Not reported		ESE 1/4 - 1/2 (0.337 mi.)	165 / 19	178
Not reported		N 1/4 - 1/2 (0.343 mi.)	AQ166 / 20	178
Not reported		SSE 1/4 - 1/2 (0.371 mi.)	167 / 11	179
Not reported		E 1/4 - 1/2 (0.397 mi.)	168 / 8	179
Not reported		SW 1/4 - 1/2 (0.491 mi.)	169 / 15	179

MAPPED SITES SUMMARY

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION
A1 / 8	AERA ENERGY LLC		UIC	TP
2 / 8	AERA ENERGY LLC		UIC	TP
B3 / 8	AERA ENERGY LLC		UIC	TP
B4 / 8	AERA ENERGY LLC		UIC	TP
B5 / 8	AERA ENERGY LLC		UIC	TP
A6 / 8	AERA ENERGY LLC		UIC	TP
7 / 8	AERA ENERGY LLC		UIC	TP
8 / 8	AERA ENERGY LLC		UIC	TP
C9 / 8	AERA ENERGY LLC		UIC	TP
D10 / 8	AERA ENERGY LLC		UIC	TP
11 / 8	AERA ENERGY LLC		UIC	TP
D12 / 8	AERA ENERGY LLC		UIC	TP
D13 / 8	AERA ENERGY LLC		UIC	TP
14 / 8	AERA ENERGY LLC		UIC	TP
C15 / 8	AERA ENERGY LLC		UIC	TP
16 / 8	AERA ENERGY LLC		UIC	TP
E17 / 8	AERA ENERGY LLC		UIC	TP
E18 / 8	AERA ENERGY LLC		UIC	TP
E19 / 8	AERA ENERGY LLC		UIC	TP
E20 / 8	AERA ENERGY LLC		UIC	TP
F21 / 8	AERA ENERGY LLC		UIC	TP
F22 / 8	AERA ENERGY LLC		UIC	TP
F23 / 8	AERA ENERGY LLC		UIC	TP
F24 / 8	AERA ENERGY LLC		UIC	TP
F25 / 8	AERA ENERGY LLC		UIC	TP
F26 / 8	AERA ENERGY LLC		UIC	TP
G27 / 8	AERA ENERGY LLC		UIC	TP
G28 / 8	AERA ENERGY LLC		UIC	TP
H29 / 8	AERA ENERGY LLC		UIC	TP
H30 / 8	AERA ENERGY LLC		UIC	TP
31 / 8	AERA ENERGY LLC		UIC	TP
I32 / 8	AERA ENERGY LLC		UIC	TP
I33 / 8	AERA ENERGY LLC		UIC	TP
34 / 8	AERA ENERGY LLC		UIC	TP
J35 / 8	AERA ENERGY LLC		UIC	TP
K36 / 8	AERA ENERGY LLC		UIC	TP
J37 / 8	UNOCAL CALIFORNIA PI	17251 POLE LINE ROAD	EMI	TP
J38 / 8	PHILLIPS 66 - MIDDLE	17251 POLE LINE RD	FINDS	TP
J39 / 8	AERA ENERGY LLC		UIC	TP

MAPPED SITES SUMMARY

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION
K40 / 8	AERA ENERGY LLC		UIC	TP
J41 / 8	PHILLIPS 66 - MIDDLE	17251 POLE LINE RD	CERS HAZ WASTE, CUPA Listings, CERS	TP
J42 / 8	PHILLIPS 66 PIPELINE	17251 POLE LINE RD	CHMIRS, EMI, CERS	TP
43 / 8	AERA ENERGY LLC		UIC	TP
44 / 8	AERA ENERGY LLC		UIC	TP
45 / 8	AERA ENERGY LLC		UIC	TP
L46 / 8	AERA ENERGY LLC		UIC	TP
L47 / 8	AERA ENERGY LLC		UIC	TP
M48 / 8	AERA ENERGY LLC		UIC	TP
M49 / 8	AERA ENERGY LLC		UIC	TP
50 / 12	AERA ENERGY LLC		UIC	TP
51 / 15	AERA ENERGY LLC		UIC	TP
52 / 15	AERA ENERGY LLC		UIC	TP
53 / 15	AERA ENERGY LLC		UIC	TP
N54 / 15	AERA ENERGY LLC		UIC	TP
N55 / 15	AERA ENERGY LLC		UIC	TP
N56 / 15	AERA ENERGY LLC		UIC	TP
O57 / 16	AERA ENERGY LLC		UIC	TP
O58 / 16	AERA ENERGY LLC		UIC	TP
P59 / 19	AERA ENERGY LLC		UIC	TP
P60 / 19	AERA ENERGY LLC		UIC	TP
P61 / 19	AERA ENERGY LLC		UIC	TP
Q62 / 19	AERA ENERGY LLC		UIC	TP
Q63 / 19	AERA ENERGY LLC		UIC	TP
R64 / 19	AERA ENERGY LLC		UIC	TP
R65 / 19	AERA ENERGY LLC		UIC	TP
66 / 19	AERA ENERGY LLC		UIC	TP
S67 / 19	AERA ENERGY LLC		UIC	TP
S68 / 19	AERA ENERGY LLC		UIC	TP
69 / 19	AERA ENERGY LLC		UIC	TP
70 / 19	AERA ENERGY LLC		UIC	TP
T71 / 19	AERA ENERGY LLC		UIC	TP
T72 / 19	AERA ENERGY LLC		UIC	TP
73 / 19	AERA ENERGY LLC		UIC	TP
U74 / 19	AERA ENERGY LLC		UIC	TP
U75 / 19	AERA ENERGY LLC		UIC	TP
V76 / 19	AERA ENERGY LLC		UIC	TP
V77 / 19	AERA ENERGY LLC		UIC	TP
V78 / 19	AERA ENERGY LLC		UIC	TP

MAPPED SITES SUMMARY

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION
79 / 19	AERA ENERGY LLC		UIC	TP
W80 / 19	AERA ENERGY LLC		UIC	TP
W81 / 19	AERA ENERGY LLC		UIC	TP
82 / 19	AERA ENERGY LLC		UIC	TP
83 / 19	AERA ENERGY LLC		UIC	TP
X84 / 19	AERA ENERGY LLC		UIC	TP
X85 / 19	AERA ENERGY LLC		UIC	TP
Y86 / 19	AERA ENERGY LLC		UIC	TP
Y87 / 19	AERA ENERGY LLC		UIC	TP
Z88 / 19	AERA ENERGY LLC		UIC	TP
Z89 / 19	AERA ENERGY LLC		UIC	TP
Y90 / 19	AERA ENERGY LLC		UIC	TP
Y91 / 19	AERA ENERGY LLC		UIC	TP
AA92 / 19	AERA ENERGY LLC		UIC	TP
93 / 19	AERA ENERGY LLC		UIC	TP
AA94 / 19	AERA ENERGY LLC		UIC	TP
AB95 / 19	AERA ENERGY LLC		UIC	TP
AB96 / 19	AERA ENERGY LLC		UIC	TP
97 / 19	AERA ENERGY LLC		UIC	TP
AC98 / 19	AERA ENERGY LLC		UIC	TP
AB99 / 19	AERA ENERGY LLC		UIC	TP
AC100 / 19	AERA ENERGY LLC		UIC	TP
101 / 19	AERA ENERGY LLC		UIC	TP
AD102 / 19	AERA ENERGY LLC		UIC	TP
AD103 / 19	AERA ENERGY LLC		UIC	TP
104 / 19	AERA ENERGY LLC		UIC	TP
AE105 / 19	AERA ENERGY LLC		UIC	TP
AF106 / 19	AERA ENERGY LLC		UIC	TP
AF107 / 19	AERA ENERGY LLC		UIC	TP
AG108 / 19	AERA ENERGY LLC		UIC	TP
AE109 / 19	AERA ENERGY LLC		UIC	TP
AG110 / 19	AERA ENERGY LLC		UIC	TP
AG111 / 19	AERA ENERGY LLC		UIC	TP
AH112 / 19	AERA ENERGY LLC		UIC	TP
AH113 / 19	AERA ENERGY LLC		UIC	TP
AI114 / 19	AERA ENERGY LLC		UIC	TP
115 / 19	AERA ENERGY LLC		UIC	TP
AI116 / 19	AERA ENERGY LLC		UIC	TP
117 / 19	AERA ENERGY LLC		UIC	TP

MAPPED SITES SUMMARY

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

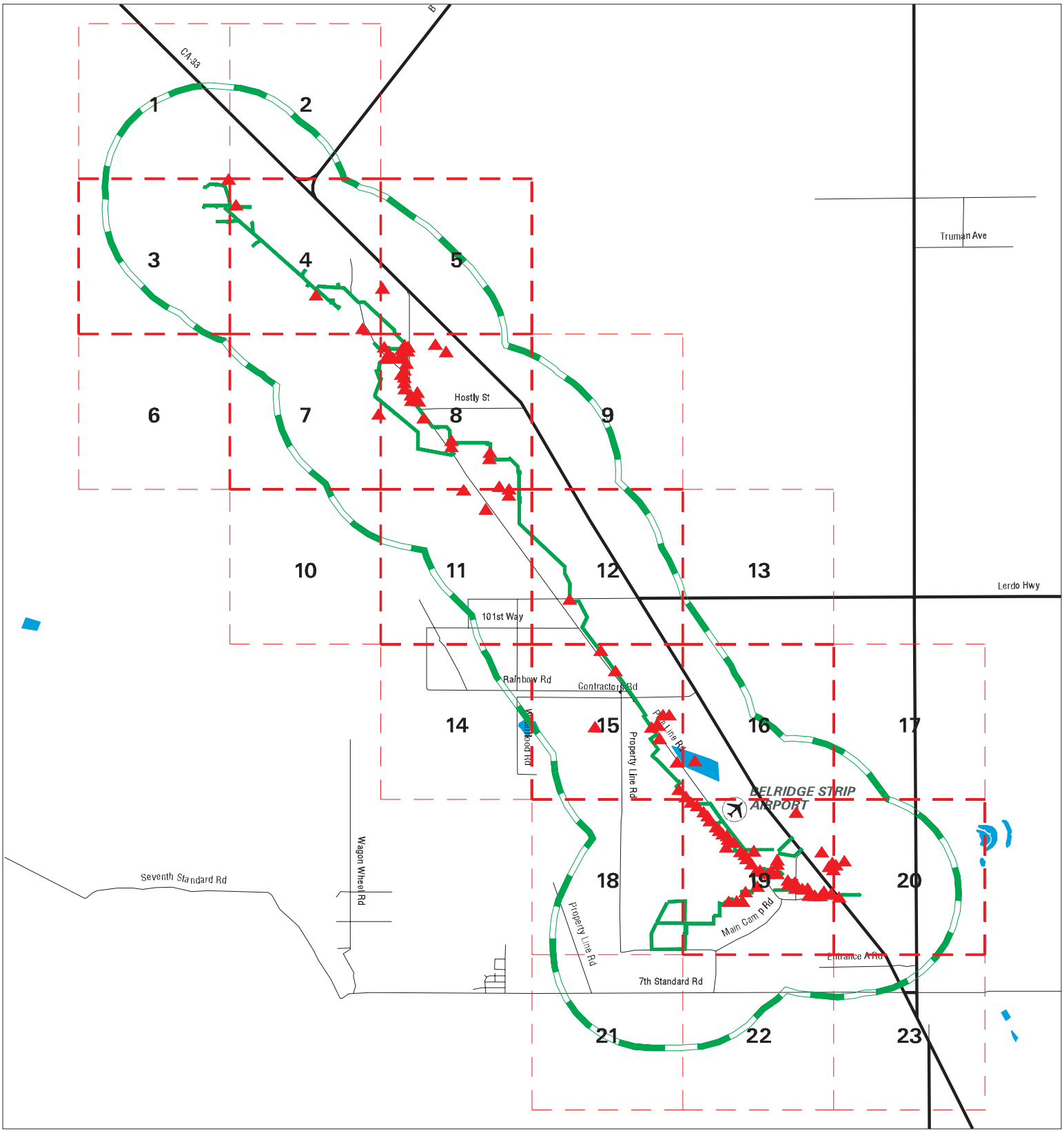
MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION
AI118 / 19	AERA ENERGY LLC		UIC	TP
119 / 20	AERA ENERGY LLC		UIC	TP
AJ120 / 19	AERA ENERGY LLC		UIC	TP
121 / 19	AERA ENERGY LLC		UIC	TP
122 / 19	AERA ENERGY LLC		UIC	TP
AJ123 / 19	AERA ENERGY LLC		UIC	TP
C124 / 8			WASTEWATER PITS	76 0.014 South
AI125 / 19			WASTEWATER PITS	147 0.028 North
126 / 19			WASTEWATER PITS	162 0.031 ESE
127 / 4			WASTEWATER PITS	169 0.032 NW
128 / 19			WASTEWATER PITS	189 0.036 South
AK129 / 8			WASTEWATER PITS	222 0.042 South
AK130 / 8	NORTH BELRIDGE OIL F	NORTH BELRIDGE OIL F	Cortese, ENF, CERS	222 0.042 South
131 / 4			WASTEWATER PITS	232 0.044 SW
AL132 / 15	CLARIANT OIL SERVICE	18426 POLE LINE RD	CUPA Listings, HAZNET, HWTS	254 0.048 SE
AL133 / 15	CLARIANT OIL SERVICE	18426 POLE LINE RD	RCRA NonGen / NLR	254 0.048 SE
AL134 / 15	KS INDUSTRIES LP	18426 POLE LINE RD	RCRA NonGen / NLR	254 0.048 SE
AM135 / 15			WASTEWATER PITS	257 0.049 NE
136 / 19			WASTEWATER PITS	264 0.050 North
137 / 15			WASTEWATER PITS	338 0.064 NE
AM138 / 15			WASTEWATER PITS	344 0.065 NE
139 / 19			WASTEWATER PITS	382 0.072 West
140 / 3			WASTEWATER PITS	412 0.078 NE
AM141 / 15			WASTEWATER PITS	451 0.085 NE
AN142 / 8			WASTEWATER PITS	530 0.100 West
AN143 / 11			WASTEWATER PITS	546 0.103 West
AO144 / 11			WASTEWATER PITS	548 0.104 West
AO145 / 11			WASTEWATER PITS	562 0.106 West
146 / 7	NORTH BELRIDGE LANDF	1 MI NE BELRIDGE OIL	SWF/LF, Financial Assurance, CERS	593 0.112 SW
147 / 15			WASTEWATER PITS	694 0.131 NE
148 / 15			WASTEWATER PITS	886 0.168 NE
AP149 / 8			WASTEWATER PITS	1047 0.198 West
150 / 4			WASTEWATER PITS	1057 0.200 NW
151 / 19			WASTEWATER PITS	1060 0.201 East
AP152 / 8			WASTEWATER PITS	1077 0.204 West
153 / 15			WASTEWATER PITS	1159 0.220 NE
154 / 5			WASTEWATER PITS	1218 0.231 NE
155 / 19			WASTEWATER PITS	1339 0.254 North
156 / 16			WASTEWATER PITS	1399 0.265 NE

MAPPED SITES SUMMARY

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION
157 / 19			WASTEWATER PITS	1421 0.269 North
158 / 8			WASTEWATER PITS	1507 0.285 East
159 / 19			WASTEWATER PITS	1564 0.296 NE
160 / 20			WASTEWATER PITS	1646 0.312 NNW
AQ161 / 20			WASTEWATER PITS	1687 0.320 North
AQ162 / 20			WASTEWATER PITS	1738 0.329 North
AQ163 / 20			WASTEWATER PITS	1742 0.330 North
164 / 11			WASTEWATER PITS	1778 0.337 West
165 / 19			WASTEWATER PITS	1778 0.337 ESE
AQ166 / 20			WASTEWATER PITS	1813 0.343 North
167 / 11			WASTEWATER PITS	1957 0.371 SSE
168 / 8			WASTEWATER PITS	2098 0.397 East
169 / 15			WASTEWATER PITS	2591 0.491 SW

Key Map - 7133623.8s



Sites
Target Property
Search Buffer
Focus Map - No Sites
Focus Map - Sites
National Priority List Sites
Areas of Concern
Dept. Defense Sites
Indian Reservations BIA

0 1 2 Miles

SITE NAME: Aera Belridge CCS Phase I ESA	CLIENT: Stantec
ADDRESS: Aera Belridge CCS Phase I ESA	CONTACT: Emily Medler
CITY/STATE: Lost Hills CA	INQUIRY #: 7133623.8s
ZIP: 93249	DATE: 09/30/22 10:33 AM

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MAP FINDINGS SUMMARY

Database	Search Distance (Miles)	Target Property	< 1/8	1/8 - 1/4	1/4 - 1/2	1/2 - 1	> 1	Total Plotted
STANDARD ENVIRONMENTAL RECORDS								
Lists of Federal NPL (Superfund) sites								
NPL	1.000		0	0	0	0	NR	0
Proposed NPL	1.000		0	0	0	0	NR	0
NPL LIENS	1.000		0	0	0	0	NR	0
Lists of Federal Delisted NPL sites								
Delisted NPL	1.000		0	0	0	0	NR	0
Lists of Federal sites subject to CERCLA removals and CERCLA orders								
FEDERAL FACILITY	0.500		0	0	0	NR	NR	0
SEMS	0.500		0	0	0	NR	NR	0
Lists of Federal CERCLA sites with NFRAP								
SEMS-ARCHIVE	0.500		0	0	0	NR	NR	0
Lists of Federal RCRA facilities undergoing Corrective Action								
CORRACTS	1.000		0	0	0	0	NR	0
Lists of Federal RCRA TSD facilities								
RCRA-TSDF	0.500		0	0	0	NR	NR	0
Lists of Federal RCRA generators								
RCRA-LQG	0.250		0	0	NR	NR	NR	0
RCRA-SQG	0.250		0	0	NR	NR	NR	0
RCRA-VSQG	0.250		0	0	NR	NR	NR	0
Federal institutional controls / engineering controls registries								
LUCIS	0.500		0	0	0	NR	NR	0
US ENG CONTROLS	0.500		0	0	0	NR	NR	0
US INST CONTROLS	0.500		0	0	0	NR	NR	0
Federal ERNS list								
ERNS	TP		NR	NR	NR	NR	NR	0
Lists of state- and tribal (Superfund) equivalent sites								
RESPONSE	1.000		0	0	0	0	NR	0
Lists of state- and tribal hazardous waste facilities								
ENVIROSTOR	1.000		0	0	0	0	NR	0
Lists of state and tribal landfills and solid waste disposal facilities								
SWF/LF	0.500		1	0	0	NR	NR	1

MAP FINDINGS SUMMARY

Database	Search Distance (Miles)	Target Property	< 1/8	1/8 - 1/4	1/4 - 1/2	1/2 - 1	> 1	Total Plotted
Lists of state and tribal leaking storage tanks								
LUST	0.500		0	0	0	NR	NR	0
INDIAN LUST	0.500		0	0	0	NR	NR	0
CPS-SLIC	0.500		0	0	0	NR	NR	0
Lists of state and tribal registered storage tanks								
FEMA UST	0.250		0	0	NR	NR	NR	0
UST	0.250		0	0	NR	NR	NR	0
AST	0.250		0	0	NR	NR	NR	0
INDIAN UST	0.250		0	0	NR	NR	NR	0
Lists of state and tribal voluntary cleanup sites								
INDIAN VCP	0.500		0	0	0	NR	NR	0
VCP	0.500		0	0	0	NR	NR	0
Lists of state and tribal brownfield sites								
BROWNFIELDS	0.500		0	0	0	NR	NR	0
ADDITIONAL ENVIRONMENTAL RECORDS								
Local Brownfield lists								
US BROWNFIELDS	0.500		0	0	0	NR	NR	0
Local Lists of Landfill / Solid Waste Disposal Sites								
WMUDS/SWAT	0.500		0	0	0	NR	NR	0
SWRCY	0.500		0	0	0	NR	NR	0
HAULERS	TP		NR	NR	NR	NR	NR	0
INDIAN ODI	0.500		0	0	0	NR	NR	0
DEBRIS REGION 9	0.500		0	0	0	NR	NR	0
ODI	0.500		0	0	0	NR	NR	0
IHS OPEN DUMPS	0.500		0	0	0	NR	NR	0
Local Lists of Hazardous waste / Contaminated Sites								
US HIST CDL	TP		NR	NR	NR	NR	NR	0
HIST Cal-Sites	1.000		0	0	0	0	NR	0
SCH	0.250		0	0	NR	NR	NR	0
CDL	TP		NR	NR	NR	NR	NR	0
CERS HAZ WASTE	0.250	1	0	0	NR	NR	NR	1
Toxic Pits	1.000		0	0	0	0	NR	0
US CDL	TP		NR	NR	NR	NR	NR	0
PFAS	0.500		0	0	0	NR	NR	0
AQUEOUS FOAM	TP		NR	NR	NR	NR	NR	0
Local Lists of Registered Storage Tanks								
SWEEPS UST	0.250		0	0	NR	NR	NR	0
HIST UST	0.250		0	0	NR	NR	NR	0
CA FID UST	0.250		0	0	NR	NR	NR	0

MAP FINDINGS SUMMARY

Database	Search Distance (Miles)	Target Property	< 1/8	1/8 - 1/4	1/4 - 1/2	1/2 - 1	> 1	Total Plotted
CERS TANKS	0.250		0	0	NR	NR	NR	0
Local Land Records								
LIENS	TP		NR	NR	NR	NR	NR	0
LIENS 2	TP		NR	NR	NR	NR	NR	0
DEED	0.500		0	0	0	NR	NR	0
Records of Emergency Release Reports								
HMIRS	TP		NR	NR	NR	NR	NR	0
CHMIRS	TP	1	NR	NR	NR	NR	NR	1
LDS	TP		NR	NR	NR	NR	NR	0
MCS	TP		NR	NR	NR	NR	NR	0
SPILLS 90	TP		NR	NR	NR	NR	NR	0
Other Ascertainable Records								
RCRA NonGen / NLR	0.250		2	0	NR	NR	NR	2
FUDS	1.000		0	0	0	0	NR	0
DOD	1.000		0	0	0	0	NR	0
SCRD DRYCLEANERS	0.500		0	0	0	NR	NR	0
US FIN ASSUR	TP		NR	NR	NR	NR	NR	0
EPA WATCH LIST	TP		NR	NR	NR	NR	NR	0
2020 COR ACTION	0.250		0	0	NR	NR	NR	0
TSCA	TP		NR	NR	NR	NR	NR	0
TRIS	TP		NR	NR	NR	NR	NR	0
SSTS	TP		NR	NR	NR	NR	NR	0
ROD	1.000		0	0	0	0	NR	0
RMP	TP		NR	NR	NR	NR	NR	0
RAATS	TP		NR	NR	NR	NR	NR	0
PRP	TP		NR	NR	NR	NR	NR	0
PADS	TP		NR	NR	NR	NR	NR	0
ICIS	TP		NR	NR	NR	NR	NR	0
FTTS	TP		NR	NR	NR	NR	NR	0
MLTS	TP		NR	NR	NR	NR	NR	0
COAL ASH DOE	TP		NR	NR	NR	NR	NR	0
COAL ASH EPA	0.500		0	0	0	NR	NR	0
PCB TRANSFORMER	TP		NR	NR	NR	NR	NR	0
RADINFO	TP		NR	NR	NR	NR	NR	0
HIST FTTS	TP		NR	NR	NR	NR	NR	0
DOT OPS	TP		NR	NR	NR	NR	NR	0
CONSENT	1.000		0	0	0	0	NR	0
INDIAN RESERV	1.000		0	0	0	0	NR	0
FUSRAP	1.000		0	0	0	0	NR	0
UMTRA	0.500		0	0	0	NR	NR	0
LEAD SMELTERS	TP		NR	NR	NR	NR	NR	0
US AIRS	TP		NR	NR	NR	NR	NR	0
US MINES	0.250		0	0	NR	NR	NR	0
ABANDONED MINES	0.250		0	0	NR	NR	NR	0
FINDS	TP	1	NR	NR	NR	NR	NR	1
DOCKET HWC	TP		NR	NR	NR	NR	NR	0
UXO	1.000		0	0	0	0	NR	0
ECHO	TP		NR	NR	NR	NR	NR	0

MAP FINDINGS SUMMARY

Database	Search Distance (Miles)	Target Property	< 1/8	1/8 - 1/4	1/4 - 1/2	1/2 - 1	> 1	Total Plotted
FUELS PROGRAM	0.250		0	0	NR	NR	NR	0
CA BOND EXP. PLAN	1.000		0	0	0	0	NR	0
Cortese	0.500		1	0	0	NR	NR	1
CUPA Listings	0.250	1	1	0	NR	NR	NR	2
DRYCLEANERS	0.250		0	0	NR	NR	NR	0
EMI	TP	2	NR	NR	NR	NR	NR	2
ENF	TP		NR	NR	NR	NR	NR	0
Financial Assurance	TP		NR	NR	NR	NR	NR	0
HAZNET	TP		NR	NR	NR	NR	NR	0
ICE	TP		NR	NR	NR	NR	NR	0
HIST CORTESE	0.500		0	0	0	NR	NR	0
HWP	1.000		0	0	0	0	NR	0
HWT	0.250		0	0	NR	NR	NR	0
MINES	0.250		0	0	NR	NR	NR	0
MWMP	0.250		0	0	NR	NR	NR	0
NPDES	TP		NR	NR	NR	NR	NR	0
PEST LIC	TP		NR	NR	NR	NR	NR	0
PROC	0.500		0	0	0	NR	NR	0
Notify 65	1.000		0	0	0	0	NR	0
UIC	TP	119	NR	NR	NR	NR	NR	119
UIC GEO	TP		NR	NR	NR	NR	NR	0
WASTEWATER PITS	0.500		18	8	15	NR	NR	41
WDS	TP		NR	NR	NR	NR	NR	0
WIP	0.250		0	0	NR	NR	NR	0
MILITARY PRIV SITES	TP		NR	NR	NR	NR	NR	0
PROJECT	TP		NR	NR	NR	NR	NR	0
WDR	TP		NR	NR	NR	NR	NR	0
CIWQS	TP		NR	NR	NR	NR	NR	0
CERS	TP	2	NR	NR	NR	NR	NR	2
NON-CASE INFO	TP		NR	NR	NR	NR	NR	0
OTHER OIL GAS	TP		NR	NR	NR	NR	NR	0
PROD WATER PONDS	TP		NR	NR	NR	NR	NR	0
SAMPLING POINT	TP		NR	NR	NR	NR	NR	0
WELL STIM PROJ	TP		NR	NR	NR	NR	NR	0
HWTS	TP		NR	NR	NR	NR	NR	0
MINES MRDS	TP		NR	NR	NR	NR	NR	0
EDR HIGH RISK HISTORICAL RECORDS								
EDR Exclusive Records								
EDR MGP	1.000		0	0	0	0	NR	0
EDR Hist Auto	0.125		0	NR	NR	NR	NR	0
EDR Hist Cleaner	0.125		0	NR	NR	NR	NR	0
EDR RECOVERED GOVERNMENT ARCHIVES								
Exclusive Recovered Govt. Archives								
RGA LF	TP		NR	NR	NR	NR	NR	0
RGA LUST	TP		NR	NR	NR	NR	NR	0
- Totals --		127	23	8	15	0	0	173

MAP FINDINGS SUMMARY

Database	Search Distance (Miles)	Target Property	< 1/8	1/8 - 1/4	1/4 - 1/2	1/2 - 1	> 1	Total Plotted

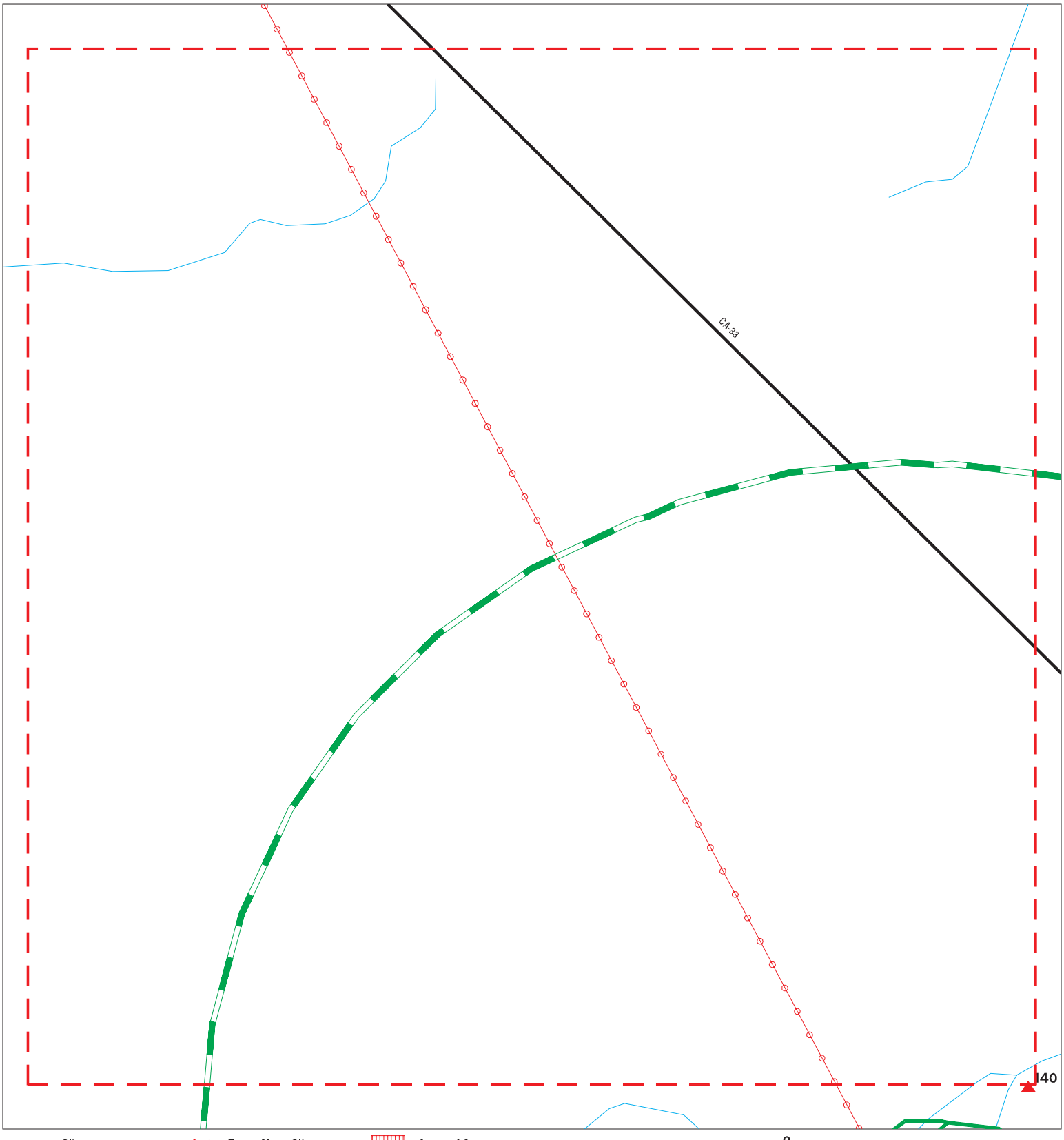
NOTES:

TP = Target Property

NR = Not Requested at this Search Distance

Sites may be listed in more than one database

Focus Map - 1 - 7133623.8s



Sites
Target Property
Search Buffer
Focus Map - No Sites
Focus Map - Sites
Power Line
Pipe Line
National Priority List Sites
Areas of Concern
Dept. Defense Sites
Indian Reservations BIA

0 1/8 1/4 Miles

SITE NAME: Aera Belridge CCS Phase I ESA ADDRESS: Aera Belridge CCS Phase I ESA CITY/STATE: Lost Hills CA ZIP: 93249	CLIENT: Stantec CONTACT: Emily Medler INQUIRY #: 7133623.8s DATE: 09/30/22

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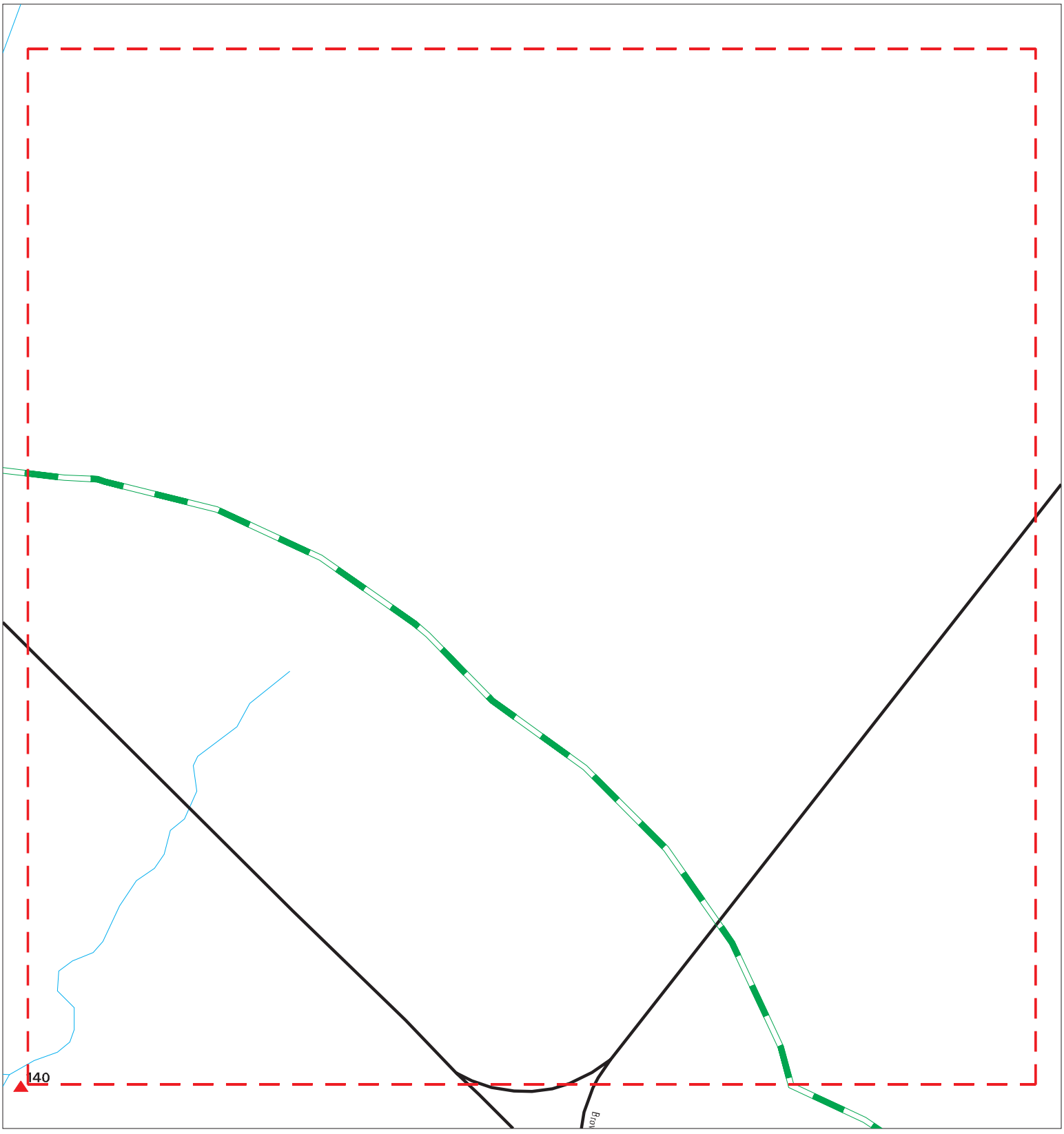
MAPPED SITES SUMMARY - FOCUS MAP 1

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION

NO MAPPED SITES FOUND

Focus Map - 2 - 7133623.8s



Sites
Target Property
Search Buffer
Focus Map - No Sites
Focus Map - Sites
Power Line
Pipe Line
National Priority List Sites
Areas of Concern
Dept. Defense Sites
Indian Reservations BIA

0 1/8 1/4 Miles

SITE NAME: Aera Belridge CCS Phase I ESA ADDRESS: Aera Belridge CCS Phase I ESA CITY/STATE: Lost Hills CA ZIP: 93249	CLIENT: Stantec CONTACT: Emily Medler INQUIRY #: 7133623.8s DATE: 09/30/22

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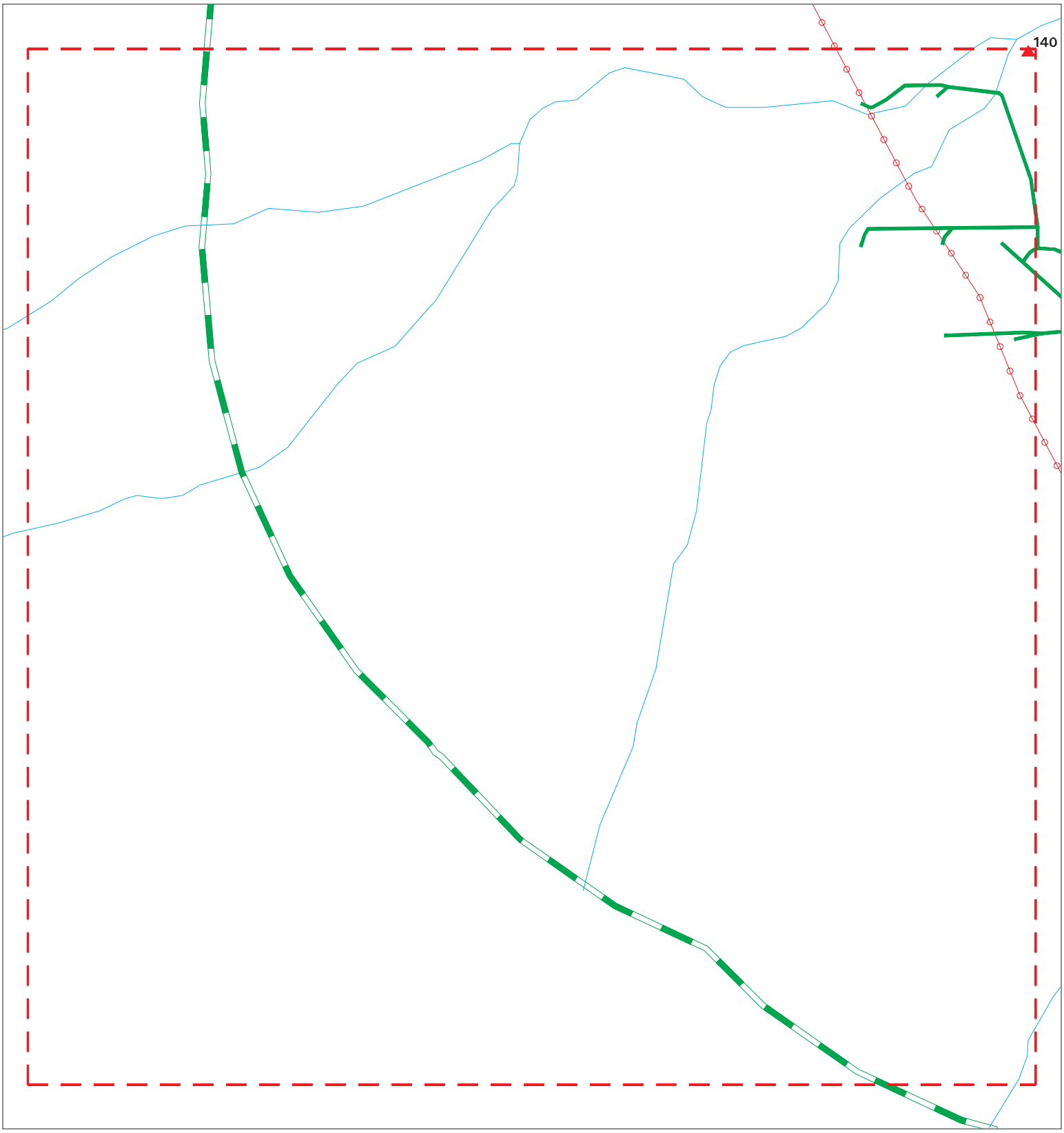
MAPPED SITES SUMMARY - FOCUS MAP 2

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION

NO MAPPED SITES FOUND

Focus Map - 3 - 7133623.8s



Sites
Target Property
Search Buffer
Focus Map - No Sites
Focus Map - Sites
Power Line
Pipe Line
National Priority List Sites
Areas of Concern
Dept. Defense Sites
Indian Reservations BIA

0 1/8 1/4 Miles

SITE NAME: Aera Belridge CCS Phase I ESA ADDRESS: Aera Belridge CCS Phase I ESA CITY/STATE: Lost Hills CA ZIP: 93249	CLIENT: Stantec CONTACT: Emily Medler INQUIRY #: 7133623.8s DATE: 09/30/22

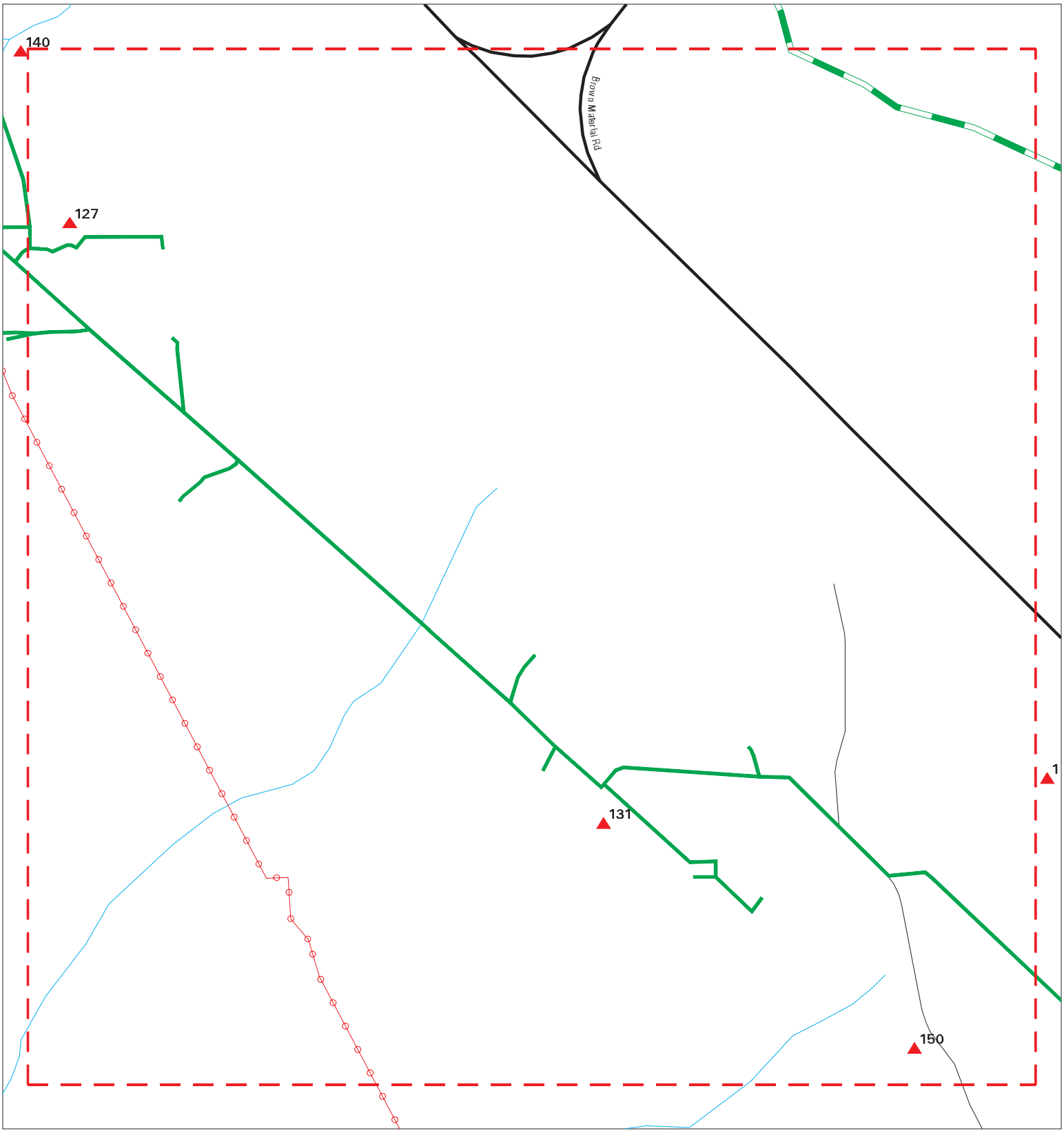
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MAPPED SITES SUMMARY - FOCUS MAP 3

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION
140 / 3			WASTEWATER PITS	412 0.078 NE

Focus Map - 4 - 7133623.8s



Sites
Target Property
Search Buffer
Focus Map - No Sites
Focus Map - Sites
Power Line
Pipe Line
National Priority List Sites
Areas of Concern
Dept. Defense Sites
Indian Reservations BIA

0 1/8 1/4 Miles

SITE NAME: Aera Belridge CCS Phase I ESA	CLIENT: Stantec
ADDRESS: Aera Belridge CCS Phase I ESA	CONTACT: Emily Medler
CITY/STATE: Lost Hills CA	INQUIRY #: 7133623.8s
ZIP: 93249	DATE: 09/30/22

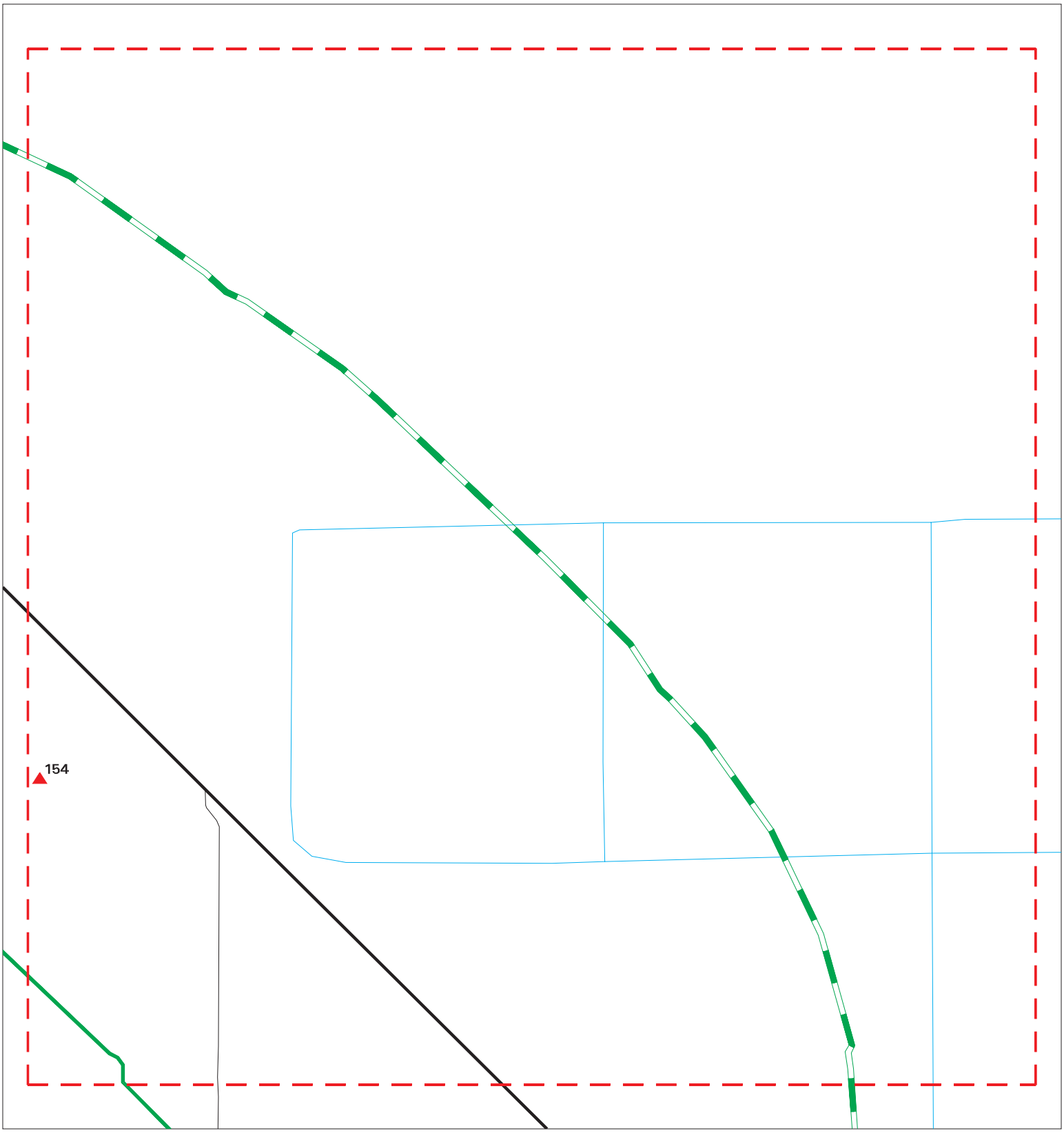
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MAPPED SITES SUMMARY - FOCUS MAP 4

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION
127 / 4			WASTEWATER PITS	169 0.032 NW
131 / 4			WASTEWATER PITS	232 0.044 SW
150 / 4			WASTEWATER PITS	1057 0.200 NW

Focus Map - 5 - 7133623.8s



Sites
Target Property
Search Buffer
Focus Map - No Sites
Focus Map - Sites
Power Line
Pipe Line
National Priority List Sites
Areas of Concern
Dept. Defense Sites
Indian Reservations BIA

0 1/8 1/4 Miles

SITE NAME: Aera Belridge CCS Phase I ESA ADDRESS: Aera Belridge CCS Phase I ESA CITY/STATE: Lost Hills CA ZIP: 93249	CLIENT: Stantec CONTACT: Emily Medler INQUIRY #: 7133623.8s DATE: 09/30/22

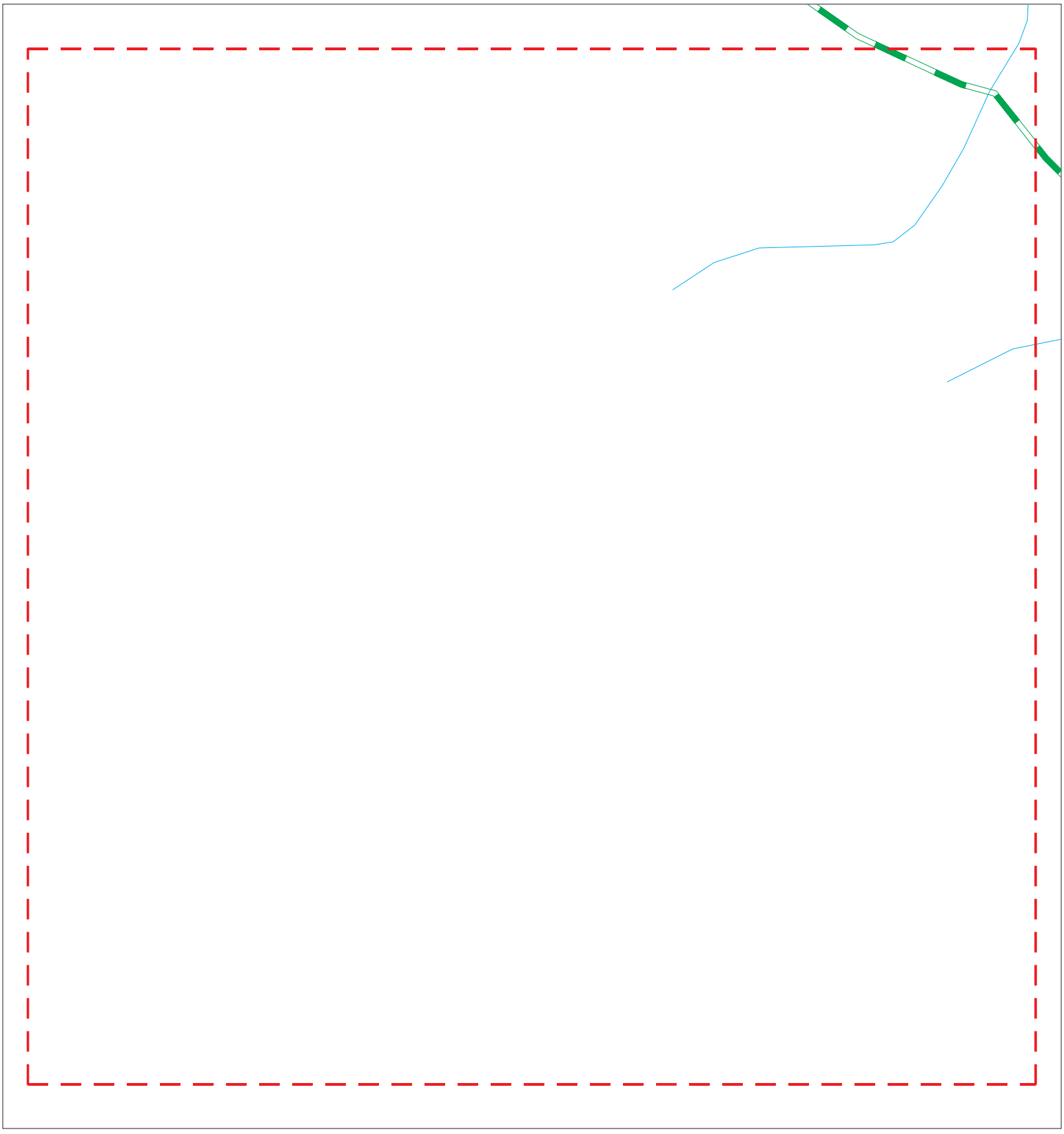
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MAPPED SITES SUMMARY - FOCUS MAP 5

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION
154 / 5			WASTEWATER PITS	1218 0.231 NE

Focus Map - 6 - 7133623.8s



Sites
Target Property
Search Buffer
Focus Map - No Sites
Focus Map - Sites
Power Line
Pipe Line
National Priority List Sites
Areas of Concern
Dept. Defense Sites
Indian Reservations BIA

0 1/8 1/4 Miles

SITE NAME: Aera Belridge CCS Phase I ESA	CLIENT: Stantec
ADDRESS: Aera Belridge CCS Phase I ESA	CONTACT: Emily Medler
CITY/STATE: Lost Hills CA	INQUIRY #: 7133623.8s
ZIP: 93249	DATE: 09/30/22

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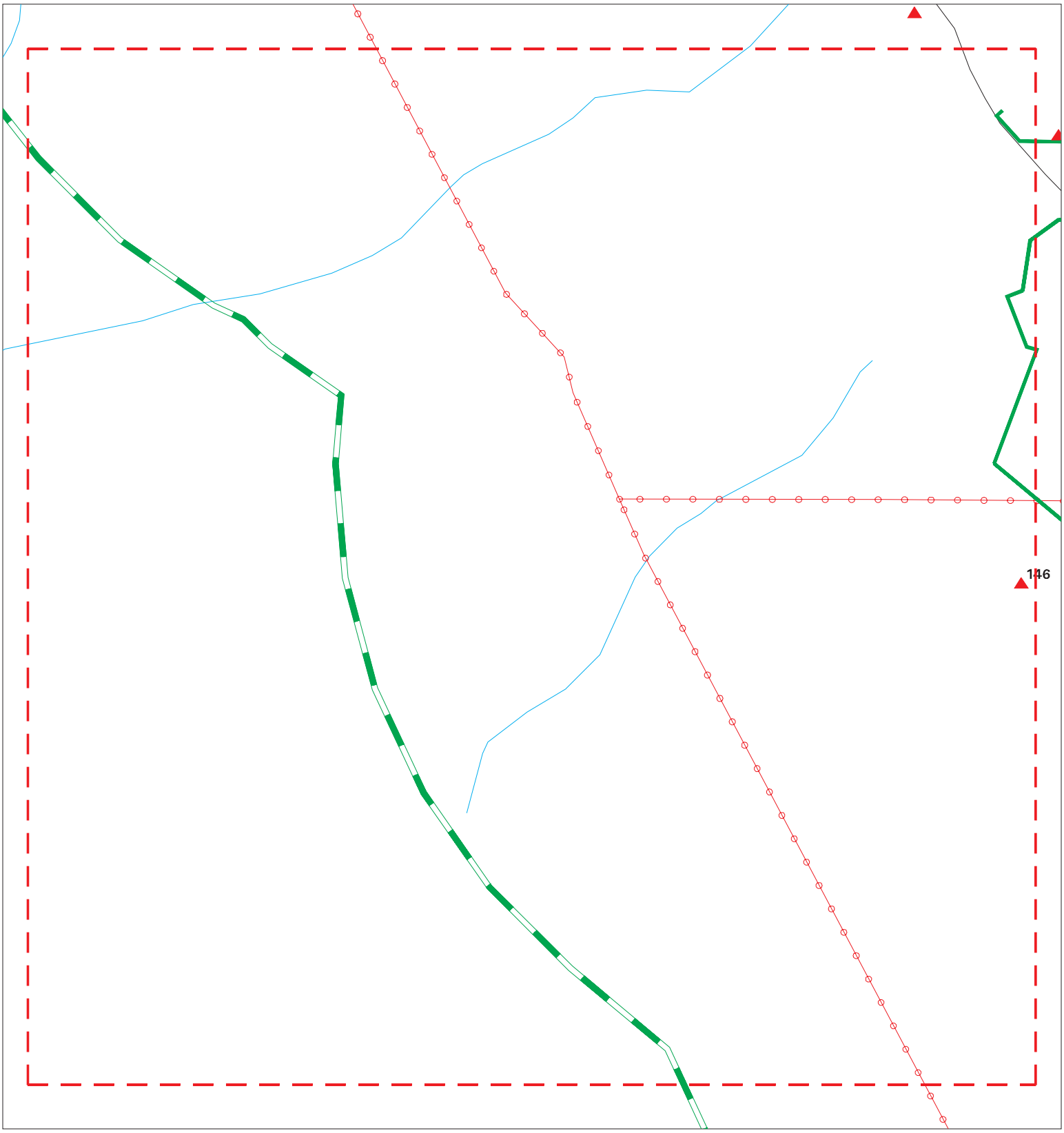
MAPPED SITES SUMMARY - FOCUS MAP 6

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION

NO MAPPED SITES FOUND

Focus Map - 7 - 7133623.8s



Sites
Target Property
Search Buffer
Focus Map - No Sites
Focus Map - Sites
Power Line
Pipe Line
National Priority List Sites
Areas of Concern
Dept. Defense Sites
Indian Reservations BIA

0 1/8 1/4 Miles

SITE NAME: Aera Belridge CCS Phase I ESA ADDRESS: Aera Belridge CCS Phase I ESA CITY/STATE: Lost Hills CA ZIP: 93249	CLIENT: Stantec CONTACT: Emily Medler INQUIRY #: 7133623.8s DATE: 09/30/22

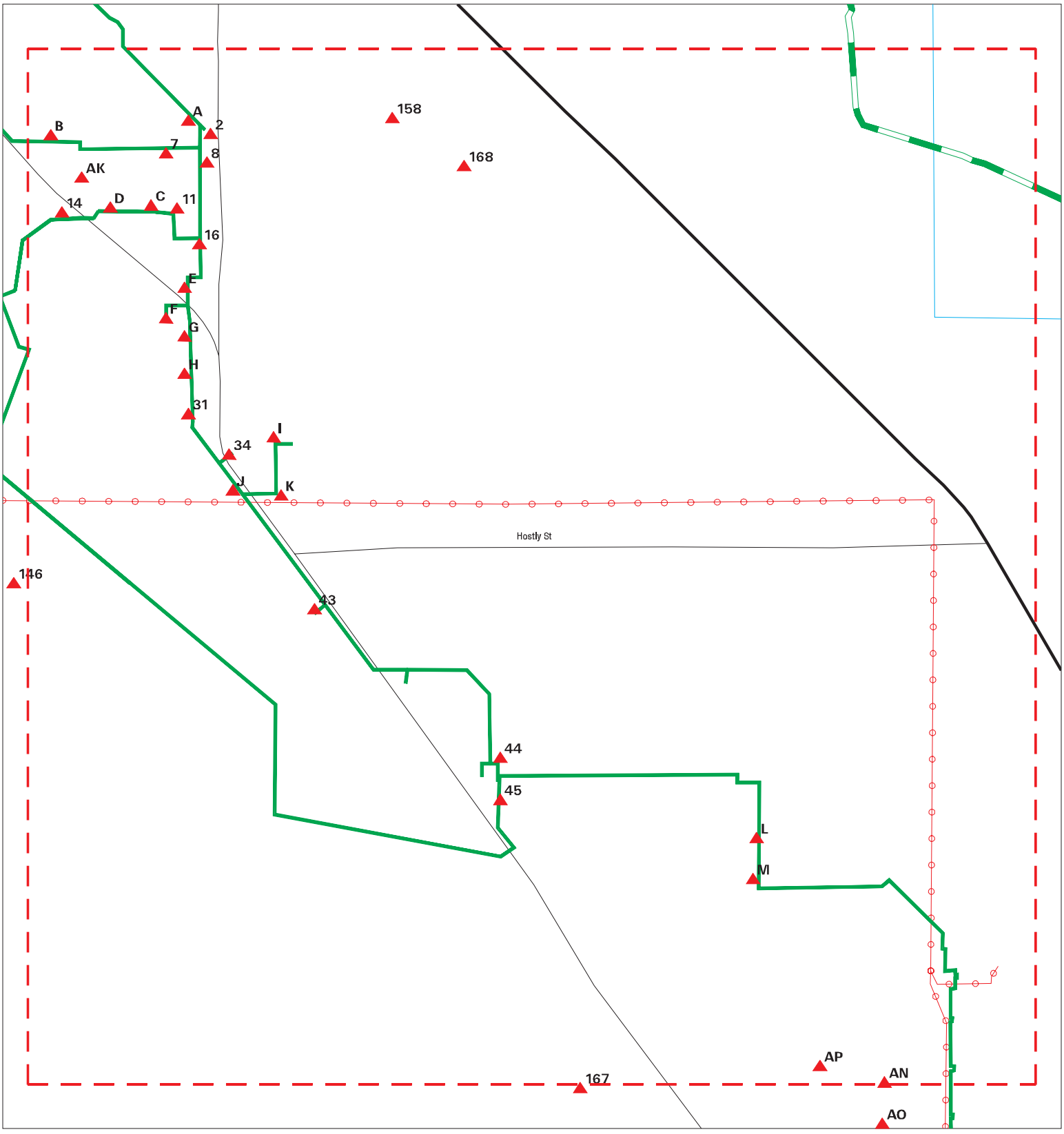
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MAPPED SITES SUMMARY - FOCUS MAP 7

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION
146 / 7	NORTH BELRIDGE LANDF	1 MI NE BELRIDGE OIL	SWF/LF, Financial Assurance, CERS	593 0.112 SW

Focus Map - 8 - 7133623.8s



Sites
Target Property
Search Buffer
Focus Map - No Sites
Focus Map - Sites
Power Line
Pipe Line
National Priority List Sites
Areas of Concern
Dept. Defense Sites
Indian Reservations BIA

SITE NAME: Aera Belridge CCS Phase I ESA	CLIENT: Stantec
ADDRESS: Aera Belridge CCS Phase I ESA	CONTACT: Emily Medler
CITY/STATE: Lost Hills CA	INQUIRY #: 7133623.8s
ZIP: 93249	DATE: 09/30/22

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MAPPED SITES SUMMARY - FOCUS MAP 8

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

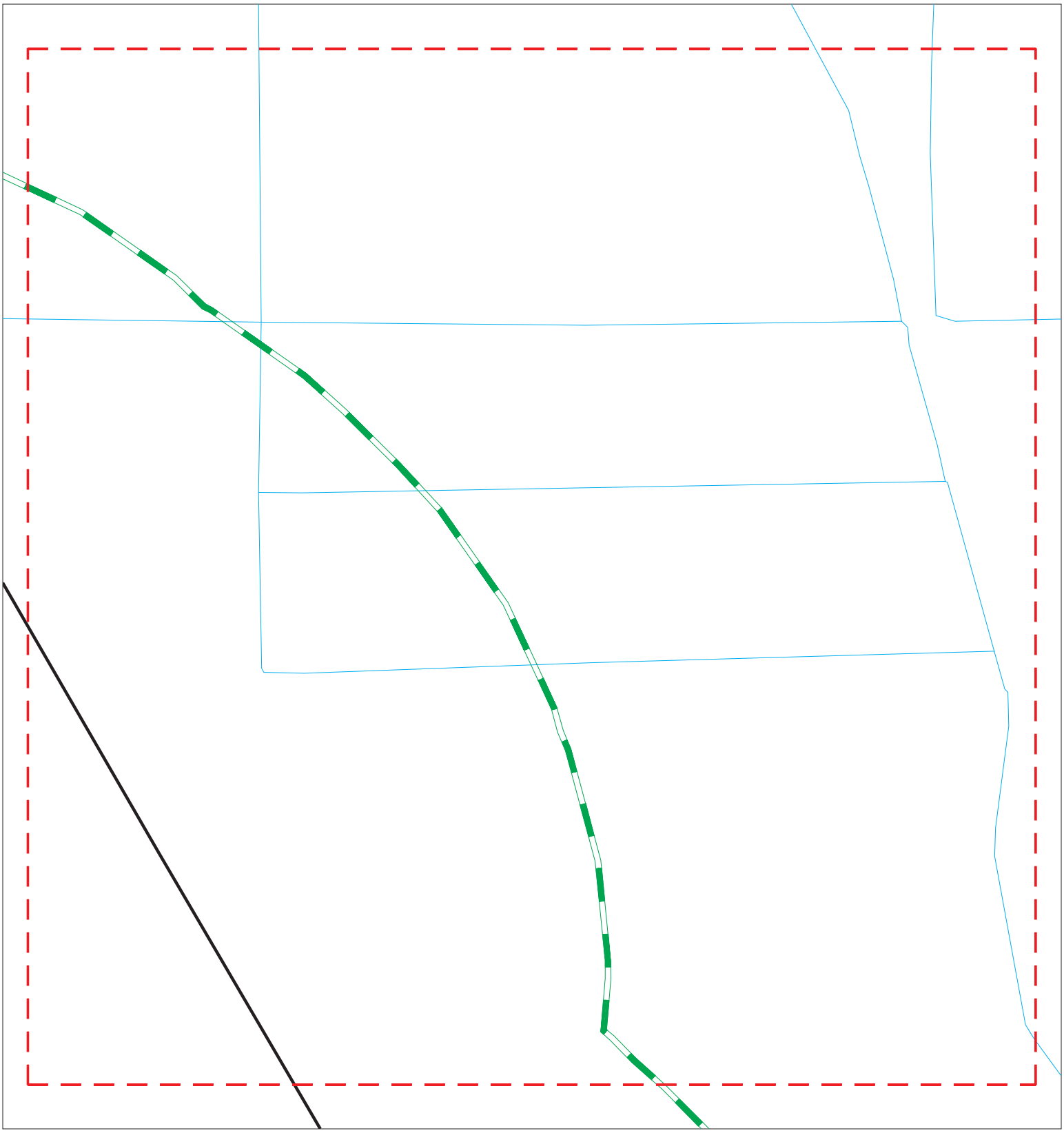
MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION
A1 / 8	AERA ENERGY LLC		UIC	TP
2 / 8	AERA ENERGY LLC		UIC	TP
B3 / 8	AERA ENERGY LLC		UIC	TP
B4 / 8	AERA ENERGY LLC		UIC	TP
B5 / 8	AERA ENERGY LLC		UIC	TP
A6 / 8	AERA ENERGY LLC		UIC	TP
7 / 8	AERA ENERGY LLC		UIC	TP
8 / 8	AERA ENERGY LLC		UIC	TP
C9 / 8	AERA ENERGY LLC		UIC	TP
D10 / 8	AERA ENERGY LLC		UIC	TP
11 / 8	AERA ENERGY LLC		UIC	TP
D12 / 8	AERA ENERGY LLC		UIC	TP
D13 / 8	AERA ENERGY LLC		UIC	TP
14 / 8	AERA ENERGY LLC		UIC	TP
C15 / 8	AERA ENERGY LLC		UIC	TP
16 / 8	AERA ENERGY LLC		UIC	TP
E17 / 8	AERA ENERGY LLC		UIC	TP
E18 / 8	AERA ENERGY LLC		UIC	TP
E19 / 8	AERA ENERGY LLC		UIC	TP
E20 / 8	AERA ENERGY LLC		UIC	TP
F21 / 8	AERA ENERGY LLC		UIC	TP
F22 / 8	AERA ENERGY LLC		UIC	TP
F23 / 8	AERA ENERGY LLC		UIC	TP
F24 / 8	AERA ENERGY LLC		UIC	TP
F25 / 8	AERA ENERGY LLC		UIC	TP
F26 / 8	AERA ENERGY LLC		UIC	TP
G27 / 8	AERA ENERGY LLC		UIC	TP
G28 / 8	AERA ENERGY LLC		UIC	TP
H29 / 8	AERA ENERGY LLC		UIC	TP
H30 / 8	AERA ENERGY LLC		UIC	TP
31 / 8	AERA ENERGY LLC		UIC	TP
I32 / 8	AERA ENERGY LLC		UIC	TP
I33 / 8	AERA ENERGY LLC		UIC	TP
34 / 8	AERA ENERGY LLC		UIC	TP
J35 / 8	AERA ENERGY LLC		UIC	TP
K36 / 8	AERA ENERGY LLC		UIC	TP
J37 / 8	UNOCAL CALIFORNIA PI	17251 POLE LINE ROAD	EMI	TP
J38 / 8	PHILLIPS 66 - MIDDLE	17251 POLE LINE RD	FINDS	TP
J39 / 8	AERA ENERGY LLC		UIC	TP

MAPPED SITES SUMMARY - FOCUS MAP 8

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION
K40 / 8	AERA ENERGY LLC		UIC	TP
J41 / 8	PHILLIPS 66 - MIDDLE	17251 POLE LINE RD	CERS HAZ WASTE, CUPA Listings, CERS	TP
J42 / 8	PHILLIPS 66 PIPELINE	17251 POLE LINE RD	CHMIRS, EMI, CERS	TP
43 / 8	AERA ENERGY LLC		UIC	TP
44 / 8	AERA ENERGY LLC		UIC	TP
45 / 8	AERA ENERGY LLC		UIC	TP
L46 / 8	AERA ENERGY LLC		UIC	TP
L47 / 8	AERA ENERGY LLC		UIC	TP
M48 / 8	AERA ENERGY LLC		UIC	TP
M49 / 8	AERA ENERGY LLC		UIC	TP
C124 / 8			WASTEWATER PITS	76 0.014 South
AK129 / 8			WASTEWATER PITS	222 0.042 South
AK130 / 8	NORTH BELRIDGE OIL F	NORTH BELRIDGE OIL F	Cortese, ENF, CERS	222 0.042 South
AN142 / 8			WASTEWATER PITS	530 0.100 West
AP149 / 8			WASTEWATER PITS	1047 0.198 West
AP152 / 8			WASTEWATER PITS	1077 0.204 West
158 / 8			WASTEWATER PITS	1507 0.285 East
168 / 8			WASTEWATER PITS	2098 0.397 East

Focus Map - 9 - 7133623.8s



Sites
Target Property
Search Buffer
Focus Map - No Sites
Focus Map - Sites
Power Line
Pipe Line
National Priority List Sites
Areas of Concern
Dept. Defense Sites
Indian Reservations BIA

0 1/8 1/4 Miles

SITE NAME: Aera Belridge CCS Phase I ESA	CLIENT: Stantec
ADDRESS: Aera Belridge CCS Phase I ESA	CONTACT: Emily Medler
CITY/STATE: Lost Hills CA	INQUIRY #: 7133623.8s
ZIP: 93249	DATE: 09/30/22

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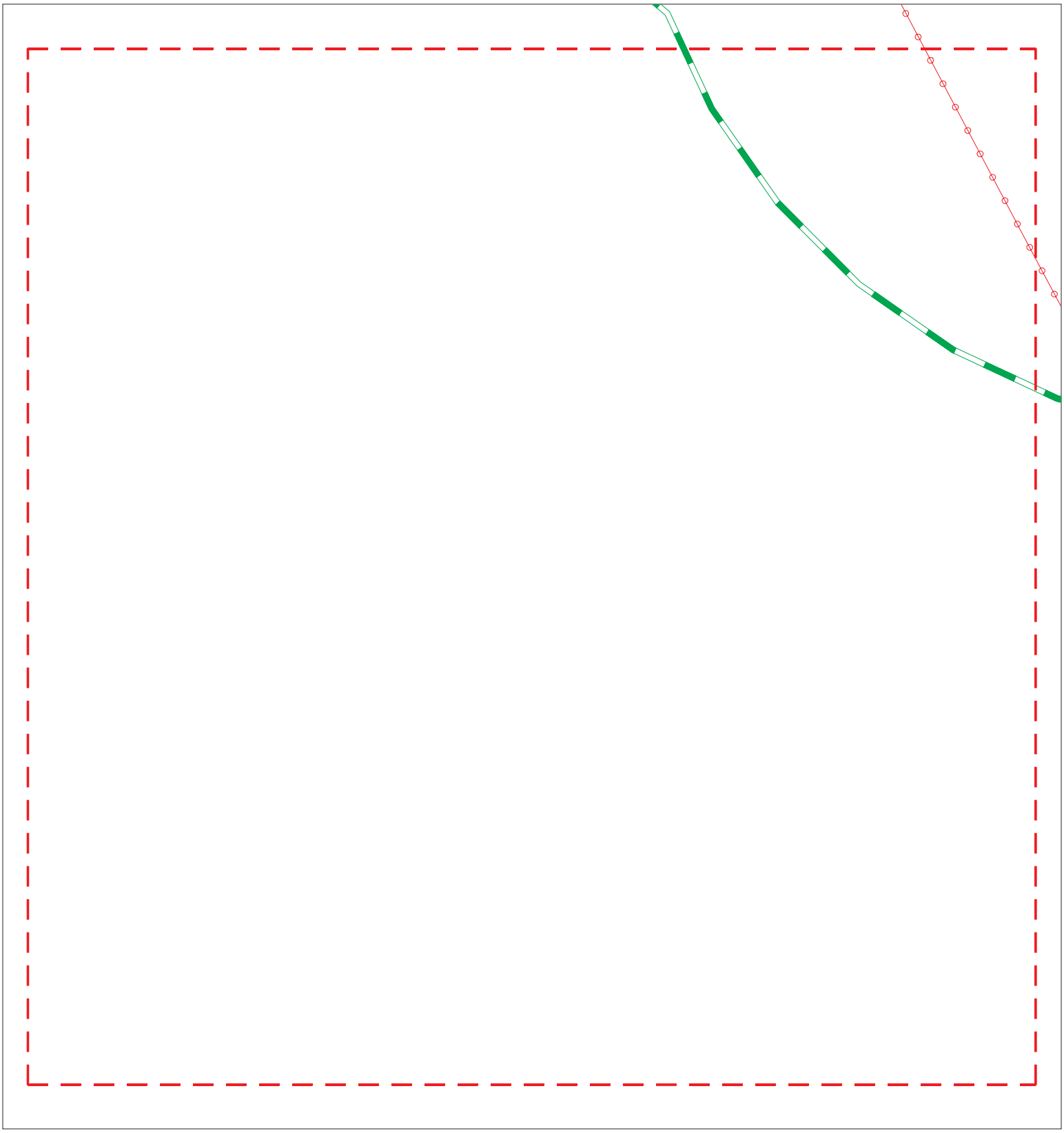
MAPPED SITES SUMMARY - FOCUS MAP 9

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION

NO MAPPED SITES FOUND

Focus Map - 10 - 7133623.8s



Sites
Target Property
Search Buffer
Focus Map - No Sites
Focus Map - Sites
Power Line
Pipe Line
National Priority List Sites
Areas of Concern
Dept. Defense Sites
Indian Reservations BIA

0 1/8 1/4 Miles

SITE NAME: Aera Belridge CCS Phase I ESA	CLIENT: Stantec
ADDRESS: Aera Belridge CCS Phase I ESA	CONTACT: Emily Medler
CITY/STATE: Lost Hills CA	INQUIRY #: 7133623.8s
ZIP: 93249	DATE: 09/30/22

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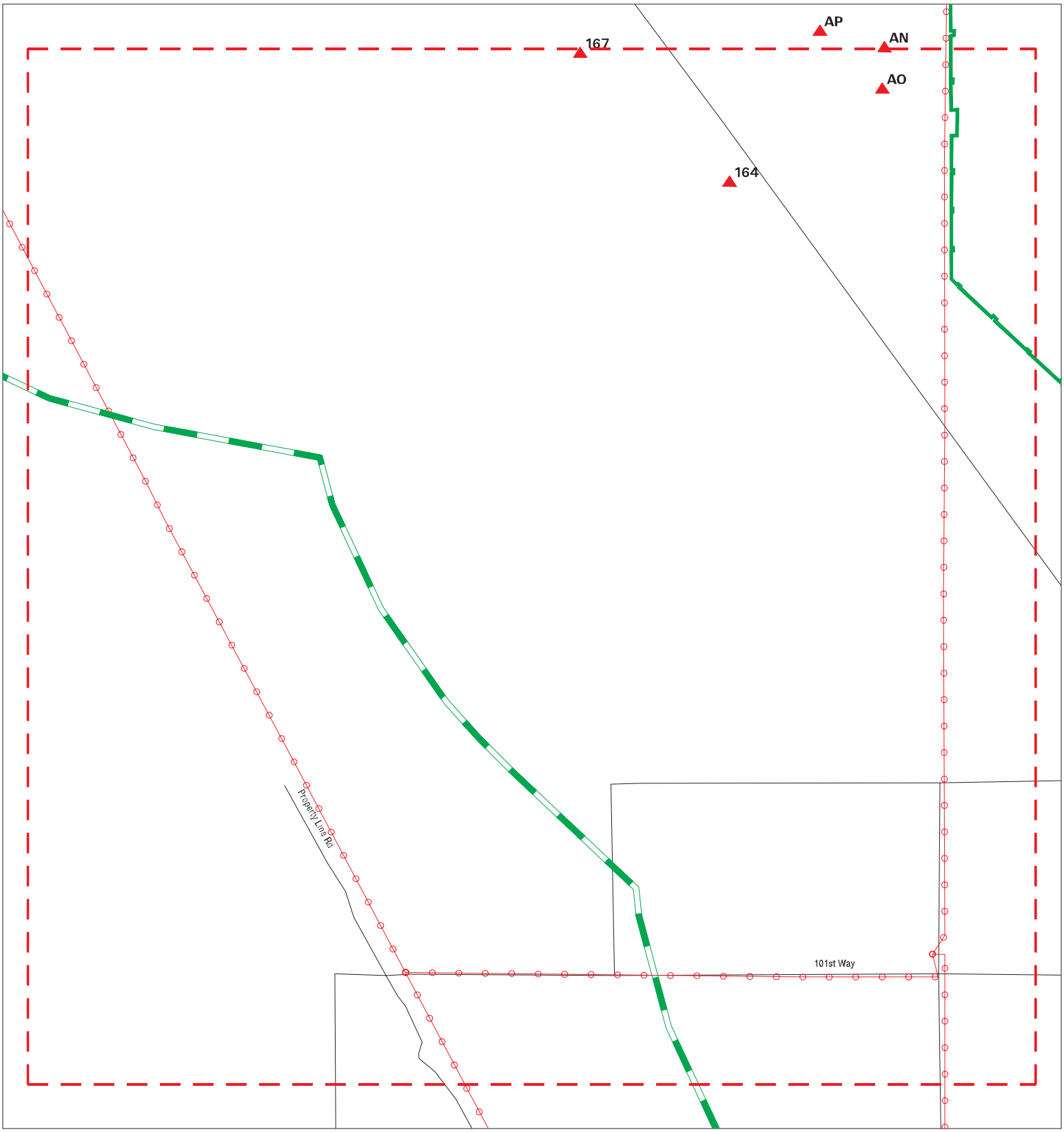
MAPPED SITES SUMMARY - FOCUS MAP 10

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION

NO MAPPED SITES FOUND

Focus Map - 11 - 7133623.8s



Sites
Target Property
Search Buffer
Focus Map - No Sites
Focus Map - Sites
Power Line
Pipe Line
National Priority List Sites
Areas of Concern
Dept. Defense Sites
Indian Reservations BIA

0 1/8 1/4 Miles

SITE NAME: Aera Belridge CCS Phase I ESA	CLIENT: Stantec
ADDRESS: Aera Belridge CCS Phase I ESA	CONTACT: Emily Medler
CITY/STATE: Lost Hills CA	INQUIRY #: 7133623.8s
ZIP: 93249	DATE: 09/30/22

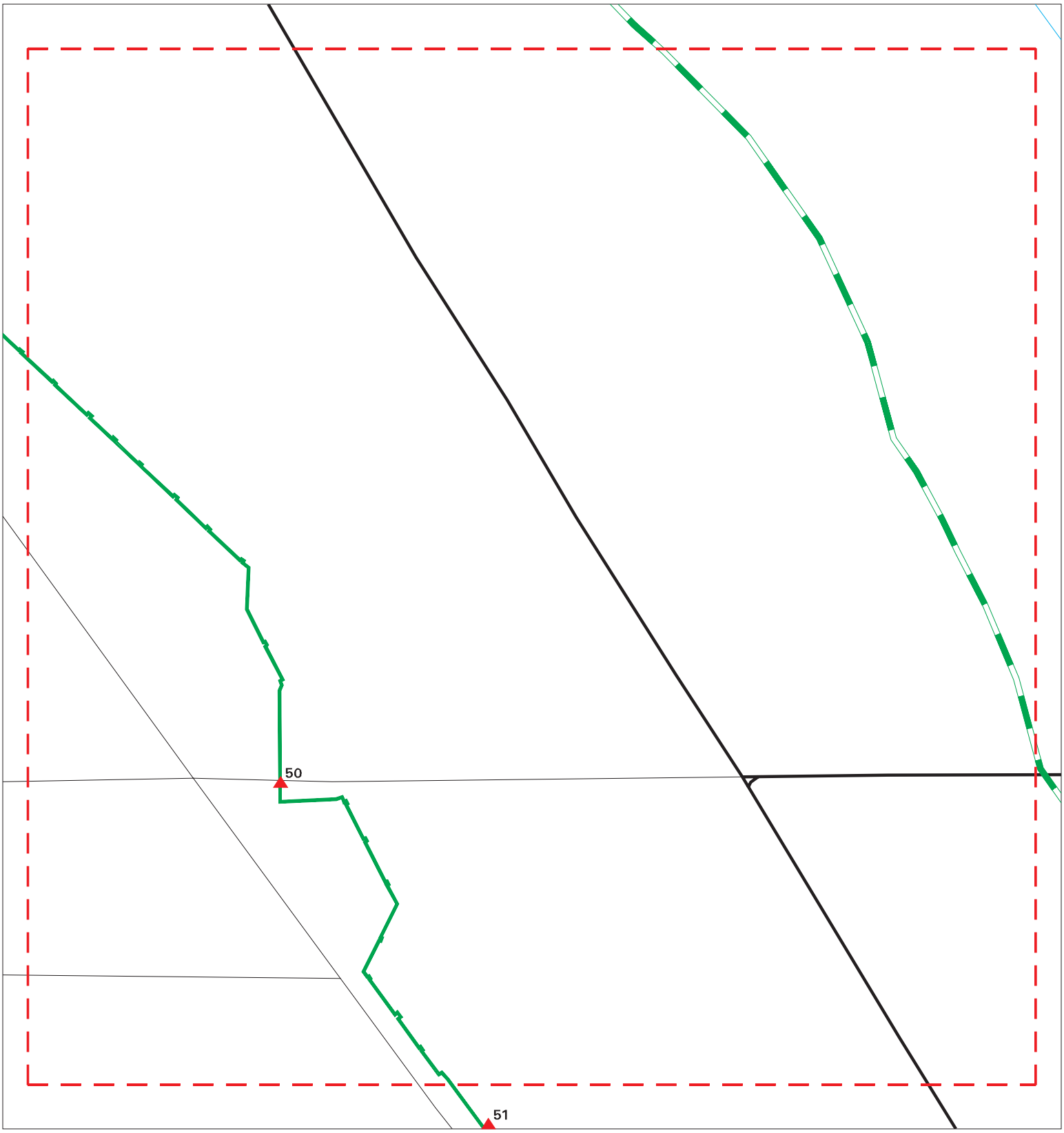
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MAPPED SITES SUMMARY - FOCUS MAP 11

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION
AN143 / 11			WASTEWATER PITS	546 0.103 West
AO144 / 11			WASTEWATER PITS	548 0.104 West
AO145 / 11			WASTEWATER PITS	562 0.106 West
164 / 11			WASTEWATER PITS	1778 0.337 West
167 / 11			WASTEWATER PITS	1957 0.371 SSE

Focus Map - 12 - 7133623.8s



Sites
Target Property
Search Buffer
Focus Map - No Sites
Focus Map - Sites
Power Line
Pipe Line
National Priority List Sites
Areas of Concern
Dept. Defense Sites
Indian Reservations BIA

0 1/8 1/4 Miles

SITE NAME: Aera Belridge CCS Phase I ESA	CLIENT: Stantec
ADDRESS: Aera Belridge CCS Phase I ESA	CONTACT: Emily Medler
CITY/STATE: Lost Hills CA	INQUIRY #: 7133623.8s
ZIP: 93249	DATE: 09/30/22

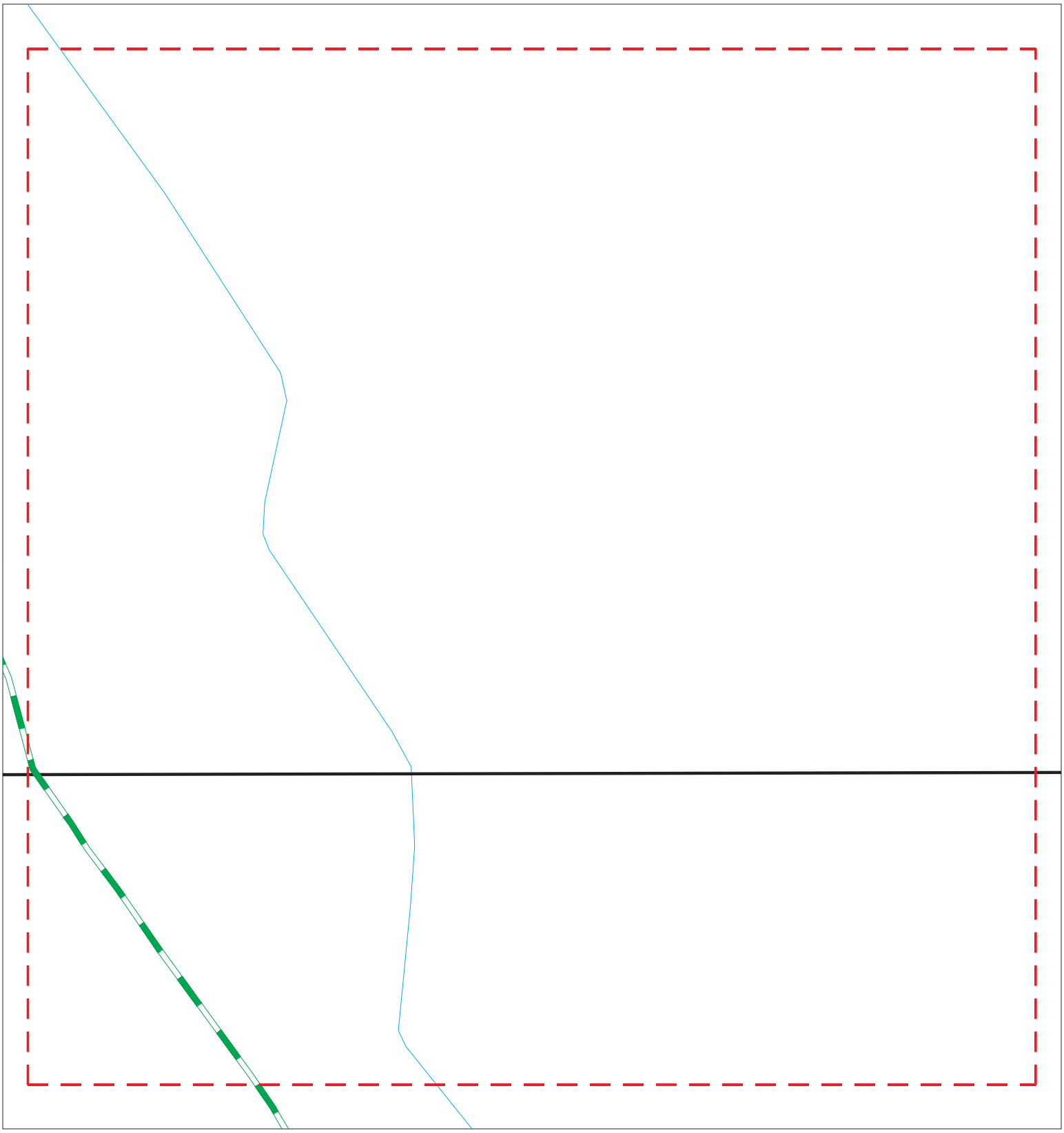
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MAPPED SITES SUMMARY - FOCUS MAP 12

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION
50 / 12	AERA ENERGY LLC		UIC	TP

Focus Map - 13 - 7133623.8s



Sites
Target Property
Search Buffer
Focus Map - No Sites
Focus Map - Sites
Power Line
Pipe Line
National Priority List Sites
Areas of Concern
Dept. Defense Sites
Indian Reservations BIA

0 1/8 1/4 Miles

SITE NAME: Aera Belridge CCS Phase I ESA	CLIENT: Stantec
ADDRESS: Aera Belridge CCS Phase I ESA	CONTACT: Emily Medler
CITY/STATE: Lost Hills CA	INQUIRY #: 7133623.8s
ZIP: 93249	DATE: 09/30/22

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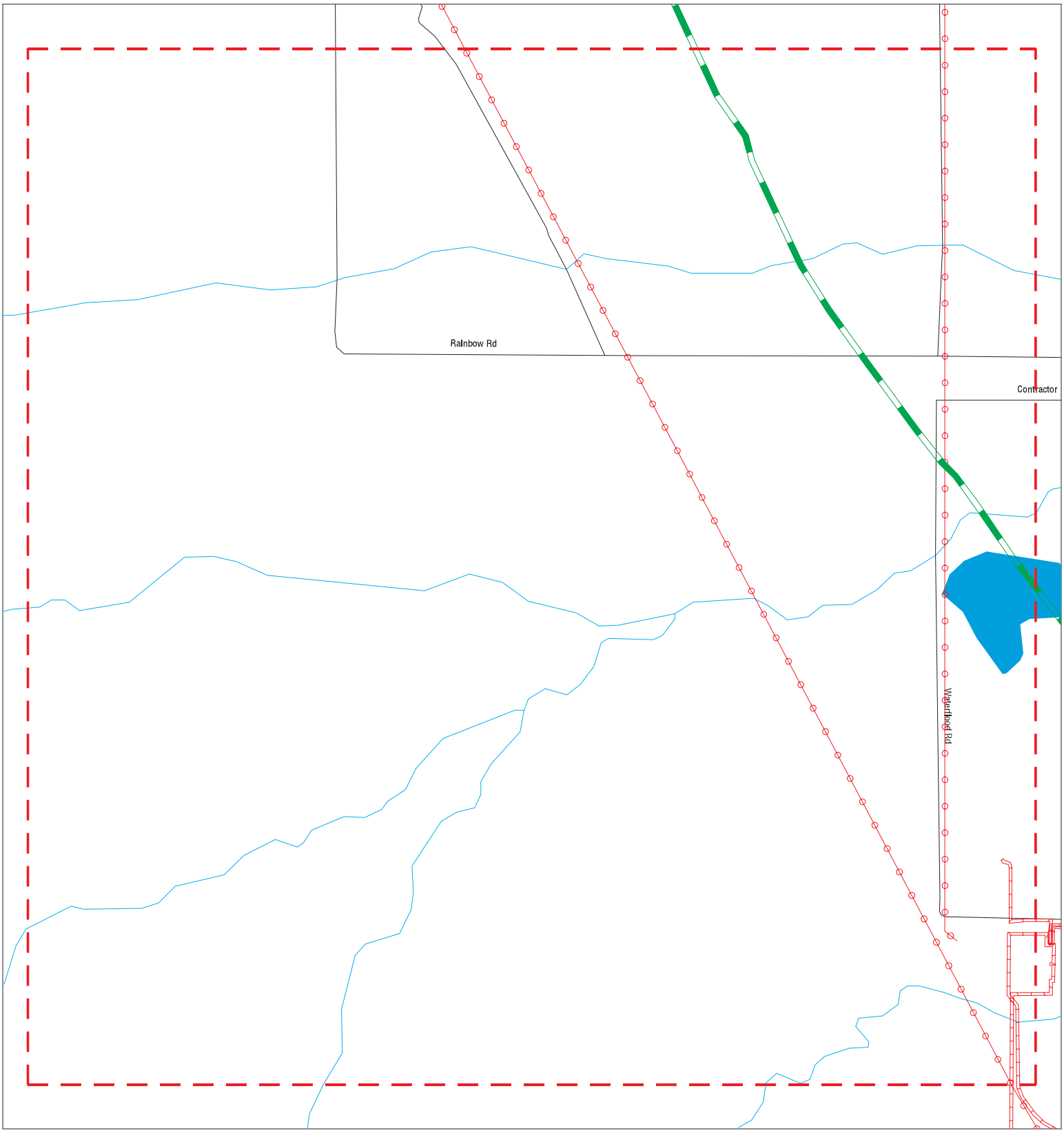
MAPPED SITES SUMMARY - FOCUS MAP 13

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION

NO MAPPED SITES FOUND

Focus Map - 14 - 7133623.8s



Sites
Target Property
Search Buffer
Focus Map - No Sites
Focus Map - Sites
Power Line
Pipe Line
National Priority List Sites
Areas of Concern
Dept. Defense Sites
Indian Reservations BIA

0 1/8 1/4 Miles

SITE NAME: Aera Belridge CCS Phase I ESA	CLIENT: Stantec
ADDRESS: Aera Belridge CCS Phase I ESA	CONTACT: Emily Medler
CITY/STATE: Lost Hills CA	INQUIRY #: 7133623.8s
ZIP: 93249	DATE: 09/30/22

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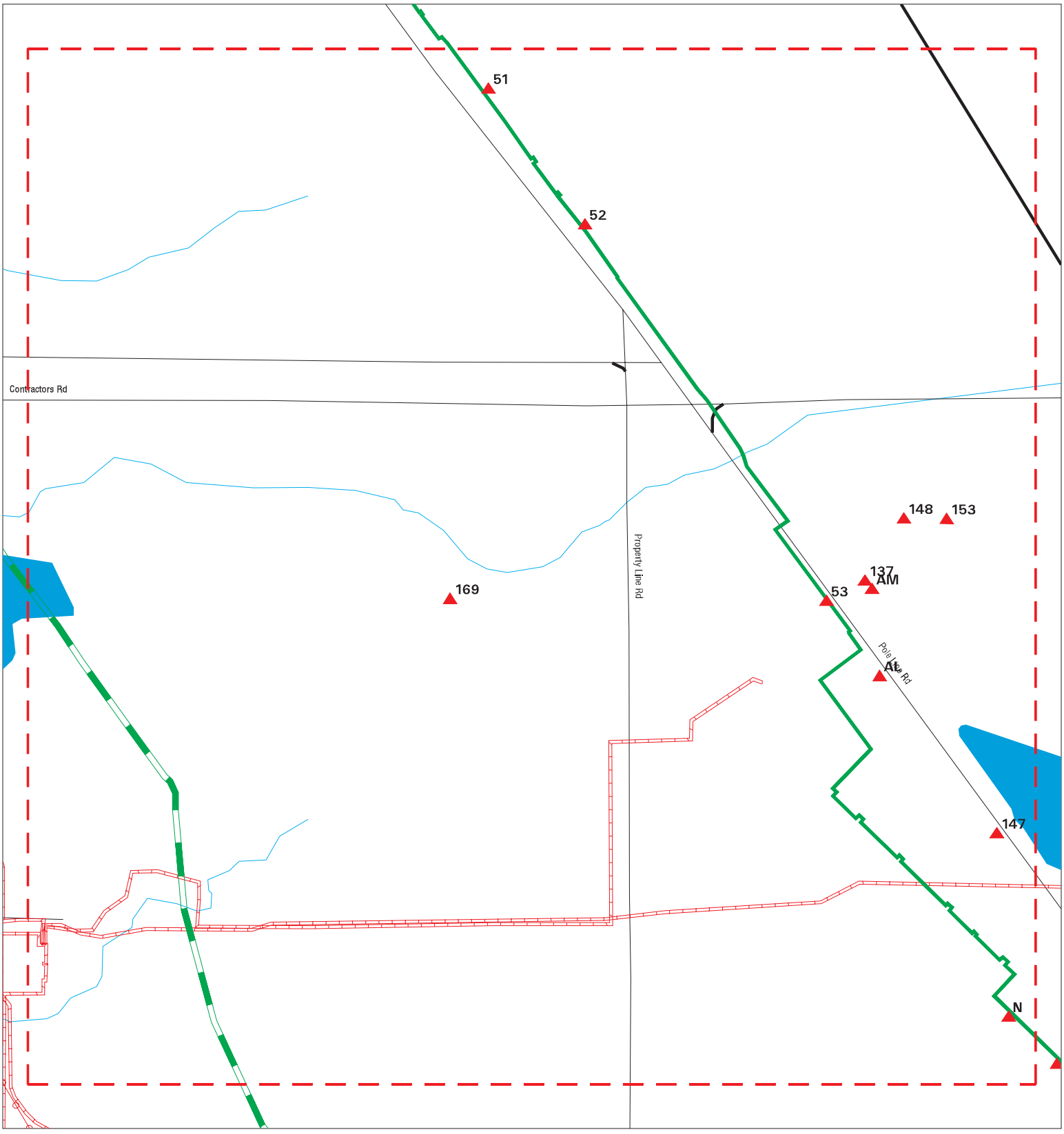
MAPPED SITES SUMMARY - FOCUS MAP 14

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION

NO MAPPED SITES FOUND

Focus Map - 15 - 7133623.8s



Sites
Target Property
Search Buffer
Focus Map - No Sites
Focus Map - Sites
Power Line
Pipe Line
National Priority List Sites
Areas of Concern
Dept. Defense Sites
Indian Reservations BIA

0 1/8 1/4 Miles

SITE NAME: Aera Belridge CCS Phase I ESA	CLIENT: Stantec
ADDRESS: Aera Belridge CCS Phase I ESA	CONTACT: Emily Medler
CITY/STATE: Lost Hills CA	INQUIRY #: 7133623.8s
ZIP: 93249	DATE: 09/30/22

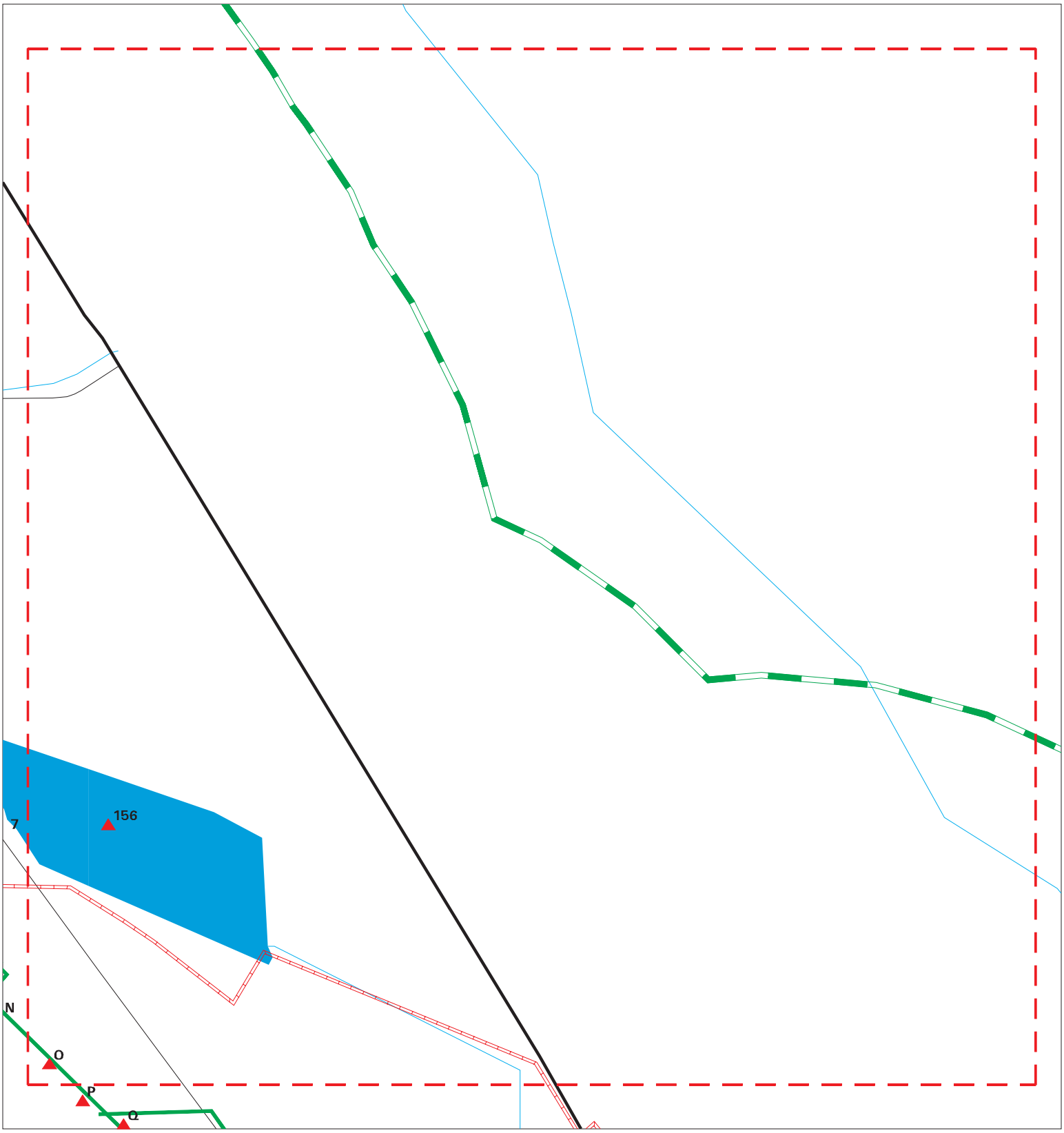
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MAPPED SITES SUMMARY - FOCUS MAP 15

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION
51 / 15	AERA ENERGY LLC		UIC	TP
52 / 15	AERA ENERGY LLC		UIC	TP
53 / 15	AERA ENERGY LLC		UIC	TP
N54 / 15	AERA ENERGY LLC		UIC	TP
N55 / 15	AERA ENERGY LLC		UIC	TP
N56 / 15	AERA ENERGY LLC		UIC	TP
AL132 / 15	CLARIANT OIL SERVICE	18426 POLE LINE RD	CUPA Listings, HAZNET, HWTS	254 0.048 SE
AL133 / 15	CLARIANT OIL SERVICE	18426 POLE LINE RD	RCRA NonGen / NLR	254 0.048 SE
AL134 / 15	KS INDUSTRIES LP	18426 POLE LINE RD	RCRA NonGen / NLR	254 0.048 SE
AM135 / 15			WASTEWATER PITS	257 0.049 NE
137 / 15			WASTEWATER PITS	338 0.064 NE
AM138 / 15			WASTEWATER PITS	344 0.065 NE
AM141 / 15			WASTEWATER PITS	451 0.085 NE
147 / 15			WASTEWATER PITS	694 0.131 NE
148 / 15			WASTEWATER PITS	886 0.168 NE
153 / 15			WASTEWATER PITS	1159 0.220 NE
169 / 15			WASTEWATER PITS	2591 0.491 SW

Focus Map - 16 - 7133623.8s



Sites
Target Property
Search Buffer
Focus Map - No Sites
Focus Map - Sites
Power Line
Pipe Line
National Priority List Sites
Areas of Concern
Dept. Defense Sites
Indian Reservations BIA

0 1/8 1/4 Miles

SITE NAME: Aera Belridge CCS Phase I ESA	CLIENT: Stantec
ADDRESS: Aera Belridge CCS Phase I ESA	CONTACT: Emily Medler
CITY/STATE: Lost Hills CA	INQUIRY #: 7133623.8s
ZIP: 93249	DATE: 09/30/22

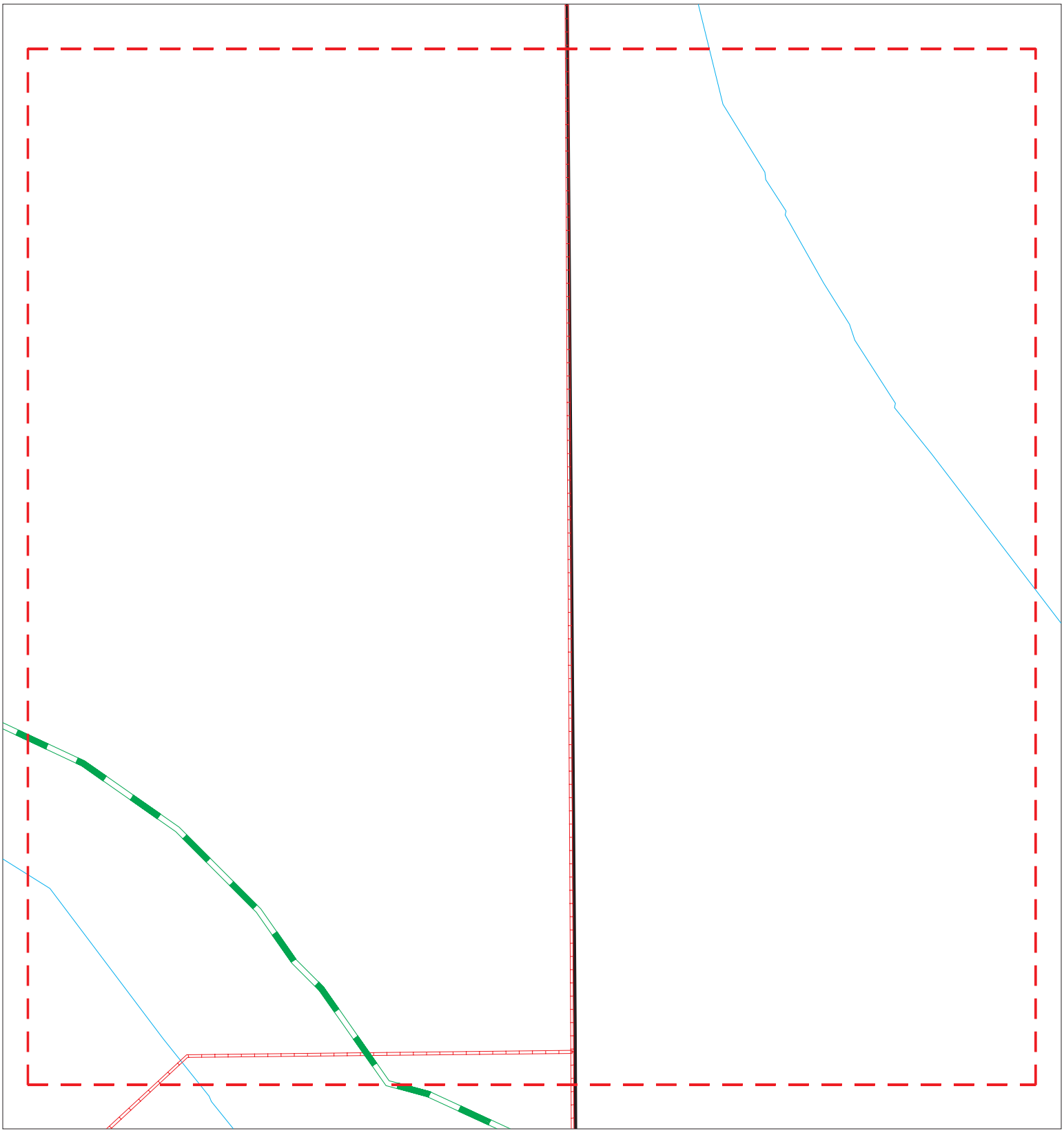
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MAPPED SITES SUMMARY - FOCUS MAP 16

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION
O57 / 16	AERA ENERGY LLC		UIC	TP
O58 / 16	AERA ENERGY LLC		UIC	TP
156 / 16			WASTEWATER PITS	1399 0.265 NE

Focus Map - 17 - 7133623.8s



Sites
Target Property
Search Buffer
Focus Map - No Sites
Focus Map - Sites
Power Line
Pipe Line
National Priority List Sites
Areas of Concern
Dept. Defense Sites
Indian Reservations BIA

0 1/8 1/4 Miles

SITE NAME: Aera Belridge CCS Phase I ESA	CLIENT: Stantec
ADDRESS: Aera Belridge CCS Phase I ESA	CONTACT: Emily Medler
CITY/STATE: Lost Hills CA	INQUIRY #: 7133623.8s
ZIP: 93249	DATE: 09/30/22

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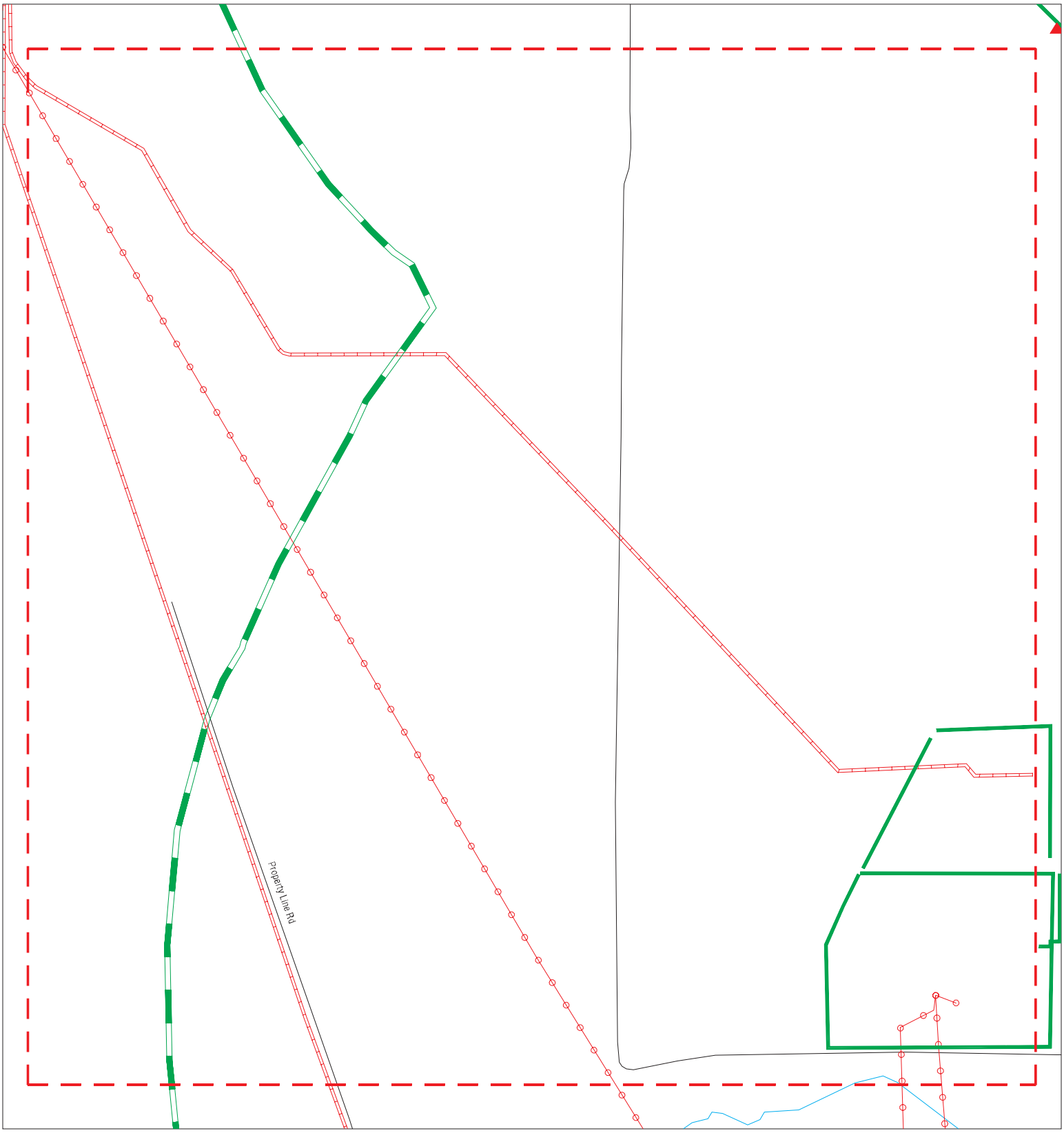
MAPPED SITES SUMMARY - FOCUS MAP 17

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION

NO MAPPED SITES FOUND

Focus Map - 18 - 7133623.8s



Sites
Target Property
Search Buffer
Focus Map - No Sites
Focus Map - Sites
Power Line
Pipe Line
National Priority List Sites
Areas of Concern
Dept. Defense Sites
Indian Reservations BIA

0 1/8 1/4 Miles

SITE NAME: Aera Belridge CCS Phase I ESA	CLIENT: Stantec
ADDRESS: Aera Belridge CCS Phase I ESA	CONTACT: Emily Medler
CITY/STATE: Lost Hills CA	INQUIRY #: 7133623.8s
ZIP: 93249	DATE: 09/30/22

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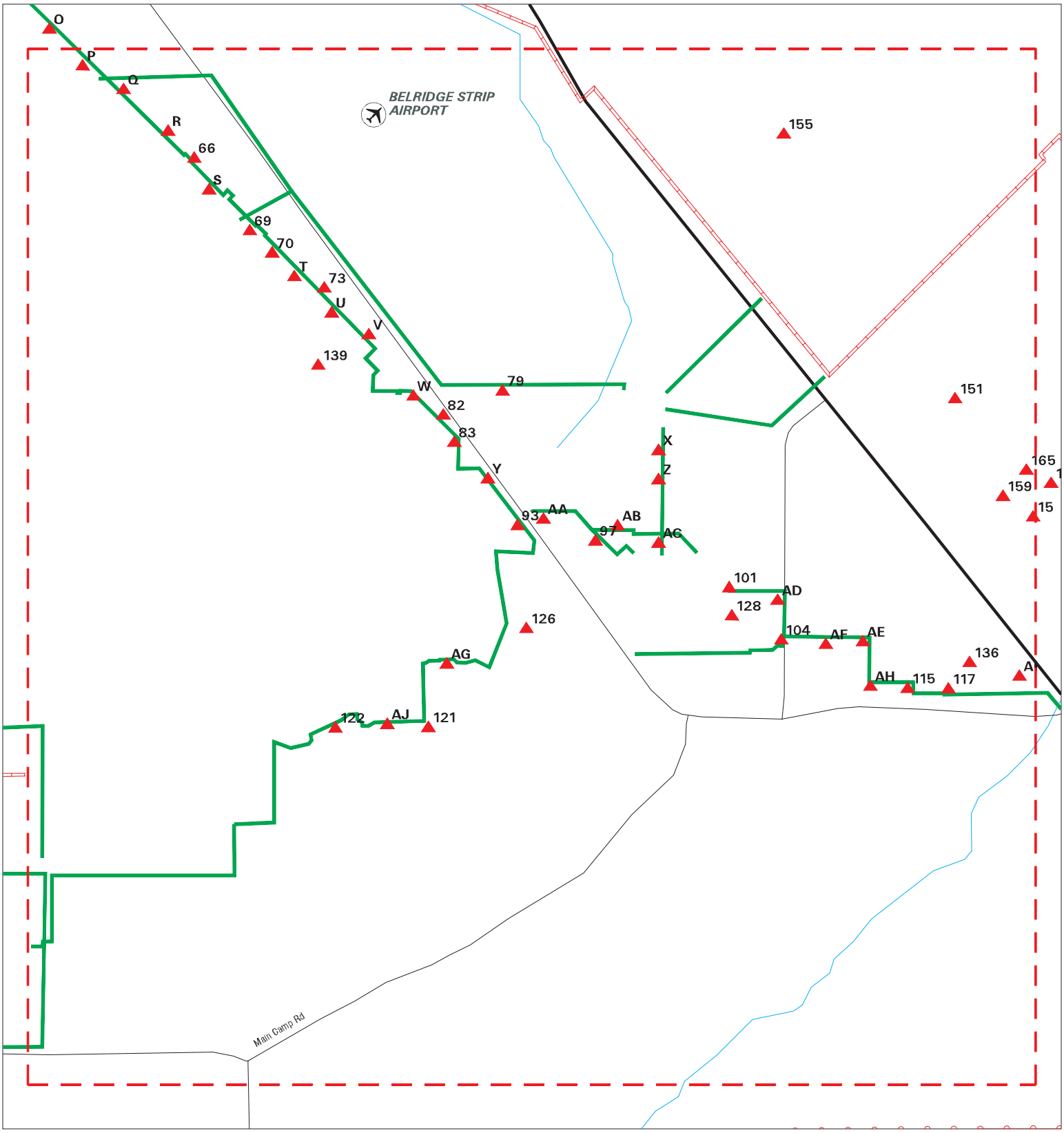
MAPPED SITES SUMMARY - FOCUS MAP 18

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION

NO MAPPED SITES FOUND

Focus Map - 19 - 7133623.8s



Sites
Target Property
Search Buffer
Focus Map - No Sites
Focus Map - Sites
Power Line
Pipe Line
National Priority List Sites
Areas of Concern
Dept. Defense Sites
Indian Reservations BIA

0 1/8 1/4 Miles

SITE NAME: Aera Belridge CCS Phase I ESA	CLIENT: Stantec
ADDRESS: Aera Belridge CCS Phase I ESA	CONTACT: Emily Medler
CITY/STATE: Lost Hills CA	INQUIRY #: 7133623.8s
ZIP: 93249	DATE: 09/30/22

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MAPPED SITES SUMMARY - FOCUS MAP 19

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

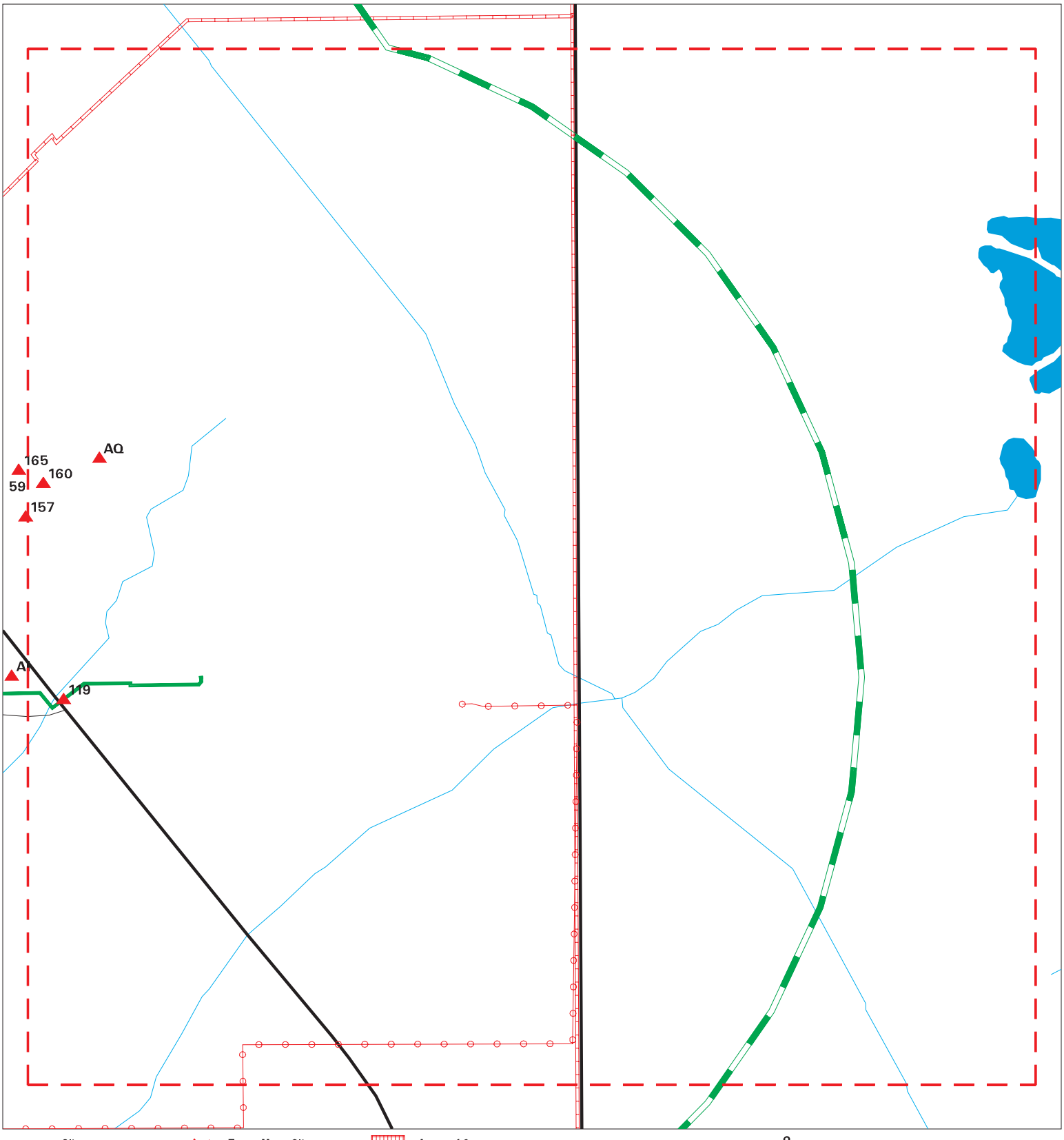
MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION
P59 / 19	AERA ENERGY LLC		UIC	TP
P60 / 19	AERA ENERGY LLC		UIC	TP
P61 / 19	AERA ENERGY LLC		UIC	TP
Q62 / 19	AERA ENERGY LLC		UIC	TP
Q63 / 19	AERA ENERGY LLC		UIC	TP
R64 / 19	AERA ENERGY LLC		UIC	TP
R65 / 19	AERA ENERGY LLC		UIC	TP
66 / 19	AERA ENERGY LLC		UIC	TP
S67 / 19	AERA ENERGY LLC		UIC	TP
S68 / 19	AERA ENERGY LLC		UIC	TP
69 / 19	AERA ENERGY LLC		UIC	TP
70 / 19	AERA ENERGY LLC		UIC	TP
T71 / 19	AERA ENERGY LLC		UIC	TP
T72 / 19	AERA ENERGY LLC		UIC	TP
73 / 19	AERA ENERGY LLC		UIC	TP
U74 / 19	AERA ENERGY LLC		UIC	TP
U75 / 19	AERA ENERGY LLC		UIC	TP
V76 / 19	AERA ENERGY LLC		UIC	TP
V77 / 19	AERA ENERGY LLC		UIC	TP
V78 / 19	AERA ENERGY LLC		UIC	TP
79 / 19	AERA ENERGY LLC		UIC	TP
W80 / 19	AERA ENERGY LLC		UIC	TP
W81 / 19	AERA ENERGY LLC		UIC	TP
82 / 19	AERA ENERGY LLC		UIC	TP
83 / 19	AERA ENERGY LLC		UIC	TP
X84 / 19	AERA ENERGY LLC		UIC	TP
X85 / 19	AERA ENERGY LLC		UIC	TP
Y86 / 19	AERA ENERGY LLC		UIC	TP
Y87 / 19	AERA ENERGY LLC		UIC	TP
Z88 / 19	AERA ENERGY LLC		UIC	TP
Z89 / 19	AERA ENERGY LLC		UIC	TP
Y90 / 19	AERA ENERGY LLC		UIC	TP
Y91 / 19	AERA ENERGY LLC		UIC	TP
AA92 / 19	AERA ENERGY LLC		UIC	TP
93 / 19	AERA ENERGY LLC		UIC	TP
AA94 / 19	AERA ENERGY LLC		UIC	TP
AB95 / 19	AERA ENERGY LLC		UIC	TP
AB96 / 19	AERA ENERGY LLC		UIC	TP
97 / 19	AERA ENERGY LLC		UIC	TP

MAPPED SITES SUMMARY - FOCUS MAP 19

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION
AC98 / 19	AERA ENERGY LLC		UIC	TP
AB99 / 19	AERA ENERGY LLC		UIC	TP
AC100 / 19	AERA ENERGY LLC		UIC	TP
101 / 19	AERA ENERGY LLC		UIC	TP
AD102 / 19	AERA ENERGY LLC		UIC	TP
AD103 / 19	AERA ENERGY LLC		UIC	TP
104 / 19	AERA ENERGY LLC		UIC	TP
AE105 / 19	AERA ENERGY LLC		UIC	TP
AF106 / 19	AERA ENERGY LLC		UIC	TP
AF107 / 19	AERA ENERGY LLC		UIC	TP
AG108 / 19	AERA ENERGY LLC		UIC	TP
AE109 / 19	AERA ENERGY LLC		UIC	TP
AG110 / 19	AERA ENERGY LLC		UIC	TP
AG111 / 19	AERA ENERGY LLC		UIC	TP
AH112 / 19	AERA ENERGY LLC		UIC	TP
AH113 / 19	AERA ENERGY LLC		UIC	TP
AI114 / 19	AERA ENERGY LLC		UIC	TP
115 / 19	AERA ENERGY LLC		UIC	TP
AI116 / 19	AERA ENERGY LLC		UIC	TP
117 / 19	AERA ENERGY LLC		UIC	TP
AI118 / 19	AERA ENERGY LLC		UIC	TP
AJ120 / 19	AERA ENERGY LLC		UIC	TP
121 / 19	AERA ENERGY LLC		UIC	TP
122 / 19	AERA ENERGY LLC		UIC	TP
AJ123 / 19	AERA ENERGY LLC		UIC	TP
AI125 / 19			WASTEWATER PITS	147 0.028 North
126 / 19			WASTEWATER PITS	162 0.031 ESE
128 / 19			WASTEWATER PITS	189 0.036 South
136 / 19			WASTEWATER PITS	264 0.050 North
139 / 19			WASTEWATER PITS	382 0.072 West
151 / 19			WASTEWATER PITS	1060 0.201 East
155 / 19			WASTEWATER PITS	1339 0.254 North
157 / 19			WASTEWATER PITS	1421 0.269 North
159 / 19			WASTEWATER PITS	1564 0.296 NE
165 / 19			WASTEWATER PITS	1778 0.337 ESE

Focus Map - 20 - 7133623.8s



Sites
Target Property
Search Buffer
Focus Map - No Sites
Focus Map - Sites
Power Line
Pipe Line
National Priority List Sites
Areas of Concern
Dept. Defense Sites
Indian Reservations BIA

0 1/8 1/4 Miles

SITE NAME: Aera Belridge CCS Phase I ESA	CLIENT: Stantec
ADDRESS: Aera Belridge CCS Phase I ESA	CONTACT: Emily Medler
CITY/STATE: Lost Hills CA	INQUIRY #: 7133623.8s
ZIP: 93249	DATE: 09/30/22

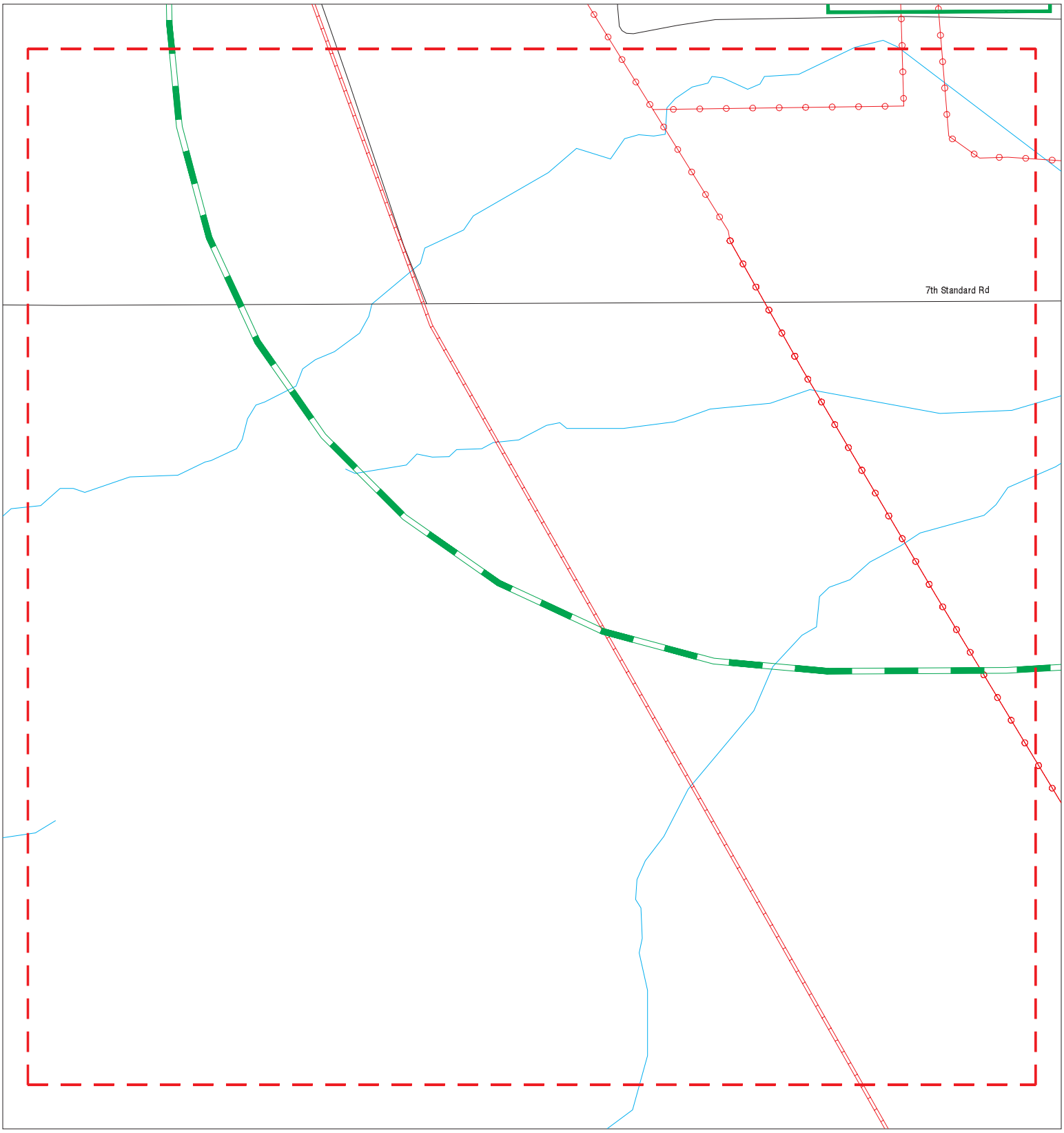
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MAPPED SITES SUMMARY - FOCUS MAP 20

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION		
119 / 20	AERA ENERGY LLC		UIC	TP		
160 / 20			WASTEWATER PITS	1646	0.312	NNW
AQ161 / 20			WASTEWATER PITS	1687	0.320	North
AQ162 / 20			WASTEWATER PITS	1738	0.329	North
AQ163 / 20			WASTEWATER PITS	1742	0.330	North
AQ166 / 20			WASTEWATER PITS	1813	0.343	North

Focus Map - 21 - 7133623.8s



Sites
Target Property
Search Buffer
Focus Map - No Sites
Focus Map - Sites
Power Line
Pipe Line
National Priority List Sites
Areas of Concern
Dept. Defense Sites
Indian Reservations BIA

0 1/8 1/4 Miles

SITE NAME: Aera Belridge CCS Phase I ESA	CLIENT: Stantec
ADDRESS: Aera Belridge CCS Phase I ESA	CONTACT: Emily Medler
CITY/STATE: Lost Hills CA	INQUIRY #: 7133623.8s
ZIP: 93249	DATE: 09/30/22

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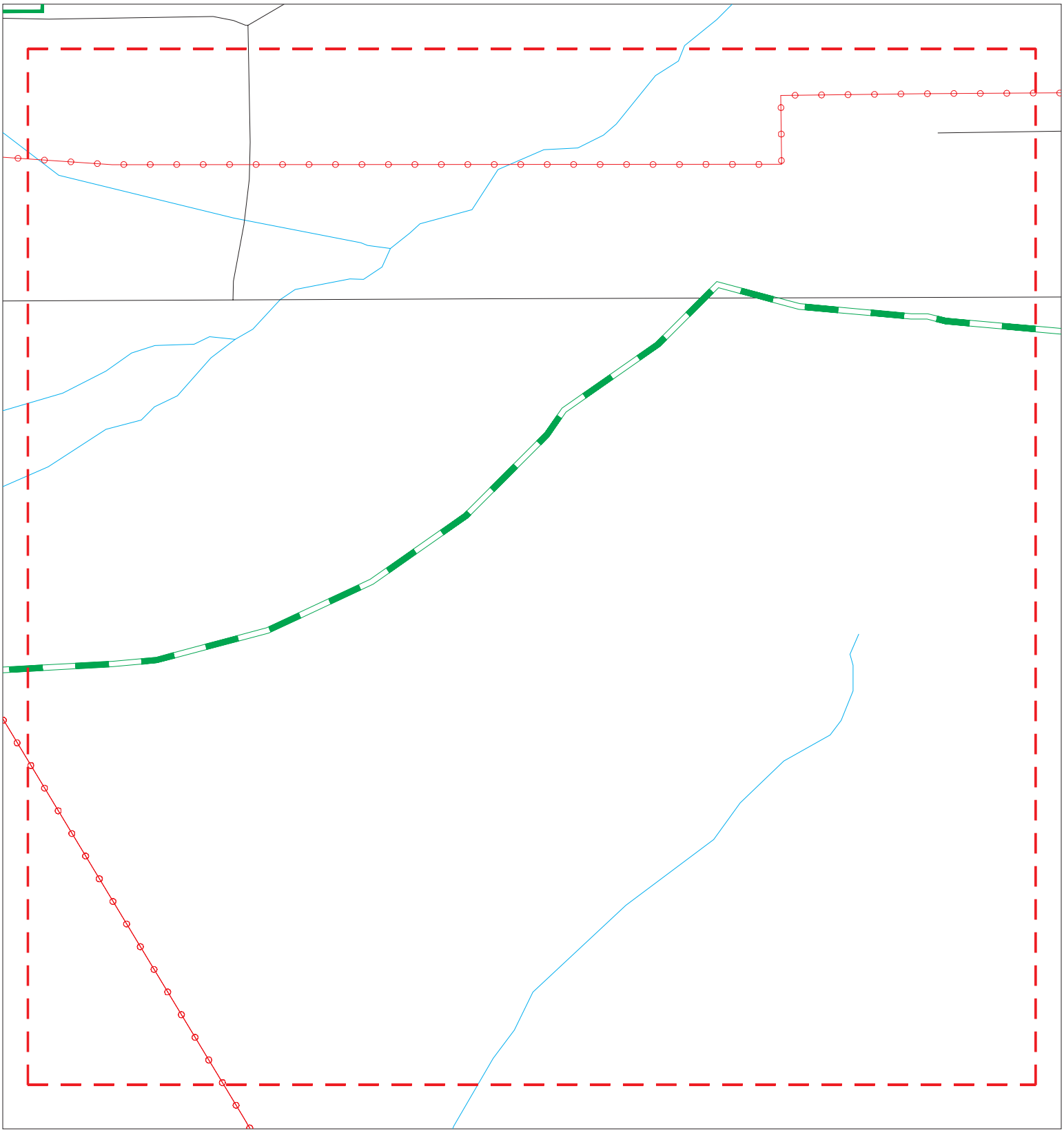
MAPPED SITES SUMMARY - FOCUS MAP 21

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION

NO MAPPED SITES FOUND

Focus Map - 22 - 7133623.8s



Sites
Target Property
Search Buffer
Focus Map - No Sites
Focus Map - Sites
Power Line
Pipe Line
National Priority List Sites
Areas of Concern
Dept. Defense Sites
Indian Reservations BIA

0 1/8 1/4 Miles

SITE NAME: Aera Belridge CCS Phase I ESA	CLIENT: Stantec
ADDRESS: Aera Belridge CCS Phase I ESA	CONTACT: Emily Medler
CITY/STATE: Lost Hills CA	INQUIRY #: 7133623.8s
ZIP: 93249	DATE: 09/30/22

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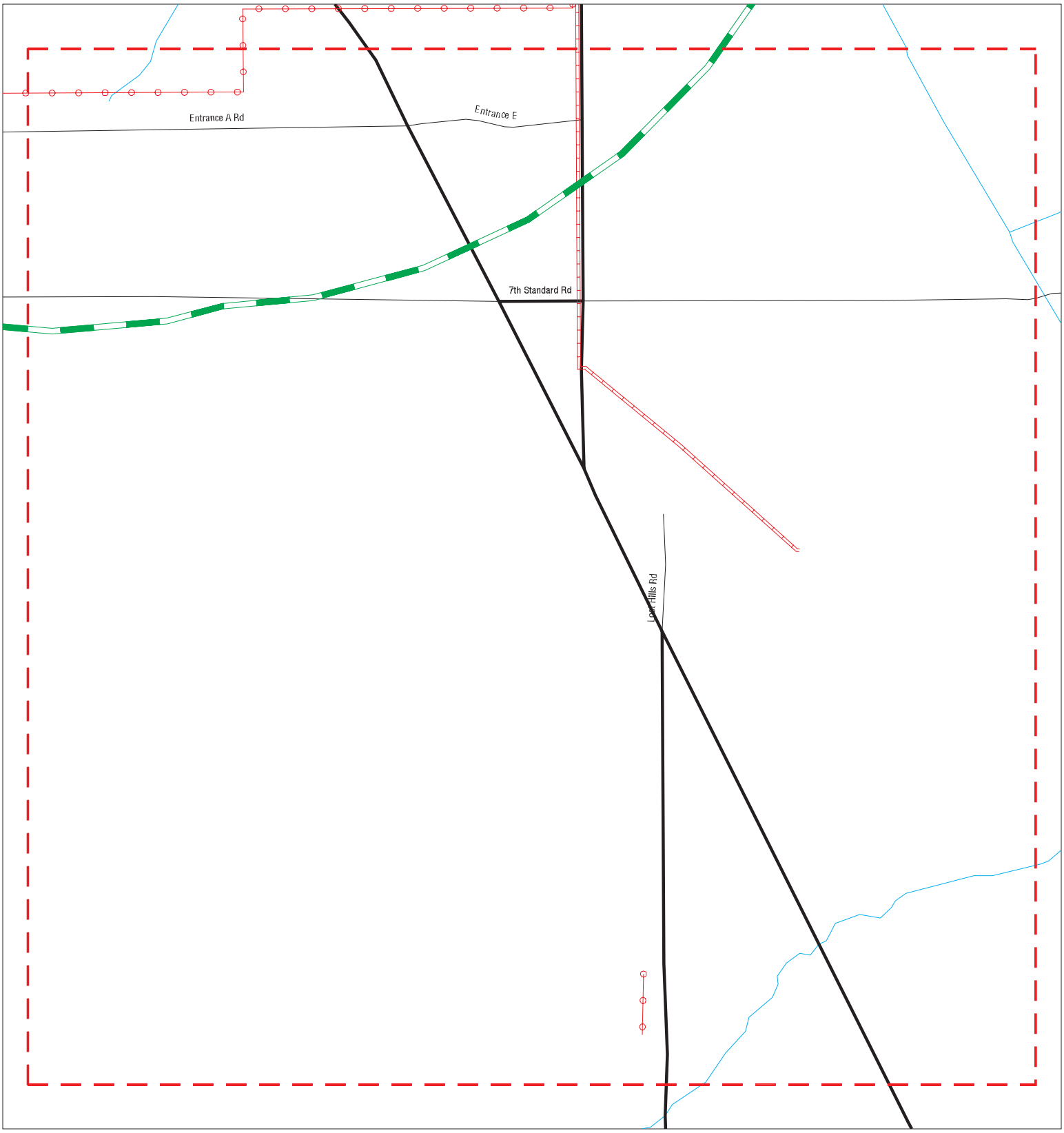
MAPPED SITES SUMMARY - FOCUS MAP 22

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION

NO MAPPED SITES FOUND

Focus Map - 23 - 7133623.8s



Sites
Target Property
Search Buffer
Focus Map - No Sites
Focus Map - Sites
Power Line
Pipe Line
National Priority List Sites
Areas of Concern
Dept. Defense Sites
Indian Reservations BIA

0 1/8 1/4 Miles

SITE NAME: Aera Belridge CCS Phase I ESA	CLIENT: Stantec
ADDRESS: Aera Belridge CCS Phase I ESA	CONTACT: Emily Medler
CITY/STATE: Lost Hills CA	INQUIRY #: 7133623.8s
ZIP: 93249	DATE: 09/30/22

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MAPPED SITES SUMMARY - FOCUS MAP 23

Target Property:
AERA BELRIDGE CCS PHASE I ESA
LOST HILLS, CA 93249

MAP ID / FOCUS MAP	SITE NAME	ADDRESS	DATABASE ACRONYMS	DIST (ft. & mi.) DIRECTION

NO MAPPED SITES FOUND

A1 **AERA ENERGY LLC** **UIC** **S125646542**
Target Property **KERN (County), CA** **N/A**

Site 1 of 2 in cluster A

Actual: **632 ft.**
Focus Map: **8**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402985975
Confidential Well:	No
Well Number:	531G-35
Direction:	Y
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.53628
Longitude:	-119.7813
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

---

2 **AERA ENERGY LLC** **UIC** **S125655311**
Target Property **KERN (County), CA** **N/A**

Actual: **627 ft.**
Focus Map: **8**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403043213
Confidential Well:	No
Well Number:	532R3-35
Direction:	N
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.53599
Longitude:	-119.7807
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610

AERA ENERGY LLC (Continued) **S125655311**

Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

B3 **AERA ENERGY LLC** **UIC** **S125657740**
Target Property **KERN (County), CA** **N/A**

Site 1 of 3 in cluster B

Actual: **643 ft.**
Focus Map: **8**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403053350
Confidential Well:	No
Well Number:	530M3-35
Direction:	N
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.53596
Longitude:	-119.7850
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

B4 **AERA ENERGY LLC** **UIC** **S125654599**
Target Property **KERN (County), CA** **N/A**

Site 2 of 3 in cluster B

Actual: **643 ft.**
Focus Map: **8**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403040328
Confidential Well:	No
Well Number:	530M2-35

AERA ENERGY LLC (Continued) **S125654599**

Direction:	N
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.53594
Longitude:	-119.7849
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

B5 **AERA ENERGY LLC** **UIC** **S125650616**
Target Property **KERN (County), CA** **N/A**

Site 3 of 3 in cluster B

Actual: 643 ft.

Focus Map: 8

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403019766
Confidential Well:	No
Well Number:	530Z1-35
Direction:	N
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.53590
Longitude:	-119.7850
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

A6 **AERA ENERGY LLC** **UIC** **S125654601**
Target Property **KERN (County), CA** **N/A**

Site 2 of 2 in cluster A

Actual: 632 ft.
Focus Map: 8

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403040330
Confidential Well:	No
Well Number:	531N3-35
Direction:	Y
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.53583
Longitude:	-119.7817
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

---

7 **AERA ENERGY LLC** **UIC** **S125650408**
Target Property **KERN (County), CA** **N/A**

Actual: 633 ft.
Focus Map: 8

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403018530
Confidential Well:	No
Well Number:	531X1-35
Direction:	N
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.53556
Longitude:	-119.7819
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610

AERA ENERGY LLC (Continued) **S125650408**

Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

---

8 **AERA ENERGY LLC** **UIC** **S125651217**
Target Property **KERN (County), CA** **N/A**

Actual: 628 ft.
Focus Map: 8

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403022957
Confidential Well:	No
Well Number:	531NR-35
Direction:	Y
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	mip
Latitude:	35.53536
Longitude:	-119.7808
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

C9 **AERA ENERGY LLC** **UIC** **S125642781**
Target Property **KERN (County), CA** **N/A**

Site 1 of 3 in cluster C

Actual: 640 ft.
Focus Map: 8

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402959840
Confidential Well:	No
Well Number:	534-35
Direction:	N
Lease Name:	Unspecified

AERA ENERGY LLC (Continued) **S125642781**

Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.53441
Longitude:	-119.7823
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

D10 **AERA ENERGY LLC** **UIC** **S125645790**
Target Property **KERN (County), CA** **N/A**

Site 1 of 3 in cluster D

Actual: **651 ft.**
Focus Map: **8**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402980208
Confidential Well:	No
Well Number:	535G-35
Direction:	N
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.53437
Longitude:	-119.7834
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

11 **AERA ENERGY LLC** **UIC** **S125652289**
Target Property **KERN (County), CA** **N/A**

Actual: 631 ft.
Focus Map: 8

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403028976
Confidential Well:	No
Well Number:	534P2-35
Direction:	N
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.53435
Longitude:	-119.7816
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

D12 **AERA ENERGY LLC** **UIC** **S125651514**
Target Property **KERN (County), CA** **N/A**

Site 2 of 3 in cluster D

Actual: 647 ft.
Focus Map: 8

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403024515
Confidential Well:	No
Well Number:	535GR-35
Direction:	N
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	mip
Latitude:	35.53434
Longitude:	-119.7830
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610

AERA ENERGY LLC (Continued) **S125651514**

Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

D13 **AERA ENERGY LLC** **UIC** **S125650360**
Target Property **KERN (County), CA** **N/A**

Site 3 of 3 in cluster D

Actual: 650 ft.
Focus Map: 8

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403018204
Confidential Well:	No
Well Number:	534R1-35
Direction:	N
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.53428
Longitude:	-119.7832
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

---

14 **AERA ENERGY LLC** **UIC** **S125655317**
Target Property **KERN (County), CA** **N/A**

Actual: 650 ft.
Focus Map: 8

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403043219
Confidential Well:	No
Well Number:	535M2-35
Direction:	N
Lease Name:	Unspecified

AERA ENERGY LLC (Continued) **S125655317**

Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.53426
Longitude:	-119.7847
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

C15 **AERA ENERGY LLC** **UIC** **S125651324**
Target Property **KERN (County), CA** **N/A**

Site 2 of 3 in cluster C

Actual: **633 ft.**

Focus Map: **8**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403023466
Confidential Well:	No
Well Number:	534ZR-35
Direction:	Y
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	mip
Latitude:	35.53425
Longitude:	-119.7817
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

16 **AERA ENERGY LLC** **UIC** **S125650233**
Target Property **KERN (County), CA** **N/A**

Actual: 632 ft.
Focus Map: 8

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403017481
Confidential Well:	No
Well Number:	533R1-35
Direction:	Y
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.53356
Longitude:	-119.7810
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

E17 **AERA ENERGY LLC** **UIC** **S125654681**
Target Property **KERN (County), CA** **N/A**

Site 1 of 4 in cluster E

Actual: 638 ft.
Focus Map: 8

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403040623
Confidential Well:	No
Well Number:	548J3-35
Direction:	Y
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.53260
Longitude:	-119.7814
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610

AERA ENERGY LLC (Continued) **S125654681**

Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

E18 **AERA ENERGY LLC** **UIC** **S125644981**
Target Property **KERN (County), CA** **N/A**

Site 2 of 4 in cluster E

Actual: **637 ft.**
Focus Map: **8**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402974404
Confidential Well:	No
Well Number:	547G-35
Direction:	N
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.53258
Longitude:	-119.7813
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

E19 **AERA ENERGY LLC** **UIC** **S125658758**
Target Property **KERN (County), CA** **N/A**

Site 3 of 4 in cluster E

Actual: **639 ft.**
Focus Map: **8**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403059333
Confidential Well:	No
Well Number:	547P5-35

AERA ENERGY LLC (Continued) **S125658758**

Direction:	N
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.53256
Longitude:	-119.7815
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

E20 **AERA ENERGY LLC** **UIC** **S125656155**
Target Property **KERN (County), CA** **N/A**

Site 4 of 4 in cluster E

Actual: 639 ft.

Focus Map: 8

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403046519
Confidential Well:	No
Well Number:	547P3-35
Direction:	Y
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.53251
Longitude:	-119.7815
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

F21 **AERA ENERGY LLC** **UIC** **S125650234**
Target Property **KERN (County), CA** **N/A**

Site 1 of 6 in cluster F

Actual: **640 ft.**
Focus Map: **8**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403017482
Confidential Well:	No
Well Number:	547S1-35
Direction:	N
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.53193
Longitude:	-119.7819
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

F22 **AERA ENERGY LLC** **UIC** **S125654683**
Target Property **KERN (County), CA** **N/A**

Site 2 of 6 in cluster F

Actual: **640 ft.**
Focus Map: **8**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403040625
Confidential Well:	No
Well Number:	547S2-35
Direction:	N
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.53187
Longitude:	-119.7819
Well Type:	Water Flood

AERA ENERGY LLC (Continued) **S125654683**

Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

F23 **AERA ENERGY LLC** **UIC** **S125658567**
Target Property **KERN (County), CA** **N/A**

Site 3 of 6 in cluster F

Actual: **640 ft.**
Focus Map: **8**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403058110
Confidential Well:	No
Well Number:	547S3-35
Direction:	Y
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.53179
Longitude:	-119.7819
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

F24 **AERA ENERGY LLC** **UIC** **S121256866**
Target Property **KERN (County), CA** **N/A**

Site 4 of 6 in cluster F

Actual: **638 ft.**
Focus Map: **8**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403059321

AERA ENERGY LLC (Continued) **S121256866**

Confidential Well:	No
Well Number:	548R4-35
Direction:	Y
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.53163
Longitude:	-119.7814
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

F25 **AERA ENERGY LLC** **UIC** **S125650336**
Target Property **KERN (County), CA** **N/A**

Site 5 of 6 in cluster F

Actual: 638 ft.

Focus Map: 8

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403018084
Confidential Well:	No
Well Number:	550T1-35
Direction:	N
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.53159
Longitude:	-119.7814
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

F26 **AERA ENERGY LLC** **UIC** **S125658752**
Target Property **KERN (County), CA** **N/A**

Site 6 of 6 in cluster F

Actual: **638 ft.**
Focus Map: **8**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403059322
Confidential Well:	No
Well Number:	550H5-35
Direction:	N
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.53158
Longitude:	-119.7814
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

G27 **AERA ENERGY LLC** **UIC** **S125652292**
Target Property **KERN (County), CA** **N/A**

Site 1 of 2 in cluster G

Actual: **638 ft.**
Focus Map: **8**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403028979
Confidential Well:	No
Well Number:	550H2-35
Direction:	N
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.53153
Longitude:	-119.7814
Well Type:	Water Flood

AERA ENERGY LLC (Continued) **S125652292**

Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

G28 **AERA ENERGY LLC** **UIC** **S125651637**
Target Property **KERN (County), CA** **N/A**

Site 2 of 2 in cluster G

Actual: 636 ft.
Focus Map: 8

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403025377
Confidential Well:	No
Well Number:	549E2-35
Direction:	Y
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	mip
Latitude:	35.53129
Longitude:	-119.7811
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

H29 **AERA ENERGY LLC** **UIC** **S125652742**
Target Property **KERN (County), CA** **N/A**

Site 1 of 2 in cluster H

Actual: 637 ft.
Focus Map: 8

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403031056

AERA ENERGY LLC (Continued) **S125652742**

Confidential Well:	No
Well Number:	550U2-35
Direction:	Y
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.53071
Longitude:	-119.7814
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

H30 **AERA ENERGY LLC** **UIC** **S125644982**
Target Property **KERN (County), CA** **N/A**

Site 2 of 2 in cluster H

Actual: 636 ft.

Focus Map: 8

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402974405
Confidential Well:	No
Well Number:	550G-35
Direction:	N
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.53064
Longitude:	-119.7814
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

31 **AERA ENERGY LLC** **UIC** **S125645200**
Target Property **KERN (County), CA** **N/A**

Actual: 635 ft.
Focus Map: 8

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402976379
Confidential Well:	No
Well Number:	550N-35
Direction:	N
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.52982
Longitude:	-119.7813
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

I32 **AERA ENERGY LLC** **UIC** **S125651519**
Target Property **KERN (County), CA** **N/A**

Site 1 of 2 in cluster I

Actual: 623 ft.
Focus Map: 8

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403024520
Confidential Well:	No
Well Number:	564V2-35
Direction:	N
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	mip
Latitude:	35.52931
Longitude:	-119.7790
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610

AERA ENERGY LLC (Continued) **S125651519**

Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

I33 **AERA ENERGY LLC** **UIC** **S125653981**
Target Property **KERN (County), CA** **N/A**

Site 2 of 2 in cluster I

Actual: 623 ft.
Focus Map: 8

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403037694
Confidential Well:	No
Well Number:	557J2-36
Direction:	Y
Lease Name:	Result
Field Name:	Belridge, North
Area Name:	Any Area
Section:	36
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.52924
Longitude:	-119.7785
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

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34 **AERA ENERGY LLC** **UIC** **S125654701**
Target Property **KERN (County), CA** **N/A**

Actual: 627 ft.
Focus Map: 8

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403040662
Confidential Well:	No
Well Number:	564N1-35
Direction:	Y
Lease Name:	Unspecified

AERA ENERGY LLC (Continued) **S125654701**

Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.52893
Longitude:	-119.7802
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

J35 **AERA ENERGY LLC** **UIC** **S125645771**
Target Property **KERN (County), CA** **N/A**

Site 1 of 6 in cluster J

Actual: **626 ft.**

Focus Map: **8**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402980068
Confidential Well:	No
Well Number:	564L-35
Direction:	N
Lease Name:	Unspecified
Field Name:	Belridge, North
Area Name:	Any Area
Section:	35
Township:	27S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.52814
Longitude:	-119.7801
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

K36 **AERA ENERGY LLC** **UIC** **S125658273**
Target **N/A**
Property **KERN (County), CA**

Site 1 of 2 in cluster K

Actual: **626 ft.**
Focus Map: **8**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403056007
Confidential Well:	No
Well Number:	511E7-1
Direction:	Y
Lease Name:	Lease by Aera Energy LLC
Field Name:	Belridge, North
Area Name:	Any Area
Section:	01
Township:	28S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.52803
Longitude:	-119.7788
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

J37 **UNOCAL CALIFORNIA PIPELINE CO** **EMI** **S108433624**
Target **17251 POLE LINE ROAD** **N/A**
Property **LOST HILLS, CA 93249**

Site 2 of 6 in cluster J

Actual: **626 ft.**
Focus Map: **8**

EMI:

Name:	UNOCAL CALIFORNIA PIPELINE CO
Address:	17251 POLE LINE ROAD
City,State,Zip:	LOST HILLS, CA 93249
Year:	2005
County Code:	15
Air Basin:	SJV
Facility ID:	1520
Air District Name:	SJU
SIC Code:	4612
Air District Name:	SAN JOAQUIN VALLEY UNIFIED APCD
Community Health Air Pollution Info System:	Not reported
Consolidated Emission Reporting Rule:	Not reported
Total Organic Hydrocarbon Gases Tons/Yr:	5.531880225234176718
Reactive Organic Gases Tons/Yr:	4.442804304187185991
Carbon Monoxide Emissions Tons/Yr:	2.01994151401027963
NOX - Oxides of Nitrogen Tons/Yr:	1.90899552582390259
SOX - Oxides of Sulphur Tons/Yr:	.049873070143908328
Particulate Matter Tons/Yr:	.052182190396276767 9

UNOCAL CALIFORNIA PIPELINE CO (Continued) **S108433624**

Part. Matter 10 Micrometers and Smllr Tons/Yr:.0206861006747763275

Name:	UNOCAL CALIFORNIA PIPELINE CO
Address:	17251 POLE LINE ROAD
City,State,Zip:	LOST HILLS, CA 93249
Year:	2006
County Code:	15
Air Basin:	SJV
Facility ID:	1520
Air District Name:	SJU
SIC Code:	4612
Air District Name:	SAN JOAQUIN VALLEY UNIFIED APCD
Community Health Air Pollution Info System:	Not reported
Consolidated Emission Reporting Rule:	Not reported
Total Organic Hydrocarbon Gases Tons/Yr:	17.32710172412699597
Reactive Organic Gases Tons/Yr:	6.241028427821959212
Carbon Monoxide Emissions Tons/Yr:	5.371294935009628725
NOX - Oxides of Nitrogen Tons/Yr:	1.46942848926596047
SOX - Oxides of Sulphur Tons/Yr:	.089059364142213062
Particulate Matter Tons/Yr:	.3949901399564224296
Part. Matter 10 Micrometers and Smllr Tons/Yr:	.393462137963808955

Name:	UNOCAL CALIFORNIA PIPELINE CO
Address:	17251 POLE LINE ROAD
City,State,Zip:	LOST HILLS, CA 93249
Year:	2007
County Code:	15
Air Basin:	SJV
Facility ID:	1520
Air District Name:	SJU
SIC Code:	4612
Air District Name:	SAN JOAQUIN VALLEY UNIFIED APCD
Community Health Air Pollution Info System:	Not reported
Consolidated Emission Reporting Rule:	Not reported
Total Organic Hydrocarbon Gases Tons/Yr:	19.41820682607031511
Reactive Organic Gases Tons/Yr:	6.602634451558068182
Carbon Monoxide Emissions Tons/Yr:	6.259252561941324457
NOX - Oxides of Nitrogen Tons/Yr:	1.68506241345420366
SOX - Oxides of Sulphur Tons/Yr:	.0948664895650298086
Particulate Matter Tons/Yr:	.4369268528948991042
Part. Matter 10 Micrometers and Smllr Tons/Yr:	.435147251204773333

Name:	UNOCAL CALIFORNIA PIPELINE CO
Address:	17251 POLE LINE ROAD
City,State,Zip:	LOST HILLS, CA 93249
Year:	2008
County Code:	15
Air Basin:	SJV
Facility ID:	1520
Air District Name:	SJU
SIC Code:	4612
Air District Name:	SAN JOAQUIN VALLEY UNIFIED APCD
Community Health Air Pollution Info System:	Not reported
Consolidated Emission Reporting Rule:	Not reported
Total Organic Hydrocarbon Gases Tons/Yr:	10.07341695001473716
Reactive Organic Gases Tons/Yr:	4.471707938935235082
Carbon Monoxide Emissions Tons/Yr:	2.583979599978625774

UNOCAL CALIFORNIA PIPELINE CO (Continued) **S108433624**

NOX - Oxides of Nitrogen Tons/Yr:	.89887300374999596
SOX - Oxides of Sulphur Tons/Yr:	.0810867408152968286
Particulate Matter Tons/Yr:	.2924835399431151173
Part. Matter 10 Micrometers and Smllr Tons/Yr:	.291740002159401833

Name:	UNOCAL CALIFORNIA PIPELINE CO
Address:	17251 POLE LINE ROAD
City,State,Zip:	LOST HILLS, CA 93249
Year:	2009
County Code:	15
Air Basin:	SJV
Facility ID:	1520
Air District Name:	SJU
SIC Code:	4612
Air District Name:	SAN JOAQUIN VALLEY UNIFIED APCD
Community Health Air Pollution Info System:	Not reported
Consolidated Emission Reporting Rule:	Not reported
Total Organic Hydrocarbon Gases Tons/Yr:	0.0265244760676865
Reactive Organic Gases Tons/Yr:	1.0820742997702699E-2
Carbon Monoxide Emissions Tons/Yr:	0.27230010856679399
NOX - Oxides of Nitrogen Tons/Yr:	4.0368840188441002E-2
SOX - Oxides of Sulphur Tons/Yr:	6.9983829243218396E-3
Particulate Matter Tons/Yr:	2.7657986478340502E-2
Part. Matter 10 Micrometers and Smllr Tons/Yr:	2.7558814605465502E-2

Name:	UNOCAL CALIFORNIA PIPELINE CO
Address:	17251 POLE LINE ROAD
City,State,Zip:	LOST HILLS, CA 93249
Year:	2010
County Code:	15
Air Basin:	SJV
Facility ID:	1520
Air District Name:	SJU
SIC Code:	4612
Air District Name:	SAN JOAQUIN VALLEY UNIFIED APCD
Community Health Air Pollution Info System:	Not reported
Consolidated Emission Reporting Rule:	Not reported
Total Organic Hydrocarbon Gases Tons/Yr:	1.5645351719693801
Reactive Organic Gases Tons/Yr:	1.3725913439999999
Carbon Monoxide Emissions Tons/Yr:	6.4892000000000005E-2
NOX - Oxides of Nitrogen Tons/Yr:	0.04326
SOX - Oxides of Sulphur Tons/Yr:	6.8442399999999997E-3
Particulate Matter Tons/Yr:	2.0958578850150001E-2
Part. Matter 10 Micrometers and Smllr Tons/Yr:	2.0920000000000001E-2

J38 **PHILLIPS 66 - MIDDLEWATER PUMP STA** **FINDS** **1023237825**
Target **17251 POLE LINE RD** **N/A**
Property **LOST HILLS, CA 93249**

Site 3 of 6 in cluster J

Actual: **626 ft.**

FINDS:
Registry ID: 110065253969

Focus Map: **8**

Click Here for FRS Facility Detail Report:

Environmental Interest/Information System:
STATE MASTER

PHILLIPS 66 - MIDDLEWATER PUMP STA (Continued) **1023237825**

Click this hyperlink while viewing on your computer to access additional FINDS: detail in the EDR Site Report.

J39 **AERA ENERGY LLC** **UIC** **S125650928**
Target Property **KERN (County), CA** **N/A**

Site 4 of 6 in cluster J

Actual: **626 ft.**
Focus Map: **8**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403021536
Confidential Well:	No
Well Number:	501B1-2
Direction:	N
Lease Name:	Lease by Aera Energy LLC
Field Name:	Belridge, North
Area Name:	Any Area
Section:	02
Township:	28S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.52800
Longitude:	-119.7800
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

K40 **AERA ENERGY LLC** **UIC** **S125650107**
Target Property **KERN (County), CA** **N/A**

Site 2 of 2 in cluster K

Actual: **626 ft.**
Focus Map: **8**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403016697
Confidential Well:	No
Well Number:	511W1-1
Direction:	N
Lease Name:	Lease by Aera Energy LLC
Field Name:	Belridge, North
Area Name:	Any Area
Section:	01

AERA ENERGY LLC (Continued) **S125650107**

Township:	28S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.52798
Longitude:	-119.7789
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

J41 **PHILLIPS 66 - MIDDLEWATER PUMP STA** **CERS HAZ WASTE** **S121788390**
Target **17251 POLE LINE RD** **CUPA Listings** **N/A**
Property **LOST HILLS, CA 93249** **CERS**

Site 5 of 6 in cluster J

Actual: **626 ft.**
Focus Map: **8**

CERS HAZ WASTE:

Name:	PHILLIPS 66 - MIDDLEWATER PUMP STA
Address:	17251 POLE LINE RD
City,State,Zip:	LOST HILLS, CA 93249
Site ID:	57420
CERS ID:	10234276
CERS Description:	Hazardous Waste Generator

KERN CO CUPA:

Facility ID:	FA0003099
CERS ID:	10234276
Name:	PHILLIPS 66 - MIDDLEWATER PUMP STA
Address:	17251 POLE LINE RD
Address 2:	17251 POLE LINE RD
City,State,Zip:	LOST HILLS, CA
Billing Status:	Active, billable
Program Element:	BUS PLAN LARGE LOW RISK 1 UNIT
Program Element Code:	CB3T
HMIRRP Due Date:	6/30/2013
Current Inspection Date:	8/1/2022
Employee:	BODDETI
Mailing Address:	1441 Wade Avenue
Mailing Address 2:	Not reported
Mailing City:	Taft
Mailing State:	CA
Mailing Zip:	93268

CERS:

Name:	PHILLIPS 66 - MIDDLEWATER PUMP STA
Address:	17251 POLE LINE RD
City,State,Zip:	LOST HILLS, CA 93249
Site ID:	57420
CERS ID:	10234276
CERS Description:	Chemical Storage Facilities

PHILLIPS 66 - MIDDLEWATER PUMP STA (Continued) **S121788390**

Evaluation:

Eval General Type:	Compliance Evaluation Inspection
Eval Date:	01-10-2014
Violations Found:	No
Eval Type:	Routine done by local agency
Eval Notes:	Not reported
Eval Division:	Kern County Env Health Services Department
Eval Program:	HMRRP
Eval Source:	CERS,

Eval General Type:	Compliance Evaluation Inspection
Eval Date:	08-10-2016
Violations Found:	No
Eval Type:	Routine done by local agency
Eval Notes:	Not reported
Eval Division:	Kern County Env Health Services Department
Eval Program:	HMRRP
Eval Source:	CERS,

Eval General Type:	Compliance Evaluation Inspection
Eval Date:	08-10-2016
Violations Found:	No
Eval Type:	Routine done by local agency
Eval Notes:	Not reported
Eval Division:	Kern County Env Health Services Department
Eval Program:	HW
Eval Source:	CERS,

Eval General Type:	Compliance Evaluation Inspection
Eval Date:	09-12-2019
Violations Found:	No
Eval Type:	Routine done by local agency
Eval Notes:	Not reported
Eval Division:	Kern County Env Health Services Department
Eval Program:	APSA
Eval Source:	CERS,

Eval General Type:	Compliance Evaluation Inspection
Eval Date:	09-12-2019
Violations Found:	No
Eval Type:	Routine done by local agency
Eval Notes:	Not reported
Eval Division:	Kern County Env Health Services Department
Eval Program:	HW
Eval Source:	CERS,

Eval General Type:	Compliance Evaluation Inspection
Eval Date:	01-10-2014
Violations Found:	No
Eval Type:	Routine done by local agency
Eval Notes:	Not reported
Eval Division:	Kern County Env Health Services Department
Eval Program:	HW
Eval Source:	CERS,

Eval General Type:	Compliance Evaluation Inspection
Eval Date:	08-10-2016

PHILLIPS 66 - MIDDLEWATER PUMP STA (Continued) **S121788390**

Violations Found: No
Eval Type: Routine done by local agency
Eval Notes: The facility is using the following tank: 1.) 158 gallon tank colored single wall steel cubical shaped non-Underwriter's Laboratory (UL) listed tank sitting over a single wall steel containment tub. Tank is used to supply diesel to the station's fire water pump. These tanks will be referred to the Kern County Fire Prevention Unit for compliance followup. Please contact Captain Tom Ellison or Engineer Anthony Romero at (661) 391-7080 for more information.
Eval Division: Kern County Env Health Services Department
Eval Program: APSA
Eval Source: CERS,

Eval General Type: Compliance Evaluation Inspection
Eval Date: 09-12-2019
Violations Found: No
Eval Type: Routine done by local agency
Eval Notes: Not reported
Eval Division: Kern County Env Health Services Department
Eval Program: HMRRP
Eval Source: CERS,

Eval General Type: Compliance Evaluation Inspection
Eval Date: 01-10-2014
Violations Found: No
Eval Type: Routine done by local agency
Eval Notes: Not reported
Eval Division: Kern County Env Health Services Department
Eval Program: APSA
Eval Source: CERS,

Affiliation:
Affiliation Type Desc: Facility Mailing Address
Entity Name: Mailing Address
Entity Title: Not reported
Affiliation Address: 1441 Wade Avenue
Affiliation City: Taft
Affiliation State: CA
Affiliation Country: Not reported
Affiliation Zip: 93268
Affiliation Phone: ,

Affiliation Type Desc: Identification Signer
Entity Name: Jim Adams
Entity Title: Env. Coordinator
Affiliation Address: Not reported
Affiliation City: Not reported
Affiliation State: Not reported
Affiliation Country: Not reported
Affiliation Zip: Not reported
Affiliation Phone: ,

Affiliation Type Desc: Operator
Entity Name: PHILLIPS 66 PIPELINE LLC
Entity Title: Not reported
Affiliation Address: Not reported
Affiliation City: Not reported

PHILLIPS 66 - MIDDLEWATER PUMP STA (Continued) **S121788390**

Affiliation State:	Not reported
Affiliation Country:	Not reported
Affiliation Zip:	Not reported
Affiliation Phone:	(661) 763-8963,
Affiliation Type Desc:	Parent Corporation
Entity Name:	PHILLIPS 66
Entity Title:	Not reported
Affiliation Address:	Not reported
Affiliation City:	Not reported
Affiliation State:	Not reported
Affiliation Country:	Not reported
Affiliation Zip:	Not reported
Affiliation Phone:	,
Affiliation Type Desc:	CUPA District
Entity Name:	Kern County Environmental Health Services Departme
Entity Title:	Not reported
Affiliation Address:	2700 M Street, Suite 300
Affiliation City:	Bakersfield
Affiliation State:	CA
Affiliation Country:	Not reported
Affiliation Zip:	93301-2370
Affiliation Phone:	(661) 862-8740,
Affiliation Type Desc:	Environmental Contact
Entity Name:	JIM ADAMS
Entity Title:	Not reported
Affiliation Address:	3900 Kilroy Airport Way #210
Affiliation City:	Long Beach
Affiliation State:	CA
Affiliation Country:	Not reported
Affiliation Zip:	90806
Affiliation Phone:	,
Affiliation Type Desc:	Legal Owner
Entity Name:	PHILLIPS 66 PIPELINE LLC
Entity Title:	Not reported
Affiliation Address:	1441 Wade Avenue
Affiliation City:	Taft
Affiliation State:	CA
Affiliation Country:	United States
Affiliation Zip:	93268
Affiliation Phone:	(661) 763-8963,
Affiliation Type Desc:	Document Preparer
Entity Name:	Jim Adams
Entity Title:	Not reported
Affiliation Address:	Not reported
Affiliation City:	Not reported
Affiliation State:	Not reported
Affiliation Country:	Not reported
Affiliation Zip:	Not reported
Affiliation Phone:	,

J42 **PHILLIPS 66 PIPELINE LLC** **CHMIRS** **S107448890**
Target **17251 POLE LINE RD** **EMI** **N/A**
Property **LOST HILLS, CA 93249** **CERS**

Site 6 of 6 in cluster J

Actual: **626 ft.**

Focus Map: **8**

CHMIRS:

Name:	Not reported
Address:	17251 POLE LINE RD
City,State,Zip:	LOST HILLS, CA 93268
OES Incident Number:	4-6216
OES notification:	11/30/2004
OES Date:	Not reported
OES Time:	Not reported
Date Completed:	**Not reported**
Property Use:	Not reported
Agency Id Number:	Not reported
Agency Incident Number:	Not reported
Time Notified:	Not reported
Time Completed:	Not reported
Surrounding Area:	Not reported
Estimated Temperature:	Not reported
Property Management:	Not reported
More Than Two Substances Involved?:	Not reported
Resp Agncy Personel # Of Decontaminated:	Not reported
Responding Agency Personel # Of Injuries:	Not reported
Responding Agency Personel # Of Fatalities:	Not reported
Others Number Of Decontaminated:	Not reported
Others Number Of Injuries:	Not reported
Others Number Of Fatalities:	Not reported
Vehicle Make/year:	Not reported
Vehicle License Number:	Not reported
Vehicle State:	Not reported
Vehicle Id Number:	Not reported
CA DOT PUC/ICC Number:	Not reported
Company Name:	Not reported
Reporting Officer Name/ID:	Not reported
Report Date:	Not reported
Facility Telephone:	Not reported
Waterway Involved:	Not reported
Waterway:	Not reported
Spill Site:	Not reported
Cleanup By:	Reporting Party
Containment:	Not reported
What Happened:	Not reported
Type:	Not reported
Measure:	Not reported
Other:	Not reported
Date/Time:	Not reported
Year:	2004
Agency:	Conoco Phillips Co
Incident Date:	11/30/200412:00:00 AM
Admin Agency:	Kern Co. Environmental Health Services Dept
Amount:	Not reported
Contained:	Yes
Site Type:	Oil Field
E Date:	Not reported
Substance:	Crude Oil
BBLS:	50

PHILLIPS 66 PIPELINE LLC (Continued) **S107448890**

Gallons:	0.000000
Unknown:	0
Substance #2:	Not reported
Substance #3:	Not reported
Evacuations:	0
Number of Injuries:	0
Number of Fatalities:	0
#1 Pipeline:	Not reported
#2 Pipeline:	Not reported
#3 Pipeline:	Not reported
#1 Vessel >= 300 Tons:	Not reported
#2 Vessel >= 300 Tons:	Not reported
#3 Vessel >= 300 Tons:	Not reported
Evacs:	Not reported
Injuries:	Not reported
Fatals:	Not reported
Comments:	Not reported
Description:	Substance released due to a portable tank overfill. Substance is contained to bermed containment area. Facility is shut down. Conoco Phillips personnel are on scene.

EMI:

Name:	PHILLIPS 66 PIPELINE LLC
Address:	17251 POLE LINE ROAD
City,State,Zip:	LOST HILLS, CA 93249
Year:	2011
County Code:	15
Air Basin:	SJV
Facility ID:	1520
Air District Name:	SJU
SIC Code:	4612
Air District Name:	SAN JOAQUIN VALLEY UNIFIED APCD
Community Health Air Pollution Info System:	Not reported
Consolidated Emission Reporting Rule:	Not reported
Total Organic Hydrocarbon Gases Tons/Yr:	1.4433372089
Reactive Organic Gases Tons/Yr:	1.2655443994
Carbon Monoxide Emissions Tons/Yr:	0.18935411351
NOX - Oxides of Nitrogen Tons/Yr:	0.043028840818
SOX - Oxides of Sulphur Tons/Yr:	0.0069948006161
Particulate Matter Tons/Yr:	0.025138674039
Part. Matter 10 Micrometers and Smllr Tons/Yr:	0.025063738042

Name:	PHILLIPS 66 PIPELINE LLC
Address:	17251 POLE LINE ROAD
City,State,Zip:	LOST HILLS, CA 93249
Year:	2012
County Code:	15
Air Basin:	SJV
Facility ID:	1520
Air District Name:	SJU
SIC Code:	4612
Air District Name:	SAN JOAQUIN VALLEY UNIFIED APCD
Community Health Air Pollution Info System:	Not reported
Consolidated Emission Reporting Rule:	Not reported
Total Organic Hydrocarbon Gases Tons/Yr:	2.1061210375
Reactive Organic Gases Tons/Yr:	1.5302330923

PHILLIPS 66 PIPELINE LLC (Continued) **S107448890**

Carbon Monoxide Emissions Tons/Yr:	3.2468017624
NOX - Oxides of Nitrogen Tons/Yr:	0.28916685221
SOX - Oxides of Sulphur Tons/Yr:	0.069621265363
Particulate Matter Tons/Yr:	0.2404554581
Part. Matter 10 Micrometers and Smllr Tons/Yr:	0.23991398143

Name:	PHILLIPS 66 PIPELINE LLC
Address:	17251 POLE LINE ROAD
City,State,Zip:	LOST HILLS, CA 93249
Year:	2013
County Code:	15
Air Basin:	SJV
Facility ID:	1520
Air District Name:	SJU
SIC Code:	4612
Air District Name:	SAN JOAQUIN VALLEY UNIFIED APCD
Community Health Air Pollution Info System:	Not reported
Consolidated Emission Reporting Rule:	Not reported
Total Organic Hydrocarbon Gases Tons/Yr:	1.9132538237
Reactive Organic Gases Tons/Yr:	1.403459844
Carbon Monoxide Emissions Tons/Yr:	3.096085928
NOX - Oxides of Nitrogen Tons/Yr:	0.268043997
SOX - Oxides of Sulphur Tons/Yr:	0.06150424
Particulate Matter Tons/Yr:	0.21622719152
Part. Matter 10 Micrometers and Smllr Tons/Yr:	0.215710001

Name:	PHILLIPS 66 PIPELINE LLC
Address:	17251 POLE LINE RD
City,State,Zip:	LOST HILLS, CA 93249
Year:	2014
County Code:	15
Air Basin:	SJV
Facility ID:	1520
Air District Name:	SJU
SIC Code:	4612
Air District Name:	SAN JOAQUIN VALLEY APCD
Community Health Air Pollution Info System:	Not reported
Consolidated Emission Reporting Rule:	Not reported
Total Organic Hydrocarbon Gases Tons/Yr:	1.6844190908
Reactive Organic Gases Tons/Yr:	1.3681918988
Carbon Monoxide Emissions Tons/Yr:	2.7406777271
NOX - Oxides of Nitrogen Tons/Yr:	0.29220584564
SOX - Oxides of Sulphur Tons/Yr:	0.070352740276
Particulate Matter Tons/Yr:	0.24867601763
Part. Matter 10 Micrometers and Smllr Tons/Yr:	0.24807381757

Name:	PHILLIPS 66 PIPELINE LLC
Address:	17251 POLE LINE RD
City,State,Zip:	LOST HILLS, CA 93249
Year:	2015
County Code:	15
Air Basin:	SJV
Facility ID:	1520
Air District Name:	SJU
SIC Code:	4612
Air District Name:	SAN JOAQUIN VALLEY APCD
Community Health Air Pollution Info System:	Not reported

PHILLIPS 66 PIPELINE LLC (Continued) **S107448890**

Consolidated Emission Reporting Rule:	Not reported
Total Organic Hydrocarbon Gases Tons/Yr:	1.7505083698
Reactive Organic Gases Tons/Yr:	1.435343
Carbon Monoxide Emissions Tons/Yr:	0.651339988
NOX - Oxides of Nitrogen Tons/Yr:	0.173355
SOX - Oxides of Sulphur Tons/Yr:	0.07117924
Particulate Matter Tons/Yr:	0.25477656477
Part. Matter 10 Micrometers and Smllr Tons/Yr:	0.254137998

Name:	PHILLIPS 66 PIPELINE LLC
Address:	17251 POLE LINE RD
City,State,Zip:	LOST HILLS, CA 93249
Year:	2016
County Code:	15
Air Basin:	SJV
Facility ID:	1520
Air District Name:	SJU
SIC Code:	4612
Air District Name:	SAN JOAQUIN VALLEY APCD
Community Health Air Pollution Info System:	Not reported
Consolidated Emission Reporting Rule:	Not reported
Total Organic Hydrocarbon Gases Tons/Yr:	1.5972479961
Reactive Organic Gases Tons/Yr:	1.325505
Carbon Monoxide Emissions Tons/Yr:	0.354305
NOX - Oxides of Nitrogen Tons/Yr:	0.1396025
SOX - Oxides of Sulphur Tons/Yr:	0.05519674
Particulate Matter Tons/Yr:	0.18252372876
Part. Matter 10 Micrometers and Smllr Tons/Yr:	0.182169999

Name:	PHILLIPS 66 PIPELINE LLC
Address:	17251 POLE LINE RD
City,State,Zip:	LOST HILLS, CA 93249
Year:	2017
County Code:	15
Air Basin:	SJV
Facility ID:	1520
Air District Name:	SJU
SIC Code:	4612
Air District Name:	SAN JOAQUIN VALLEY APCD
Community Health Air Pollution Info System:	Not reported
Consolidated Emission Reporting Rule:	Not reported
Total Organic Hydrocarbon Gases Tons/Yr:	1.6119514324
Reactive Organic Gases Tons/Yr:	1.323945156
Carbon Monoxide Emissions Tons/Yr:	1.936576945
NOX - Oxides of Nitrogen Tons/Yr:	0.1571475
SOX - Oxides of Sulphur Tons/Yr:	0.05425174
Particulate Matter Tons/Yr:	0.18742445209
Part. Matter 10 Micrometers and Smllr Tons/Yr:	0.186997998

Name:	PHILLIPS 66 PIPELINE LLC
Address:	17251 POLE LINE RD
City,State,Zip:	LOST HILLS, CA 93249
Year:	2018
County Code:	15
Air Basin:	SJV
Facility ID:	1520
Air District Name:	SJU

PHILLIPS 66 PIPELINE LLC (Continued) **S107448890**

SIC Code:	4612
Air District Name:	SAN JOAQUIN VALLEY APCD
Community Health Air Pollution Info System:	Not reported
Consolidated Emission Reporting Rule:	Not reported
Total Organic Hydrocarbon Gases Tons/Yr:	1.7012432938
Reactive Organic Gases Tons/Yr:	1.385121156
Carbon Monoxide Emissions Tons/Yr:	1.909581973
NOX - Oxides of Nitrogen Tons/Yr:	0.181967504
SOX - Oxides of Sulphur Tons/Yr:	0.06038674
Particulate Matter Tons/Yr:	0.20315899596
Part. Matter 10 Micrometers and Smllr Tons/Yr:	0.202754002

Name:	PHILLIPS 66 PIPELINE LLC
Address:	17251 POLE LINE RD
City,State,Zip:	LOST HILLS, CA 93249
Year:	2019
County Code:	15
Air Basin:	SJV
Facility ID:	1520
Air District Name:	SJU
SIC Code:	4612
Air District Name:	SAN JOAQUIN VALLEY APCD
Community Health Air Pollution Info System:	Not reported
Consolidated Emission Reporting Rule:	Not reported
Total Organic Hydrocarbon Gases Tons/Yr:	1.7571144207
Reactive Organic Gases Tons/Yr:	1.412072578
Carbon Monoxide Emissions Tons/Yr:	1.769746973
NOX - Oxides of Nitrogen Tons/Yr:	0.226350004
SOX - Oxides of Sulphur Tons/Yr:	0.07530424
Particulate Matter Tons/Yr:	0.23990869415
Part. Matter 10 Micrometers and Smllr Tons/Yr:	0.239534002

Name:	PHILLIPS 66 PIPELINE LLC
Address:	17251 POLE LINE RD
City,State,Zip:	LOST HILLS, CA 93249
Year:	2020
County Code:	15
Air Basin:	SJV
Facility ID:	1520
Air District Name:	SJU
SIC Code:	4612
Air District Name:	SAN JOAQUIN VALLEY APCD
Community Health Air Pollution Info System:	Not reported
Consolidated Emission Reporting Rule:	Not reported
Total Organic Hydrocarbon Gases Tons/Yr:	1.5054181086
Reactive Organic Gases Tons/Yr:	1.2366795
Carbon Monoxide Emissions Tons/Yr:	0.969298986
NOX - Oxides of Nitrogen Tons/Yr:	0.169004994
SOX - Oxides of Sulphur Tons/Yr:	0.05917424
Particulate Matter Tons/Yr:	0.17931480285
Part. Matter 10 Micrometers and Smllr Tons/Yr:	0.179109994

CERS:

Name:	PHILLIPS 66 PIPELINE LLC
Address:	17251 POLE LINE RD
City,State,Zip:	LOST HILLS, CA 93249
Site ID:	501457

PHILLIPS 66 PIPELINE LLC (Continued) **S107448890**

CERS ID: 110037996719
CERS Description: US EPA Air Emission Inventory System (EIS)

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43 **AERA ENERGY LLC** **UIC** **S125658449**
Target Property **KERN (County), CA** **N/A**

Actual: 625 ft.
Focus Map: 8

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403057442
Confidential Well:	No
Well Number:	912K-1
Direction:	Y
Lease Name:	Lease by Aera Energy LLC
Field Name:	Belridge, North
Area Name:	Any Area
Section:	01
Township:	28S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.52553
Longitude:	-119.7779
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

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44 **AERA ENERGY LLC** **UIC** **S125645951**
Target Property **KERN (County), CA** **N/A**

Actual: 623 ft.
Focus Map: 8

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402981932
Confidential Well:	No
Well Number:	534-1
Direction:	N
Lease Name:	Lease by Aera Energy LLC
Field Name:	Belridge, North
Area Name:	Any Area
Section:	01
Township:	28S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator

AERA ENERGY LLC (Continued) **S125645951**

Latitude:	35.52226
Longitude:	-119.7729
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

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45 **AERA ENERGY LLC** **UIC** **S125645105**
Target Property **KERN (County), CA** **N/A**

Actual: **626 ft.**
Focus Map: **8**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402975610
Confidential Well:	No
Well Number:	534D-1
Direction:	N
Lease Name:	Lease by Aera Energy LLC
Field Name:	Belridge, North
Area Name:	Any Area
Section:	01
Township:	28S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.52133
Longitude:	-119.7729
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

L46 **AERA ENERGY LLC** **UIC** **S125646538**
Target Property **KERN (County), CA** **N/A**

Site 1 of 2 in cluster L

Actual: **613 ft.**
Focus Map: **8**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA

AERA ENERGY LLC (Continued) **S125646538**

API Number:	0402985958
Confidential Well:	No
Well Number:	565-1
Direction:	N
Lease Name:	Lease by Aera Energy LLC
Field Name:	Belridge, North
Area Name:	Any Area
Section:	01
Township:	28S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.52049
Longitude:	-119.7660
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

L47 **AERA ENERGY LLC** **UIC** **S125656134**
Target **N/A**
Property **KERN (County), CA**

Site 2 of 2 in cluster L

Actual: **613 ft.**

Focus Map: **8**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403046491
Confidential Well:	No
Well Number:	565Z4-1
Direction:	Y
Lease Name:	Lease by Aera Energy LLC
Field Name:	Belridge, North
Area Name:	Any Area
Section:	01
Township:	28S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.52033
Longitude:	-119.7661
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported

AERA ENERGY LLC (Continued) **S125656134**

Aband Status: Not reported

M48 **AERA ENERGY LLC** **UIC** **S125653605**
Target Property **KERN (County), CA** **N/A**

Site 1 of 2 in cluster M

Actual: 615 ft.
Focus Map: 8

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403035567
Confidential Well:	No
Well Number:	565D2-1
Direction:	Y
Lease Name:	Lease by Aera Energy LLC
Field Name:	Belridge, North
Area Name:	Any Area
Section:	01
Township:	28S
Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.51959
Longitude:	-119.7661
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

M49 **AERA ENERGY LLC** **UIC** **S125646541**
Target Property **KERN (County), CA** **N/A**

Site 2 of 2 in cluster M

Actual: 615 ft.
Focus Map: 8

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402985961
Confidential Well:	No
Well Number:	565D-1
Direction:	Y
Lease Name:	Lease by Aera Energy LLC
Field Name:	Belridge, North
Area Name:	Any Area
Section:	01
Township:	28S

AERA ENERGY LLC (Continued) **S125646541**

Range:	20E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.51956
Longitude:	-119.7660
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

---

50 **AERA ENERGY LLC** **UIC** **S125648381**
Target Property **KERN (County), CA** **N/A**

Actual:
592 ft.

Focus Map:
12

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403005946
Confidential Well:	No
Well Number:	651JU-18
Direction:	N
Lease Name:	Unspecified
Field Name:	Belridge, South
Area Name:	Any Area
Section:	18
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.49893
Longitude:	-119.7517
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

51 **AERA ENERGY LLC** **UIC** **S125652023**
Target Property **KERN (County), CA** **N/A**

Actual: 580 ft.
Focus Map: 15

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403027513
Confidential Well:	No
Well Number:	WWD2-18
Direction:	N
Lease Name:	Unspecified
Field Name:	Belridge, South
Area Name:	Any Area
Section:	18
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.49141
Longitude:	-119.7461
Well Type:	Water Disposal
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

---

52 **AERA ENERGY LLC** **UIC** **S125652022**
Target Property **KERN (County), CA** **N/A**

Actual: 573 ft.
Focus Map: 15

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403027512
Confidential Well:	No
Well Number:	WWD1-18
Direction:	N
Lease Name:	Unspecified
Field Name:	Belridge, South
Area Name:	Any Area
Section:	18
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.48842
Longitude:	-119.7435
Well Type:	Water Disposal
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported

AERA ENERGY LLC (Continued) **S125652022**

EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

---

53 **AERA ENERGY LLC** **UIC** **S125650304**
Target Property **KERN (County), CA** **N/A**

Actual: 567 ft.
Focus Map: 15

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403017912
Confidential Well:	No
Well Number:	333KR-20
Direction:	N
Lease Name:	Lease by Aera Energy LLC
Field Name:	Belridge, South
Area Name:	Any Area
Section:	20
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.48013
Longitude:	-119.7370
Well Type:	Water Disposal
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

N54 **AERA ENERGY LLC** **UIC** **S125645288**
Target Property **KERN (County), CA** **N/A**

Site 1 of 3 in cluster N

Actual: 592 ft.
Focus Map: 15

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402977051
Confidential Well:	No
Well Number:	658P-20
Direction:	N
Lease Name:	Lease by Aera Energy LLC
Field Name:	Belridge, South
Area Name:	Any Area

AERA ENERGY LLC (Continued) **S125645288**

Section:	20
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.47097
Longitude:	-119.7321
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

N55 **AERA ENERGY LLC** **UIC** **S125646920**
Target Property **KERN (County), CA** **N/A**

Site 2 of 3 in cluster N

Actual: 593 ft.
Focus Map: 15

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402988375
Confidential Well:	No
Well Number:	658PL-20
Direction:	N
Lease Name:	Lease by Aera Energy LLC
Field Name:	Belridge, South
Area Name:	Any Area
Section:	20
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.47091
Longitude:	-119.7321
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

N56 **AERA ENERGY LLC** **UIC** **S125647673**
Target Property **KERN (County), CA** **N/A**

Site 3 of 3 in cluster N

Actual: **592 ft.**
Focus Map: **15**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403002477
Confidential Well:	No
Well Number:	658PG-20
Direction:	N
Lease Name:	Lease by Aera Energy LLC
Field Name:	Belridge, South
Area Name:	Any Area
Section:	20
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.47074
Longitude:	-119.7319
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

O57 **AERA ENERGY LLC** **UIC** **S125647856**
Target Property **KERN (County), CA** **N/A**

Site 1 of 2 in cluster O

Actual: **592 ft.**
Focus Map: **16**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403003043
Confidential Well:	No
Well Number:	661FG-29
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	29
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.46993
Longitude:	-119.7308
Well Type:	Steam Flood

AERA ENERGY LLC (Continued) **S125647856**

Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

O58 **AERA ENERGY LLC** **UIC** **S125646867**
Target Property **KERN (County), CA** **N/A**

Site 2 of 2 in cluster O

Actual: 593 ft.
Focus Map: 16

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402988114
Confidential Well:	No
Well Number:	661FL-29
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	29
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.46989
Longitude:	-119.7308
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

P59 **AERA ENERGY LLC** **UIC** **S125645292**
Target Property **KERN (County), CA** **N/A**

Site 1 of 3 in cluster P

Actual: 593 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402977055

AERA ENERGY LLC (Continued) **S125645292**

Confidential Well:	No
Well Number:	661P-29
Direction:	Y
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	29
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.46912
Longitude:	-119.7299
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

P60 **AERA ENERGY LLC** **UIC** **S125646869**
Target Property **KERN (County), CA** **N/A**

Site 2 of 3 in cluster P

Actual: 593 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402988116
Confidential Well:	No
Well Number:	661PL-29
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	29
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.46912
Longitude:	-119.7298
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

P61 **AERA ENERGY LLC** **UIC** **S125647676**
Target Property **KERN (County), CA** **N/A**

Site 3 of 3 in cluster P

Actual: **593 ft.**
Focus Map: **19**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403002480
Confidential Well:	No
Well Number:	661PG-29
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	29
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.46909
Longitude:	-119.7298
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

Q62 **AERA ENERGY LLC** **UIC** **S125646868**
Target Property **KERN (County), CA** **N/A**

Site 1 of 2 in cluster Q

Actual: **590 ft.**
Focus Map: **19**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402988115
Confidential Well:	No
Well Number:	672FL-29
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	29
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.46860
Longitude:	-119.7288
Well Type:	Steam Flood

AERA ENERGY LLC (Continued) **S125646868**

Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

Q63 **AERA ENERGY LLC** **UIC** **S111553319**
Target Property **KERN (County), CA** **N/A**

Site 2 of 2 in cluster Q

Actual: 593 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402977056
Confidential Well:	No
Well Number:	672F-29
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	29
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.46825
Longitude:	-119.7288
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

R64 **AERA ENERGY LLC** **UIC** **S125645298**
Target Property **KERN (County), CA** **N/A**

Site 1 of 2 in cluster R

Actual: 590 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402977103

AERA ENERGY LLC (Continued) **S125645298**

Confidential Well:	No
Well Number:	672P-29
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	29
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.46768
Longitude:	-119.7276
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

R65 **AERA ENERGY LLC** **UIC** **S125646827**
Target Property **KERN (County), CA** **N/A**

Site 2 of 2 in cluster R

Actual: 590 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402987900
Confidential Well:	No
Well Number:	672PL-29
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	29
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.46768
Longitude:	-119.7276
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

66 **AERA ENERGY LLC** **UIC** **S125647677**
Target Property **KERN (County), CA** **N/A**

Actual: **591 ft.**
Focus Map: **19**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403002481
Confidential Well:	No
Well Number:	672PG-29
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	29
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.46709
Longitude:	-119.7269
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

S67 **AERA ENERGY LLC** **UIC** **S125646748**
Target Property **KERN (County), CA** **N/A**

Site 1 of 2 in cluster S

Actual: **593 ft.**
Focus Map: **19**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402987572
Confidential Well:	No
Well Number:	683FL-29
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	29
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.46639
Longitude:	-119.7265
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610

AERA ENERGY LLC (Continued) **S125646748**

Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

S68 **AERA ENERGY LLC** **UIC** **S125647675**
Target Property **KERN (County), CA** **N/A**

Site 2 of 2 in cluster S

Actual: 593 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403002479
Confidential Well:	No
Well Number:	683FG-29
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	29
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.46637
Longitude:	-119.7264
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

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69 **AERA ENERGY LLC** **UIC** **S125646750**
Target Property **KERN (County), CA** **N/A**

Actual: 594 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402987575
Confidential Well:	No
Well Number:	683PL-29
Direction:	N
Lease Name:	DTR

AERA ENERGY LLC (Continued) **S125646750**

Field Name:	Belridge, South
Area Name:	Any Area
Section:	29
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.46549
Longitude:	-119.7254
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

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70 **AERA ENERGY LLC** **UIC** **S125645025**
Target Property **KERN (County), CA** **N/A**

Actual: **593 ft.**
Focus Map: **19**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402974874
Confidential Well:	No
Well Number:	613R-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.46500
Longitude:	-119.7248
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

T71 **AERA ENERGY LLC** **UIC** **S125646732**
Target Property **KERN (County), CA** **N/A**

Site 1 of 2 in cluster T

Actual: **593 ft.**
Focus Map: **19**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402987452
Confidential Well:	No
Well Number:	614FL-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.46448
Longitude:	-119.7242
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

T72 **AERA ENERGY LLC** **UIC** **S125647674**
Target Property **KERN (County), CA** **N/A**

Site 2 of 2 in cluster T

Actual: **593 ft.**
Focus Map: **19**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403002478
Confidential Well:	No
Well Number:	614FG-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.46432
Longitude:	-119.7240
Well Type:	Steam Flood

AERA ENERGY LLC (Continued) **S125647674**

Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

---

73 **AERA ENERGY LLC** **UIC** **S125647225**
Target Property **KERN (County), CA** **N/A**

Actual: 591 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403000066
Confidential Well:	No
Well Number:	614U-28
Direction:	Y
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.46423
Longitude:	-119.7234
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

U74 **AERA ENERGY LLC** **UIC** **S125645290**
Target Property **KERN (County), CA** **N/A**

Site 1 of 2 in cluster U

Actual: 593 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402977053
Confidential Well:	No
Well Number:	614P-28

AERA ENERGY LLC (Continued) **S125645290**

Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.46368
Longitude:	-119.7232
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

U75 **AERA ENERGY LLC** **UIC** **S125646733**
Target Property **KERN (County), CA** **N/A**

Site 2 of 2 in cluster U

Actual: 593 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402987453
Confidential Well:	No
Well Number:	614PL-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.46365
Longitude:	-119.7232
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

V76 **AERA ENERGY LLC** **UIC** **S125645130**
Target Property **KERN (County), CA** **N/A**

Site 1 of 3 in cluster V

Actual: **590 ft.**
Focus Map: **19**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402975890
Confidential Well:	No
Well Number:	624A-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.46320
Longitude:	-119.7222
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

V77 **AERA ENERGY LLC** **UIC** **S125644255**
Target Property **KERN (County), CA** **N/A**

Site 2 of 3 in cluster V

Actual: **592 ft.**
Focus Map: **19**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402968849
Confidential Well:	No
Well Number:	625F-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.46280
Longitude:	-119.7222
Well Type:	Steam Flood

AERA ENERGY LLC (Continued) **S125644255**

Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

V78 **AERA ENERGY LLC** **UIC** **S125644762**
Target Property **KERN (County), CA** **N/A**

Site 3 of 3 in cluster V

Actual: 592 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402972999
Confidential Well:	No
Well Number:	6625F-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.46271
Longitude:	-119.7221
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

---

79 **AERA ENERGY LLC** **UIC** **S125658491**
Target Property **KERN (County), CA** **N/A**

Actual: 583 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403057561
Confidential Well:	No
Well Number:	543E4-33

AERA ENERGY LLC (Continued) **S125658491**

Direction:	Y
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	33
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.46196
Longitude:	-119.7186
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

W80 **AERA ENERGY LLC** **UIC** **S125644232**
Target Property **KERN (County), CA** **N/A**

Site 1 of 2 in cluster W

Actual: 592 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402968753
Confidential Well:	No
Well Number:	625P-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.46185
Longitude:	-119.7210
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

W81 **AERA ENERGY LLC** **UIC** **S125644763**
Target Property **KERN (County), CA** **N/A**

Site 2 of 2 in cluster W

Actual: **592 ft.**
Focus Map: **19**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402973000
Confidential Well:	No
Well Number:	6625P-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.46175
Longitude:	-119.7209
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

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82 **AERA ENERGY LLC** **UIC** **S125641268**
Target Property **KERN (County), CA** **N/A**

Actual: **590 ft.**
Focus Map: **19**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402931389
Confidential Well:	No
Well Number:	35A-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.46143
Longitude:	-119.7202
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610

AERA ENERGY LLC (Continued) **S125641268**

Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

---

83 **AERA ENERGY LLC** **UIC** **S125644764**
Target Property **KERN (County), CA** **N/A**

Actual: 591 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402973001
Confidential Well:	No
Well Number:	6636F-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.46083
Longitude:	-119.7199
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

X84 **AERA ENERGY LLC** **UIC** **S125645127**
Target Property **KERN (County), CA** **N/A**

Site 1 of 2 in cluster X

Actual: 572 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402975887
Confidential Well:	No
Well Number:	656-28
Direction:	N
Lease Name:	DTR

AERA ENERGY LLC (Continued) **S125645127**

Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.46065
Longitude:	-119.7144
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

X85 **AERA ENERGY LLC** **UIC** **S125641267**
Target Property **KERN (County), CA** **N/A**

Site 2 of 2 in cluster X

Actual: 573 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402931366
Confidential Well:	No
Well Number:	56-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.46052
Longitude:	-119.7144
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

Y86 **AERA ENERGY LLC** **UIC** **S125644235**
Target Property **KERN (County), CA** **N/A**

Site 1 of 4 in cluster Y

Actual: **592 ft.**
Focus Map: **19**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402968757
Confidential Well:	No
Well Number:	636P-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.46003
Longitude:	-119.7190
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

Y87 **AERA ENERGY LLC** **UIC** **S125644765**
Target Property **KERN (County), CA** **N/A**

Site 2 of 4 in cluster Y

Actual: **593 ft.**
Focus Map: **19**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402973002
Confidential Well:	No
Well Number:	6636P-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.46002
Longitude:	-119.7191
Well Type:	Steam Flood

AERA ENERGY LLC (Continued) **S125644765**

Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

Z88 **AERA ENERGY LLC** **UIC** **S125644239**
Target Property **KERN (County), CA** **N/A**

Site 1 of 2 in cluster Z

Actual: 575 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402968761
Confidential Well:	No
Well Number:	656P-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.46001
Longitude:	-119.7144
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

Z89 **AERA ENERGY LLC** **UIC** **S125644769**
Target Property **KERN (County), CA** **N/A**

Site 2 of 2 in cluster Z

Actual: 575 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402973006

AERA ENERGY LLC (Continued) **S125644769**

Confidential Well:	No
Well Number:	6656P-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.45983
Longitude:	-119.7143
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

Y90 **AERA ENERGY LLC** **UIC** **S125659493**
Target Property **KERN (County), CA** **N/A**

Site 3 of 4 in cluster Y

Actual: 595 ft.

Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403067011
Confidential Well:	No
Well Number:	C936SR-28
Direction:	Y
Lease Name:	Unspecified
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Notice of Intent to Drill
Latitude:	35.45972
Longitude:	-119.7190
Well Type:	Oil & Gas (Cyclic Steam)
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

Y91 **AERA ENERGY LLC** **UIC** **S125659491**
Target Property **KERN (County), CA** **N/A**

Site 4 of 4 in cluster Y

Actual: **595 ft.**
Focus Map: **19**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403067007
Confidential Well:	No
Well Number:	C536D1-28
Direction:	Y
Lease Name:	Unspecified
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Notice of Intent to Drill
Latitude:	35.45967
Longitude:	-119.7188
Well Type:	Oil & Gas (Cyclic Steam)
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

AA92 **AERA ENERGY LLC** **UIC** **S125648439**
Target Property **KERN (County), CA** **N/A**

Site 1 of 2 in cluster AA

Actual: **592 ft.**
Focus Map: **19**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403006350
Confidential Well:	No
Well Number:	647FAA-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.45914
Longitude:	-119.7175
Well Type:	Steam Flood

AERA ENERGY LLC (Continued) **S125648439**

Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

---

93 **AERA ENERGY LLC** **UIC** **S125644780**
Target Property **KERN (County), CA** **N/A**

Actual: 597 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402973141
Confidential Well:	No
Well Number:	6647F-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.45900
Longitude:	-119.7182
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

AA94 **AERA ENERGY LLC** **UIC** **S125644258**
Target Property **KERN (County), CA** **N/A**

Site 2 of 2 in cluster AA

Actual: 595 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402968886
Confidential Well:	No
Well Number:	647F-28

AERA ENERGY LLC (Continued) **S125644258**

Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.45900
Longitude:	-119.7180
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

AB95 Target Property **AERA ENERGY LLC** **UIC** **S125644240**
N/A

KERN (County), CA

Site 1 of 3 in cluster AB

Actual: 581 ft.

Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402968762
Confidential Well:	No
Well Number:	657F-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.45899
Longitude:	-119.7155
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

AB96 **AERA ENERGY LLC** **UIC** **S125644781**
Target Property **KERN (County), CA** **N/A**

Site 2 of 3 in cluster AB

Actual: 581 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402973142
Confidential Well:	No
Well Number:	6657F-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.45897
Longitude:	-119.7153
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

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97 **AERA ENERGY LLC** **UIC** **S125641270**
Target Property **KERN (County), CA** **N/A**

Actual: 586 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402931531
Confidential Well:	No
Well Number:	57J-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.45866
Longitude:	-119.7161
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610

AERA ENERGY LLC (Continued) **S125641270**

Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

AC98 **AERA ENERGY LLC** **UIC** **S125645033**
Target Property **KERN (County), CA** **N/A**

Site 1 of 2 in cluster AC

Actual: 580 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402974979
Confidential Well:	No
Well Number:	657-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.45861
Longitude:	-119.7144
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

AB99 **AERA ENERGY LLC** **UIC** **S125648443**
Target Property **KERN (County), CA** **N/A**

Site 3 of 3 in cluster AB

Actual: 584 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403006354
Confidential Well:	No
Well Number:	657MAA-28

AERA ENERGY LLC (Continued) **S125648443**

Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.45853
Longitude:	-119.7155
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

AC100 **AERA ENERGY LLC** **UIC** **S125644241**
Target **N/A**
Property **KERN (County), CA**

Site 2 of 2 in cluster AC

Actual: **583 ft.**

Focus Map: **19**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402968763
Confidential Well:	No
Well Number:	657P-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.45820
Longitude:	-119.7144
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

101 **AERA ENERGY LLC** **UIC** **S125648368**
Target Property **KERN (County), CA** **N/A**

Actual: 580 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403005854
Confidential Well:	No
Well Number:	668HAA-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.45763
Longitude:	-119.7125
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

AD102 **AERA ENERGY LLC** **UIC** **S125648369**
Target Property **KERN (County), CA** **N/A**

Site 1 of 2 in cluster AD

Actual: 576 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403005855
Confidential Well:	No
Well Number:	678FAA-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.45735
Longitude:	-119.7112
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610

AERA ENERGY LLC (Continued) **S125648369**

Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

AD103 **AERA ENERGY LLC** **UIC** **S125644784**
Target Property **KERN (County), CA** **N/A**

Site 2 of 2 in cluster AD

Actual: 577 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402973145
Confidential Well:	No
Well Number:	6678F-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.45721
Longitude:	-119.7111
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

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104 **AERA ENERGY LLC** **UIC** **S125648370**
Target Property **KERN (County), CA** **N/A**

Actual: 580 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403005856
Confidential Well:	No
Well Number:	678MAA-28
Direction:	N
Lease Name:	DTR

AERA ENERGY LLC (Continued) **S125648370**

Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.45648
Longitude:	-119.7111
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

AE105 **AERA ENERGY LLC** **UIC** **S125648357**
Target Property **KERN (County), CA** **N/A**

Site 1 of 2 in cluster AE

Actual: **572 ft.**
Focus Map: **19**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403005744
Confidential Well:	No
Well Number:	688MAA-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.45644
Longitude:	-119.7089
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

AF106 **AERA ENERGY LLC** **UIC** **S125644246**
Target Property **KERN (County), CA** **N/A**

Site 1 of 2 in cluster AF

Actual: 577 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402968769
Confidential Well:	No
Well Number:	678P-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.45638
Longitude:	-119.7099
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

AF107 **AERA ENERGY LLC** **UIC** **S125648371**
Target Property **KERN (County), CA** **N/A**

Site 2 of 2 in cluster AF

Actual: 577 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403005857
Confidential Well:	No
Well Number:	678PAA-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.45637
Longitude:	-119.7100
Well Type:	Steam Flood

AERA ENERGY LLC (Continued) **S125648371**

Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

AG108 **AERA ENERGY LLC** **UIC** **S125645985**
Target Property **KERN (County), CA** **N/A**

Site 1 of 3 in cluster AG

Actual: 625 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402982225
Confidential Well:	No
Well Number:	538A-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.45595
Longitude:	-119.7201
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

AE109 **AERA ENERGY LLC** **UIC** **S125645093**
Target Property **KERN (County), CA** **N/A**

Site 2 of 2 in cluster AE

Actual: 573 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402975507

AERA ENERGY LLC (Continued) **S125645093**

Confidential Well:	No
Well Number:	688A-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.45594
Longitude:	-119.7088
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

AG110 **AERA ENERGY LLC** **UIC** **S125654901**
Target Property **KERN (County), CA** **N/A**

Site 2 of 3 in cluster AG

Actual: 623 ft.

Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403041570
Confidential Well:	No
Well Number:	738AL-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.45589
Longitude:	-119.7199
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

AG111 **AERA ENERGY LLC** **UIC** **S125654900**
Target Property **KERN (County), CA** **N/A**

Site 3 of 3 in cluster AG

Actual: 622 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403041569
Confidential Well:	No
Well Number:	738AU-28
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	28
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.45584
Longitude:	-119.7199
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

AH112 **AERA ENERGY LLC** **UIC** **S125648374**
Target Property **KERN (County), CA** **N/A**

Site 1 of 2 in cluster AH

Actual: 574 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403005860
Confidential Well:	No
Well Number:	681FAA-33
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	33
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.45546
Longitude:	-119.7087
Well Type:	Steam Flood

AERA ENERGY LLC (Continued) **S125648374**

Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

AH113 **AERA ENERGY LLC** **UIC** **S125644820**
Target Property **KERN (County), CA** **N/A**

Site 2 of 2 in cluster AH

Actual: 574 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402973298
Confidential Well:	No
Well Number:	6681F-33
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	33
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.45543
Longitude:	-119.7088
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

AI114 **AERA ENERGY LLC** **UIC** **S125641893**
Target Property **KERN (County), CA** **N/A**

Site 1 of 4 in cluster AI

Actual: 557 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402949257

AERA ENERGY LLC (Continued) **S125641893**

Confidential Well:	No
Well Number:	621FX-34
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	34
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	GPS
Latitude:	35.45542
Longitude:	-119.7044
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

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115 **AERA ENERGY LLC** **UIC** **S125654833**
Target Property **KERN (County), CA** **N/A**

Actual: 570 ft.

Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0403041233
Confidential Well:	No
Well Number:	681HAA-33
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	33
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Well Summary
Latitude:	35.45541
Longitude:	-119.7077
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

AI116 **AERA ENERGY LLC** **UIC** **S125644156**
Target Property **KERN (County), CA** **N/A**

Site 2 of 4 in cluster AI

Actual: **557 ft.**
Focus Map: **19**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402968249
Confidential Well:	No
Well Number:	621F-34
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	34
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.45541
Longitude:	-119.7043
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

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117 **AERA ENERGY LLC** **UIC** **S125646606**
Target Property **KERN (County), CA** **N/A**

Actual: **565 ft.**
Focus Map: **19**

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402986640
Confidential Well:	No
Well Number:	6611F-34
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	34
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.45540
Longitude:	-119.7066
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610

AERA ENERGY LLC (Continued) **S125646606**

Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

AI118 **AERA ENERGY LLC** **UIC** **S125644863**
Target Property **KERN (County), CA** **N/A**

Site 3 of 4 in cluster AI

Actual: 557 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402973668
Confidential Well:	No
Well Number:	6621F-34
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	34
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.45540
Longitude:	-119.7044
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

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119 **AERA ENERGY LLC** **UIC** **S125641281**
Target Property **KERN (County), CA** **N/A**

Actual: 554 ft.
Focus Map: 20

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402933526
Confidential Well:	No
Well Number:	21-34
Direction:	N
Lease Name:	DTR

AERA ENERGY LLC (Continued) **S125641281**

Field Name:	Belridge, South
Area Name:	Any Area
Section:	34
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.45517
Longitude:	-119.7033
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

AJ120 **AERA ENERGY LLC** **UIC** **S125642731**
Target Property **KERN (County), CA** **N/A**

Site 1 of 2 in cluster AJ

Actual: 629 ft.

Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402959201
Confidential Well:	No
Well Number:	521N-33
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	33
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.45462
Longitude:	-119.7217
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

121 **AERA ENERGY LLC** **UIC** **S125645003**
Target Property **KERN (County), CA** **N/A**

Actual: 623 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402974675
Confidential Well:	No
Well Number:	531L-33
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	33
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.45455
Longitude:	-119.7206
Well Type:	Water Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported
EPA Well:	Not reported
Location:	Not reported
Dryhole:	Not reported
Well DEP:	Not reported
Aband Status:	Not reported

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122 **AERA ENERGY LLC** **UIC** **S125644339**
Target Property **KERN (County), CA** **N/A**

Actual: 629 ft.
Focus Map: 19

UIC:

Name:	AERA ENERGY LLC
Address:	Not reported
City,State,Zip:	CA
API Number:	0402969356
Confidential Well:	No
Well Number:	611S-33
Direction:	N
Lease Name:	DTR
Field Name:	Belridge, South
Area Name:	Any Area
Section:	33
Township:	28S
Range:	21E
Base And Meridian; Part Of The PLSS:	MD
GIS Source Code:	Operator
Latitude:	35.45454
Longitude:	-119.7231
Well Type:	Steam Flood
Well Status:	Not reported
Operator Code:	A0610
Operator Name:	Aera Energy LLC
BLM Well:	Not reported

AERA ENERGY LLC (Continued) **S125644339**

EPA Well: Not reported
Location: Not reported
Dryhole: Not reported
Well DEP: Not reported
Aband Status: Not reported

AJ123 **AERA ENERGY LLC** **UIC** **S125653407**
Target **N/A**
Property **KERN (County), CA**

Site 2 of 2 in cluster AJ

Actual: **626 ft.**
Focus Map: **19**

UIC:
Name: AERA ENERGY LLC
Address: Not reported
City,State,Zip: CA
API Number: 0403034492
Confidential Well: No
Well Number: 521NR2-33
Direction: Y
Lease Name: DTR
Field Name: Belridge, South
Area Name: Any Area
Section: 33
Township: 28S
Range: 21E
Base And Meridian; Part Of The PLSS: MD
GIS Source Code: GPS
Latitude: 35.45450
Longitude: -119.7212
Well Type: Water Flood
Well Status: Not reported
Operator Code: A0610
Operator Name: Aera Energy LLC
BLM Well: Not reported
EPA Well: Not reported
Location: Not reported
Dryhole: Not reported
Well DEP: Not reported
Aband Status: Not reported

C124 **WASTEWATER PITS** **S127594134**
South **N/A**
< 1/8 **, CA**
0.014 mi.
76 ft. **Site 3 of 3 in cluster C**

Actual: **647 ft.**
Focus Map: **8**

WASTEWATER PITS:
Name: Not reported
Address: Not reported
City,State,Zip: CA
Status: Inactive
Field: Belridge North
Lease: Sec 35
Operator: Aera Energy LLC
Geo Tracker Global ID: T10000006758

(Continued) **S127594134**

Number of Ponds: 1
Latitude: 35.53405
Longitude: -119.78276

AI125 **WASTEWATER PITS** **S127593524**
North **N/A**
< 1/8 **, CA**
0.028 mi.
147 ft. **Site 4 of 4 in cluster AI**

Actual:
557 ft.

Focus Map:
19

WASTEWATER PITS:
Name: Not reported
Address: Not reported
City,State,Zip: CA
Status: Closed - NFA
Field: Belridge South
Lease: Aera Belridge South Facility Ponds
Operator: Aera Energy LLC
Geo Tracker Global ID: T10000008078
Number of Ponds: 1
Latitude: 35.45568
Longitude: -119.70469

---

126 **WASTEWATER PITS** **S127593546**
ESE **N/A**
< 1/8 **, CA**
0.031 mi.
162 ft.

Actual:
602 ft.

Focus Map:
19

WASTEWATER PITS:
Name: Not reported
Address: Not reported
City,State,Zip: CA
Status: Inactive
Field: Belridge South
Lease: Aera Belridge South Facility Ponds
Operator: Aera Energy LLC
Geo Tracker Global ID: T10000008078
Number of Ponds: 1
Latitude: 35.45673
Longitude: -119.71796

---

127 **WASTEWATER PITS** **S127594356**
NW **N/A**
< 1/8 **, CA**
0.032 mi.
169 ft.

Actual:
672 ft.

Focus Map:
4

WASTEWATER PITS:
Name: Not reported
Address: Not reported
City,State,Zip: CA
Status: Inactive
Field: Belridge North
Lease: Section 27

(Continued) **S127594356**

Operator: Aera Energy LLC
Geo Tracker Global ID: T10000006757
Number of Ponds: 1
Latitude: 35.55681
Longitude: -119.81161

128
South
< 1/8
0.036 mi.
189 ft.

Actual:
580 ft.

Focus Map:
19

, CA

WASTEWATER PITS **S127593557**
N/A

WASTEWATER PITS:
Name: Not reported
Address: Not reported
City,State,Zip: CA
Status: Inactive
Field: Belridge South
Lease: Aera Belridge South Facility Ponds
Operator: Aera Energy LLC
Geo Tracker Global ID: T10000008078
Number of Ponds: 1
Latitude: 35.45701
Longitude: -119.71243

AK129
South
< 1/8
0.042 mi.
222 ft.

Actual:
645 ft.

Focus Map:
8

, CA

Site 1 of 2 in cluster AK

WASTEWATER PITS **S127594023**
N/A

WASTEWATER PITS:
Name: Not reported
Address: Not reported
City,State,Zip: CA
Status: Inactive
Field: Belridge North
Lease: Sec 35
Operator: Aera Energy LLC
Geo Tracker Global ID: T10000006758
Number of Ponds: 1
Latitude: 35.53503
Longitude: -119.78417

AK130
South
< 1/8
0.042 mi.
222 ft.

Actual:
645 ft.

Focus Map:
8

NORTH BELRIDGE OIL FIELD, SECTION 35 LEASE
NORTH BELRIDGE OIL FIELD
BELRIDGE NORTH, CA

Site 2 of 2 in cluster AK

Cortese **S121759357**
ENF **N/A**
CERS

CORTESE:
Name: NORTH BELRIDGE OIL FIELD, SECTION 35 LEASE
Address: NORTH BELRIDGE OIL FIELD
City,State,Zip: BELRIDGE NORTH, CA
Region: CORTESE

NORTH BELRIDGE OIL FIELD, SECTION 35 LEASE (Continued) **S121759357**

Envirostor Id:	Not reported
Global ID:	Not reported
Site/Facility Type:	Not reported
Cleanup Status:	Not reported
Status Date:	Not reported
Site Code:	Not reported
Latitude:	Not reported
Longitude:	Not reported
Owner:	Not reported
Enf Type:	Not reported
Swat R:	Not reported
Flag:	CORTESE
Order No:	Not reported
Waste Discharge System No:	Not reported
Effective Date:	12/07/2014
Region 2:	Not reported
WID Id:	Not reported
Solid Waste Id No:	Not reported
Waste Management Uit Name:	Not reported
File Name:	Cease Desist Orders & Cleanup Abatement Orders

ENF:

Name:	NORTH BELRIDGE OIL FIELD, SECTION 35 LEASE
Address:	NORTH BELRIDGE OIL FIELD
City,State,Zip:	BELRIDGE NORTH, CA
Region:	Not reported
Facility Id:	814153
Agency Name:	Aera Energy LLC
Place Type:	Mining
Place Subtype:	Oil/Gas Extraction
Facility Type:	Industrial
Agency Type:	Privately-Owned Business
# Of Agencies:	1
Place Latitude:	35.53503
Place Longitude:	-119.78417
SIC Code 1:	Not reported
SIC Desc 1:	Not reported
SIC Code 2:	Not reported
SIC Desc 2:	Not reported
SIC Code 3:	Not reported
SIC Desc 3:	Not reported
NAICS Code 1:	Not reported
NAICS Desc 1:	Not reported
NAICS Code 2:	Not reported
NAICS Desc 2:	Not reported
NAICS Code 3:	Not reported
NAICS Desc 3:	Not reported
# Of Places:	1
Source Of Facility:	Reg Meas
Design Flow:	Not reported
Threat To Water Quality:	Not reported
Complexity:	Not reported
Pretreatment:	Not reported
Facility Waste Type:	Not reported
Facility Waste Type 2:	Not reported
Facility Waste Type 3:	Not reported
Facility Waste Type 4:	Not reported

NORTH BELRIDGE OIL FIELD, SECTION 35 LEASE (Continued) **S121759357**

Program:	DISCHLND
Program Category1:	UNREGS
Program Category2:	UNREGS
# Of Programs:	1
WDID:	Not reported
Reg Measure Id:	400412
Reg Measure Type:	Unregulated
Region:	Not reported
Order #:	Not reported
Npdes# CA#:	Not reported
Major-Minor:	Not reported
Npdes Type:	Not reported
Reclamation:	Not reported
Dredge Fill Fee:	Not reported
301H:	Not reported
Application Fee Amt Received:	Not reported
Status:	Active
Status Date:	03/30/2015
Effective Date:	12/07/2014
Expiration/Review Date:	Not reported
Termination Date:	Not reported
WDR Review - Amend:	Not reported
WDR Review - Revise/Renew:	Not reported
WDR Review - Rescind:	Not reported
WDR Review - No Action Required:	Not reported
WDR Review - Pending:	Not reported
WDR Review - Planned:	Not reported
Status Enrollee:	N
Individual/General:	I
Fee Code:	Not reported
Direction/Voice:	Passive
Enforcement Id(EID):	401974
Region:	Not reported
Order / Resolution Number:	R5-2015-0735
Enforcement Action Type:	Clean-up and Abatement Order
Effective Date:	11/20/2015
Adoption/Issuance Date:	11/20/2015
Achieve Date:	Not reported
Termination Date:	Not reported
ACL Issuance Date:	Not reported
EPL Issuance Date:	Not reported
Status:	Active
Title:	CAO R5-2015-0735 for Aera Engery LLC
Description:	Final CAO
Program:	ENFCAO
Latest Milestone Completion Date:	Not reported
# Of Programs1:	1
Total Assessment Amount:	0
Initial Assessed Amount:	0
Liability $ Amount:	0
Project $ Amount:	0
Liability $ Paid:	0
Project $ Completed:	0
Total $ Paid/Completed Amount:	0
Name:	NORTH BELRIDGE OIL FIELD, SECTION 35 LEASE
Address:	NORTH BELRIDGE OIL FIELD

NORTH BELRIDGE OIL FIELD, SECTION 35 LEASE (Continued) **S121759357**

City,State,Zip:	BELRIDGE NORTH, CA
Region:	Not reported
Facility Id:	814153
Agency Name:	Aera Energy LLC
Place Type:	Mining
Place Subtype:	Oil/Gas Extraction
Facility Type:	Industrial
Agency Type:	Privately-Owned Business
# Of Agencies:	1
Place Latitude:	35.53503
Place Longitude:	-119.78417
SIC Code 1:	Not reported
SIC Desc 1:	Not reported
SIC Code 2:	Not reported
SIC Desc 2:	Not reported
SIC Code 3:	Not reported
SIC Desc 3:	Not reported
NAICS Code 1:	Not reported
NAICS Desc 1:	Not reported
NAICS Code 2:	Not reported
NAICS Desc 2:	Not reported
NAICS Code 3:	Not reported
NAICS Desc 3:	Not reported
# Of Places:	1
Source Of Facility:	Reg Meas
Design Flow:	Not reported
Threat To Water Quality:	Not reported
Complexity:	Not reported
Pretreatment:	Not reported
Facility Waste Type:	Not reported
Facility Waste Type 2:	Not reported
Facility Waste Type 3:	Not reported
Facility Waste Type 4:	Not reported
Program:	DISCHLND
Program Category1:	UNREGS
Program Category2:	UNREGS
# Of Programs:	1
WDID:	Not reported
Reg Measure Id:	400412
Reg Measure Type:	Unregulated
Region:	Not reported
Order #:	Not reported
Npdes# CA#:	Not reported
Major-Minor:	Not reported
Npdes Type:	Not reported
Reclamation:	Not reported
Dredge Fill Fee:	Not reported
301H:	Not reported
Application Fee Amt Received:	Not reported
Status:	Active
Status Date:	03/30/2015
Effective Date:	12/07/2014
Expiration/Review Date:	Not reported
Termination Date:	Not reported
WDR Review - Amend:	Not reported
WDR Review - Revise/Renew:	Not reported
WDR Review - Rescind:	Not reported

NORTH BELRIDGE OIL FIELD, SECTION 35 LEASE (Continued) **S121759357**

WDR Review - No Action Required:	Not reported
WDR Review - Pending:	Not reported
WDR Review - Planned:	Not reported
Status Enrollee:	N
Individual/General:	I
Fee Code:	Not reported
Direction/Voice:	Passive
Enforcement Id(EID):	400688
Region:	Not reported
Order / Resolution Number:	Not reported
Enforcement Action Type:	Notice of Violation
Effective Date:	04/10/2015
Adoption/Issuance Date:	04/10/2015
Achieve Date:	Not reported
Termination Date:	04/10/2015
ACL Issuance Date:	Not reported
EPL Issuance Date:	Not reported
Status:	Historical
Title:	NOV 04/10/2015 for Aera Engery LLC
Description:	Not reported
Program:	DISCHLND
Latest Milestone Completion Date:	Not reported
# Of Programs1:	1
Total Assessment Amount:	0
Initial Assessed Amount:	0
Liability $ Amount:	0
Project $ Amount:	0
Liability $ Paid:	0
Project $ Completed:	0
Total $ Paid/Completed Amount:	0

CERS:

Name:	NORTH BELRIDGE OIL FIELD, SECTION 35 LEASE
Address:	NORTH BELRIDGE OIL FIELD
City,State,Zip:	BELRIDGE NORTH, CA
Site ID:	276753
CERS ID:	814153
CERS Description:	Waste Discharge Requirements

Violations:

Site ID:	276753
Site Name:	North Belridge Oil Field, Section 35 Lease
Violation Date:	12-17-2014
Citation:	California Water Code
Violation Description:	Not reported
Violation Notes:	Violation of CWC 13260(a), discharge without a WDRs.
Violation Division:	Water Boards
Violation Program:	DISCHLND
Violation Source:	CIWQS,

Evaluation:

Eval General Type:	Compliance Evaluation Inspection
Eval Date:	12-17-2014
Violations Found:	Yes
Eval Type:	RWQCB Type B compliance inspection
Eval Notes:	Not reported
Eval Division:	Water Boards

NORTH BELRIDGE OIL FIELD, SECTION 35 LEASE (Continued) **S121759357**

Eval Program: WDRMINING
Eval Source: CIWQS,

Eval General Type: Compliance Evaluation Inspection
Eval Date: 12-17-2014
Violations Found: Yes
Eval Type: RWQCB Type B compliance inspection
Eval Notes: Not reported
Eval Division: Water Boards
Eval Program: ENFCAO
Eval Source: CIWQS,

Eval General Type: Compliance Evaluation Inspection
Eval Date: 12-17-2014
Violations Found: Yes
Eval Type: RWQCB Type B compliance inspection
Eval Notes: Not reported
Eval Division: Water Boards
Eval Program: DISCHLND
Eval Source: CIWQS,

Enforcement Action:
Site ID: 276753
Site Name: North Belridge Oil Field, Section 35 Lease
Site Address: NORTH BELRIDGE OIL FIELD
Site City: BELRIDGE NORTH
Site Zip: Not reported
Enf Action Date: 04-10-2015
Enf Action Type: Notice of Violation (Water)
Enf Action Description: Notice of Violation Letter (Informal)
Enf Action Notes: Not reported
Enf Action Division: Water Boards
Enf Action Program: DISCHLND
Enf Action Source: CIWQS,

Site ID: 276753
Site Name: North Belridge Oil Field, Section 35 Lease
Site Address: NORTH BELRIDGE OIL FIELD
Site City: BELRIDGE NORTH
Site Zip: Not reported
Enf Action Date: 04-10-2015
Enf Action Type: Notice of Violation (Water)
Enf Action Description: Notice of Violation Letter (Informal)
Enf Action Notes: Not reported
Enf Action Division: Water Boards
Enf Action Program: ENFCAO
Enf Action Source: CIWQS,

Site ID: 276753
Site Name: North Belridge Oil Field, Section 35 Lease
Site Address: NORTH BELRIDGE OIL FIELD
Site City: BELRIDGE NORTH
Site Zip: Not reported
Enf Action Date: 04-10-2015
Enf Action Type: Notice of Violation (Water)
Enf Action Description: Notice of Violation Letter (Informal)
Enf Action Notes: Not reported

NORTH BELRIDGE OIL FIELD, SECTION 35 LEASE (Continued) **S121759357**

Enf Action Division: Water Boards
Enf Action Program: WDRMINING
Enf Action Source: CIWQS,

Site ID: 276753
Site Name: North Belridge Oil Field, Section 35 Lease
Site Address: NORTH BELRIDGE OIL FIELD
Site City: BELRIDGE NORTH
Site Zip: Not reported
Enf Action Date: 11-20-2015
Enf Action Type: Clean-up and Abatement Order
Enf Action Description: Clean-up and Abatement Order
Enf Action Notes: Not reported
Enf Action Division: Water Boards
Enf Action Program: DISCHLND
Enf Action Source: CIWQS,

Site ID: 276753
Site Name: North Belridge Oil Field, Section 35 Lease
Site Address: NORTH BELRIDGE OIL FIELD
Site City: BELRIDGE NORTH
Site Zip: Not reported
Enf Action Date: 11-20-2015
Enf Action Type: Clean-up and Abatement Order
Enf Action Description: Clean-up and Abatement Order
Enf Action Notes: Not reported
Enf Action Division: Water Boards
Enf Action Program: ENFCAO
Enf Action Source: CIWQS,

Site ID: 276753
Site Name: North Belridge Oil Field, Section 35 Lease
Site Address: NORTH BELRIDGE OIL FIELD
Site City: BELRIDGE NORTH
Site Zip: Not reported
Enf Action Date: 11-20-2015
Enf Action Type: Clean-up and Abatement Order
Enf Action Description: Clean-up and Abatement Order
Enf Action Notes: Not reported
Enf Action Division: Water Boards
Enf Action Program: WDRMINING
Enf Action Source: CIWQS,

Affiliation:
Affiliation Type Desc: Owner and Operator
Entity Name: Aera Energy LLC
Entity Title: Not reported
Affiliation Address: Not reported
Affiliation City: Not reported
Affiliation State: Not reported
Affiliation Country: Not reported
Affiliation Zip: Not reported
Affiliation Phone: ,

131
SW
< 1/8
0.044 mi.
232 ft.

, CA

WASTEWATER PITS **S127593330**
N/A

Actual:
675 ft.

Focus Map:
4

WASTEWATER PITS:

Name:	Not reported
Address:	Not reported
City,State,Zip:	CA
Status:	Inactive
Field:	Belridge North
Lease:	Section 27
Operator:	Aera Energy LLC
Geo Tracker Global ID:	T10000006757
Number of Ponds:	1
Latitude:	35.54360
Longitude:	-119.79724

AL132
SE
< 1/8
0.048 mi.
254 ft.

CLARIANT OIL SERVICES/BELRIDGE
18426 POLE LINE RD
MCKITTRICK, CA 93251

Site 1 of 3 in cluster AL

CUPA Listings **S118232062**
HAZNET **N/A**
HWTS

Actual:
567 ft.

Focus Map:
15

KERN CO CUPA:

Facility ID:	FA0034792
CERS ID:	10237873
Name:	KS INDUSTRIES - BELRIDGE
Address:	18426 POLE LINE RD
Address 2:	18426 POLE LINE RD
City,State,Zip:	MCKITTRICK, CA
Billing Status:	Active, billable
Program Element:	BUS PLAN SMALL LOW RISK 1 UNIT
Program Element Code:	CB1T
HMIRRP Due Date:	5/31/2013
Current Inspection Date:	7/1/2025
Employee:	BODDETI
Mailing Address:	6205 DISTRICT BLVD
Mailing Address 2:	Not reported
Mailing City:	BAKERSFIELD
Mailing State:	CA
Mailing Zip:	93313

HAZNET:

Name:	CLARIANT OIL SERVICES/BELRIDGE
Address:	18426 POLE LINE RD
Address 2:	Not reported
City,State,Zip:	MCKITTRICK, CA 93251
Contact:	GIL INSLEY
Telephone:	7043317722
Mailing Name:	Not reported
Mailing Address:	4000 MONROE ROAD
Year:	2016
Gepaid:	CAL000357095
TSD EPA ID:	CAD066113465
CA Waste Code:	134 - Aqueous solution with total organic residues less than 10 percent

CLARIANT OIL SERVICES/BELRIDGE (Continued) **S118232062**

Disposal Method: H141 - Storage, Bulking, And/Or Transfer Off Site--No Treatment/Reovery (H010-H129) Or (H131-H135)
Tons: 0.882

Year: 2015
Gepaid: CAL000357095
TSD EPA ID: NMD002208627
CA Waste Code: 181 - Other inorganic solid waste
Disposal Method: H141 - Storage, Bulking, And/Or Transfer Off Site--No Treatment/Reovery (H010-H129) Or (H131-H135)
Tons: 0.9315

Year: 2015
Gepaid: CAL000357095
TSD EPA ID: NMD002208627
CA Waste Code: 343 - Unspecified organic liquid mixture
Disposal Method: H141 - Storage, Bulking, And/Or Transfer Off Site--No Treatment/Reovery (H010-H129) Or (H131-H135)
Tons: 0.5905

Year: 2015
Gepaid: CAL000357095
TSD EPA ID: NMD002208627
CA Waste Code: 214 - Unspecified solvent mixture
Disposal Method: H141 - Storage, Bulking, And/Or Transfer Off Site--No Treatment/Reovery (H010-H129) Or (H131-H135)
Tons: 0.978

Year: 2014
Gepaid: CAL000357095
TSD EPA ID: NVT330010000
CA Waste Code: 352 - Other organic solids
Disposal Method: H132 - Landfill Or Surface Impoundment That Will Be Closed As Landfill(To Include On-Site Treatment And/Or Stabilization)
Tons: 33.712

Additional Info:
Year: 2016
Gen EPA ID: CAL000357095

Shipment Date: 20151007
Creation Date: 5/4/2016 22:15:28
Receipt Date: 20151028
Manifest ID: 008827186FLE
Trans EPA ID: CAR000070540
Trans Name: ADVANCED CHEMICAL TRANSPORT INC (SV)
Trans 2 EPA ID: CAR000183152
Trans 2 Name: LD TRANSPORTATION LLC
TSDF EPA ID: NMD002208627
Trans Name: ADVANCED CHEMICAL TREATMENT
TSDF Alt EPA ID: Not reported
TSDF Alt Name: Not reported
Waste Code Description: 214 - Unspecified solvent mixture
RCRA Code: D001
Meth Code: H141 - Storage, Bulking, And/Or Transfer Off Site--No Treatment/Reovery (H010-H129) Or (H131-H135)

CLARIANT OIL SERVICES/BELRIDGE (Continued) **S118232062**

Quantity Tons:	0.978
Waste Quantity:	1956
Quantity Unit:	P
Additional Code 1:	Not reported
Additional Code 2:	Not reported
Additional Code 3:	Not reported
Additional Code 4:	Not reported
Additional Code 5:	Not reported
Shipment Date:	20151007
Creation Date:	5/4/2016 22:15:28
Receipt Date:	20151028
Manifest ID:	008827186FLE
Trans EPA ID:	CAR000070540
Trans Name:	ADVANCED CHEMICAL TRANSPORT INC (SV)
Trans 2 EPA ID:	CAR000183152
Trans 2 Name:	LD TRANSPORTATION LLC
TSDF EPA ID:	NMD002208627
Trans Name:	ADVANCED CHEMICAL TREATMENT
TSDF Alt EPA ID:	Not reported
TSDF Alt Name:	Not reported
Waste Code Description:	181 - Other inorganic solid waste Organics
RCRA Code:	Not reported
Meth Code:	H141 - Storage, Bulking, And/Or Transfer Off Site--No Treatment/Reovery (H010-H129) Or (H131-H135)
Quantity Tons:	0.266
Waste Quantity:	532
Quantity Unit:	P
Additional Code 1:	Not reported
Additional Code 2:	Not reported
Additional Code 3:	Not reported
Additional Code 4:	Not reported
Additional Code 5:	Not reported
Shipment Date:	20151007
Creation Date:	5/4/2016 22:15:28
Receipt Date:	20151028
Manifest ID:	008827186FLE
Trans EPA ID:	CAR000070540
Trans Name:	ADVANCED CHEMICAL TRANSPORT INC (SV)
Trans 2 EPA ID:	CAR000183152
Trans 2 Name:	LD TRANSPORTATION LLC
TSDF EPA ID:	NMD002208627
Trans Name:	ADVANCED CHEMICAL TREATMENT
TSDF Alt EPA ID:	Not reported
TSDF Alt Name:	Not reported
Waste Code Description:	181 - Other inorganic solid waste Organics
RCRA Code:	Not reported
Meth Code:	H141 - Storage, Bulking, And/Or Transfer Off Site--No Treatment/Reovery (H010-H129) Or (H131-H135)
Quantity Tons:	0.1135
Waste Quantity:	227
Quantity Unit:	P
Additional Code 1:	Not reported
Additional Code 2:	Not reported
Additional Code 3:	Not reported
Additional Code 4:	Not reported

CLARIANT OIL SERVICES/BELRIDGE (Continued) **S118232062**

Additional Code 5:	Not reported
Shipment Date:	20151007
Creation Date:	5/4/2016 22:15:28
Receipt Date:	20151028
Manifest ID:	008827186FLE
Trans EPA ID:	CAR000070540
Trans Name:	ADVANCED CHEMICAL TRANSPORT INC (SV)
Trans 2 EPA ID:	CAR000183152
Trans 2 Name:	LD TRANSPORTATION LLC
TSDF EPA ID:	NMD002208627
Trans Name:	ADVANCED CHEMICAL TREATMENT
TSDF Alt EPA ID:	Not reported
TSDF Alt Name:	Not reported
Waste Code Description:	343 - Unspecified organic liquid mixture
RCRA Code:	Not reported
Meth Code:	H141 - Storage, Bulking, And/Or Transfer Off Site--No Treatment/Reovery (H010-H129) Or (H131-H135)
Quantity Tons:	0.4345
Waste Quantity:	869
Quantity Unit:	P
Additional Code 1:	Not reported
Additional Code 2:	Not reported
Additional Code 3:	Not reported
Additional Code 4:	Not reported
Additional Code 5:	Not reported
Shipment Date:	20150910
Creation Date:	5/4/2016 22:15:28
Receipt Date:	20151006
Manifest ID:	008827075FLE
Trans EPA ID:	CAR000070540
Trans Name:	ADVANCED CHEMICAL TRANSPORT INC (SV)
Trans 2 EPA ID:	CAR000180737
Trans 2 Name:	PONDER ENVIRONMENTAL SERVICES INC
TSDF EPA ID:	NMD002208627
Trans Name:	ADVANCED CHEMICAL TREATMENT
TSDF Alt EPA ID:	Not reported
TSDF Alt Name:	Not reported
Waste Code Description:	343 - Unspecified organic liquid mixture
RCRA Code:	Not reported
Meth Code:	H141 - Storage, Bulking, And/Or Transfer Off Site--No Treatment/Reovery (H010-H129) Or (H131-H135)
Quantity Tons:	0.156
Waste Quantity:	312
Quantity Unit:	P
Additional Code 1:	Not reported
Additional Code 2:	Not reported
Additional Code 3:	Not reported
Additional Code 4:	Not reported
Additional Code 5:	Not reported
Shipment Date:	20150910
Creation Date:	5/4/2016 22:15:28
Receipt Date:	20151006
Manifest ID:	008827075FLE
Trans EPA ID:	CAR000070540

CLARIANT OIL SERVICES/BELRIDGE (Continued) **S118232062**

Trans Name:	ADVANCED CHEMICAL TRANSPORT INC (SV)
Trans 2 EPA ID:	CAR000180737
Trans 2 Name:	PONDER ENVIRONMENTAL SERVICES INC
TSDF EPA ID:	NMD002208627
Trans Name:	ADVANCED CHEMICAL TREATMENT
TSDF Alt EPA ID:	Not reported
TSDF Alt Name:	Not reported
Waste Code Description:	181 - Other inorganic solid waste Organics
RCRA Code:	Not reported
Meth Code:	H141 - Storage, Bulking, And/Or Transfer Off Site--No Treatment/Reovery (H010-H129) Or (H131-H135)
Quantity Tons:	0.552
Waste Quantity:	1104
Quantity Unit:	P
Additional Code 1:	Not reported
Additional Code 2:	Not reported
Additional Code 3:	Not reported
Additional Code 4:	Not reported
Additional Code 5:	Not reported

Additional Info:

Year:	2015
Gen EPA ID:	CAL000357095
Shipment Date:	20151007
Creation Date:	5/4/2016 22:15:28
Receipt Date:	20151028
Manifest ID:	008827186FLE
Trans EPA ID:	CAR000070540
Trans Name:	ADVANCED CHEMICAL TRANSPORT INC (SV)
Trans 2 EPA ID:	CAR000183152
Trans 2 Name:	LD TRANSPORTATION LLC
TSDF EPA ID:	NMD002208627
Trans Name:	ADVANCED CHEMICAL TREATMENT
TSDF Alt EPA ID:	Not reported
TSDF Alt Name:	Not reported
Waste Code Description:	214 - Unspecified solvent mixture
RCRA Code:	D001
Meth Code:	H141 - Storage, Bulking, And/Or Transfer Off Site--No Treatment/Reovery (H010-H129) Or (H131-H135)
Quantity Tons:	0.978
Waste Quantity:	1956
Quantity Unit:	P
Additional Code 1:	Not reported
Additional Code 2:	Not reported
Additional Code 3:	Not reported
Additional Code 4:	Not reported
Additional Code 5:	Not reported
Shipment Date:	20151007
Creation Date:	5/4/2016 22:15:28
Receipt Date:	20151028
Manifest ID:	008827186FLE
Trans EPA ID:	CAR000070540
Trans Name:	ADVANCED CHEMICAL TRANSPORT INC (SV)
Trans 2 EPA ID:	CAR000183152
Trans 2 Name:	LD TRANSPORTATION LLC

CLARIANT OIL SERVICES/BELRIDGE (Continued) **S118232062**

TSDF EPA ID:	NMD002208627
Trans Name:	ADVANCED CHEMICAL TREATMENT
TSDF Alt EPA ID:	Not reported
TSDF Alt Name:	Not reported
Waste Code Description:	181 - Other inorganic solid waste Organics
RCRA Code:	Not reported
Meth Code:	H141 - Storage, Bulking, And/Or Transfer Off Site--No Treatment/Reovery (H010-H129) Or (H131-H135)
Quantity Tons:	0.266
Waste Quantity:	532
Quantity Unit:	P
Additional Code 1:	Not reported
Additional Code 2:	Not reported
Additional Code 3:	Not reported
Additional Code 4:	Not reported
Additional Code 5:	Not reported
Shipment Date:	20151007
Creation Date:	5/4/2016 22:15:28
Receipt Date:	20151028
Manifest ID:	008827186FLE
Trans EPA ID:	CAR000070540
Trans Name:	ADVANCED CHEMICAL TRANSPORT INC (SV)
Trans 2 EPA ID:	CAR000183152
Trans 2 Name:	LD TRANSPORTATION LLC
TSDF EPA ID:	NMD002208627
Trans Name:	ADVANCED CHEMICAL TREATMENT
TSDF Alt EPA ID:	Not reported
TSDF Alt Name:	Not reported
Waste Code Description:	181 - Other inorganic solid waste Organics
RCRA Code:	Not reported
Meth Code:	H141 - Storage, Bulking, And/Or Transfer Off Site--No Treatment/Reovery (H010-H129) Or (H131-H135)
Quantity Tons:	0.1135
Waste Quantity:	227
Quantity Unit:	P
Additional Code 1:	Not reported
Additional Code 2:	Not reported
Additional Code 3:	Not reported
Additional Code 4:	Not reported
Additional Code 5:	Not reported
Shipment Date:	20151007
Creation Date:	5/4/2016 22:15:28
Receipt Date:	20151028
Manifest ID:	008827186FLE
Trans EPA ID:	CAR000070540
Trans Name:	ADVANCED CHEMICAL TRANSPORT INC (SV)
Trans 2 EPA ID:	CAR000183152
Trans 2 Name:	LD TRANSPORTATION LLC
TSDF EPA ID:	NMD002208627
Trans Name:	ADVANCED CHEMICAL TREATMENT
TSDF Alt EPA ID:	Not reported
TSDF Alt Name:	Not reported
Waste Code Description:	343 - Unspecified organic liquid mixture
RCRA Code:	Not reported
Meth Code:	H141 - Storage, Bulking, And/Or Transfer Off Site--No

CLARIANT OIL SERVICES/BELRIDGE (Continued) **S118232062**

	Treatment/Reovery (H010-H129) Or (H131-H135)
Quantity Tons:	0.4345
Waste Quantity:	869
Quantity Unit:	P
Additional Code 1:	Not reported
Additional Code 2:	Not reported
Additional Code 3:	Not reported
Additional Code 4:	Not reported
Additional Code 5:	Not reported
Shipment Date:	20150910
Creation Date:	5/4/2016 22:15:28
Receipt Date:	20151006
Manifest ID:	008827075FLE
Trans EPA ID:	CAR000070540
Trans Name:	ADVANCED CHEMICAL TRANSPORT INC (SV)
Trans 2 EPA ID:	CAR000180737
Trans 2 Name:	PONDER ENVIRONMENTAL SERVICES INC
TSDF EPA ID:	NMD002208627
Trans Name:	ADVANCED CHEMICAL TREATMENT
TSDF Alt EPA ID:	Not reported
TSDF Alt Name:	Not reported
Waste Code Description:	343 - Unspecified organic liquid mixture
RCRA Code:	Not reported
Meth Code:	H141 - Storage, Bulking, And/Or Transfer Off Site--No Treatment/Reovery (H010-H129) Or (H131-H135)
Quantity Tons:	0.156
Waste Quantity:	312
Quantity Unit:	P
Additional Code 1:	Not reported
Additional Code 2:	Not reported
Additional Code 3:	Not reported
Additional Code 4:	Not reported
Additional Code 5:	Not reported
Shipment Date:	20150910
Creation Date:	5/4/2016 22:15:28
Receipt Date:	20151006
Manifest ID:	008827075FLE
Trans EPA ID:	CAR000070540
Trans Name:	ADVANCED CHEMICAL TRANSPORT INC (SV)
Trans 2 EPA ID:	CAR000180737
Trans 2 Name:	PONDER ENVIRONMENTAL SERVICES INC
TSDF EPA ID:	NMD002208627
Trans Name:	ADVANCED CHEMICAL TREATMENT
TSDF Alt EPA ID:	Not reported
TSDF Alt Name:	Not reported
Waste Code Description:	181 - Other inorganic solid waste Organics
RCRA Code:	Not reported
Meth Code:	H141 - Storage, Bulking, And/Or Transfer Off Site--No Treatment/Reovery (H010-H129) Or (H131-H135)
Quantity Tons:	0.552
Waste Quantity:	1104
Quantity Unit:	P
Additional Code 1:	Not reported
Additional Code 2:	Not reported
Additional Code 3:	Not reported

CLARIANT OIL SERVICES/BELRIDGE (Continued) **S118232062**

Additional Code 4: Not reported
Additional Code 5: Not reported

Additional Info:
Year: 2014
Gen EPA ID: CAL000357095

Shipment Date: 20141023
Creation Date: 4/29/2015 22:15:12
Receipt Date: 20141024
Manifest ID: 006985391FLE
Trans EPA ID: CAR000070540
Trans Name: ADVANCED CHEMICAL TRANSPORT INC (SV)
Trans 2 EPA ID: Not reported
Trans 2 Name: Not reported
TSDF EPA ID: NVT330010000
Trans Name: US ECOLOGY NEVADA INC
TSDF Alt EPA ID: Not reported
TSDF Alt Name: Not reported
Waste Code Description: 352 - Other organic solids
RCRA Code: Not reported
Meth Code: H132 - Landfill Or Surface Impoundment That Will Be Closed As Landfill(To Include On-Site Treatment And/Or Stabilization)
Quantity Tons: 33.712
Waste Quantity: 40
Quantity Unit: Y
Additional Code 1: Not reported
Additional Code 2: Not reported
Additional Code 3: Not reported
Additional Code 4: Not reported
Additional Code 5: Not reported

HWTS:
Name: KS INDUSTRIES LP
Address: 18426 POLE LINE RD
Address 2: Not reported
City,State,Zip: MC KITTRICK, CA 93251
EPA ID: CAL000419769
Inactive Date: Not reported
Create Date: 08/23/2016
Last Act Date: Not reported
Mailing Name: Not reported
Mailing Address: 6205 DISTRICT BLVD
Mailing Address 2: Not reported
Mailing City,State,Zip: BAKERSFIELD, CA 933132141
Owner Name: KS INDUSTRIES, LP
Owner Address: 6205 DISTRICT BLVD
Owner Address 2: Not reported
Owner City,State,Zip: BAKERSFIELD, CA 933132141
Contact Name: PHILLIP CLARKE
Contact Address: 6205 DISTRICT BLVD
Contact Address 2: Not reported
City,State,Zip: BAKERSFIELD, CA 93313
Facility Status: Active
Facility Type: PERMANENT
Category: STATE

CLARIANT OIL SERVICES/BELRIDGE (Continued) **S118232062**

Latitude: -90
Longitude: 180

NAICS:
EPA ID: CAL000419769
Create Date: 2016-08-23 10:20:40.500
NAICS Code: 23492
NAICS Description: Power and Communication Transmission Line Construction
Issued EPA ID Date: 2016-08-23 10:20:40.45700
Inactive Date: Not reported
Facility Name: KS INDUSTRIES LP
Facility Address: 18426 POLE LINE RD
Facility Address 2: Not reported
Facility City: MC KITTRICK
Facility County: Not reported
Facility State: CA
Facility Zip: 93251

Name: CLARIANT CORPORATION-BELRIDGE
Address: CONTRACTORS RD
Address 2: Not reported
City,State,Zip: MCKITTRICK, CA 93251
EPA ID: CAL000357095
Inactive Date: Not reported
Create Date: 09/23/2010
Last Act Date: Not reported
Mailing Name: Not reported
Mailing Address: 5301 DISTRICT BLVD
Mailing Address 2: Not reported
Mailing City,State,Zip: BAKERSFIELD, CA 93313
Owner Name: CLARIANT CORPORATION
Owner Address: 500 EAST MOREHEAD ST STE 400
Owner Address 2: Not reported
Owner City,State,Zip: CHARLOTTE, NC 282020000
Contact Name: MATT CARTER
Contact Address: 325 AUTUMN RIDGE DR
Contact Address 2: Not reported
City,State,Zip: BOSSIER CITY, CA 71111
Facility Status: Active
Facility Type: PERMANENT
Category: STATE
Latitude: 35.472006
Longitude: -119.729505

NAICS:
EPA ID: CAL000357095
Create Date: 2010-09-23 09:01:34.080
NAICS Code: 213112
NAICS Description: Support Activities for Oil and Gas Operations
Issued EPA ID Date: 2010-09-23 09:01:34.06700
Inactive Date: Not reported
Facility Name: CLARIANT OIL SERVICES/BELRIDGE
Facility Address: CONTRACTORS RD
Facility Address 2: Not reported
Facility City: McKittrick
Facility County: Not reported
Facility State: CA

CLARIANT OIL SERVICES/BELRIDGE (Continued) **S118232062**

Facility Zip: 93251

AL133 **CLARIANT OIL SERVICES/BELRIDGE** **RCRA NonGen / NLR** **1024827457**
SE **18426 POLE LINE RD** **CAL000357095**
< 1/8 **MCKITTRICK, CA 93251**
0.048 mi.
254 ft. **Site 2 of 3 in cluster AL**

Actual:
567 ft.

Focus Map:
15

RCRA Listings:

Date Form Received by Agency:		20100923
Handler Name:	CLARIANT OIL SERVICES/BELRIDGE	
Handler Address:		18426 POLE LINE RD
Handler City,State,Zip:		MCKITTRICK, CA 93251
EPA ID:		CAL000357095
Contact Name:		GIL INSLEY
Contact Address:		4000 MONROE ROAD
Contact City,State,Zip:		CHARLOTTE, NC 28205
Contact Telephone:		704-331-7722
Contact Fax:		Not reported
Contact Email:		GIL.INSLEY@CLARIANT.COM
Contact Title:		Not reported
EPA Region:		09
Land Type:		Not reported
Federal Waste Generator Description:		Not a generator, verified
Non-Notifier:		Not reported
Biennial Report Cycle:		Not reported
Accessibility:		Not reported
Active Site Indicator:		Handler Activities
State District Owner:		Not reported
State District:		Not reported
Mailing Address:		4000 MONROE ROAD
Mailing City,State,Zip:		CHARLOTTE, NC 28205-0000
Owner Name:	CLARIANT CORP	
Owner Type:		Other
Operator Name:	GIL INSLEY	
Operator Type:		Other
Short-Term Generator Activity:		No
Importer Activity:		No
Mixed Waste Generator:		No
Transporter Activity:		No
Transfer Facility Activity:		No
Recycler Activity with Storage:		No
Small Quantity On-Site Burner Exemption:		No
Smelting Melting and Refining Furnace Exemption:		No
Underground Injection Control:		No
Off-Site Waste Receipt:		No
Universal Waste Indicator:		Yes
Universal Waste Destination Facility:		Yes
Federal Universal Waste:		No
Active Site Fed-Reg Treatment Storage and Disposal Facility:		Not reported
Active Site Converter Treatment storage and Disposal Facility:		Not reported
Active Site State-Reg Treatment Storage and Disposal Facility:		Not reported
Active Site State-Reg Handler:		---
Federal Facility Indicator:		Not reported
Hazardous Secondary Material Indicator:		N
Sub-Part K Indicator:		Not reported
Commercial TSD Indicator:		No

CLARIANT OIL SERVICES/BELRIDGE (Continued) **1024827457**

Treatment Storage and Disposal Type:	Not reported
2018 GPRA Permit Baseline:	Not on the Baseline
2018 GPRA Renewals Baseline:	Not on the Baseline
Permit Renewals Workload Universe:	Not reported
Permit Workload Universe:	Not reported
Permit Progress Universe:	Not reported
Post-Closure Workload Universe:	Not reported
Closure Workload Universe:	Not reported
202 GPRA Corrective Action Baseline:	No
Corrective Action Workload Universe:	No
Subject to Corrective Action Universe:	No
Non-TSDFs Where RCRA CA has Been Imposed Universe:	No
TSDFs Potentially Subject to CA Under 3004 (u)/(v) Universe:	No
TSDFs Only Subject to CA under Discretionary Auth Universe:	No
Corrective Action Priority Ranking:	No NCAPS ranking
Environmental Control Indicator:	No
Institutional Control Indicator:	No
Human Exposure Controls Indicator:	N/A
Groundwater Controls Indicator:	N/A
Operating TSDF Universe:	Not reported
Full Enforcement Universe:	Not reported
Significant Non-Complier Universe:	No
Unaddressed Significant Non-Complier Universe:	No
Addressed Significant Non-Complier Universe:	No
Significant Non-Complier With a Compliance Schedule Universe:	No
Financial Assurance Required:	Not reported
Handler Date of Last Change:	20180905
Recognized Trader-Importer:	No
Recognized Trader-Exporter:	No
Importer of Spent Lead Acid Batteries:	No
Exporter of Spent Lead Acid Batteries:	No
Recycler Activity Without Storage:	No
Manifest Broker:	No
Sub-Part P Indicator:	No

Handler - Owner Operator:

Owner/Operator Indicator:	Operator
Owner/Operator Name: GIL INSLEY	
Legal Status:	Other
Date Became Current:	Not reported
Date Ended Current:	Not reported
Owner/Operator Address:	4000 MONROE ROAD
Owner/Operator City,State,Zip:	CHARLOTTE, NC 28205
Owner/Operator Telephone:	704-331-7722
Owner/Operator Telephone Ext:	Not reported
Owner/Operator Fax:	Not reported
Owner/Operator Email:	Not reported

Owner/Operator Indicator:	Owner
Owner/Operator Name: CLARIANT CORP	
Legal Status:	Other
Date Became Current:	Not reported
Date Ended Current:	Not reported
Owner/Operator Address:	4000 MONROE ROAD
Owner/Operator City,State,Zip:	CHARLOTTE, NC 28205-0000
Owner/Operator Telephone:	704-331-7722

CLARIANT OIL SERVICES/BELRIDGE (Continued) **1024827457**

Owner/Operator Telephone Ext: Not reported
Owner/Operator Fax: Not reported
Owner/Operator Email: Not reported

Historic Generators:
Receive Date: 20100923
Handler Name: CLARIANT OIL SERVICES/BELRIDGE
Federal Waste Generator Description: Not a generator, verified
State District Owner: Not reported
Large Quantity Handler of Universal Waste: No
Recognized Trader Importer: No
Recognized Trader Exporter: No
Spent Lead Acid Battery Importer: No
Spent Lead Acid Battery Exporter: No
Current Record: Yes
Non Storage Recycler Activity: Not reported
Electronic Manifest Broker: Not reported

List of NAICS Codes and Descriptions:
NAICS Code: 213112
NAICS Description: SUPPORT ACTIVITIES FOR OIL AND GAS OPERATIONS

Facility Has Received Notices of Violations:
Violations: No Violations Found

Evaluation Action Summary:
Evaluations: No Evaluations Found

AL134 **KS INDUSTRIES LP** **RCRA NonGen / NLR** **1025870031**
SE **18426 POLE LINE RD** **CAL000419769**
< 1/8 **MC KITTRICK, CA 93251**
0.048 mi.
254 ft. **Site 3 of 3 in cluster AL**

Actual:
567 ft.

Focus Map:
15

RCRA Listings:
Date Form Received by Agency: 20160823
Handler Name: KS INDUSTRIES LP
Handler Address: 18426 POLE LINE RD
Handler City,State,Zip: MC KITTRICK, CA 93251
EPA ID: CAL000419769
Contact Name: DOUGLAS OAKES
Contact Address: 6205 DISTRICT BLVD
Contact City,State,Zip: BAKERSFIELD, CA 93313-2141
Contact Telephone: 661-979-1984
Contact Fax: 661-832-5126
Contact Email: DWOAKES@KSILP.COM
Contact Title: Not reported
EPA Region: 09
Land Type: Not reported
Federal Waste Generator Description: Not a generator, verified
Non-Notifier: Not reported
Biennial Report Cycle: Not reported
Accessibility: Not reported
Active Site Indicator: Not reported
State District Owner: Not reported

KS INDUSTRIES LP (Continued) **1025870031**

State District:		Not reported
Mailing Address:		6205 DISTRICT BLVD
Mailing City,State,Zip:		BAKERSFIELD, CA 93313-2141
Owner Name:	KS INDUSTRIES, LP	
Owner Type:		Other
Operator Name:	DOUGLAS OAKES	
Operator Type:		Other
Short-Term Generator Activity:		No
Importer Activity:		No
Mixed Waste Generator:		No
Transporter Activity:		No
Transfer Facility Activity:		No
Recycler Activity with Storage:		No
Small Quantity On-Site Burner Exemption:		No
Smelting Melting and Refining Furnace Exemption:		No
Underground Injection Control:		No
Off-Site Waste Receipt:		No
Universal Waste Indicator:		No
Universal Waste Destination Facility:		No
Federal Universal Waste:		No
Active Site Fed-Reg Treatment Storage and Disposal Facility:		Not reported
Active Site Converter Treatment storage and Disposal Facility:		Not reported
Active Site State-Reg Treatment Storage and Disposal Facility:		Not reported
Active Site State-Reg Handler:		---
Federal Facility Indicator:		Not reported
Hazardous Secondary Material Indicator:		N
Sub-Part K Indicator:		Not reported
Commercial TSD Indicator:		No
Treatment Storage and Disposal Type:		Not reported
2018 GPRA Permit Baseline:		Not on the Baseline
2018 GPRA Renewals Baseline:		Not on the Baseline
Permit Renewals Workload Universe:		Not reported
Permit Workload Universe:		Not reported
Permit Progress Universe:		Not reported
Post-Closure Workload Universe:		Not reported
Closure Workload Universe:		Not reported
202 GPRA Corrective Action Baseline:		No
Corrective Action Workload Universe:		No
Subject to Corrective Action Universe:		No
Non-TSDFs Where RCRA CA has Been Imposed Universe:		No
TSDFs Potentially Subject to CA Under 3004 (u)/(v) Universe:		No
TSDFs Only Subject to CA under Discretionary Auth Universe:		No
Corrective Action Priority Ranking:		No NCAPS ranking
Environmental Control Indicator:		No
Institutional Control Indicator:		No
Human Exposure Controls Indicator:		N/A
Groundwater Controls Indicator:		N/A
Operating TSDF Universe:		Not reported
Full Enforcement Universe:		Not reported
Significant Non-Complier Universe:		No
Unaddressed Significant Non-Complier Universe:		No
Addressed Significant Non-Complier Universe:		No
Significant Non-Complier With a Compliance Schedule Universe:		No
Financial Assurance Required:		Not reported
Handler Date of Last Change:		20190910
Recognized Trader-Importer:		No
Recognized Trader-Exporter:		No

KS INDUSTRIES LP (Continued) **1025870031**

Importer of Spent Lead Acid Batteries:	No
Exporter of Spent Lead Acid Batteries:	No
Recycler Activity Without Storage:	No
Manifest Broker:	No
Sub-Part P Indicator:	No

Handler - Owner Operator:

Owner/Operator Indicator:	Operator
Owner/Operator Name: DOUGLAS OAKES	
Legal Status:	Other
Date Became Current:	Not reported
Date Ended Current:	Not reported
Owner/Operator Address:	6205 DISTRICT BLVD
Owner/Operator City,State,Zip:	BAKERSFIELD, CA 93313-2141
Owner/Operator Telephone:	661-979-1984
Owner/Operator Telephone Ext:	Not reported
Owner/Operator Fax:	Not reported
Owner/Operator Email:	Not reported

Owner/Operator Indicator:	Owner
Owner/Operator Name: KS INDUSTRIES, LP	
Legal Status:	Other
Date Became Current:	Not reported
Date Ended Current:	Not reported
Owner/Operator Address:	6205 DISTRICT BLVD
Owner/Operator City,State,Zip:	BAKERSFIELD, CA 93313-2141
Owner/Operator Telephone:	661-617-1700
Owner/Operator Telephone Ext:	Not reported
Owner/Operator Fax:	Not reported
Owner/Operator Email:	Not reported

Historic Generators:

Receive Date:	20160823
Handler Name: KS INDUSTRIES LP	
Federal Waste Generator Description:	Not a generator, verified
State District Owner:	Not reported
Large Quantity Handler of Universal Waste:	No
Recognized Trader Importer:	Not reported
Recognized Trader Exporter:	Not reported
Spent Lead Acid Battery Importer:	Not reported
Spent Lead Acid Battery Exporter:	Not reported
Current Record:	Yes
Non Storage Recycler Activity:	Not reported
Electronic Manifest Broker:	Not reported

List of NAICS Codes and Descriptions:

NAICS Code:	23492
NAICS Description:	POWER AND COMMUNICATION TRANSMISSION LINE CONSTRUCTION

Facility Has Received Notices of Violations:

Violations:	No Violations Found

Evaluation Action Summary:

Evaluations:	No Evaluations Found

AM135 **WASTEWATER PITS** **S127593668**
NE **N/A**
< 1/8 **, CA**
0.049 mi.
257 ft. **Site 1 of 3 in cluster AM**

Actual: WASTEWATER PITS:
564 ft.
Name: Not reported
Focus Map: Address: Not reported
15 City,State,Zip: CA
Status: Active
Field: Belridge South
Lease: Dehydration Plant 20
Operator: Aera Energy LLC
Geo Tracker Global ID: T10000011582
Number of Ponds: 1
Latitude: 35.48000
Longitude: -119.73579

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136 **WASTEWATER PITS** **S127593568**
North **N/A**
< 1/8 **, CA**
0.050 mi.
264 ft.

Actual: WASTEWATER PITS:
561 ft.
Name: Not reported
Focus Map: Address: Not reported
19 City,State,Zip: CA
Status: Inactive
Field: Belridge South
Lease: Aera Belridge South Facility Ponds
Operator: Aera Energy LLC
Geo Tracker Global ID: T10000008078
Number of Ponds: 1
Latitude: 35.45598
Longitude: -119.70603

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137 **WASTEWATER PITS** **S127593646**
NE **N/A**
< 1/8 **, CA**
0.064 mi.
338 ft.

Actual: WASTEWATER PITS:
564 ft.
Name: Not reported
Focus Map: Address: Not reported
15 City,State,Zip: CA
Status: Active
Field: Belridge South
Lease: Dehydration Plant 20
Operator: Aera Energy LLC
Geo Tracker Global ID: T10000011582
Number of Ponds: 1
Latitude: 35.48057
Longitude: -119.73597

AM138 **WASTEWATER PITS** **S127593657**
NE **N/A**
< 1/8 **, CA**
0.065 mi.
344 ft. **Site 2 of 3 in cluster AM**

Actual: WASTEWATER PITS:
563 ft.
Name: Not reported
Address: Not reported
Focus Map: City,State,Zip: CA
15 Status: Active
Field: Belridge South
Lease: Dehydration Plant 20
Operator: Aera Energy LLC
Geo Tracker Global ID: T10000011582
Number of Ponds: 1
Latitude: 35.48039
Longitude: -119.73578

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139 **WASTEWATER PITS** **S127593580**
West **N/A**
< 1/8 **, CA**
0.072 mi.
382 ft.

Actual: WASTEWATER PITS:
597 ft.
Name: Not reported
Address: Not reported
Focus Map: City,State,Zip: CA
19 Status: Inactive
Field: Belridge South
Lease: Aera Belridge South Facility Ponds
Operator: Aera Energy LLC
Geo Tracker Global ID: T10000008078
Number of Ponds: 1
Latitude: 35.46253
Longitude: -119.72356

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140 **WASTEWATER PITS** **S127593912**
NE **N/A**
< 1/8 **, CA**
0.078 mi.
412 ft.

Actual: WASTEWATER PITS:
660 ft.
Name: Not reported
Address: Not reported
Focus Map: City,State,Zip: CA
3 Status: Inactive
Field: Belridge North
Lease: Belridge A
Operator: Aera Energy LLC
Geo Tracker Global ID: L10002981694
Number of Ponds: 1
Latitude: 35.56058
Longitude: -119.81293

AM141 **WASTEWATER PITS** **S127593679**
NE **N/A**
< 1/8 **, CA**
0.085 mi.
451 ft. **Site 3 of 3 in cluster AM**

Actual: WASTEWATER PITS:
560 ft.
Name: Not reported
Focus Map: Address: Not reported
15 City,State,Zip: CA
Status: Active
Field: Belridge South
Lease: Dehydration Plant 20
Operator: Aera Energy LLC
Geo Tracker Global ID: T10000011582
Number of Ponds: 1
Latitude: 35.48031
Longitude: -119.73526

AN142 **WASTEWATER PITS** **S127594223**
West **N/A**
< 1/8 **, CA**
0.100 mi.
530 ft. **Site 1 of 2 in cluster AN**

Actual: WASTEWATER PITS:
616 ft.
Name: Not reported
Focus Map: Address: Not reported
8 City,State,Zip: CA
Status: Inactive
Field: Belridge North
Lease: Dow Chanslor
Operator: Aera Energy LLC
Geo Tracker Global ID: L10005630246
Number of Ponds: 1
Latitude: 35.51511
Longitude: -119.76256

AN143 **WASTEWATER PITS** **S127593518**
West **N/A**
< 1/8 **, CA**
0.103 mi.
546 ft. **Site 2 of 2 in cluster AN**

Actual: WASTEWATER PITS:
619 ft.
Name: Not reported
Focus Map: Address: Not reported
11 City,State,Zip: CA
Status: Closed - NFA
Field: Belridge North
Lease: Dow Chanslor
Operator: Aera Energy LLC
Geo Tracker Global ID: L10005630246
Number of Ponds: 1
Latitude: 35.51477
Longitude: -119.76261

AO144 **WASTEWATER PITS** **S127593519**
West **N/A**
< 1/8 **, CA**
0.104 mi.
548 ft. **Site 1 of 2 in cluster AO**

Actual: WASTEWATER PITS:
620 ft.

Name:	Not reported
Address:	Not reported
City,State,Zip:	CA
Status:	Closed - NFA
Field:	Belridge North
Lease:	Dow Chanslor
Operator:	Aera Energy LLC
Geo Tracker Global ID:	L10005630246
Number of Ponds:	1
Latitude:	35.51420
Longitude:	-119.76262

Focus Map:
11

AO145 **WASTEWATER PITS** **S127593520**
West **N/A**
< 1/8 **, CA**
0.106 mi.
562 ft. **Site 2 of 2 in cluster AO**

Actual: WASTEWATER PITS:
622 ft.

Name:	Not reported
Address:	Not reported
City,State,Zip:	CA
Status:	Closed - NFA
Field:	Belridge North
Lease:	Dow Chanslor
Operator:	Aera Energy LLC
Geo Tracker Global ID:	L10005630246
Number of Ponds:	1
Latitude:	35.51390
Longitude:	-119.76266

Focus Map:
11

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146 **NORTH BELRIDGE LANDFILL** **SWF/LF** **S102360346**
SW **1 MI NE BELRIDGE OIL CO** **Financial Assurance** **N/A**
< 1/8 **LOST HILLS, CA 93249** **CERS**
0.112 mi.
593 ft.

Actual: SWF/LF (SWIS):
663 ft.

Name:	NORTH BELRIDGE LANDFILL
Address:	1 MI NE BELRIDGE OIL CO
City,State,Zip:	LOST HILLS, CA 93249
Region:	STATE
Facility ID:	15-AA-0067
SWIS Number:	15-AA-0067
Point of Contact:	Bill Hereth
Is Archived:	No
Is Closed Illegal Abandoned:	Yes
Is Site Inert Debris Engineered Fill:	No
Is Financial Assurances Responsible:	Yes
Absorbed On:	Not reported
Operational Status:	Closed

Focus Map:
7

NORTH BELRIDGE LANDFILL (Continued) **S102360346**

Absorbed By:	Not reported
Closed Illegal Abandoned Category:	Not reported
EPA Federal Registry ID:	1.1001797303e+11
ARB District:	San Joaquin Valley Unified
SWRCB Region:	Central Valley
Local Government:	Kern County (Unincorporated)
Reporting Agency Legal Name:	County of Kern
Reporting Agency Department:	Environmental Health Division
Enforcing Agency Legal Name:	County of Kern
Enforcing Agency Department:	Environmental Health Division
Regulation Status:	Permitted

Activity:

SWIS Number:	15-AA-0067
Site Name:	North Belridge Landfill
Activity:	Solid Waste Landfill
Activity Is Archived:	No
Category:	Disposal
Activity Classification:	Solid Waste Facility
WDR Number:	Not reported
WDR Landfill Class:	III
Cease Operation:	9/1/2007
Cease Operation Type:	Actual
Inspection Frequency:	Annual
Throughput:	Not reported
Throughput Units:	Tons per day
Remaining Capacity:	Not reported
Remaining Capacity Date:	Not reported
Capacity:	210000
Capacity Units:	Cubic Yards
Total Acreage:	31.7
Disposal Acreage:	28.7
Permitted Elevation:	692
Permitted Elevation Type:	MSL
Permitted Depth:	10
Permitted Depth Type:	BGL
Point of Contact:	Bill Hereth
Site Operational Status:	Closed
Site Regulatory Status:	Permitted
Site Is Archived:	No
Is Closed Illegal Abandoned:	Yes
Is Site Inert Debris Engineered Fill:	No
Is Financial Assurances Responsible:	Yes
Absorbed On:	Not reported
Absorbed By:	Not reported
Closed Illegal Abandoned Category:	Not reported
EPA Federal Registry ID:	1.1001797303e+11
County:	Kern
ARB District:	San Joaquin Valley Unified
SWRCB Region:	Central Valley
Local Government:	Kern County (Unincorporated)
Street Address:	1 Mi Ne Belridge Oil Co
City:	Lost Hills
State:	CA
ZIP Code:	93249
Reporting Agency Legal Name:	County of Kern
Reporting Agency Department:	Environmental Health Division
Enforcing Agency Legal Name:	County of Kern

NORTH BELRIDGE LANDFILL (Continued) **S102360346**

Enforcing Agency Department: Environmental Health Division

Operator:
SWIS Number: 15-AA-0067
Site Name: North Belridge Landfill
Site Operational Status: Closed
Site Type: Disposal Only
Site Regulatory Status: Permitted
Latitude: 35.52613
Longitude: -119.78603
Is Archived: No
Operator: Aera Energy LLC
Started On: Not reported
Contact Name: R. L. Chambers
Contact Title: Lead Envir., Health & Safety Coord.
Contact Email: Not reported
Contact Phone: (661) 665-5000
Street Address: PO Box 11164
Operator City: Bakersfield
Operator State: CA
Operator Zip: 93389-1164

Owner:
SWIS Number: 15-AA-0067
Owner: Aera Energy LLC
Owner Address: PO Box 11164
Owner City: Bakersfield
Owner State: CA
Owner Zip: 93389-1164
Site Name: North Belridge Landfill
Site Operational Status: Closed
Site Type: Disposal Only
Site Regulatory Status: Permitted
Latitude: 35.52613
Longitude: -119.78603
Is Archived: No
Started On: Not reported
Contact Name: R. L. Chambers
Contact Title: Lead Envir., Health & Safety Coord.
Contact Email: Not reported
Contact Phone: (661) 665-5000

Waste:
SWIS Number: 15-AA-0067
Site Name: North Belridge Landfill
Activity: Solid Waste Landfill
Waste Type: Asbestos
Site Is Archived: No
Site Operational Status: Closed
Site Regulatory Status: Permitted
Site Type: Disposal Only
Point of Contact: Bill Hereth
Activity Is Archived: No
Activity Operational Status: Closed
Activity Regulatory Status: Permitted
Activity Category: Disposal

NORTH BELRIDGE LANDFILL (Continued) **S102360346**

Activity Classification: Solid Waste Facility

SWIS Number: 15-AA-0067
Site Name: North Belridge Landfill
Activity: Asbestos Containing Waste Disposal Site
Waste Type: Asbestos, friable
Site Is Archived: No
Site Operational Status: Closed
Site Regulatory Status: Permitted
Site Type: Disposal Only
Point of Contact: Bill Hereth
Activity Is Archived: Yes
Activity Operational Status: Closed
Activity Regulatory Status: Permitted
Activity Category: Disposal
Activity Classification: Solid Waste Facility

SWIS Number: 15-AA-0067
Site Name: North Belridge Landfill
Activity: Solid Waste Landfill
Waste Type: Construction/demolition
Site Is Archived: No
Site Operational Status: Closed
Site Regulatory Status: Permitted
Site Type: Disposal Only
Point of Contact: Bill Hereth
Activity Is Archived: No
Activity Operational Status: Closed
Activity Regulatory Status: Permitted
Activity Category: Disposal
Activity Classification: Solid Waste Facility

SWIS Number: 15-AA-0067
Site Name: North Belridge Landfill
Activity: Solid Waste Landfill
Waste Type: Industrial
Site Is Archived: No
Site Operational Status: Closed
Site Regulatory Status: Permitted
Site Type: Disposal Only
Point of Contact: Bill Hereth
Activity Is Archived: No
Activity Operational Status: Closed
Activity Regulatory Status: Permitted
Activity Category: Disposal
Activity Classification: Solid Waste Facility

Financial Assurance 2:
Name: NORTH BELRIDGE LANDFILL
Address: 1 MI NE BELRIDGE OIL CO
City,State,Zip: LOST HILLS, CA 93249
SWIS Number: 15-AA-0067
Review Date: 01/09/2020
Log Type: Closure
Coverage: 0
Adequate Mechanism: Yes

NORTH BELRIDGE LANDFILL (Continued) **S102360346**

Mechanism:	Not reported
Disbursements:	0
Inflation Estimate:	0
Inflation Estimate Date:	Not reported
Plan Cost Estimate:	0
Plan Cost Date:	11/27/2019
Responsible Party:	Not reported
Financial Assurances Provider Name:	Safeco Insurance Company of America

Name:	NORTH BELRIDGE LANDFILL
Address:	1 MI NE BELRIDGE OIL CO
City,State,Zip:	LOST HILLS, CA 93249
SWIS Number:	15-AA-0067
Review Date:	01/09/2020
Log Type:	Postclosure
Coverage:	250039
Adequate Mechanism:	Yes
Mechanism:	Surety Bond
Disbursements:	0
Inflation Estimate:	250039
Inflation Estimate Date:	06/01/2019
Plan Cost Estimate:	7500
Plan Cost Date:	11/27/2019
Responsible Party:	Not reported
Financial Assurances Provider Name:	Safeco Insurance Company of America

Name:	NORTH BELRIDGE LANDFILL
Address:	1 MI NE BELRIDGE OIL CO
City,State,Zip:	LOST HILLS, CA 93249
SWIS Number:	15-AA-0067
Review Date:	01/09/2020
Log Type:	Corrective Action
Coverage:	72000
Adequate Mechanism:	Yes
Mechanism:	Surety Bond
Disbursements:	0
Inflation Estimate:	72000
Inflation Estimate Date:	03/30/2016
Plan Cost Estimate:	45000
Plan Cost Date:	03/28/2016
Responsible Party:	Not reported
Financial Assurances Provider Name:	Safeco Insurance Company of America

CERS:

Name:	NORTH BELRIDGE LANDFILL
Address:	1 MI NE BELRIDGE OIL CO
City,State,Zip:	LOST HILLS, CA
Site ID:	510493
CERS ID:	15-AA-0067
CERS Description:	Solid Waste and Recycle Sites

Affiliation:

Affiliation Type Desc:	Legal Operator
Entity Name:	Aera Energy LLC
Entity Title:	Not reported
Affiliation Address:	P.O. Box 1116410000 Ming Avenue
Affiliation City:	Bakersfield

NORTH BELRIDGE LANDFILL (Continued) **S102360346**

Affiliation State:	CA
Affiliation Country:	Not reported
Affiliation Zip:	93389-1164
Affiliation Phone:	6616655000,
Affiliation Type Desc:	Legal Owner
Entity Name:	Aera Energy LLC
Entity Title:	Not reported
Affiliation Address:	P.O. Box 1116410000 Ming Avenue
Affiliation City:	Bakersfield
Affiliation State:	CA
Affiliation Country:	Not reported
Affiliation Zip:	93389-1164
Affiliation Phone:	6616655000,

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147 **WASTEWATER PITS** **S127593535**
NE **N/A**
1/8-1/4 , CA
0.131 mi.
694 ft.

Actual:
573 ft.

Focus Map:
15

WASTEWATER PITS:

Name:	Not reported
Address:	Not reported
City,State,Zip:	CA
Status:	Closed - NFA
Field:	Belridge South
Lease:	Aera Belridge South Facility Ponds
Operator:	Aera Energy LLC
Geo Tracker Global ID:	T10000008078
Number of Ponds:	1
Latitude:	35.47501
Longitude:	-119.73242

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148 **WASTEWATER PITS** **S127593635**
NE **N/A**
1/8-1/4 , CA
0.168 mi.
886 ft.

Actual:
554 ft.

Focus Map:
15

WASTEWATER PITS:

Name:	Not reported
Address:	Not reported
City,State,Zip:	CA
Status:	Active
Field:	Belridge South
Lease:	Dehydration Plant 20
Operator:	Aera Energy LLC
Geo Tracker Global ID:	T10000011582
Number of Ponds:	1
Latitude:	35.48194
Longitude:	-119.73492

AP149 **WASTEWATER PITS** **S127594212**
West **N/A**
1/8-1/4 **, CA**
0.198 mi.
1047 ft. **Site 1 of 2 in cluster AP**

Actual: WASTEWATER PITS:
620 ft.

Name:	Not reported
Address:	Not reported
City,State,Zip:	CA
Status:	Inactive
Field:	Belridge North
Lease:	Dow Chanslor
Operator:	Aera Energy LLC
Geo Tracker Global ID:	L10005630246
Number of Ponds:	1
Latitude:	35.51547
Longitude:	-119.76430

Focus Map:
8

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150 **WASTEWATER PITS** **S127594245**
NW **N/A**
1/8-1/4 **, CA**
0.200 mi.
1057 ft.

Actual: WASTEWATER PITS:
655 ft.

Name:	Not reported
Address:	Not reported
City,State,Zip:	CA
Status:	Inactive
Field:	Belridge North
Lease:	Sec 35
Operator:	Aera Energy LLC
Geo Tracker Global ID:	T10000006758
Number of Ponds:	1
Latitude:	35.538652
Longitude:	-119.788871

Focus Map:
4

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151 **WASTEWATER PITS** **S127593746**
East **N/A**
1/8-1/4 **, CA**
0.201 mi.
1060 ft.

Actual: WASTEWATER PITS:
545 ft.

Name:	Not reported
Address:	Not reported
City,State,Zip:	CA
Status:	Active
Field:	Belridge South
Lease:	Water Plant 27
Operator:	Aera Energy LLC
Geo Tracker Global ID:	T10000011585
Number of Ponds:	1
Latitude:	35.46179
Longitude:	-119.70642

Focus Map:
19

AP152 **WASTEWATER PITS** **S127593517**
West **N/A**
1/8-1/4 **, CA**
0.204 mi.
1077 ft. **Site 2 of 2 in cluster AP**

Actual: WASTEWATER PITS:
621 ft.

Name:	Not reported
Address:	Not reported
City,State,Zip:	CA
Status:	Closed - NFA
Field:	Belridge North
Lease:	Dow Chanslor
Operator:	Aera Energy LLC
Geo Tracker Global ID:	L10005630246
Number of Ponds:	1
Latitude:	35.51546
Longitude:	-119.76440

Focus Map:
8

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153 **WASTEWATER PITS** **S127593691**
NE **N/A**
1/8-1/4 **, CA**
0.220 mi.
1159 ft.

Actual: WASTEWATER PITS:
554 ft.

Name:	Not reported
Address:	Not reported
City,State,Zip:	CA
Status:	Active
Field:	Belridge South
Lease:	Dehydration Plant 20
Operator:	Aera Energy LLC
Geo Tracker Global ID:	T10000011582
Number of Ponds:	1
Latitude:	35.48193
Longitude:	-119.73377

Focus Map:
15

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154 **WASTEWATER PITS** **S127593801**
NE **N/A**
1/8-1/4 **, CA**
0.231 mi.
1218 ft.

Actual: WASTEWATER PITS:
613 ft.

Name:	Not reported
Address:	Not reported
City,State,Zip:	CA
Status:	Closed - PC WDRs
Field:	Belridge North
Lease:	North Surface Impoundments
Operator:	Aera Energy LLC
Geo Tracker Global ID:	-
Number of Ponds:	16
Latitude:	35.54459
Longitude:	-119.78530

Focus Map:
5

155
North
1/4-1/2 , CA
0.254 mi.
1339 ft.

WASTEWATER PITS **S127593513**
N/A

Actual:
537 ft.

Focus Map:
19

WASTEWATER PITS:

Name:	Not reported
Address:	Not reported
City,State,Zip:	CA
Status:	Closed - PC WDRs
Field:	Belridge South
Lease:	Highway 33 Wastewater Disposal Facility
Operator:	Aera Energy LLC
Geo Tracker Global ID:	WDR100026926
Number of Ponds:	28
Latitude:	35.46762
Longitude:	-119.71103

156
NE
1/4-1/2 , CA
0.265 mi.
1399 ft.

WASTEWATER PITS **S127593602**
N/A

Actual:
564 ft.

Focus Map:
16

WASTEWATER PITS:

Name:	Not reported
Address:	Not reported
City,State,Zip:	CA
Status:	Closed - PC WDRs
Field:	Belridge South
Lease:	Reagan Wastewater Disposal Facility
Operator:	Aera Energy LLC
Geo Tracker Global ID:	WDR100026929
Number of Ponds:	32
Latitude:	35.47520
Longitude:	-119.72921

157
North
1/4-1/2 , CA
0.269 mi.
1421 ft.

WASTEWATER PITS **S127593779**
N/A

Actual:
545 ft.

Focus Map:
19

WASTEWATER PITS:

Name:	Not reported
Address:	Not reported
City,State,Zip:	CA
Status:	Active
Field:	Belridge South
Lease:	Water Plant 27
Operator:	Aera Energy LLC
Geo Tracker Global ID:	T10000011585
Number of Ponds:	1
Latitude:	35.45919
Longitude:	-119.70432

158
East
1/4-1/2
0.285 mi.
1507 ft.
, CA

WASTEWATER PITS **S127593894**
N/A

Actual:
610 ft.

Focus Map:
8

WASTEWATER PITS:

Name:	Not reported
Address:	Not reported
City,State,Zip:	CA
Status:	Inactive
Field:	Belridge North
Lease:	McPhail
Operator:	Greka Oil & Gas, Inc.
Geo Tracker Global ID:	L10005431189
Number of Ponds:	1
Latitude:	35.53634
Longitude:	-119.77581

159
NE
1/4-1/2
0.296 mi.
1564 ft.
, CA

WASTEWATER PITS **S127593702**
N/A

Actual:
547 ft.

Focus Map:
19

WASTEWATER PITS:

Name:	Not reported
Address:	Not reported
City,State,Zip:	CA
Status:	Active
Field:	Belridge South
Lease:	Water Plant 27
Operator:	Aera Energy LLC
Geo Tracker Global ID:	T10000011585
Number of Ponds:	1
Latitude:	35.45964
Longitude:	-119.70513

160
NNW
1/4-1/2
0.312 mi.
1646 ft.
, CA

WASTEWATER PITS **S127593790**
N/A

Actual:
541 ft.

Focus Map:
20

WASTEWATER PITS:

Name:	Not reported
Address:	Not reported
City,State,Zip:	CA
Status:	Active
Field:	Belridge South
Lease:	Water Plant 27
Operator:	Aera Energy LLC
Geo Tracker Global ID:	T10000011585
Number of Ponds:	1
Latitude:	35.45993
Longitude:	-119.70384

AQ161 **WASTEWATER PITS** **S127593757**
North **N/A**
1/4-1/2 **, CA**
0.320 mi.
1687 ft. **Site 1 of 4 in cluster AQ**

Actual: WASTEWATER PITS:
537 ft.
Name: Not reported
Focus Map: Address: Not reported
20 City,State,Zip: CA
Status: Active
Field: Belridge South
Lease: Water Plant 27
Operator: Aera Energy LLC
Geo Tracker Global ID: T10000011585
Number of Ponds: 1
Latitude: 35.46013
Longitude: -119.70279

AQ162 **WASTEWATER PITS** **S127593735**
North **N/A**
1/4-1/2 **, CA**
0.329 mi.
1738 ft. **Site 2 of 4 in cluster AQ**

Actual: WASTEWATER PITS:
536 ft.
Name: Not reported
Focus Map: Address: Not reported
20 City,State,Zip: CA
Status: Active
Field: Belridge South
Lease: Water Plant 27
Operator: Aera Energy LLC
Geo Tracker Global ID: T10000011585
Number of Ponds: 1
Latitude: 35.46027
Longitude: -119.70267

AQ163 **WASTEWATER PITS** **S127593713**
North **N/A**
1/4-1/2 **, CA**
0.330 mi.
1742 ft. **Site 3 of 4 in cluster AQ**

Actual: WASTEWATER PITS:
537 ft.
Name: Not reported
Focus Map: Address: Not reported
20 City,State,Zip: CA
Status: Active
Field: Belridge South
Lease: Water Plant 27
Operator: Aera Energy LLC
Geo Tracker Global ID: T10000011585
Number of Ponds: 1
Latitude: 35.46028
Longitude: -119.70287

164
West
1/4-1/2
0.337 mi.
1778 ft.
, CA

WASTEWATER PITS **S127594246**
N/A

Actual:
636 ft.

Focus Map:
11

WASTEWATER PITS:

Name:	Not reported
Address:	Not reported
City,State,Zip:	CA
Status:	Inactive
Field:	Belridge South
Lease:	Dow Chanslor
Operator:	Aera Energy LLC
Geo Tracker Global ID:	L10005630246
Number of Ponds:	1
Latitude:	35.51215
Longitude:	-119.76673

165
ESE
1/4-1/2
0.337 mi.
1778 ft.
, CA

WASTEWATER PITS **S127593768**
N/A

Actual:
542 ft.

Focus Map:
19

WASTEWATER PITS:

Name:	Not reported
Address:	Not reported
City,State,Zip:	CA
Status:	Active
Field:	Belridge South
Lease:	Water Plant 27
Operator:	Aera Energy LLC
Geo Tracker Global ID:	T10000011585
Number of Ponds:	1
Latitude:	35.46022
Longitude:	-119.70450

AQ166
North
1/4-1/2
0.343 mi.
1813 ft.
, CA

Site 4 of 4 in cluster AQ

WASTEWATER PITS **S127593724**
N/A

Actual:
534 ft.

Focus Map:
20

WASTEWATER PITS:

Name:	Not reported
Address:	Not reported
City,State,Zip:	CA
Status:	Active
Field:	Belridge South
Lease:	Water Plant 27
Operator:	Aera Energy LLC
Geo Tracker Global ID:	T10000011585
Number of Ponds:	1
Latitude:	35.46048
Longitude:	-119.70233

167
SSE
1/4-1/2 , CA
0.371 mi.
1957 ft.

WASTEWATER PITS **S127594234**
N/A

Actual:
639 ft.

Focus Map:
11

WASTEWATER PITS:

Name:	Not reported
Address:	Not reported
City,State,Zip:	CA
Status:	Inactive
Field:	Belridge North
Lease:	Dow Chanslor
Operator:	Aera Energy LLC
Geo Tracker Global ID:	L10005630246
Number of Ponds:	1
Latitude:	35.51499
Longitude:	-119.77075

168
East
1/4-1/2 , CA
0.397 mi.
2098 ft.

WASTEWATER PITS **S127593893**
N/A

Actual:
603 ft.

Focus Map:
8

WASTEWATER PITS:

Name:	Not reported
Address:	Not reported
City,State,Zip:	CA
Status:	Inactive
Field:	Belridge North
Lease:	Gibson
Operator:	Greka Oil & Gas, Inc.
Geo Tracker Global ID:	L10005431189
Number of Ponds:	1
Latitude:	35.53528
Longitude:	-119.77388

169
SW
1/4-1/2 , CA
0.491 mi.
2591 ft.

WASTEWATER PITS **S127593490**
N/A

Actual:
594 ft.

Focus Map:
15

WASTEWATER PITS:

Name:	Not reported
Address:	Not reported
City,State,Zip:	CA
Status:	Inactive
Field:	Belridge South
Lease:	Hill
Operator:	Berry Petroleum Company, LLC
Geo Tracker Global ID:	-
Number of Ponds:	1
Latitude:	35.48017
Longitude:	-119.74713

Count: 70 records

ORPHAN SUMMARY

City	EDR ID	Site Name	Site Address	Zip	Database(s)
BELRIDGE	1023254823	KVS FACILITY #2	AERA SOUTH BELRIDGE	93251	FINDS
BELRIDGENA CA	1023302832	BAKER HUGHES OILFIELD OPERATIONS INC - CONTRACTORS ROW 4	CONTRACTORS ROW 4	93249	FINDS
DERBY ACRES	A100421727	LDD ENERGY - WEBBER LEASE	HIGHWAY 33	93251	AST
DERBY ACRES	1023383148	LDD ENERGY - WEBBER LEASE	HIGHWAY 33	93251	FINDS
FELLOWS	S123143171	MWSS 2019 25C CYCLIC PACKAGE	26251 HIGHWAY 33	93251	NPDES
KERN COUNTY	2000515968		19600 WESTSIDE HWY		ERNS
KERN COUNTY	8865577		MCKITTRICK FEE PROPERTY;1 MILE WEST OF HIGHWAY 33;3MILES NOR		ERNS
KERN COUNTY	8860906		24Z LACT / SEC 24 T 30S R 22E ELK HILLS NAVAL PETROLEUM RESE		ERNS
KERN COUNTY	S106391652		SECTION 29, TOWNSHIP 30S, RANGE 24E WELL 88-29S, NAVEL PETROLEUM RESERVE NO. 1 TUPMAN CA		CHMIRS
LOST HILLS	2018222444		16435 HIGHWAY 33	93249	ERNS
LOST HILLS	2018222436		16435 HIGHWAY 33	93249	ERNS
LOST HILLS	2004740405		17251 POLE LINE RD.	93249	ERNS
LOST HILLS	2017182894		(LOST HILLS 2 AERA)		ERNS
LOST HILLS	A100423436	PHILLIPS 66 - MIDDLEWATER PUMP STA	17251 POLE LINE RD	93249	AST
LOST HILLS	S127804188	BERRENDA MESA WATER DISTRICT	14823 HIGHWAY 33	93249	HAULERS
LOST HILLS	S127792132	DEVIL DEN IRRIGATION	HIGHWAY 33, 6 MILE NORTH OF HIGHWAY 46	93249	HAULERS
LOST HILLS	S127791377	PACIFIC ALMOND	14333 GENERAL PETROLEUM ROAD	93249	HAULERS
LOST HILLS	S106934346	WEST HILLS ALMOND CO-OP	HIGHWAY 33	93249	SWEEPS UST
LOST HILLS	S106923264	BERRENDA MESA WATER DISTRICT	HIGHWAY 33	93249	SWEEPS UST
LOST HILLS	U001582097	BERRENDA MESA WTR DIST. O&M CE	HIGHWAY 33	93249	HIST UST
LOST HILLS	S118416739	VERRENDA MESA WTR DIST OANDM CE	HIGHWAY 33	93249	HIST UST
LOST HILLS	S112829996		HIGHWAY 33 X HIGHWAY 46	93249	CHMIRS
LOST HILLS	S110421142		ALLIED WESTERN PETROLEUM, DAGANY GAP TANK FARM, BARKER ROAD, SECTION 10 OF TOWNSHIP 25S RANGE 18E GP		CHMIRS
LOST HILLS	S110981101		JUST NORTH OF MIDDLE WATER PUMP STATION LOCATED AT 17251 POLE LINE RD		CHMIRS
LOST HILLS	1023378779	AT AND T MOBILITY - DIFFFENBAUGH (48552)	HIGHWAY 33	93249	FINDS
LOST HILLS	1023255506	NORTH BELRIDGENA DOW CHANSLOR	NW OF CONTRACTORS RD/ WATERFLOOD RD	93249	FINDS
LOST HILLS	1023295851	SOUTH BELRIDGENA DOW CHANSLOR	NW OF CONTRACTORS RD / WATERFLOOD RD	93249	FINDS
LOST HILLS	1024391947	KS INDUSTRIES, LP	CONTRACTORS RD. AND HWY 33	93249	FINDS
LOST HILLS	1024407546	PAUL GRAHAM DRILLING AND SERVICE CO.	1/2 MI N OF LERDO HWY & POLE LINE RD	93249	FINDS
LOST HILLS	S118494322	VINTAGE PRODUCTION CALIFORNIA LLC	OFF POLE LINE & DUMP SITE RD	93249	EMI
LOST HILLS	S120712911	CALIFORNIA RESOURCES PRODUCTION CORP	OFF POLE LINE & DUMP SITE RD	93249	EMI
LOST HILLS	S128659128	L1203 MP 5 00 REMOVAL	NORTH OF HWY 33 AND HOSTLY AVE	93249	NPDES
LOST HILLS	S125339538	AERA ENERGY LLC - NORTH BELRIDGE OIL FIELD - WATER FLOOD - PROJECT 05000012	POLE LINE ROAD	93249	UIC GEO
MC KITTRICK	1024396771	PRO-VAC, INC.	CONTRACTORS RD AND JACK JONES BLVD	93251	FINDS
MC KITTRICK	S126339504	PENGO WIRELINE BELRIDGE YARD	CONTRACTORS ROW LOT 107		CUPA Listings
MCKITTRICK	92150568		POLE LINE RD, OFF OF HWY	93251	ERNS

Count: 70 records

ORPHAN SUMMARY

City	EDR ID	Site Name	Site Address	Zip	Database(s)
MCKITTRICK	S126983174	SECTION 3 TRASH FACILITY	1/2 MILE S OF 7TH STANDARD RD ON BURMA R	93251	SWF/LF
MCKITTRICK	A100324402	CONOCOPHILLIPS-MIDDLEWATER PUMP STA	17251 POLE LINE	93251	AST
MCKITTRICK	S127791764	SMITH & SON TIRE, INC.	CONTRACTORS ROW #11, BELRIDGE FIELD	93251	HAULERS
MCKITTRICK	S105645938		SOUTH BELRIDGE REEF TANK FARMS 19651 HIGHWAY 33	93251	CHMIRS
MCKITTRICK	S105640740		S2, T29S, R21E 19651 HIGHWAY 33	93251	CHMIRS
MCKITTRICK	S110424125		SECTION 2, TOWNSHIP 28 SOUTH, RANGE 21 EAST, CLOSEST LOCATION IS HIGHWAY 33 AND LOST HILLS ROAD, BEL	93251	CHMIRS
MCKITTRICK	S126113790		NEAR HIGHWAY 33 AT CYMRIC RD, MCKITTRICK UNIT LEASE, SECTION 6, TOWNSHIP 30S, RANGE 22E	93251	CHMIRS
MCKITTRICK	1025866443	ROBERT HEELY CONSTRUCTION	2000 CONTRACTORS RD	93251	RCRA NonGen / NLR
MCKITTRICK	1024821077	SMITH & SON TIRE INC	LOT 11, SPACE 2 CONTRACTORS RD-	93251	RCRA NonGen / NLR
MCKITTRICK	1024820035	KEY ENERGY SERVICES LLC	6 CONTRACTORS RD	93251	RCRA NonGen / NLR
MCKITTRICK	1023328947	MOJAVE PIPELINE N MIDWAY MS	HIGHWAY 33	93251	FINDS
MCKITTRICK	1023306473	BELGIAN ANTICLINENA MCKITTRIK 1	E OF CA-33 AND CYMRIC RD. SEC19&24N	93251	FINDS
MCKITTRICK	1023220099	BELGIAN ANTICLINENA MCKITTRICK 1	E OF CA-33 AND CYMRIC RD.	93251	FINDS
MCKITTRICK	1023224654	MCKITTRICK SCHOOL	HIGHWAY 58 & HIGHWAY 33	93251	FINDS
MCKITTRICK	1023283123	CYMRIC OIL FIELDNA LEHI LEASE	SW OF 7TH STANDARD RD / PROPERTY LINE RD	93251	FINDS
MCKITTRICK	1023285974	BELRIDGENA REAGAN	SEOF CONTRACTORS RD / WEST SIDE HWY 33	93251	FINDS
MCKITTRICK	1023254395	CLARIANT OIL SERVICES	CONTRACTORS RD	93251	FINDS
MCKITTRICK	1023288251	BELRIDGENA TILLINGHAST	SW OF CONTRACTORS RD / WATERFLOOD RD	93251	FINDS
MCKITTRICK	1024682641	SMITH & SON TIRE INC	LOT 11, SPACE 2 CONTRACTORS RD-	93251	FINDS, ECHO
MCKITTRICK	1026386563	ROBERT HEELY CONSTRUCTION	2000 CONTRACTORS RD	93251	FINDS
MCKITTRICK	1023343303	BELRIDGENA SOUTHNA KING	NE OF MAIL CAMP RD / PROPERTY LINE RD	93251	FINDS
MCKITTRICK	1023356983	BELRIDGENA HIGHWAY 33	SE OF CONTRACTORS RD/ WEST SIDE HWY 33	93251	FINDS
MCKITTRICK	1023349253	SMITH AND SON TIRE INC	11 CONTRACTORS ROW	93251	FINDS
MCKITTRICK	1023220647	CLARIANT OIL SERVICES	CONTRACTORS ROAD & HWY 33	93251	FINDS
MCKITTRICK	1023227165	BELRIDGENA SOUTHNA CARNEROS	NE OF MAIN CAMP RD / PROPERTY LINE RD	93251	FINDS
MCKITTRICK	1024684124	KEY ENERGY SERVICES LLC	6 CONTRACTORS RD	93251	FINDS, ECHO
MCKITTRICK	1023208903	STURGEON SERVICES, INT'L	CONTRACTORS RD	93251	FINDS
MCKITTRICK	1026037271	ROBERT HEELY CONSTRUCTION	2000 CONTRACTORS RD	93251	ECHO
MCKITTRICK	S118494966	LIQUID WASTE MANAGEMENT INC	HIGHWAY 33 & HIGHWAY 58	93251	EMI
MCKITTRICK	S125639083	BELRIDGE CENTRAL WASTE RECYCLING FACILIOTY	PROPERTY LINE RD [SECS 29 &32,T28S, R21E, MDB&M]	93251	OTHER OIL GAS
OUTSIDE MCKITTRICK	U001582199	MCKITTRICK PUMP STATION	STATE HIGHWAY 33	93251	HIST UST
UNINCORPORATED COUN	S107451978		HIGHWAY 33 AT LERDO HWY, CLOSEST CITY IS MCKITTRICK	93251	CHMIRS
UNINCORPORATED COUN	S106396179		HIGHWAY 33, 12 MILES NORTH OF MCKITTRICK	93251	CHMIRS
UNINCORPORATED COUN	S108404663		BELRIDGE LEASE, 1/2 MILE WEST OF HIGHWAY 33 NEAR WELL 917-C4.	93251	CHMIRS

GOVERNMENT RECORDS SEARCHED / DATA CURRENCY TRACKING

To maintain currency of the following federal and state databases, EDR contacts the appropriate governmental agency on a monthly or quarterly basis, as required.

Number of Days to Update: Provides confirmation that EDR is reporting records that have been updated within 90 days from the date the government agency made the information available to the public.

STANDARD ENVIRONMENTAL RECORDS

Lists of Federal NPL (Superfund) sites

NPL: National Priority List

National Priorities List (Superfund). The NPL is a subset of CERCLIS and identifies over 1,200 sites for priority cleanup under the Superfund Program. NPL sites may encompass relatively large areas. As such, EDR provides polygon coverage for over 1,000 NPL site boundaries produced by EPA's Environmental Photographic Interpretation Center (EPIC) and regional EPA offices.

Date of Government Version: 07/26/2022
Date Data Arrived at EDR: 08/02/2022
Date Made Active in Reports: 08/22/2022
Number of Days to Update: 20

Source: EPA
Telephone: N/A
Last EDR Contact: 09/01/2022
Next Scheduled EDR Contact: 10/10/2022
Data Release Frequency: Quarterly

NPL Site Boundaries

Sources:

EPA's Environmental Photographic Interpretation Center (EPIC)
Telephone: 202-564-7333

EPA Region 1
Telephone 617-918-1143

EPA Region 6
Telephone: 214-655-6659

EPA Region 3
Telephone 215-814-5418

EPA Region 7
Telephone: 913-551-7247

EPA Region 4
Telephone 404-562-8033

EPA Region 8
Telephone: 303-312-6774

EPA Region 5
Telephone 312-886-6686

EPA Region 9
Telephone: 415-947-4246

EPA Region 10
Telephone 206-553-8665

Proposed NPL: Proposed National Priority List Sites

A site that has been proposed for listing on the National Priorities List through the issuance of a proposed rule in the Federal Register. EPA then accepts public comments on the site, responds to the comments, and places on the NPL those sites that continue to meet the requirements for listing.

Date of Government Version: 07/26/2022
Date Data Arrived at EDR: 08/02/2022
Date Made Active in Reports: 08/22/2022
Number of Days to Update: 20

Source: EPA
Telephone: N/A
Last EDR Contact: 09/01/2022
Next Scheduled EDR Contact: 10/10/2022
Data Release Frequency: Quarterly

NPL LIENS: Federal Superfund Liens

Federal Superfund Liens. Under the authority granted the USEPA by CERCLA of 1980, the USEPA has the authority to file liens against real property in order to recover remedial action expenditures or when the property owner received notification of potential liability. USEPA compiles a listing of filed notices of Superfund Liens.

Date of Government Version: 10/15/1991
Date Data Arrived at EDR: 02/02/1994
Date Made Active in Reports: 03/30/1994
Number of Days to Update: 56

Source: EPA
Telephone: 202-564-4267
Last EDR Contact: 08/15/2011
Next Scheduled EDR Contact: 11/28/2011
Data Release Frequency: No Update Planned

Lists of Federal Delisted NPL sites

Delisted NPL: National Priority List Deletions

The National Oil and Hazardous Substances Pollution Contingency Plan (NCP) establishes the criteria that the EPA uses to delete sites from the NPL. In accordance with 40 CFR 300.425.(e), sites may be deleted from the NPL where no further response is appropriate.

Date of Government Version: 07/26/2022
Date Data Arrived at EDR: 08/02/2022
Date Made Active in Reports: 08/22/2022
Number of Days to Update: 20

Source: EPA
Telephone: N/A
Last EDR Contact: 09/01/2022
Next Scheduled EDR Contact: 10/10/2022
Data Release Frequency: Quarterly

Lists of Federal sites subject to CERCLA removals and CERCLA orders

FEDERAL FACILITY: Federal Facility Site Information listing

A listing of National Priority List (NPL) and Base Realignment and Closure (BRAC) sites found in the Comprehensive Environmental Response, Compensation and Liability Information System (CERCLIS) Database where EPA Federal Facilities Restoration and Reuse Office is involved in cleanup activities.

Date of Government Version: 05/25/2021
Date Data Arrived at EDR: 06/24/2021
Date Made Active in Reports: 09/20/2021
Number of Days to Update: 88

Source: Environmental Protection Agency
Telephone: 703-603-8704
Last EDR Contact: 09/06/2022
Next Scheduled EDR Contact: 01/10/2023
Data Release Frequency: Varies

SEMS: Superfund Enterprise Management System

SEMS (Superfund Enterprise Management System) tracks hazardous waste sites, potentially hazardous waste sites, and remedial activities performed in support of EPA's Superfund Program across the United States. The list was formerly know as CERCLIS, renamed to SEMS by the EPA in 2015. The list contains data on potentially hazardous waste sites that have been reported to the USEPA by states, municipalities, private companies and private persons, pursuant to Section 103 of the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA). This dataset also contains sites which are either proposed to or on the National Priorities List (NPL) and the sites which are in the screening and assessment phase for possible inclusion on the NPL.

Date of Government Version: 07/26/2022
Date Data Arrived at EDR: 08/02/2022
Date Made Active in Reports: 08/22/2022
Number of Days to Update: 20

Source: EPA
Telephone: 800-424-9346
Last EDR Contact: 09/01/2022
Next Scheduled EDR Contact: 10/24/2022
Data Release Frequency: Quarterly

Lists of Federal CERCLA sites with NFRAP

SEMS-ARCHIVE: Superfund Enterprise Management System Archive

SEMS-ARCHIVE (Superfund Enterprise Management System Archive) tracks sites that have no further interest under the Federal Superfund Program based on available information. The list was formerly known as the CERCLIS-NFRAP, renamed to SEMS ARCHIVE by the EPA in 2015. EPA may perform a minimal level of assessment work at a site while it is archived if site conditions change and/or new information becomes available. Archived sites have been removed and archived from the inventory of SEMS sites. Archived status indicates that, to the best of EPA's knowledge, assessment at a site has been completed and that EPA has determined no further steps will be taken to list the site on the National Priorities List (NPL), unless information indicates this decision was not appropriate or other considerations require a recommendation for listing at a later time. The decision does not necessarily mean that there is no hazard associated with a given site; it only means that. based upon available information, the location is not judged to be potential NPL site.

Date of Government Version: 07/26/2022
Date Data Arrived at EDR: 08/02/2022
Date Made Active in Reports: 08/22/2022
Number of Days to Update: 20

Source: EPA
Telephone: 800-424-9346
Last EDR Contact: 09/01/2022
Next Scheduled EDR Contact: 10/24/2022
Data Release Frequency: Quarterly

Lists of Federal RCRA facilities undergoing Corrective Action

CORRACTS: Corrective Action Report

CORRACTS identifies hazardous waste handlers with RCRA corrective action activity.

Date of Government Version: 06/20/2022
Date Data Arrived at EDR: 06/21/2022
Date Made Active in Reports: 06/28/2022
Number of Days to Update: 7

Source: EPA
Telephone: 800-424-9346
Last EDR Contact: 09/19/2022
Next Scheduled EDR Contact: 01/02/2023
Data Release Frequency: Quarterly

Lists of Federal RCRA TSD facilities

RCRA-TSDF: RCRA - Treatment, Storage and Disposal

RCRAInfo is EPA's comprehensive information system, providing access to data supporting the Resource Conservation and Recovery Act (RCRA) of 1976 and the Hazardous and Solid Waste Amendments (HSWA) of 1984. The database includes selective information on sites which generate, transport, store, treat and/or dispose of hazardous waste as defined by the Resource Conservation and Recovery Act (RCRA). Transporters are individuals or entities that move hazardous waste from the generator offsite to a facility that can recycle, treat, store, or dispose of the waste. TSDFs treat, store, or dispose of the waste.

Date of Government Version: 06/20/2022
Date Data Arrived at EDR: 06/21/2022
Date Made Active in Reports: 06/28/2022
Number of Days to Update: 7

Source: Environmental Protection Agency
Telephone: (415) 495-8895
Last EDR Contact: 09/19/2022
Next Scheduled EDR Contact: 01/02/2023
Data Release Frequency: Quarterly

Lists of Federal RCRA generators

RCRA-LQG: RCRA - Large Quantity Generators

RCRAInfo is EPA's comprehensive information system, providing access to data supporting the Resource Conservation and Recovery Act (RCRA) of 1976 and the Hazardous and Solid Waste Amendments (HSWA) of 1984. The database includes selective information on sites which generate, transport, store, treat and/or dispose of hazardous waste as defined by the Resource Conservation and Recovery Act (RCRA). Large quantity generators (LQGs) generate over 1,000 kilograms (kg) of hazardous waste, or over 1 kg of acutely hazardous waste per month.

Date of Government Version: 06/20/2022
Date Data Arrived at EDR: 06/21/2022
Date Made Active in Reports: 06/28/2022
Number of Days to Update: 7

Source: Environmental Protection Agency
Telephone: (415) 495-8895
Last EDR Contact: 09/19/2022
Next Scheduled EDR Contact: 01/02/2023
Data Release Frequency: Quarterly

RCRA-SQG: RCRA - Small Quantity Generators

RCRAInfo is EPA's comprehensive information system, providing access to data supporting the Resource Conservation and Recovery Act (RCRA) of 1976 and the Hazardous and Solid Waste Amendments (HSWA) of 1984. The database includes selective information on sites which generate, transport, store, treat and/or dispose of hazardous waste as defined by the Resource Conservation and Recovery Act (RCRA). Small quantity generators (SQGs) generate between 100 kg and 1,000 kg of hazardous waste per month.

Date of Government Version: 06/20/2022
Date Data Arrived at EDR: 06/21/2022
Date Made Active in Reports: 06/28/2022
Number of Days to Update: 7

Source: Environmental Protection Agency
Telephone: (415) 495-8895
Last EDR Contact: 09/19/2022
Next Scheduled EDR Contact: 01/02/2023
Data Release Frequency: Quarterly

RCRA-VSQG: RCRA - Very Small Quantity Generators (Formerly Conditionally Exempt Small Quantity Generators)

RCRAInfo is EPA's comprehensive information system, providing access to data supporting the Resource Conservation and Recovery Act (RCRA) of 1976 and the Hazardous and Solid Waste Amendments (HSWA) of 1984. The database includes selective information on sites which generate, transport, store, treat and/or dispose of hazardous waste as defined by the Resource Conservation and Recovery Act (RCRA). Very small quantity generators (VSQGs) generate less than 100 kg of hazardous waste, or less than 1 kg of acutely hazardous waste per month.

Date of Government Version: 06/20/2022
Date Data Arrived at EDR: 06/21/2022
Date Made Active in Reports: 06/28/2022
Number of Days to Update: 7

Source: Environmental Protection Agency
Telephone: (415) 495-8895
Last EDR Contact: 09/19/2022
Next Scheduled EDR Contact: 01/02/2023
Data Release Frequency: Quarterly

Federal institutional controls / engineering controls registries

LUCIS: Land Use Control Information System

LUCIS contains records of land use control information pertaining to the former Navy Base Realignment and Closure properties.

Date of Government Version: 05/16/2022
Date Data Arrived at EDR: 05/19/2022
Date Made Active in Reports: 07/29/2022
Number of Days to Update: 71

Source: Department of the Navy
Telephone: 843-820-7326
Last EDR Contact: 08/03/2022
Next Scheduled EDR Contact: 11/21/2022
Data Release Frequency: Varies

US ENG CONTROLS: Engineering Controls Sites List

A listing of sites with engineering controls in place. Engineering controls include various forms of caps, building foundations, liners, and treatment methods to create pathway elimination for regulated substances to enter environmental media or effect human health.

Date of Government Version: 05/16/2022
Date Data Arrived at EDR: 05/24/2022
Date Made Active in Reports: 07/29/2022
Number of Days to Update: 66

Source: Environmental Protection Agency
Telephone: 703-603-0695
Last EDR Contact: 08/17/2022
Next Scheduled EDR Contact: 12/05/2022
Data Release Frequency: Varies

US INST CONTROLS: Institutional Controls Sites List

A listing of sites with institutional controls in place. Institutional controls include administrative measures, such as groundwater use restrictions, construction restrictions, property use restrictions, and post remediation care requirements intended to prevent exposure to contaminants remaining on site. Deed restrictions are generally required as part of the institutional controls.

Date of Government Version: 05/16/2022
Date Data Arrived at EDR: 05/24/2022
Date Made Active in Reports: 07/29/2022
Number of Days to Update: 66

Source: Environmental Protection Agency
Telephone: 703-603-0695
Last EDR Contact: 08/17/2022
Next Scheduled EDR Contact: 12/05/2022
Data Release Frequency: Varies

Federal ERNS list

ERNS: Emergency Response Notification System

Emergency Response Notification System. ERNS records and stores information on reported releases of oil and hazardous substances.

Date of Government Version: 06/14/2022
Date Data Arrived at EDR: 06/15/2022
Date Made Active in Reports: 06/21/2022
Number of Days to Update: 6

Source: National Response Center, United States Coast Guard
Telephone: 202-267-2180
Last EDR Contact: 09/20/2022
Next Scheduled EDR Contact: 01/02/2023
Data Release Frequency: Quarterly

Lists of state- and tribal (Superfund) equivalent sites

RESPONSE: State Response Sites

Identifies confirmed release sites where DTSC is involved in remediation, either in a lead or oversight capacity. These confirmed release sites are generally high-priority and high potential risk.

Date of Government Version: 04/25/2022
Date Data Arrived at EDR: 04/26/2022
Date Made Active in Reports: 07/15/2022
Number of Days to Update: 80

Source: Department of Toxic Substances Control
Telephone: 916-323-3400
Last EDR Contact: 07/25/2022
Next Scheduled EDR Contact: 11/07/2022
Data Release Frequency: Quarterly

Lists of state- and tribal hazardous waste facilities

ENVIROSTOR: EnviroStor Database

The Department of Toxic Substances Control's (DTSC's) Site Mitigation and Brownfields Reuse Program's (SMBRP's) EnviroStor database identifes sites that have known contamination or sites for which there may be reasons to investigate further. The database includes the following site types: Federal Superfund sites (National Priorities List (NPL)); State Response, including Military Facilities and State Superfund; Voluntary Cleanup; and School sites. EnviroStor provides similar information to the information that was available in CalSites, and provides additional site information, including, but not limited to, identification of formerly-contaminated properties that have been released for reuse, properties where environmental deed restrictions have been recorded to prevent inappropriate land uses, and risk characterization information that is used to assess potential impacts to public health and the environment at contaminated sites.

Date of Government Version: 04/25/2022
Date Data Arrived at EDR: 04/26/2022
Date Made Active in Reports: 07/15/2022
Number of Days to Update: 80

Source: Department of Toxic Substances Control
Telephone: 916-323-3400
Last EDR Contact: 07/25/2022
Next Scheduled EDR Contact: 11/07/2022
Data Release Frequency: Quarterly

Lists of state and tribal landfills and solid waste disposal facilities

SWF/LF (SWIS): Solid Waste Information System

Active, Closed and Inactive Landfills. SWF/LF records typically contain an inve ntory of solid waste disposal facilities or landfills. These may be active or i nactive facilities or open dumps that failed to meet RCRA Section 4004 criteria for solid waste landfills or disposal sites.

Date of Government Version: 05/09/2022
Date Data Arrived at EDR: 05/09/2022
Date Made Active in Reports: 07/29/2022
Number of Days to Update: 81

Source: Department of Resources Recycling and Recovery
Telephone: 916-341-6320
Last EDR Contact: 08/08/2022
Next Scheduled EDR Contact: 11/21/2022
Data Release Frequency: Quarterly

Lists of state and tribal leaking storage tanks

LUST REG 2: Fuel Leak List

Leaking Underground Storage Tank locations. Alameda, Contra Costa, Marin, Napa, San Francisco, San Mateo, Santa Clara, Solano, Sonoma counties.

Date of Government Version: 09/30/2004
Date Data Arrived at EDR: 10/20/2004
Date Made Active in Reports: 11/19/2004
Number of Days to Update: 30

Source: California Regional Water Quality Control Board San Francisco Bay Region (2)
Telephone: 510-622-2433
Last EDR Contact: 09/19/2011
Next Scheduled EDR Contact: 01/02/2012
Data Release Frequency: No Update Planned

LUST REG 3: Leaking Underground Storage Tank Database

Leaking Underground Storage Tank locations. Monterey, San Benito, San Luis Obispo, Santa Barbara, Santa Cruz counties.

Date of Government Version: 05/19/2003
Date Data Arrived at EDR: 05/19/2003
Date Made Active in Reports: 06/02/2003
Number of Days to Update: 14

Source: California Regional Water Quality Control Board Central Coast Region (3)
Telephone: 805-542-4786
Last EDR Contact: 07/18/2011
Next Scheduled EDR Contact: 10/31/2011
Data Release Frequency: No Update Planned

LUST: Leaking Underground Fuel Tank Report (GEOTRACKER)

Leaking Underground Storage Tank (LUST) Sites included in GeoTracker. GeoTracker is the Water Boards data management system for sites that impact, or have the potential to impact, water quality in California, with emphasis on groundwater.

Date of Government Version: 05/23/2022
Date Data Arrived at EDR: 05/23/2022
Date Made Active in Reports: 05/24/2022
Number of Days to Update: 1

Source: State Water Resources Control Board
Telephone: see region list
Last EDR Contact: 08/31/2022
Next Scheduled EDR Contact: 12/19/2022
Data Release Frequency: Quarterly

LUST REG 6V: Leaking Underground Storage Tank Case Listing

Leaking Underground Storage Tank locations. Inyo, Kern, Los Angeles, Mono, San Bernardino counties.

Date of Government Version: 06/07/2005
Date Data Arrived at EDR: 06/07/2005
Date Made Active in Reports: 06/29/2005
Number of Days to Update: 22

Source: California Regional Water Quality Control Board Victorville Branch Office (6)
Telephone: 760-241-7365
Last EDR Contact: 09/12/2011
Next Scheduled EDR Contact: 12/26/2011
Data Release Frequency: No Update Planned

LUST REG 1: Active Toxic Site Investigation

Del Norte, Humboldt, Lake, Mendocino, Modoc, Siskiyou, Sonoma, Trinity counties. For more current information, please refer to the State Water Resources Control Board's LUST database.

Date of Government Version: 02/01/2001
Date Data Arrived at EDR: 02/28/2001
Date Made Active in Reports: 03/29/2001
Number of Days to Update: 29

Source: California Regional Water Quality Control Board North Coast (1)
Telephone: 707-570-3769
Last EDR Contact: 08/01/2011
Next Scheduled EDR Contact: 11/14/2011
Data Release Frequency: No Update Planned

LUST REG 6L: Leaking Underground Storage Tank Case Listing

For more current information, please refer to the State Water Resources Control Board's LUST database.

Date of Government Version: 09/09/2003
Date Data Arrived at EDR: 09/10/2003
Date Made Active in Reports: 10/07/2003
Number of Days to Update: 27

Source: California Regional Water Quality Control Board Lahontan Region (6)
Telephone: 530-542-5572
Last EDR Contact: 09/12/2011
Next Scheduled EDR Contact: 12/26/2011
Data Release Frequency: No Update Planned

LUST REG 9: Leaking Underground Storage Tank Report

Orange, Riverside, San Diego counties. For more current information, please refer to the State Water Resources Control Board's LUST database.

Date of Government Version: 03/01/2001
Date Data Arrived at EDR: 04/23/2001
Date Made Active in Reports: 05/21/2001
Number of Days to Update: 28

Source: California Regional Water Quality Control Board San Diego Region (9)
Telephone: 858-637-5595
Last EDR Contact: 09/26/2011
Next Scheduled EDR Contact: 01/09/2012
Data Release Frequency: No Update Planned

LUST REG 8: Leaking Underground Storage Tanks

California Regional Water Quality Control Board Santa Ana Region (8). For more current information, please refer to the State Water Resources Control Board's LUST database.

Date of Government Version: 02/14/2005
Date Data Arrived at EDR: 02/15/2005
Date Made Active in Reports: 03/28/2005
Number of Days to Update: 41

Source: California Regional Water Quality Control Board Santa Ana Region (8)
Telephone: 909-782-4496
Last EDR Contact: 08/15/2011
Next Scheduled EDR Contact: 11/28/2011
Data Release Frequency: No Update Planned

LUST REG 7: Leaking Underground Storage Tank Case Listing

Leaking Underground Storage Tank locations. Imperial, Riverside, San Diego, Santa Barbara counties.

Date of Government Version: 02/26/2004
Date Data Arrived at EDR: 02/26/2004
Date Made Active in Reports: 03/24/2004
Number of Days to Update: 27

Source: California Regional Water Quality Control Board Colorado River Basin Region (7)
Telephone: 760-776-8943
Last EDR Contact: 08/01/2011
Next Scheduled EDR Contact: 11/14/2011
Data Release Frequency: No Update Planned

LUST REG 5: Leaking Underground Storage Tank Database

Leaking Underground Storage Tank locations. Alameda, Alpine, Amador, Butte, Colusa, Contra Costa, Calveras, El Dorado, Fresno, Glenn, Kern, Kings, Lake, Lassen, Madera, Mariposa, Merced, Modoc, Napa, Nevada, Placer, Plumas, Sacramento, San Joaquin, Shasta, Solano, Stanislaus, Sutter, Tehama, Tulare, Tuolumne, Yolo, Yuba counties.

Date of Government Version: 07/01/2008
Date Data Arrived at EDR: 07/22/2008
Date Made Active in Reports: 07/31/2008
Number of Days to Update: 9

Source: California Regional Water Quality Control Board Central Valley Region (5)
Telephone: 916-464-4834
Last EDR Contact: 07/01/2011
Next Scheduled EDR Contact: 10/17/2011
Data Release Frequency: No Update Planned

LUST REG 4: Underground Storage Tank Leak List

Los Angeles, Ventura counties. For more current information, please refer to the State Water Resources Control Board's LUST database.

Date of Government Version: 09/07/2004
Date Data Arrived at EDR: 09/07/2004
Date Made Active in Reports: 10/12/2004
Number of Days to Update: 35

Source: California Regional Water Quality Control Board Los Angeles Region (4)
Telephone: 213-576-6710
Last EDR Contact: 09/06/2011
Next Scheduled EDR Contact: 12/19/2011
Data Release Frequency: No Update Planned

INDIAN LUST R9: Leaking Underground Storage Tanks on Indian Land

LUSTs on Indian land in Arizona, California, New Mexico and Nevada

Date of Government Version: 04/08/2022
Date Data Arrived at EDR: 06/13/2022
Date Made Active in Reports: 08/16/2022
Number of Days to Update: 64

Source: Environmental Protection Agency
Telephone: 415-972-3372
Last EDR Contact: 06/13/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Varies

INDIAN LUST R10: Leaking Underground Storage Tanks on Indian Land

LUSTs on Indian land in Alaska, Idaho, Oregon and Washington.

Date of Government Version: 04/20/2022
Date Data Arrived at EDR: 06/13/2022
Date Made Active in Reports: 08/16/2022
Number of Days to Update: 64

Source: EPA Region 10
Telephone: 206-553-2857
Last EDR Contact: 06/13/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Varies

INDIAN LUST R5: Leaking Underground Storage Tanks on Indian Land
Leaking underground storage tanks located on Indian Land in Michigan, Minnesota and Wisconsin.

Date of Government Version: 04/11/2022
Date Data Arrived at EDR: 06/13/2022
Date Made Active in Reports: 08/16/2022
Number of Days to Update: 64
Source: EPA, Region 5
Telephone: 312-886-7439
Last EDR Contact: 06/13/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Varies

INDIAN LUST R4: Leaking Underground Storage Tanks on Indian Land
LUSTs on Indian land in Florida, Mississippi and North Carolina.

Date of Government Version: 06/02/2022
Date Data Arrived at EDR: 06/13/2022
Date Made Active in Reports: 08/31/2022
Number of Days to Update: 79
Source: EPA Region 4
Telephone: 404-562-8677
Last EDR Contact: 06/13/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Varies

INDIAN LUST R8: Leaking Underground Storage Tanks on Indian Land
LUSTs on Indian land in Colorado, Montana, North Dakota, South Dakota, Utah and Wyoming.

Date of Government Version: 04/20/2022
Date Data Arrived at EDR: 06/13/2022
Date Made Active in Reports: 08/16/2022
Number of Days to Update: 64
Source: EPA Region 8
Telephone: 303-312-6271
Last EDR Contact: 06/13/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Varies

INDIAN LUST R1: Leaking Underground Storage Tanks on Indian Land
A listing of leaking underground storage tank locations on Indian Land.

Date of Government Version: 04/28/2021
Date Data Arrived at EDR: 06/11/2021
Date Made Active in Reports: 09/07/2021
Number of Days to Update: 88
Source: EPA Region 1
Telephone: 617-918-1313
Last EDR Contact: 06/13/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Varies

INDIAN LUST R6: Leaking Underground Storage Tanks on Indian Land
LUSTs on Indian land in New Mexico and Oklahoma.

Date of Government Version: 04/28/2022
Date Data Arrived at EDR: 06/13/2022
Date Made Active in Reports: 08/16/2022
Number of Days to Update: 64
Source: EPA Region 6
Telephone: 214-665-6597
Last EDR Contact: 06/13/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Varies

INDIAN LUST R7: Leaking Underground Storage Tanks on Indian Land
LUSTs on Indian land in Iowa, Kansas, and Nebraska

Date of Government Version: 04/14/2022
Date Data Arrived at EDR: 06/13/2022
Date Made Active in Reports: 08/16/2022
Number of Days to Update: 64
Source: EPA Region 7
Telephone: 913-551-7003
Last EDR Contact: 06/13/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Varies

CPS-SLIC: Statewide SLIC Cases (GEOTRACKER)
Cleanup Program Sites (CPS; also known as Site Cleanups [SC] and formerly known as Spills, Leaks, Investigations, and Cleanups [SLIC] sites) included in GeoTracker. GeoTracker is the Water Boards data management system for sites that impact, or have the potential to impact, water quality in California, with emphasis on groundwater.

Date of Government Version: 05/23/2022
Date Data Arrived at EDR: 05/23/2022
Date Made Active in Reports: 05/24/2022
Number of Days to Update: 1
Source: State Water Resources Control Board
Telephone: 866-480-1028
Last EDR Contact: 08/31/2022
Next Scheduled EDR Contact: 12/19/2022
Data Release Frequency: Varies

SLIC REG 1: Active Toxic Site Investigations
The SLIC (Spills, Leaks, Investigations and Cleanup) program is designed to protect and restore water quality from spills, leaks, and similar discharges.

Date of Government Version: 04/03/2003
Date Data Arrived at EDR: 04/07/2003
Date Made Active in Reports: 04/25/2003
Number of Days to Update: 18

Source: California Regional Water Quality Control Board, North Coast Region (1)
Telephone: 707-576-2220
Last EDR Contact: 08/01/2011
Next Scheduled EDR Contact: 11/14/2011
Data Release Frequency: No Update Planned

SLIC REG 2: Spills, Leaks, Investigation & Cleanup Cost Recovery Listing
The SLIC (Spills, Leaks, Investigations and Cleanup) program is designed to protect and restore water quality from spills, leaks, and similar discharges.

Date of Government Version: 09/30/2004
Date Data Arrived at EDR: 10/20/2004
Date Made Active in Reports: 11/19/2004
Number of Days to Update: 30

Source: Regional Water Quality Control Board San Francisco Bay Region (2)
Telephone: 510-286-0457
Last EDR Contact: 09/19/2011
Next Scheduled EDR Contact: 01/02/2012
Data Release Frequency: No Update Planned

SLIC REG 3: Spills, Leaks, Investigation & Cleanup Cost Recovery Listing
The SLIC (Spills, Leaks, Investigations and Cleanup) program is designed to protect and restore water quality from spills, leaks, and similar discharges.

Date of Government Version: 05/18/2006
Date Data Arrived at EDR: 05/18/2006
Date Made Active in Reports: 06/15/2006
Number of Days to Update: 28

Source: California Regional Water Quality Control Board Central Coast Region (3)
Telephone: 805-549-3147
Last EDR Contact: 07/18/2011
Next Scheduled EDR Contact: 10/31/2011
Data Release Frequency: No Update Planned

SLIC REG 4: Spills, Leaks, Investigation & Cleanup Cost Recovery Listing
The SLIC (Spills, Leaks, Investigations and Cleanup) program is designed to protect and restore water quality from spills, leaks, and similar discharges.

Date of Government Version: 11/17/2004
Date Data Arrived at EDR: 11/18/2004
Date Made Active in Reports: 01/04/2005
Number of Days to Update: 47

Source: Region Water Quality Control Board Los Angeles Region (4)
Telephone: 213-576-6600
Last EDR Contact: 07/01/2011
Next Scheduled EDR Contact: 10/17/2011
Data Release Frequency: No Update Planned

SLIC REG 5: Spills, Leaks, Investigation & Cleanup Cost Recovery Listing
The SLIC (Spills, Leaks, Investigations and Cleanup) program is designed to protect and restore water quality from spills, leaks, and similar discharges.

Date of Government Version: 04/01/2005
Date Data Arrived at EDR: 04/05/2005
Date Made Active in Reports: 04/21/2005
Number of Days to Update: 16

Source: Regional Water Quality Control Board Central Valley Region (5)
Telephone: 916-464-3291
Last EDR Contact: 09/12/2011
Next Scheduled EDR Contact: 12/26/2011
Data Release Frequency: No Update Planned

SLIC REG 6V: Spills, Leaks, Investigation & Cleanup Cost Recovery Listing
The SLIC (Spills, Leaks, Investigations and Cleanup) program is designed to protect and restore water quality from spills, leaks, and similar discharges.

Date of Government Version: 05/24/2005
Date Data Arrived at EDR: 05/25/2005
Date Made Active in Reports: 06/16/2005
Number of Days to Update: 22

Source: Regional Water Quality Control Board, Victorville Branch
Telephone: 619-241-6583
Last EDR Contact: 08/15/2011
Next Scheduled EDR Contact: 11/28/2011
Data Release Frequency: No Update Planned

SLIC REG 6L: SLIC Sites
The SLIC (Spills, Leaks, Investigations and Cleanup) program is designed to protect and restore water quality from spills, leaks, and similar discharges.

Date of Government Version: 09/07/2004
Date Data Arrived at EDR: 09/07/2004
Date Made Active in Reports: 10/12/2004
Number of Days to Update: 35
Source: California Regional Water Quality Control Board, Lahontan Region
Telephone: 530-542-5574
Last EDR Contact: 08/15/2011
Next Scheduled EDR Contact: 11/28/2011
Data Release Frequency: No Update Planned

SLIC REG 7: SLIC List
The SLIC (Spills, Leaks, Investigations and Cleanup) program is designed to protect and restore water quality from spills, leaks, and similar discharges.

Date of Government Version: 11/24/2004
Date Data Arrived at EDR: 11/29/2004
Date Made Active in Reports: 01/04/2005
Number of Days to Update: 36
Source: California Regional Quality Control Board, Colorado River Basin Region
Telephone: 760-346-7491
Last EDR Contact: 08/01/2011
Next Scheduled EDR Contact: 11/14/2011
Data Release Frequency: No Update Planned

SLIC REG 8: Spills, Leaks, Investigation & Cleanup Cost Recovery Listing
The SLIC (Spills, Leaks, Investigations and Cleanup) program is designed to protect and restore water quality from spills, leaks, and similar discharges.

Date of Government Version: 04/03/2008
Date Data Arrived at EDR: 04/03/2008
Date Made Active in Reports: 04/14/2008
Number of Days to Update: 11
Source: California Region Water Quality Control Board Santa Ana Region (8)
Telephone: 951-782-3298
Last EDR Contact: 09/12/2011
Next Scheduled EDR Contact: 12/26/2011
Data Release Frequency: No Update Planned

SLIC REG 9: Spills, Leaks, Investigation & Cleanup Cost Recovery Listing
The SLIC (Spills, Leaks, Investigations and Cleanup) program is designed to protect and restore water quality from spills, leaks, and similar discharges.

Date of Government Version: 09/10/2007
Date Data Arrived at EDR: 09/11/2007
Date Made Active in Reports: 09/28/2007
Number of Days to Update: 17
Source: California Regional Water Quality Control Board San Diego Region (9)
Telephone: 858-467-2980
Last EDR Contact: 08/08/2011
Next Scheduled EDR Contact: 11/21/2011
Data Release Frequency: No Update Planned

Lists of state and tribal registered storage tanks

FEMA UST: Underground Storage Tank Listing
A listing of all FEMA owned underground storage tanks.

Date of Government Version: 10/14/2021
Date Data Arrived at EDR: 11/05/2021
Date Made Active in Reports: 02/01/2022
Number of Days to Update: 88
Source: FEMA
Telephone: 202-646-5797
Last EDR Contact: 09/27/2022
Next Scheduled EDR Contact: 01/16/2023
Data Release Frequency: Varies

UST: Active UST Facilities
Active UST facilities gathered from the local regulatory agencies

Date of Government Version: 06/06/2022
Date Data Arrived at EDR: 06/07/2022
Date Made Active in Reports: 08/24/2022
Number of Days to Update: 78
Source: SWRCB
Telephone: 916-341-5851
Last EDR Contact: 08/31/2022
Next Scheduled EDR Contact: 12/19/2022
Data Release Frequency: Semi-Annually

UST CLOSURE: Proposed Closure of Underground Storage Tank (UST) Cases

UST cases that are being considered for closure by either the State Water Resources Control Board or the Executive Director have been posted for a 60-day public comment period. UST Case Closures being proposed for consideration by the State Water Resources Control Board. These are primarily UST cases that meet closure criteria under the decisional framework in State Water Board Resolution No. 92-49 and other Board orders. UST Case Closures proposed for consideration by the Executive Director pursuant to State Water Board Resolution No. 2012-0061. These are cases that meet the criteria of the Low-Threat UST Case Closure Policy. UST Case Closure Review Denials and Approved Orders.

Date of Government Version: 06/01/2022
Date Data Arrived at EDR: 06/09/2022
Date Made Active in Reports: 08/26/2022
Number of Days to Update: 78

Source: State Water Resources Control Board
Telephone: 916-327-7844
Last EDR Contact: 08/31/2022
Next Scheduled EDR Contact: 12/19/2022
Data Release Frequency: Varies

MILITARY UST SITES: Military UST Sites (GEOTRACKER)

Military ust sites

Date of Government Version: 05/23/2022
Date Data Arrived at EDR: 05/23/2022
Date Made Active in Reports: 06/02/2022
Number of Days to Update: 10

Source: State Water Resources Control Board
Telephone: 866-480-1028
Last EDR Contact: 08/31/2022
Next Scheduled EDR Contact: 12/19/2022
Data Release Frequency: Varies

AST: Aboveground Petroleum Storage Tank Facilities

A listing of aboveground storage tank petroleum storage tank locations.

Date of Government Version: 07/06/2016
Date Data Arrived at EDR: 07/12/2016
Date Made Active in Reports: 09/19/2016
Number of Days to Update: 69

Source: California Environmental Protection Agency
Telephone: 916-327-5092
Last EDR Contact: 09/07/2022
Next Scheduled EDR Contact: 12/26/2022
Data Release Frequency: Varies

INDIAN UST R10: Underground Storage Tanks on Indian Land

The Indian Underground Storage Tank (UST) database provides information about underground storage tanks on Indian land in EPA Region 10 (Alaska, Idaho, Oregon, Washington, and Tribal Nations).

Date of Government Version: 04/20/2022
Date Data Arrived at EDR: 06/13/2022
Date Made Active in Reports: 08/16/2022
Number of Days to Update: 64

Source: EPA Region 10
Telephone: 206-553-2857
Last EDR Contact: 06/13/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Varies

INDIAN UST R4: Underground Storage Tanks on Indian Land

The Indian Underground Storage Tank (UST) database provides information about underground storage tanks on Indian land in EPA Region 4 (Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee and Tribal Nations)

Date of Government Version: 06/02/2022
Date Data Arrived at EDR: 06/13/2022
Date Made Active in Reports: 08/31/2022
Number of Days to Update: 79

Source: EPA Region 4
Telephone: 404-562-9424
Last EDR Contact: 06/13/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Varies

INDIAN UST R6: Underground Storage Tanks on Indian Land

The Indian Underground Storage Tank (UST) database provides information about underground storage tanks on Indian land in EPA Region 6 (Louisiana, Arkansas, Oklahoma, New Mexico, Texas and 65 Tribes).

Date of Government Version: 04/28/2022
Date Data Arrived at EDR: 06/13/2022
Date Made Active in Reports: 08/16/2022
Number of Days to Update: 64

Source: EPA Region 6
Telephone: 214-665-7591
Last EDR Contact: 06/13/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Varies

INDIAN UST R7: Underground Storage Tanks on Indian Land

The Indian Underground Storage Tank (UST) database provides information about underground storage tanks on Indian land in EPA Region 7 (Iowa, Kansas, Missouri, Nebraska, and 9 Tribal Nations).

Date of Government Version: 04/14/2022
Date Data Arrived at EDR: 06/13/2022
Date Made Active in Reports: 08/16/2022
Number of Days to Update: 64

Source: EPA Region 7
Telephone: 913-551-7003
Last EDR Contact: 06/13/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Varies

INDIAN UST R8: Underground Storage Tanks on Indian Land

The Indian Underground Storage Tank (UST) database provides information about underground storage tanks on Indian land in EPA Region 8 (Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming and 27 Tribal Nations).

Date of Government Version: 04/20/2022
Date Data Arrived at EDR: 06/13/2022
Date Made Active in Reports: 08/16/2022
Number of Days to Update: 64

Source: EPA Region 8
Telephone: 303-312-6137
Last EDR Contact: 06/13/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Varies

INDIAN UST R9: Underground Storage Tanks on Indian Land

The Indian Underground Storage Tank (UST) database provides information about underground storage tanks on Indian land in EPA Region 9 (Arizona, California, Hawaii, Nevada, the Pacific Islands, and Tribal Nations).

Date of Government Version: 04/08/2022
Date Data Arrived at EDR: 06/13/2022
Date Made Active in Reports: 08/16/2022
Number of Days to Update: 64

Source: EPA Region 9
Telephone: 415-972-3368
Last EDR Contact: 06/13/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Varies

INDIAN UST R5: Underground Storage Tanks on Indian Land

The Indian Underground Storage Tank (UST) database provides information about underground storage tanks on Indian land in EPA Region 5 (Michigan, Minnesota and Wisconsin and Tribal Nations).

Date of Government Version: 04/11/2022
Date Data Arrived at EDR: 06/13/2022
Date Made Active in Reports: 08/16/2022
Number of Days to Update: 64

Source: EPA Region 5
Telephone: 312-886-6136
Last EDR Contact: 06/13/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Varies

INDIAN UST R1: Underground Storage Tanks on Indian Land

The Indian Underground Storage Tank (UST) database provides information about underground storage tanks on Indian land in EPA Region 1 (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont and ten Tribal Nations).

Date of Government Version: 04/07/2022
Date Data Arrived at EDR: 06/13/2022
Date Made Active in Reports: 08/16/2022
Number of Days to Update: 64

Source: EPA, Region 1
Telephone: 617-918-1313
Last EDR Contact: 06/13/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Varies

Lists of state and tribal voluntary cleanup sites

VCP: Voluntary Cleanup Program Properties

Contains low threat level properties with either confirmed or unconfirmed releases and the project proponents have request that DTSC oversee investigation and/or cleanup activities and have agreed to provide coverage for DTSC's costs.

Date of Government Version: 04/25/2022
Date Data Arrived at EDR: 04/26/2022
Date Made Active in Reports: 07/15/2022
Number of Days to Update: 80

Source: Department of Toxic Substances Control
Telephone: 916-323-3400
Last EDR Contact: 07/25/2022
Next Scheduled EDR Contact: 11/07/2022
Data Release Frequency: Quarterly

INDIAN VCP R1: Voluntary Cleanup Priority Listing
A listing of voluntary cleanup priority sites located on Indian Land located in Region 1.

Date of Government Version: 07/27/2015
Date Data Arrived at EDR: 09/29/2015
Date Made Active in Reports: 02/18/2016
Number of Days to Update: 142

Source: EPA, Region 1
Telephone: 617-918-1102
Last EDR Contact: 09/13/2022
Next Scheduled EDR Contact: 01/02/2023
Data Release Frequency: Varies

INDIAN VCP R7: Voluntary Cleanup Priority Lisitng
A listing of voluntary cleanup priority sites located on Indian Land located in Region 7.

Date of Government Version: 03/20/2008
Date Data Arrived at EDR: 04/22/2008
Date Made Active in Reports: 05/19/2008
Number of Days to Update: 27

Source: EPA, Region 7
Telephone: 913-551-7365
Last EDR Contact: 07/08/2021
Next Scheduled EDR Contact: 07/20/2009
Data Release Frequency: Varies

Lists of state and tribal brownfield sites

BROWNFIELDS: Considered Brownfieds Sites Listing
A listing of sites the SWRCB considers to be Brownfields since these are sites have come to them through the MOA Process.

Date of Government Version: 06/21/2022
Date Data Arrived at EDR: 06/21/2022
Date Made Active in Reports: 09/08/2022
Number of Days to Update: 79

Source: State Water Resources Control Board
Telephone: 916-323-7905
Last EDR Contact: 09/19/2022
Next Scheduled EDR Contact: 01/02/2023
Data Release Frequency: Quarterly

ADDITIONAL ENVIRONMENTAL RECORDS

Local Brownfield lists

US BROWNFIELDS: A Listing of Brownfields Sites
Brownfields are real property, the expansion, redevelopment, or reuse of which may be complicated by the presence or potential presence of a hazardous substance, pollutant, or contaminant. Cleaning up and reinvesting in these properties takes development pressures off of undeveloped, open land, and both improves and protects the environment. Assessment, Cleanup and Redevelopment Exchange System (ACRES) stores information reported by EPA Brownfields grant recipients on brownfields properties assessed or cleaned up with grant funding as well as information on Targeted Brownfields Assessments performed by EPA Regions. A listing of ACRES Brownfield sites is obtained from Cleanups in My Community. Cleanups in My Community provides information on Brownfields properties for which information is reported back to EPA, as well as areas served by Brownfields grant programs.

Date of Government Version: 02/23/2022
Date Data Arrived at EDR: 03/10/2022
Date Made Active in Reports: 03/10/2022
Number of Days to Update: 0

Source: Environmental Protection Agency
Telephone: 202-566-2777
Last EDR Contact: 09/09/2022
Next Scheduled EDR Contact: 12/26/2022
Data Release Frequency: Semi-Annually

Local Lists of Landfill / Solid Waste Disposal Sites

WMUDS/SWAT: Waste Management Unit Database
Waste Management Unit Database System. WMUDS is used by the State Water Resources Control Board staff and the Regional Water Quality Control Boards for program tracking and inventory of waste management units. WMUDS is composed of the following databases: Facility Information, Scheduled Inspections Information, Waste Management Unit Information, SWAT Program Information, SWAT Report Summary Information, SWAT Report Summary Data, Chapter 15 (formerly Subchapter 15) Information, Chapter 15 Monitoring Parameters, TPCA Program Information, RCRA Program Information, Closure Information, and Interested Parties Information.

Date of Government Version: 04/01/2000
Date Data Arrived at EDR: 04/10/2000
Date Made Active in Reports: 05/10/2000
Number of Days to Update: 30

Source: State Water Resources Control Board
Telephone: 916-227-4448
Last EDR Contact: 07/19/2022
Next Scheduled EDR Contact: 11/07/2022
Data Release Frequency: No Update Planned

SWRCY: Recycler Database
A listing of recycling facilities in California.

Date of Government Version: 06/06/2022
Date Data Arrived at EDR: 06/07/2022
Date Made Active in Reports: 08/23/2022
Number of Days to Update: 77

Source: Department of Conservation
Telephone: 916-323-3836
Last EDR Contact: 08/31/2022
Next Scheduled EDR Contact: 12/19/2022
Data Release Frequency: Quarterly

HAULERS: Registered Waste Tire Haulers Listing
A listing of registered waste tire haulers.

Date of Government Version: 08/12/2022
Date Data Arrived at EDR: 08/16/2022
Date Made Active in Reports: 08/26/2022
Number of Days to Update: 10

Source: Integrated Waste Management Board
Telephone: 916-341-6422
Last EDR Contact: 08/16/2022
Next Scheduled EDR Contact: 11/21/2022
Data Release Frequency: Varies

INDIAN ODI: Report on the Status of Open Dumps on Indian Lands
Location of open dumps on Indian land.

Date of Government Version: 12/31/1998
Date Data Arrived at EDR: 12/03/2007
Date Made Active in Reports: 01/24/2008
Number of Days to Update: 52

Source: Environmental Protection Agency
Telephone: 703-308-8245
Last EDR Contact: 07/21/2022
Next Scheduled EDR Contact: 11/07/2022
Data Release Frequency: Varies

ODI: Open Dump Inventory
An open dump is defined as a disposal facility that does not comply with one or more of the Part 257 or Part 258 Subtitle D Criteria.

Date of Government Version: 06/30/1985
Date Data Arrived at EDR: 08/09/2004
Date Made Active in Reports: 09/17/2004
Number of Days to Update: 39

Source: Environmental Protection Agency
Telephone: 800-424-9346
Last EDR Contact: 06/09/2004
Next Scheduled EDR Contact: N/A
Data Release Frequency: No Update Planned

DEBRIS REGION 9: Torres Martinez Reservation Illegal Dump Site Locations
A listing of illegal dump sites location on the Torres Martinez Indian Reservation located in eastern Riverside County and northern Imperial County, California.

Date of Government Version: 01/12/2009
Date Data Arrived at EDR: 05/07/2009
Date Made Active in Reports: 09/21/2009
Number of Days to Update: 137

Source: EPA, Region 9
Telephone: 415-947-4219
Last EDR Contact: 07/12/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: No Update Planned

IHS OPEN DUMPS: Open Dumps on Indian Land
A listing of all open dumps located on Indian Land in the United States.

Date of Government Version: 04/01/2014
Date Data Arrived at EDR: 08/06/2014
Date Made Active in Reports: 01/29/2015
Number of Days to Update: 176

Source: Department of Health & Human Serivces, Indian Health Service
Telephone: 301-443-1452
Last EDR Contact: 07/21/2022
Next Scheduled EDR Contact: 11/07/2022
Data Release Frequency: Varies

Local Lists of Hazardous waste / Contaminated Sites

US HIST CDL: National Clandestine Laboratory Register

A listing of clandestine drug lab locations that have been removed from the DEAs National Clandestine Laboratory Register.

Date of Government Version: 04/30/2022
Date Data Arrived at EDR: 05/24/2022
Date Made Active in Reports: 07/29/2022
Number of Days to Update: 66

Source: Drug Enforcement Administration
Telephone: 202-307-1000
Last EDR Contact: 08/18/2022
Next Scheduled EDR Contact: 12/05/2022
Data Release Frequency: No Update Planned

HIST CAL-SITES: Calsites Database

The Calsites database contains potential or confirmed hazardous substance release properties. In 1996, California EPA reevaluated and significantly reduced the number of sites in the Calsites database. No longer updated by the state agency. It has been replaced by ENVIROSTOR.

Date of Government Version: 08/08/2005
Date Data Arrived at EDR: 08/03/2006
Date Made Active in Reports: 08/24/2006
Number of Days to Update: 21

Source: Department of Toxic Substance Control
Telephone: 916-323-3400
Last EDR Contact: 02/23/2009
Next Scheduled EDR Contact: 05/25/2009
Data Release Frequency: No Update Planned

SCH: School Property Evaluation Program

This category contains proposed and existing school sites that are being evaluated by DTSC for possible hazardous materials contamination. In some cases, these properties may be listed in the CalSites category depending on the level of threat to public health and safety or the environment they pose.

Date of Government Version: 04/25/2022
Date Data Arrived at EDR: 04/26/2022
Date Made Active in Reports: 07/15/2022
Number of Days to Update: 80

Source: Department of Toxic Substances Control
Telephone: 916-323-3400
Last EDR Contact: 07/25/2022
Next Scheduled EDR Contact: 11/07/2022
Data Release Frequency: Quarterly

CDL: Clandestine Drug Labs

A listing of drug lab locations. Listing of a location in this database does not indicate that any illegal drug lab materials were or were not present there, and does not constitute a determination that the location either requires or does not require additional cleanup work.

Date of Government Version: 12/31/2019
Date Data Arrived at EDR: 01/20/2021
Date Made Active in Reports: 04/08/2021
Number of Days to Update: 78

Source: Department of Toxic Substances Control
Telephone: 916-255-6504
Last EDR Contact: 09/27/2022
Next Scheduled EDR Contact: 01/16/2023
Data Release Frequency: Varies

CERS HAZ WASTE: CERS HAZ WASTE

List of sites in the California Environmental Protection Agency (CalEPA) Regulated Site Portal which fall under the Hazardous Chemical Management, Hazardous Waste Onsite Treatment, Household Hazardous Waste Collection, Hazardous Waste Generator, and RCRA LQ HW Generator programs.

Date of Government Version: 04/18/2022
Date Data Arrived at EDR: 04/19/2022
Date Made Active in Reports: 07/12/2022
Number of Days to Update: 84

Source: CalEPA
Telephone: 916-323-2514
Last EDR Contact: 07/18/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Quarterly

TOXIC PITS: Toxic Pits Cleanup Act Sites

Toxic PITS Cleanup Act Sites. TOXIC PITS identifies sites suspected of containing hazardous substances where cleanup has not yet been completed.

Date of Government Version: 07/01/1995
Date Data Arrived at EDR: 08/30/1995
Date Made Active in Reports: 09/26/1995
Number of Days to Update: 27

Source: State Water Resources Control Board
Telephone: 916-227-4364
Last EDR Contact: 01/26/2009
Next Scheduled EDR Contact: 04/27/2009
Data Release Frequency: No Update Planned

US CDL: Clandestine Drug Labs

A listing of clandestine drug lab locations. The U.S. Department of Justice ("the Department") provides this web site as a public service. It contains addresses of some locations where law enforcement agencies reported they found chemicals or other items that indicated the presence of either clandestine drug laboratories or dumpsites. In most cases, the source of the entries is not the Department, and the Department has not verified the entry and does not guarantee its accuracy. Members of the public must verify the accuracy of all entries by, for example, contacting local law enforcement and local health departments.

Date of Government Version: 04/30/2022
Date Data Arrived at EDR: 05/24/2022
Date Made Active in Reports: 07/29/2022
Number of Days to Update: 66

Source: Drug Enforcement Administration
Telephone: 202-307-1000
Last EDR Contact: 08/18/2022
Next Scheduled EDR Contact: 12/05/2022
Data Release Frequency: Quarterly

AQUEOUS FOAM: Former Fire Training Facility Assessments Listing

Airports shown on this list are those believed to use Aqueous Film Forming Foam (AFFF), and certified by the Federal Aviation Administration (FAA) under Title 14, Code of Federal Regulations (CFR), Part 139 (14 CFR Part 139). This list was created by SWRCB using information available from the FAA. Location points shown are from the latitude and longitude listed on the FAA airport master record.

Date of Government Version: 02/20/2020
Date Data Arrived at EDR: 12/10/2021
Date Made Active in Reports: 02/25/2022
Number of Days to Update: 77

Source: State Water Resources Control Board
Telephone: 916-341-5455
Last EDR Contact: 09/06/2022
Next Scheduled EDR Contact: 12/19/2022
Data Release Frequency: Varies

PFAS: PFAS Contamination Site Location Listing

A listing of PFAS contaminated sites included in the GeoTracker database.

Date of Government Version: 06/06/2022
Date Data Arrived at EDR: 06/07/2022
Date Made Active in Reports: 08/24/2022
Number of Days to Update: 78

Source: State Water Resources Control Board
Telephone: 866-480-1028
Last EDR Contact: 08/31/2022
Next Scheduled EDR Contact: 12/19/2022
Data Release Frequency: Varies

Local Lists of Registered Storage Tanks

SWEEPS UST: SWEEPS UST Listing

Statewide Environmental Evaluation and Planning System. This underground storage tank listing was updated and maintained by a company contacted by the SWRCB in the early 1990's. The listing is no longer updated or maintained. The local agency is the contact for more information on a site on the SWEEPS list.

Date of Government Version: 06/01/1994
Date Data Arrived at EDR: 07/07/2005
Date Made Active in Reports: 08/11/2005
Number of Days to Update: 35

Source: State Water Resources Control Board
Telephone: N/A
Last EDR Contact: 06/03/2005
Next Scheduled EDR Contact: N/A
Data Release Frequency: No Update Planned

HIST UST: Hazardous Substance Storage Container Database

The Hazardous Substance Storage Container Database is a historical listing of UST sites. Refer to local/county source for current data.

Date of Government Version: 10/15/1990
Date Data Arrived at EDR: 01/25/1991
Date Made Active in Reports: 02/12/1991
Number of Days to Update: 18

Source: State Water Resources Control Board
Telephone: 916-341-5851
Last EDR Contact: 07/26/2001
Next Scheduled EDR Contact: N/A
Data Release Frequency: No Update Planned

SAN FRANCISCO AST: Aboveground Storage Tank Site Listing
Aboveground storage tank sites

Date of Government Version: 05/05/2022
Date Data Arrived at EDR: 05/06/2022
Date Made Active in Reports: 07/21/2022
Number of Days to Update: 76

Source: San Francisco County Department of Public Health
Telephone: 415-252-3896
Last EDR Contact: 07/26/2022
Next Scheduled EDR Contact: 11/14/2022
Data Release Frequency: Varies

CA FID UST: Facility Inventory Database
The Facility Inventory Database (FID) contains a historical listing of active and inactive underground storage tank locations from the State Water Resource Control Board. Refer to local/county source for current data.

Date of Government Version: 10/31/1994
Date Data Arrived at EDR: 09/05/1995
Date Made Active in Reports: 09/29/1995
Number of Days to Update: 24

Source: California Environmental Protection Agency
Telephone: 916-341-5851
Last EDR Contact: 12/28/1998
Next Scheduled EDR Contact: N/A
Data Release Frequency: No Update Planned

CERS TANKS: California Environmental Reporting System (CERS) Tanks
List of sites in the California Environmental Protection Agency (CalEPA) Regulated Site Portal which fall under the Aboveground Petroleum Storage and Underground Storage Tank regulatory programs.

Date of Government Version: 04/18/2022
Date Data Arrived at EDR: 04/19/2022
Date Made Active in Reports: 07/12/2022
Number of Days to Update: 84

Source: California Environmental Protection Agency
Telephone: 916-323-2514
Last EDR Contact: 07/18/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Quarterly

Local Land Records

LIENS: Environmental Liens Listing
A listing of property locations with environmental liens for California where DTSC is a lien holder.

Date of Government Version: 05/25/2022
Date Data Arrived at EDR: 05/26/2022
Date Made Active in Reports: 08/11/2022
Number of Days to Update: 77

Source: Department of Toxic Substances Control
Telephone: 916-323-3400
Last EDR Contact: 08/23/2022
Next Scheduled EDR Contact: 12/12/2022
Data Release Frequency: Varies

LIENS 2: CERCLA Lien Information
A Federal CERCLA ('Superfund') lien can exist by operation of law at any site or property at which EPA has spent Superfund monies. These monies are spent to investigate and address releases and threatened releases of contamination. CERCLIS provides information as to the identity of these sites and properties.

Date of Government Version: 07/26/2022
Date Data Arrived at EDR: 08/02/2022
Date Made Active in Reports: 08/22/2022
Number of Days to Update: 20

Source: Environmental Protection Agency
Telephone: 202-564-6023
Last EDR Contact: 09/01/2022
Next Scheduled EDR Contact: 10/10/2022
Data Release Frequency: Semi-Annually

DEED: Deed Restriction Listing

Site Mitigation and Brownfields Reuse Program Facility Sites with Deed Restrictions & Hazardous Waste Management Program Facility Sites with Deed / Land Use Restriction. The DTSC Site Mitigation and Brownfields Reuse Program (SMBRP) list includes sites cleaned up under the program's oversight and generally does not include current or former hazardous waste facilities that required a hazardous waste facility permit. The list represents deed restrictions that are active. Some sites have multiple deed restrictions. The DTSC Hazardous Waste Management Program (HWMP) has developed a list of current or former hazardous waste facilities that have a recorded land use restriction at the local county recorder's office. The land use restrictions on this list were required by the DTSC HWMP as a result of the presence of hazardous substances that remain on site after the facility (or part of the facility) has been closed or cleaned up. The types of land use restriction include deed notice, deed restriction, or a land use restriction that binds current and future owners.

Date of Government Version: 05/31/2022
Date Data Arrived at EDR: 05/31/2022
Date Made Active in Reports: 08/18/2022
Number of Days to Update: 79

Source: DTSC and SWRCB
Telephone: 916-323-3400
Last EDR Contact: 08/25/2022
Next Scheduled EDR Contact: 12/12/2022
Data Release Frequency: Semi-Annually

Records of Emergency Release Reports

HMIRS: Hazardous Materials Information Reporting System

Hazardous Materials Incident Report System. HMIRS contains hazardous material spill incidents reported to DOT.

Date of Government Version: 03/21/2022
Date Data Arrived at EDR: 03/21/2022
Date Made Active in Reports: 06/14/2022
Number of Days to Update: 85

Source: U.S. Department of Transportation
Telephone: 202-366-4555
Last EDR Contact: 09/19/2022
Next Scheduled EDR Contact: 01/02/2023
Data Release Frequency: Quarterly

CHMIRS: California Hazardous Material Incident Report System

California Hazardous Material Incident Reporting System. CHMIRS contains information on reported hazardous material incidents (accidental releases or spills).

Date of Government Version: 04/03/2022
Date Data Arrived at EDR: 04/19/2022
Date Made Active in Reports: 07/12/2022
Number of Days to Update: 84

Source: Office of Emergency Services
Telephone: 916-845-8400
Last EDR Contact: 07/18/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Semi-Annually

LDS: Land Disposal Sites Listing (GEOTRACKER)

Land Disposal sites (Landfills) included in GeoTracker. GeoTracker is the Water Boards data management system for sites that impact, or have the potential to impact, water quality in California, with emphasis on groundwater.

Date of Government Version: 05/23/2022
Date Data Arrived at EDR: 05/23/2022
Date Made Active in Reports: 05/24/2022
Number of Days to Update: 1

Source: State Water Qualilty Control Board
Telephone: 866-480-1028
Last EDR Contact: 08/31/2022
Next Scheduled EDR Contact: 12/19/2022
Data Release Frequency: Quarterly

MCS: Military Cleanup Sites Listing (GEOTRACKER)

Military sites (consisting of: Military UST sites; Military Privatized sites; and Military Cleanup sites [formerly known as DoD non UST]) included in GeoTracker. GeoTracker is the Water Boards data management system for sites that impact, or have the potential to impact, water quality in California, with emphasis on groundwater.

Date of Government Version: 05/23/2022
Date Data Arrived at EDR: 05/23/2022
Date Made Active in Reports: 05/24/2022
Number of Days to Update: 1

Source: State Water Resources Control Board
Telephone: 866-480-1028
Last EDR Contact: 08/31/2022
Next Scheduled EDR Contact: 12/19/2022
Data Release Frequency: Quarterly

SPILLS 90: SPILLS90 data from FirstSearch

Spills 90 includes those spill and release records available exclusively from FirstSearch databases. Typically, they may include chemical, oil and/or hazardous substance spills recorded after 1990. Duplicate records that are already included in EDR incident and release records are not included in Spills 90.

Date of Government Version: 06/06/2012
Date Data Arrived at EDR: 01/03/2013
Date Made Active in Reports: 02/22/2013
Number of Days to Update: 50

Source: FirstSearch
Telephone: N/A
Last EDR Contact: 01/03/2013
Next Scheduled EDR Contact: N/A
Data Release Frequency: No Update Planned

Other Ascertainable Records

RCRA NonGen / NLR: RCRA - Non Generators / No Longer Regulated

RCRAInfo is EPA's comprehensive information system, providing access to data supporting the Resource Conservation and Recovery Act (RCRA) of 1976 and the Hazardous and Solid Waste Amendments (HSWA) of 1984. The database includes selective information on sites which generate, transport, store, treat and/or dispose of hazardous waste as defined by the Resource Conservation and Recovery Act (RCRA). Non-Generators do not presently generate hazardous waste.

Date of Government Version: 06/20/2022
Date Data Arrived at EDR: 06/21/2022
Date Made Active in Reports: 06/28/2022
Number of Days to Update: 7

Source: Environmental Protection Agency
Telephone: (415) 495-8895
Last EDR Contact: 09/19/2022
Next Scheduled EDR Contact: 01/02/2023
Data Release Frequency: Quarterly

FUDS: Formerly Used Defense Sites

The listing includes locations of Formerly Used Defense Sites properties where the US Army Corps of Engineers is actively working or will take necessary cleanup actions.

Date of Government Version: 05/11/2022
Date Data Arrived at EDR: 05/17/2022
Date Made Active in Reports: 07/29/2022
Number of Days to Update: 73

Source: U.S. Army Corps of Engineers
Telephone: 202-528-4285
Last EDR Contact: 08/11/2022
Next Scheduled EDR Contact: 11/28/2022
Data Release Frequency: Varies

DOD: Department of Defense Sites

This data set consists of federally owned or administered lands, administered by the Department of Defense, that have any area equal to or greater than 640 acres of the United States, Puerto Rico, and the U.S. Virgin Islands.

Date of Government Version: 06/07/2021
Date Data Arrived at EDR: 07/13/2021
Date Made Active in Reports: 03/09/2022
Number of Days to Update: 239

Source: USGS
Telephone: 888-275-8747
Last EDR Contact: 07/13/2022
Next Scheduled EDR Contact: 10/24/2022
Data Release Frequency: Varies

FEDLAND: Federal and Indian Lands

Federally and Indian administrated lands of the United States. Lands included are administrated by: Army Corps of Engineers, Bureau of Reclamation, National Wild and Scenic River, National Wildlife Refuge, Public Domain Land, Wilderness, Wilderness Study Area, Wildlife Management Area, Bureau of Indian Affairs, Bureau of Land Management, Department of Justice, Forest Service, Fish and Wildlife Service, National Park Service.

Date of Government Version: 04/02/2018
Date Data Arrived at EDR: 04/11/2018
Date Made Active in Reports: 11/06/2019
Number of Days to Update: 574

Source: U.S. Geological Survey
Telephone: 888-275-8747
Last EDR Contact: 07/08/2022
Next Scheduled EDR Contact: 10/17/2022
Data Release Frequency: N/A

SCRD DRYCLEANERS: State Coalition for Remediation of Drycleaners Listing

The State Coalition for Remediation of Drycleaners was established in 1998, with support from the U.S. EPA Office of Superfund Remediation and Technology Innovation. It is comprised of representatives of states with established drycleaner remediation programs. Currently the member states are Alabama, Connecticut, Florida, Illinois, Kansas, Minnesota, Missouri, North Carolina, Oregon, South Carolina, Tennessee, Texas, and Wisconsin.

Date of Government Version: 01/01/2017
Date Data Arrived at EDR: 02/03/2017
Date Made Active in Reports: 04/07/2017
Number of Days to Update: 63

Source: Environmental Protection Agency
Telephone: 615-532-8599
Last EDR Contact: 08/03/2022
Next Scheduled EDR Contact: 11/21/2022
Data Release Frequency: Varies

US FIN ASSUR: Financial Assurance Information

All owners and operators of facilities that treat, store, or dispose of hazardous waste are required to provide proof that they will have sufficient funds to pay for the clean up, closure, and post-closure care of their facilities.

Date of Government Version: 06/20/2022
Date Data Arrived at EDR: 06/21/2022
Date Made Active in Reports: 08/31/2022
Number of Days to Update: 71

Source: Environmental Protection Agency
Telephone: 202-566-1917
Last EDR Contact: 09/20/2022
Next Scheduled EDR Contact: 01/02/2023
Data Release Frequency: Quarterly

EPA WATCH LIST: EPA WATCH LIST

EPA maintains a "Watch List" to facilitate dialogue between EPA, state and local environmental agencies on enforcement matters relating to facilities with alleged violations identified as either significant or high priority. Being on the Watch List does not mean that the facility has actually violated the law only that an investigation by EPA or a state or local environmental agency has led those organizations to allege that an unproven violation has in fact occurred. Being on the Watch List does not represent a higher level of concern regarding the alleged violations that were detected, but instead indicates cases requiring additional dialogue between EPA, state and local agencies - primarily because of the length of time the alleged violation has gone unaddressed or unresolved.

Date of Government Version: 08/30/2013
Date Data Arrived at EDR: 03/21/2014
Date Made Active in Reports: 06/17/2014
Number of Days to Update: 88

Source: Environmental Protection Agency
Telephone: 617-520-3000
Last EDR Contact: 07/29/2022
Next Scheduled EDR Contact: 11/14/2022
Data Release Frequency: Quarterly

2020 COR ACTION: 2020 Corrective Action Program List

The EPA has set ambitious goals for the RCRA Corrective Action program by creating the 2020 Corrective Action Universe. This RCRA cleanup baseline includes facilities expected to need corrective action. The 2020 universe contains a wide variety of sites. Some properties are heavily contaminated while others were contaminated but have since been cleaned up. Still others have not been fully investigated yet, and may require little or no remediation. Inclusion in the 2020 Universe does not necessarily imply failure on the part of a facility to meet its RCRA obligations.

Date of Government Version: 09/30/2017
Date Data Arrived at EDR: 05/08/2018
Date Made Active in Reports: 07/20/2018
Number of Days to Update: 73

Source: Environmental Protection Agency
Telephone: 703-308-4044
Last EDR Contact: 08/04/2022
Next Scheduled EDR Contact: 11/14/2022
Data Release Frequency: Varies

TSCA: Toxic Substances Control Act

Toxic Substances Control Act. TSCA identifies manufacturers and importers of chemical substances included on the TSCA Chemical Substance Inventory list. It includes data on the production volume of these substances by plant site.

Date of Government Version: 12/31/2016
Date Data Arrived at EDR: 06/17/2020
Date Made Active in Reports: 09/10/2020
Number of Days to Update: 85

Source: EPA
Telephone: 202-260-5521
Last EDR Contact: 09/12/2022
Next Scheduled EDR Contact: 12/26/2022
Data Release Frequency: Every 4 Years

TRIS: Toxic Chemical Release Inventory System

Toxic Release Inventory System. TRIS identifies facilities which release toxic chemicals to the air, water and land in reportable quantities under SARA Title III Section 313.

Date of Government Version: 12/31/2018
Date Data Arrived at EDR: 08/14/2020
Date Made Active in Reports: 11/04/2020
Number of Days to Update: 82

Source: EPA
Telephone: 202-566-0250
Last EDR Contact: 08/11/2022
Next Scheduled EDR Contact: 11/28/2022
Data Release Frequency: Annually

SSTS: Section 7 Tracking Systems

Section 7 of the Federal Insecticide, Fungicide and Rodenticide Act, as amended (92 Stat. 829) requires all registered pesticide-producing establishments to submit a report to the Environmental Protection Agency by March 1st each year. Each establishment must report the types and amounts of pesticides, active ingredients and devices being produced, and those having been produced and sold or distributed in the past year.

Date of Government Version: 07/18/2022
Date Data Arrived at EDR: 07/18/2022
Date Made Active in Reports: 07/29/2022
Number of Days to Update: 11

Source: EPA
Telephone: 202-564-4203
Last EDR Contact: 07/18/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Annually

ROD: Records Of Decision

Record of Decision. ROD documents mandate a permanent remedy at an NPL (Superfund) site containing technical and health information to aid in the cleanup.

Date of Government Version: 07/26/2022
Date Data Arrived at EDR: 08/02/2022
Date Made Active in Reports: 08/22/2022
Number of Days to Update: 20

Source: EPA
Telephone: 703-416-0223
Last EDR Contact: 09/01/2022
Next Scheduled EDR Contact: 12/12/2022
Data Release Frequency: Annually

RMP: Risk Management Plans

When Congress passed the Clean Air Act Amendments of 1990, it required EPA to publish regulations and guidance for chemical accident prevention at facilities using extremely hazardous substances. The Risk Management Program Rule (RMP Rule) was written to implement Section 112(r) of these amendments. The rule, which built upon existing industry codes and standards, requires companies of all sizes that use certain flammable and toxic substances to develop a Risk Management Program, which includes a(n): Hazard assessment that details the potential effects of an accidental release, an accident history of the last five years, and an evaluation of worst-case and alternative accidental releases; Prevention program that includes safety precautions and maintenance, monitoring, and employee training measures; and Emergency response program that spells out emergency health care, employee training measures and procedures for informing the public and response agencies (e.g the fire department) should an accident occur.

Date of Government Version: 04/27/2022
Date Data Arrived at EDR: 05/04/2022
Date Made Active in Reports: 05/10/2022
Number of Days to Update: 6

Source: Environmental Protection Agency
Telephone: 202-564-8600
Last EDR Contact: 07/14/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Varies

RAATS: RCRA Administrative Action Tracking System

RCRA Administration Action Tracking System. RAATS contains records based on enforcement actions issued under RCRA pertaining to major violators and includes administrative and civil actions brought by the EPA. For administration actions after September 30, 1995, data entry in the RAATS database was discontinued. EPA will retain a copy of the database for historical records. It was necessary to terminate RAATS because a decrease in agency resources made it impossible to continue to update the information contained in the database.

Date of Government Version: 04/17/1995
Date Data Arrived at EDR: 07/03/1995
Date Made Active in Reports: 08/07/1995
Number of Days to Update: 35

Source: EPA
Telephone: 202-564-4104
Last EDR Contact: 06/02/2008
Next Scheduled EDR Contact: 09/01/2008
Data Release Frequency: No Update Planned

PRP: Potentially Responsible Parties
A listing of verified Potentially Responsible Parties

Date of Government Version: 07/26/2022
Date Data Arrived at EDR: 08/02/2022
Date Made Active in Reports: 08/31/2022
Number of Days to Update: 29

Source: EPA
Telephone: 202-564-6023
Last EDR Contact: 09/01/2022
Next Scheduled EDR Contact: 11/14/2022
Data Release Frequency: Quarterly

PADS: PCB Activity Database System
PCB Activity Database. PADS Identifies generators, transporters, commercial storers and/or brokers and disposers of PCB's who are required to notify the EPA of such activities.

Date of Government Version: 01/20/2022
Date Data Arrived at EDR: 01/20/2022
Date Made Active in Reports: 03/25/2022
Number of Days to Update: 64

Source: EPA
Telephone: 202-566-0500
Last EDR Contact: 07/08/2022
Next Scheduled EDR Contact: 10/17/2022
Data Release Frequency: Annually

ICIS: Integrated Compliance Information System
The Integrated Compliance Information System (ICIS) supports the information needs of the national enforcement and compliance program as well as the unique needs of the National Pollutant Discharge Elimination System (NPDES) program.

Date of Government Version: 11/18/2016
Date Data Arrived at EDR: 11/23/2016
Date Made Active in Reports: 02/10/2017
Number of Days to Update: 79

Source: Environmental Protection Agency
Telephone: 202-564-2501
Last EDR Contact: 09/27/2022
Next Scheduled EDR Contact: 01/16/2023
Data Release Frequency: Quarterly

FTTS: FIFRA/ TSCA Tracking System - FIFRA (Federal Insecticide, Fungicide, & Rodenticide Act)/TSCA (Toxic Substances Control Act)
FTTS tracks administrative cases and pesticide enforcement actions and compliance activities related to FIFRA, TSCA and EPCRA (Emergency Planning and Community Right-to-Know Act). To maintain currency, EDR contacts the Agency on a quarterly basis.

Date of Government Version: 04/09/2009
Date Data Arrived at EDR: 04/16/2009
Date Made Active in Reports: 05/11/2009
Number of Days to Update: 25

Source: EPA/Office of Prevention, Pesticides and Toxic Substances
Telephone: 202-566-1667
Last EDR Contact: 08/18/2017
Next Scheduled EDR Contact: 12/04/2017
Data Release Frequency: No Update Planned

FTTS INSP: FIFRA/ TSCA Tracking System - FIFRA (Federal Insecticide, Fungicide, & Rodenticide Act)/TSCA (Toxic Substances Control Act)
A listing of FIFRA/TSCA Tracking System (FTTS) inspections and enforcements.

Date of Government Version: 04/09/2009
Date Data Arrived at EDR: 04/16/2009
Date Made Active in Reports: 05/11/2009
Number of Days to Update: 25

Source: EPA
Telephone: 202-566-1667
Last EDR Contact: 08/18/2017
Next Scheduled EDR Contact: 12/04/2017
Data Release Frequency: No Update Planned

MLTS: Material Licensing Tracking System
MLTS is maintained by the Nuclear Regulatory Commission and contains a list of approximately 8,100 sites which possess or use radioactive materials and which are subject to NRC licensing requirements. To maintain currency, EDR contacts the Agency on a quarterly basis.

Date of Government Version: 06/10/2022
Date Data Arrived at EDR: 06/14/2022
Date Made Active in Reports: 08/22/2022
Number of Days to Update: 69

Source: Nuclear Regulatory Commission
Telephone: 301-415-7169
Last EDR Contact: 07/13/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Quarterly

COAL ASH DOE: Steam-Electric Plant Operation Data
A listing of power plants that store ash in surface ponds.

Date of Government Version: 12/31/2020
Date Data Arrived at EDR: 11/30/2021
Date Made Active in Reports: 02/22/2022
Number of Days to Update: 84
Source: Department of Energy
Telephone: 202-586-8719
Last EDR Contact: 08/25/2022
Next Scheduled EDR Contact: 12/12/2022
Data Release Frequency: Varies

COAL ASH EPA: Coal Combustion Residues Surface Impoundments List
A listing of coal combustion residues surface impoundments with high hazard potential ratings.

Date of Government Version: 01/12/2017
Date Data Arrived at EDR: 03/05/2019
Date Made Active in Reports: 11/11/2019
Number of Days to Update: 251
Source: Environmental Protection Agency
Telephone: N/A
Last EDR Contact: 08/25/2022
Next Scheduled EDR Contact: 12/12/2022
Data Release Frequency: Varies

PCB TRANSFORMER: PCB Transformer Registration Database
The database of PCB transformer registrations that includes all PCB registration submittals.

Date of Government Version: 09/13/2019
Date Data Arrived at EDR: 11/06/2019
Date Made Active in Reports: 02/10/2020
Number of Days to Update: 96
Source: Environmental Protection Agency
Telephone: 202-566-0517
Last EDR Contact: 08/04/2022
Next Scheduled EDR Contact: 11/14/2022
Data Release Frequency: Varies

RADINFO: Radiation Information Database
The Radiation Information Database (RADINFO) contains information about facilities that are regulated by U.S. Environmental Protection Agency (EPA) regulations for radiation and radioactivity.

Date of Government Version: 07/01/2019
Date Data Arrived at EDR: 07/01/2019
Date Made Active in Reports: 09/23/2019
Number of Days to Update: 84
Source: Environmental Protection Agency
Telephone: 202-343-9775
Last EDR Contact: 09/21/2022
Next Scheduled EDR Contact: 01/10/2023
Data Release Frequency: Quarterly

HIST FTTS: FIFRA/TSCA Tracking System Administrative Case Listing
A complete administrative case listing from the FIFRA/TSCA Tracking System (FTTS) for all ten EPA regions. The information was obtained from the National Compliance Database (NCDB). NCDB supports the implementation of FIFRA (Federal Insecticide, Fungicide, and Rodenticide Act) and TSCA (Toxic Substances Control Act). Some EPA regions are now closing out records. Because of that, and the fact that some EPA regions are not providing EPA Headquarters with updated records, it was decided to create a HIST FTTS database. It included records that may not be included in the newer FTTS database updates. This database is no longer updated.

Date of Government Version: 10/19/2006
Date Data Arrived at EDR: 03/01/2007
Date Made Active in Reports: 04/10/2007
Number of Days to Update: 40
Source: Environmental Protection Agency
Telephone: 202-564-2501
Last EDR Contact: 12/17/2007
Next Scheduled EDR Contact: 03/17/2008
Data Release Frequency: No Update Planned

HIST FTTS INSP: FIFRA/TSCA Tracking System Inspection & Enforcement Case Listing
A complete inspection and enforcement case listing from the FIFRA/TSCA Tracking System (FTTS) for all ten EPA regions. The information was obtained from the National Compliance Database (NCDB). NCDB supports the implementation of FIFRA (Federal Insecticide, Fungicide, and Rodenticide Act) and TSCA (Toxic Substances Control Act). Some EPA regions are now closing out records. Because of that, and the fact that some EPA regions are not providing EPA Headquarters with updated records, it was decided to create a HIST FTTS database. It included records that may not be included in the newer FTTS database updates. This database is no longer updated.

Date of Government Version: 10/19/2006
Date Data Arrived at EDR: 03/01/2007
Date Made Active in Reports: 04/10/2007
Number of Days to Update: 40

Source: Environmental Protection Agency
Telephone: 202-564-2501
Last EDR Contact: 12/17/2008
Next Scheduled EDR Contact: 03/17/2008
Data Release Frequency: No Update Planned

DOT OPS: Incident and Accident Data

Department of Transporation, Office of Pipeline Safety Incident and Accident data.

Date of Government Version: 01/02/2020
Date Data Arrived at EDR: 01/28/2020
Date Made Active in Reports: 04/17/2020
Number of Days to Update: 80

Source: Department of Transporation, Office of Pipeline Safety
Telephone: 202-366-4595
Last EDR Contact: 07/21/2022
Next Scheduled EDR Contact: 11/07/2022
Data Release Frequency: Quarterly

CONSENT: Superfund (CERCLA) Consent Decrees

Major legal settlements that establish responsibility and standards for cleanup at NPL (Superfund) sites. Released periodically by United States District Courts after settlement by parties to litigation matters.

Date of Government Version: 03/31/2022
Date Data Arrived at EDR: 04/14/2022
Date Made Active in Reports: 07/12/2022
Number of Days to Update: 89

Source: Department of Justice, Consent Decree Library
Telephone: Varies
Last EDR Contact: 09/27/2022
Next Scheduled EDR Contact: 01/16/2023
Data Release Frequency: Varies

BRS: Biennial Reporting System

The Biennial Reporting System is a national system administered by the EPA that collects data on the generation and management of hazardous waste. BRS captures detailed data from two groups: Large Quantity Generators (LQG) and Treatment, Storage, and Disposal Facilities.

Date of Government Version: 12/31/2019
Date Data Arrived at EDR: 03/02/2022
Date Made Active in Reports: 03/25/2022
Number of Days to Update: 23

Source: EPA/NTIS
Telephone: 800-424-9346
Last EDR Contact: 09/19/2022
Next Scheduled EDR Contact: 01/02/2023
Data Release Frequency: Biennially

INDIAN RESERV: Indian Reservations

This map layer portrays Indian administered lands of the United States that have any area equal to or greater than 640 acres.

Date of Government Version: 12/31/2014
Date Data Arrived at EDR: 07/14/2015
Date Made Active in Reports: 01/10/2017
Number of Days to Update: 546

Source: USGS
Telephone: 202-208-3710
Last EDR Contact: 07/08/2022
Next Scheduled EDR Contact: 10/17/2022
Data Release Frequency: Semi-Annually

FUSRAP: Formerly Utilized Sites Remedial Action Program

DOE established the Formerly Utilized Sites Remedial Action Program (FUSRAP) in 1974 to remediate sites where radioactive contamination remained from Manhattan Project and early U.S. Atomic Energy Commission (AEC) operations.

Date of Government Version: 07/26/2021
Date Data Arrived at EDR: 07/27/2021
Date Made Active in Reports: 10/22/2021
Number of Days to Update: 87

Source: Department of Energy
Telephone: 202-586-3559
Last EDR Contact: 07/26/2022
Next Scheduled EDR Contact: 11/14/2022
Data Release Frequency: Varies

UMTRA: Uranium Mill Tailings Sites

Uranium ore was mined by private companies for federal government use in national defense programs. When the mills shut down, large piles of the sand-like material (mill tailings) remain after uranium has been extracted from the ore. Levels of human exposure to radioactive materials from the piles are low; however, in some cases tailings were used as construction materials before the potential health hazards of the tailings were recognized.

Date of Government Version: 08/30/2019
Date Data Arrived at EDR: 11/15/2019
Date Made Active in Reports: 01/28/2020
Number of Days to Update: 74

Source: Department of Energy
Telephone: 505-845-0011
Last EDR Contact: 08/24/2022
Next Scheduled EDR Contact: 11/28/2022
Data Release Frequency: Varies

LEAD SMELTER 1: Lead Smelter Sites

A listing of former lead smelter site locations.

Date of Government Version: 07/26/2022
Date Data Arrived at EDR: 08/02/2022
Date Made Active in Reports: 08/22/2022
Number of Days to Update: 20

Source: Environmental Protection Agency
Telephone: 703-603-8787
Last EDR Contact: 09/01/2022
Next Scheduled EDR Contact: 10/10/2022
Data Release Frequency: Varies

LEAD SMELTER 2: Lead Smelter Sites

A list of several hundred sites in the U.S. where secondary lead smelting was done from 1931and 1964. These sites may pose a threat to public health through ingestion or inhalation of contaminated soil or dust

Date of Government Version: 04/05/2001
Date Data Arrived at EDR: 10/27/2010
Date Made Active in Reports: 12/02/2010
Number of Days to Update: 36

Source: American Journal of Public Health
Telephone: 703-305-6451
Last EDR Contact: 12/02/2009
Next Scheduled EDR Contact: N/A
Data Release Frequency: No Update Planned

US AIRS (AFS): Aerometric Information Retrieval System Facility Subsystem (AFS)

The database is a sub-system of Aerometric Information Retrieval System (AIRS). AFS contains compliance data on air pollution point sources regulated by the U.S. EPA and/or state and local air regulatory agencies. This information comes from source reports by various stationary sources of air pollution, such as electric power plants, steel mills, factories, and universities, and provides information about the air pollutants they produce. Action, air program, air program pollutant, and general level plant data. It is used to track emissions and compliance data from industrial plants.

Date of Government Version: 10/12/2016
Date Data Arrived at EDR: 10/26/2016
Date Made Active in Reports: 02/03/2017
Number of Days to Update: 100

Source: EPA
Telephone: 202-564-2496
Last EDR Contact: 09/26/2017
Next Scheduled EDR Contact: 01/08/2018
Data Release Frequency: Annually

US AIRS MINOR: Air Facility System Data

A listing of minor source facilities.

Date of Government Version: 10/12/2016
Date Data Arrived at EDR: 10/26/2016
Date Made Active in Reports: 02/03/2017
Number of Days to Update: 100

Source: EPA
Telephone: 202-564-2496
Last EDR Contact: 09/26/2017
Next Scheduled EDR Contact: 01/08/2018
Data Release Frequency: Annually

MINES VIOLATIONS: MSHA Violation Assessment Data

Mines violation and assessment information. Department of Labor, Mine Safety & Health Administration.

Date of Government Version: 03/21/2022
Date Data Arrived at EDR: 03/22/2022
Date Made Active in Reports: 03/25/2022
Number of Days to Update: 3

Source: DOL, Mine Safety & Health Admi
Telephone: 202-693-9424
Last EDR Contact: 08/02/2022
Next Scheduled EDR Contact: 12/12/2022
Data Release Frequency: Quarterly

US MINES: Mines Master Index File

Contains all mine identification numbers issued for mines active or opened since 1971. The data also includes violation information.

Date of Government Version: 08/03/2022
Date Data Arrived at EDR: 08/17/2022
Date Made Active in Reports: 08/31/2022
Number of Days to Update: 14

Source: Department of Labor, Mine Safety and Health Administration
Telephone: 303-231-5959
Last EDR Contact: 08/17/2022
Next Scheduled EDR Contact: 12/05/2022
Data Release Frequency: Semi-Annually

US MINES 2: Ferrous and Nonferrous Metal Mines Database Listing

This map layer includes ferrous (ferrous metal mines are facilities that extract ferrous metals, such as iron ore or molybdenum) and nonferrous (Nonferrous metal mines are facilities that extract nonferrous metals, such as gold, silver, copper, zinc, and lead) metal mines in the United States.

Date of Government Version: 05/06/2020
Date Data Arrived at EDR: 05/27/2020
Date Made Active in Reports: 08/13/2020
Number of Days to Update: 78

Source: USGS
Telephone: 703-648-7709
Last EDR Contact: 08/17/2022
Next Scheduled EDR Contact: 12/05/2022
Data Release Frequency: Varies

US MINES 3: Active Mines & Mineral Plants Database Listing

Active Mines and Mineral Processing Plant operations for commodities monitored by the Minerals Information Team of the USGS.

Date of Government Version: 04/14/2011
Date Data Arrived at EDR: 06/08/2011
Date Made Active in Reports: 09/13/2011
Number of Days to Update: 97

Source: USGS
Telephone: 703-648-7709
Last EDR Contact: 08/17/2022
Next Scheduled EDR Contact: 12/05/2022
Data Release Frequency: Varies

ABANDONED MINES: Abandoned Mines

An inventory of land and water impacted by past mining (primarily coal mining) is maintained by OSMRE to provide information needed to implement the Surface Mining Control and Reclamation Act of 1977 (SMCRA). The inventory contains information on the location, type, and extent of AML impacts, as well as, information on the cost associated with the reclamation of those problems. The inventory is based upon field surveys by State, Tribal, and OSMRE program officials. It is dynamic to the extent that it is modified as new problems are identified and existing problems are reclaimed.

Date of Government Version: 06/14/2022
Date Data Arrived at EDR: 06/15/2022
Date Made Active in Reports: 08/22/2022
Number of Days to Update: 68

Source: Department of Interior
Telephone: 202-208-2609
Last EDR Contact: 09/13/2022
Next Scheduled EDR Contact: 12/19/2022
Data Release Frequency: Quarterly

FINDS: Facility Index System/Facility Registry System

Facility Index System. FINDS contains both facility information and 'pointers' to other sources that contain more detail. EDR includes the following FINDS databases in this report: PCS (Permit Compliance System), AIRS (Aerometric Information Retrieval System), DOCKET (Enforcement Docket used to manage and track information on civil judicial enforcement cases for all environmental statutes), FURS (Federal Underground Injection Control), C-DOCKET (Criminal Docket System used to track criminal enforcement actions for all environmental statutes), FFIS (Federal Facilities Information System), STATE (State Environmental Laws and Statutes), and PADS (PCB Activity Data System).

Date of Government Version: 05/13/2022
Date Data Arrived at EDR: 05/18/2022
Date Made Active in Reports: 05/31/2022
Number of Days to Update: 13

Source: EPA
Telephone: (415) 947-8000
Last EDR Contact: 08/25/2022
Next Scheduled EDR Contact: 12/12/2022
Data Release Frequency: Quarterly

DOCKET HWC: Hazardous Waste Compliance Docket Listing

A complete list of the Federal Agency Hazardous Waste Compliance Docket Facilities.

Date of Government Version: 05/06/2021
Date Data Arrived at EDR: 05/21/2021
Date Made Active in Reports: 08/11/2021
Number of Days to Update: 82

Source: Environmental Protection Agency
Telephone: 202-564-0527
Last EDR Contact: 08/22/2022
Next Scheduled EDR Contact: 12/05/2022
Data Release Frequency: Varies

UXO: Unexploded Ordnance Sites
A listing of unexploded ordnance site locations

Date of Government Version: 12/31/2020
Date Data Arrived at EDR: 01/11/2022
Date Made Active in Reports: 02/14/2022
Number of Days to Update: 34
Source: Department of Defense
Telephone: 703-704-1564
Last EDR Contact: 07/07/2022
Next Scheduled EDR Contact: 10/24/2022
Data Release Frequency: Varies

ECHO: Enforcement & Compliance History Information
ECHO provides integrated compliance and enforcement information for about 800,000 regulated facilities nationwide.

Date of Government Version: 04/02/2022
Date Data Arrived at EDR: 04/05/2022
Date Made Active in Reports: 06/28/2022
Number of Days to Update: 84
Source: Environmental Protection Agency
Telephone: 202-564-2280
Last EDR Contact: 07/01/2022
Next Scheduled EDR Contact: 10/17/2022
Data Release Frequency: Quarterly

FUELS PROGRAM: EPA Fuels Program Registered Listing
This listing includes facilities that are registered under the Part 80 (Code of Federal Regulations) EPA Fuels Programs. All companies now are required to submit new and updated registrations.

Date of Government Version: 05/16/2022
Date Data Arrived at EDR: 05/17/2022
Date Made Active in Reports: 07/29/2022
Number of Days to Update: 73
Source: EPA
Telephone: 800-385-6164
Last EDR Contact: 08/11/2022
Next Scheduled EDR Contact: 11/28/2022
Data Release Frequency: Quarterly

CA BOND EXP. PLAN: Bond Expenditure Plan
Department of Health Services developed a site-specific expenditure plan as the basis for an appropriation of Hazardous Substance Cleanup Bond Act funds. It is not updated.

Date of Government Version: 01/01/1989
Date Data Arrived at EDR: 07/27/1994
Date Made Active in Reports: 08/02/1994
Number of Days to Update: 6
Source: Department of Health Services
Telephone: 916-255-2118
Last EDR Contact: 05/31/1994
Next Scheduled EDR Contact: N/A
Data Release Frequency: No Update Planned

CORTESE: "Cortese" Hazardous Waste & Substances Sites List
The sites for the list are designated by the State Water Resource Control Board (LUST), the Integrated Waste Board (SWF/LS), and the Department of Toxic Substances Control (Cal-Sites).

Date of Government Version: 06/21/2022
Date Data Arrived at EDR: 06/21/2022
Date Made Active in Reports: 09/08/2022
Number of Days to Update: 79
Source: CAL EPA/Office of Emergency Information
Telephone: 916-323-3400
Last EDR Contact: 09/19/2022
Next Scheduled EDR Contact: 01/02/2023
Data Release Frequency: Quarterly

CUPA LIVERMORE-PLEASANTON: CUPA Facility Listing
list of facilities associated with the various CUPA programs in Livermore-Pleasanton

Date of Government Version: 12/07/2021
Date Data Arrived at EDR: 05/09/2022
Date Made Active in Reports: 05/17/2022
Number of Days to Update: 8
Source: Livermore-Pleasanton Fire Department
Telephone: 925-454-2361
Last EDR Contact: 08/11/2022
Next Scheduled EDR Contact: 11/21/2022
Data Release Frequency: Varies

DRYCLEAN SOUTH COAST: South Coast Air Quality Management District Drycleaner Listing
A listing of dry cleaners in the South Coast Air Quality Management District

Date of Government Version: 05/20/2022
Date Data Arrived at EDR: 05/20/2022
Date Made Active in Reports: 08/09/2022
Number of Days to Update: 81

Source: South Coast Air Quality Management District
Telephone: 909-396-3211
Last EDR Contact: 08/16/2022
Next Scheduled EDR Contact: 12/05/2022
Data Release Frequency: Varies

DRYCLEANERS: Cleaner Facilities

A list of drycleaner related facilities that have EPA ID numbers. These are facilities with certain SIC codes: power laundries, family and commercial; garment pressing and cleaner's agents; linen supply; coin-operated laundries and cleaning; drycleaning plants, except rugs; carpet and upholster cleaning; industrial launderers; laundry and garment services.

Date of Government Version: 08/27/2021
Date Data Arrived at EDR: 09/01/2021
Date Made Active in Reports: 11/19/2021
Number of Days to Update: 79

Source: Department of Toxic Substance Control
Telephone: 916-327-4498
Last EDR Contact: 09/07/2022
Next Scheduled EDR Contact: 12/12/2022
Data Release Frequency: Annually

DRYCLEAN AVAQMD: Antelope Valley Air Quality Management District Drycleaner Listing

A listing of dry cleaners in the Antelope Valley Air Quality Management District.

Date of Government Version: 05/25/2022
Date Data Arrived at EDR: 05/26/2022
Date Made Active in Reports: 08/11/2022
Number of Days to Update: 77

Source: Antelope Valley Air Quality Management District
Telephone: 661-723-8070
Last EDR Contact: 08/23/2022
Next Scheduled EDR Contact: 12/12/2022
Data Release Frequency: Varies

EMI: Emissions Inventory Data

Toxics and criteria pollutant emissions data collected by the ARB and local air pollution agencies.

Date of Government Version: 12/31/2020
Date Data Arrived at EDR: 06/13/2022
Date Made Active in Reports: 08/30/2022
Number of Days to Update: 78

Source: California Air Resources Board
Telephone: 916-322-2990
Last EDR Contact: 09/16/2022
Next Scheduled EDR Contact: 12/26/2022
Data Release Frequency: Varies

ENF: Enforcement Action Listing

A listing of Water Board Enforcement Actions. Formal is everything except Oral/Verbal Communication, Notice of Violation, Expedited Payment Letter, and Staff Enforcement Letter.

Date of Government Version: 07/12/2022
Date Data Arrived at EDR: 07/18/2022
Date Made Active in Reports: 09/29/2022
Number of Days to Update: 73

Source: State Water Resoruces Control Board
Telephone: 916-445-9379
Last EDR Contact: 07/18/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Varies

Financial Assurance 1: Financial Assurance Information Listing

Financial Assurance information

Date of Government Version: 04/19/2022
Date Data Arrived at EDR: 04/29/2022
Date Made Active in Reports: 07/15/2022
Number of Days to Update: 77

Source: Department of Toxic Substances Control
Telephone: 916-255-3628
Last EDR Contact: 07/21/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Varies

Financial Assurance 2: Financial Assurance Information Listing

A listing of financial assurance information for solid waste facilities. Financial assurance is intended to ensure that resources are available to pay for the cost of closure, post-closure care, and corrective measures if the owner or operator of a regulated facility is unable or unwilling to pay.

Date of Government Version: 08/09/2022
Date Data Arrived at EDR: 08/10/2022
Date Made Active in Reports: 08/30/2022
Number of Days to Update: 20

Source: California Integrated Waste Management Board
Telephone: 916-341-6066
Last EDR Contact: 08/02/2022
Next Scheduled EDR Contact: 11/21/2022
Data Release Frequency: Varies

HAZNET: Facility and Manifest Data

Facility and Manifest Data. The data is extracted from the copies of hazardous waste manifests received each year by the DTSC. The annual volume of manifests is typically 700,000 - 1,000,000 annually, representing approximately 350,000 - 500,000 shipments. Data are from the manifests submitted without correction, and therefore many contain some invalid values for data elements such as generator ID, TSD ID, waste category, and disposal method. This database begins with calendar year 1993.

Date of Government Version: 12/31/2021
Date Data Arrived at EDR: 07/05/2022
Date Made Active in Reports: 09/19/2022
Number of Days to Update: 76

Source: California Environmental Protection Agency
Telephone: 916-255-1136
Last EDR Contact: 09/27/2022
Next Scheduled EDR Contact: 01/16/2023
Data Release Frequency: Annually

ICE: ICE

Contains data pertaining to the Permitted Facilities with Inspections / Enforcements sites tracked in Envirostor.

Date of Government Version: 05/16/2022
Date Data Arrived at EDR: 05/17/2022
Date Made Active in Reports: 08/03/2022
Number of Days to Update: 78

Source: Department of Toxic Subsances Control
Telephone: 877-786-9427
Last EDR Contact: 08/11/2022
Next Scheduled EDR Contact: 11/28/2022
Data Release Frequency: Quarterly

HIST CORTESE: Hazardous Waste & Substance Site List

The sites for the list are designated by the State Water Resource Control Board [LUST], the Integrated Waste Board [SWF/LS], and the Department of Toxic Substances Control [CALSITES]. This listing is no longer updated by the state agency.

Date of Government Version: 04/01/2001
Date Data Arrived at EDR: 01/22/2009
Date Made Active in Reports: 04/08/2009
Number of Days to Update: 76

Source: Department of Toxic Substances Control
Telephone: 916-323-3400
Last EDR Contact: 01/22/2009
Next Scheduled EDR Contact: N/A
Data Release Frequency: No Update Planned

HWP: EnviroStor Permitted Facilities Listing

Detailed information on permitted hazardous waste facilities and corrective action ("cleanups") tracked in EnviroStor.

Date of Government Version: 05/16/2022
Date Data Arrived at EDR: 05/17/2022
Date Made Active in Reports: 08/03/2022
Number of Days to Update: 78

Source: Department of Toxic Substances Control
Telephone: 916-323-3400
Last EDR Contact: 08/11/2022
Next Scheduled EDR Contact: 11/28/2022
Data Release Frequency: Quarterly

HWT: Registered Hazardous Waste Transporter Database

A listing of hazardous waste transporters. In California, unless specifically exempted, it is unlawful for any person to transport hazardous wastes unless the person holds a valid registration issued by DTSC. A hazardous waste transporter registration is valid for one year and is assigned a unique registration number.

Date of Government Version: 07/05/2022
Date Data Arrived at EDR: 07/05/2022
Date Made Active in Reports: 09/19/2022
Number of Days to Update: 76

Source: Department of Toxic Substances Control
Telephone: 916-440-7145
Last EDR Contact: 07/05/2022
Next Scheduled EDR Contact: 10/17/2022
Data Release Frequency: Quarterly

MINES: Mines Site Location Listing
A listing of mine site locations from the Office of Mine Reclamation.

Date of Government Version: 06/06/2022
Date Data Arrived at EDR: 06/07/2022
Date Made Active in Reports: 08/23/2022
Number of Days to Update: 77
Source: Department of Conservation
Telephone: 916-322-1080
Last EDR Contact: 08/31/2022
Next Scheduled EDR Contact: 12/19/2022
Data Release Frequency: Quarterly

MWMP: Medical Waste Management Program Listing
The Medical Waste Management Program (MWMP) ensures the proper handling and disposal of medical waste by permitting and inspecting medical waste Offsite Treatment Facilities (PDF) and Transfer Stations (PDF) throughout the state. MWMP also oversees all Medical Waste Transporters.

Date of Government Version: 05/06/2022
Date Data Arrived at EDR: 05/31/2022
Date Made Active in Reports: 08/18/2022
Number of Days to Update: 79
Source: Department of Public Health
Telephone: 916-558-1784
Last EDR Contact: 08/25/2022
Next Scheduled EDR Contact: 12/12/2022
Data Release Frequency: Varies

NPDES: NPDES Permits Listing
A listing of NPDES permits, including stormwater.

Date of Government Version: 05/09/2022
Date Data Arrived at EDR: 05/09/2022
Date Made Active in Reports: 07/29/2022
Number of Days to Update: 81
Source: State Water Resources Control Board
Telephone: 916-445-9379
Last EDR Contact: 08/08/2022
Next Scheduled EDR Contact: 11/21/2022
Data Release Frequency: Quarterly

PEST LIC: Pesticide Regulation Licenses Listing
A listing of licenses and certificates issued by the Department of Pesticide Regulation. The DPR issues licenses and/or certificates to: Persons and businesses that apply or sell pesticides; Pest control dealers and brokers; Persons who advise on agricultural pesticide applications.

Date of Government Version: 05/31/2022
Date Data Arrived at EDR: 05/31/2022
Date Made Active in Reports: 08/18/2022
Number of Days to Update: 79
Source: Department of Pesticide Regulation
Telephone: 916-445-4038
Last EDR Contact: 08/25/2022
Next Scheduled EDR Contact: 12/12/2022
Data Release Frequency: Quarterly

PROC: Certified Processors Database
A listing of certified processors.

Date of Government Version: 06/06/2022
Date Data Arrived at EDR: 06/07/2022
Date Made Active in Reports: 08/23/2022
Number of Days to Update: 77
Source: Department of Conservation
Telephone: 916-323-3836
Last EDR Contact: 08/31/2022
Next Scheduled EDR Contact: 12/19/2022
Data Release Frequency: Quarterly

NOTIFY 65: Proposition 65 Records
Listings of all Proposition 65 incidents reported to counties by the State Water Resources Control Board and the Regional Water Quality Control Board. This database is no longer updated by the reporting agency.

Date of Government Version: 06/10/2022
Date Data Arrived at EDR: 06/10/2022
Date Made Active in Reports: 08/26/2022
Number of Days to Update: 77
Source: State Water Resources Control Board
Telephone: 916-445-3846
Last EDR Contact: 09/07/2022
Next Scheduled EDR Contact: 12/26/2022
Data Release Frequency: No Update Planned

UIC: UIC Listing
A listing of wells identified as underground injection wells, in the California Oil and Gas Wells database.

Date of Government Version: 06/06/2022
Date Data Arrived at EDR: 06/07/2022
Date Made Active in Reports: 08/23/2022
Number of Days to Update: 77
Source: Deaprtment of Conservation
Telephone: 916-445-2408
Last EDR Contact: 08/31/2022
Next Scheduled EDR Contact: 12/19/2022
Data Release Frequency: Varies

UIC GEO: Underground Injection Control Sites (GEOTRACKER)
Underground control injection sites

Date of Government Version: 05/23/2022
Date Data Arrived at EDR: 05/23/2022
Date Made Active in Reports: 06/02/2022
Number of Days to Update: 10
Source: State Water Resource Control Board
Telephone: 866-480-1028
Last EDR Contact: 08/31/2022
Next Scheduled EDR Contact: 12/19/2022
Data Release Frequency: Varies

WASTEWATER PITS: Oil Wastewater Pits Listing
Water officials discovered that oil producers have been dumping chemical-laden wastewater into hundreds of unlined pits that are operating without proper permits. Inspections completed by the Central Valley Regional Water Quality Control Board revealed the existence of previously unidentified waste sites. The water boards review found that more than one-third of the region's active disposal pits are operating without permission.

Date of Government Version: 02/11/2021
Date Data Arrived at EDR: 07/01/2021
Date Made Active in Reports: 09/29/2021
Number of Days to Update: 90
Source: RWQCB, Central Valley Region
Telephone: 559-445-5577
Last EDR Contact: 07/08/2022
Next Scheduled EDR Contact: 10/17/2022
Data Release Frequency: Varies

WDS: Waste Discharge System
Sites which have been issued waste discharge requirements.

Date of Government Version: 06/19/2007
Date Data Arrived at EDR: 06/20/2007
Date Made Active in Reports: 06/29/2007
Number of Days to Update: 9
Source: State Water Resources Control Board
Telephone: 916-341-5227
Last EDR Contact: 08/09/2022
Next Scheduled EDR Contact: 11/28/2022
Data Release Frequency: No Update Planned

WIP: Well Investigation Program Case List
Well Investigation Program case in the San Gabriel and San Fernando Valley area.

Date of Government Version: 07/03/2009
Date Data Arrived at EDR: 07/21/2009
Date Made Active in Reports: 08/03/2009
Number of Days to Update: 13
Source: Los Angeles Water Quality Control Board
Telephone: 213-576-6726
Last EDR Contact: 09/13/2022
Next Scheduled EDR Contact: 01/02/2023
Data Release Frequency: No Update Planned

MILITARY PRIV SITES: Military Privatized Sites (GEOTRACKER)
Military privatized sites

Date of Government Version: 05/23/2022
Date Data Arrived at EDR: 05/23/2022
Date Made Active in Reports: 06/02/2022
Number of Days to Update: 10
Source: State Water Resources Control Board
Telephone: 866-480-1028
Last EDR Contact: 08/31/2022
Next Scheduled EDR Contact: 12/19/2022
Data Release Frequency: Varies

PROJECT: Project Sites (GEOTRACKER)
Projects sites

Date of Government Version: 05/23/2022
Date Data Arrived at EDR: 05/23/2022
Date Made Active in Reports: 06/02/2022
Number of Days to Update: 10

Source: State Water Resources Control Board
Telephone: 866-480-1028
Last EDR Contact: 08/31/2022
Next Scheduled EDR Contact: 12/19/2022
Data Release Frequency: Varies

WDR: Waste Discharge Requirements Listing

In general, the Waste Discharge Requirements (WDRs) Program (sometimes also referred to as the "Non Chapter 15 (Non 15) Program") regulates point discharges that are exempt pursuant to Subsection 20090 of Title 27 and not subject to the Federal Water Pollution Control Act. Exemptions from Title 27 may be granted for nine categories of discharges (e.g., sewage, wastewater, etc.) that meet, and continue to meet, the preconditions listed for each specific exemption. The scope of the WDRs Program also includes the discharge of wastes classified as inert, pursuant to section 20230 of Title 27.

Date of Government Version: 06/06/2022
Date Data Arrived at EDR: 06/07/2022
Date Made Active in Reports: 08/24/2022
Number of Days to Update: 78

Source: State Water Resources Control Board
Telephone: 916-341-5810
Last EDR Contact: 08/31/2022
Next Scheduled EDR Contact: 12/19/2022
Data Release Frequency: Quarterly

CIWQS: California Integrated Water Quality System

The California Integrated Water Quality System (CIWQS) is a computer system used by the State and Regional Water Quality Control Boards to track information about places of environmental interest, manage permits and other orders, track inspections, and manage violations and enforcement activities.

Date of Government Version: 08/16/2022
Date Data Arrived at EDR: 08/17/2022
Date Made Active in Reports: 08/18/2022
Number of Days to Update: 1

Source: State Water Resources Control Board
Telephone: 866-794-4977
Last EDR Contact: 08/17/2022
Next Scheduled EDR Contact: 12/12/2022
Data Release Frequency: Varies

CERS: CalEPA Regulated Site Portal Data

The CalEPA Regulated Site Portal database combines data about environmentally regulated sites and facilities in California into a single database. It combines data from a variety of state and federal databases, and provides an overview of regulated activities across the spectrum of environmental programs for any given location in California. These activities include hazardous materials and waste, state and federal cleanups, impacted ground and surface waters, and toxic materials

Date of Government Version: 04/18/2022
Date Data Arrived at EDR: 04/19/2022
Date Made Active in Reports: 07/12/2022
Number of Days to Update: 84

Source: California Environmental Protection Agency
Telephone: 916-323-2514
Last EDR Contact: 07/18/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Varies

NON-CASE INFO: Non-Case Information Sites (GEOTRACKER)

Non-Case Information sites

Date of Government Version: 05/23/2022
Date Data Arrived at EDR: 05/23/2022
Date Made Active in Reports: 06/02/2022
Number of Days to Update: 10

Source: State Water Resources Control Board
Telephone: 866-480-1028
Last EDR Contact: 08/31/2022
Next Scheduled EDR Contact: 12/19/2022
Data Release Frequency: Varies

OTHER OIL GAS: Other Oil & Gas Projects Sites (GEOTRACKER)

Other Oil & Gas Projects sites

Date of Government Version: 05/23/2022
Date Data Arrived at EDR: 05/23/2022
Date Made Active in Reports: 06/02/2022
Number of Days to Update: 10

Source: State Water Resources Control Board
Telephone: 866-480-1028
Last EDR Contact: 08/31/2022
Next Scheduled EDR Contact: 12/19/2022
Data Release Frequency: Varies

PROD WATER PONDS: Produced Water Ponds Sites (GEOTRACKER)
Produced water ponds sites

Date of Government Version: 05/23/2022
Date Data Arrived at EDR: 05/23/2022
Date Made Active in Reports: 06/02/2022
Number of Days to Update: 10

Source: State Water Resources Control Board
Telephone: 866-480-1028
Last EDR Contact: 08/31/2022
Next Scheduled EDR Contact: 12/19/2022
Data Release Frequency: Varies

SAMPLING POINT: Sampling Point ? Public Sites (GEOTRACKER)
Sampling point - public sites

Date of Government Version: 05/23/2022
Date Data Arrived at EDR: 05/23/2022
Date Made Active in Reports: 06/02/2022
Number of Days to Update: 10

Source: State Water Resources Control Board
Telephone: 866-480-1028
Last EDR Contact: 08/31/2022
Next Scheduled EDR Contact: 12/19/2022
Data Release Frequency: Varies

WELL STIM PROJ: Well Stimulation Project (GEOTRACKER)
Includes areas of groundwater monitoring plans, a depiction of the monitoring network, and the facilities, boundaries, and subsurface characteristics of the oilfield and the features (oil and gas wells, produced water ponds, UIC wells, water supply wells, etc?) being monitored

Date of Government Version: 05/23/2022
Date Data Arrived at EDR: 05/23/2022
Date Made Active in Reports: 06/02/2022
Number of Days to Update: 10

Source: State Water Resources Control Board
Telephone: 866-480-1028
Last EDR Contact: 08/31/2022
Next Scheduled EDR Contact: 12/19/2022
Data Release Frequency: Varies

PCS: Permit Compliance System
PCS is a computerized management information system that contains data on National Pollutant Discharge Elimination System (NPDES) permit holding facilities. PCS tracks the permit, compliance, and enforcement status of NPDES facilities.

Date of Government Version: 07/14/2011
Date Data Arrived at EDR: 08/05/2011
Date Made Active in Reports: 09/29/2011
Number of Days to Update: 55

Source: EPA, Office of Water
Telephone: 202-564-2496
Last EDR Contact: 09/28/2022
Next Scheduled EDR Contact: 01/16/2023
Data Release Frequency: Semi-Annually

PCS INACTIVE: Listing of Inactive PCS Permits
An inactive permit is a facility that has shut down or is no longer discharging.

Date of Government Version: 11/05/2014
Date Data Arrived at EDR: 01/06/2015
Date Made Active in Reports: 05/06/2015
Number of Days to Update: 120

Source: EPA
Telephone: 202-564-2496
Last EDR Contact: 09/28/2022
Next Scheduled EDR Contact: 01/16/2023
Data Release Frequency: Semi-Annually

MINES MRDS: Mineral Resources Data System
Mineral Resources Data System

Date of Government Version: 04/06/2018
Date Data Arrived at EDR: 10/21/2019
Date Made Active in Reports: 10/24/2019
Number of Days to Update: 3

Source: USGS
Telephone: 703-648-6533
Last EDR Contact: 08/17/2022
Next Scheduled EDR Contact: 12/05/2022
Data Release Frequency: Varies

HWTS: Hazardous Waste Tracking System
DTSC maintains the Hazardous Waste Tracking System that stores ID number information since the early 1980s and manifest data since 1993. The system collects both manifest copies from the generator and destination facility.

Date of Government Version: 04/05/2022
Date Data Arrived at EDR: 04/05/2022
Date Made Active in Reports: 04/26/2022
Number of Days to Update: 21

Source: Department of Toxic Substances Control
Telephone: 916-324-2444
Last EDR Contact: 07/06/2022
Next Scheduled EDR Contact: 10/17/2022
Data Release Frequency: Varies

PCS ENF: Enforcement data
No description is available for this data

Date of Government Version: 12/31/2014
Date Data Arrived at EDR: 02/05/2015
Date Made Active in Reports: 03/06/2015
Number of Days to Update: 29

Source: EPA
Telephone: 202-564-2497
Last EDR Contact: 09/28/2022
Next Scheduled EDR Contact: 01/16/2023
Data Release Frequency: Varies

EDR HIGH RISK HISTORICAL RECORDS

EDR Exclusive Records

EDR MGP: EDR Proprietary Manufactured Gas Plants
The EDR Proprietary Manufactured Gas Plant Database includes records of coal gas plants (manufactured gas plants) compiled by EDR's researchers. Manufactured gas sites were used in the United States from the 1800's to 1950's to produce a gas that could be distributed and used as fuel. These plants used whale oil, rosin, coal, or a mixture of coal, oil, and water that also produced a significant amount of waste. Many of the byproducts of the gas production, such as coal tar (oily waste containing volatile and non-volatile chemicals), sludges, oils and other compounds are potentially hazardous to human health and the environment. The byproduct from this process was frequently disposed of directly at the plant site and can remain or spread slowly, serving as a continuous source of soil and groundwater contamination.

Date of Government Version: N/A
Date Data Arrived at EDR: N/A
Date Made Active in Reports: N/A
Number of Days to Update: N/A

Source: EDR, Inc.
Telephone: N/A
Last EDR Contact: N/A
Next Scheduled EDR Contact: N/A
Data Release Frequency: No Update Planned

EDR Hist Auto: EDR Exclusive Historical Auto Stations
EDR has searched selected national collections of business directories and has collected listings of potential gas station/filling station/service station sites that were available to EDR researchers. EDR's review was limited to those categories of sources that might, in EDR's opinion, include gas station/filling station/service station establishments. The categories reviewed included, but were not limited to gas, gas station, gasoline station, filling station, auto, automobile repair, auto service station, service station, etc. This database falls within a category of information EDR classifies as "High Risk Historical Records", or HRHR. EDR's HRHR effort presents unique and sometimes proprietary data about past sites and operations that typically create environmental concerns, but may not show up in current government records searches.

Date of Government Version: N/A
Date Data Arrived at EDR: N/A
Date Made Active in Reports: N/A
Number of Days to Update: N/A

Source: EDR, Inc.
Telephone: N/A
Last EDR Contact: N/A
Next Scheduled EDR Contact: N/A
Data Release Frequency: Varies

EDR Hist Cleaner: EDR Exclusive Historical Cleaners
EDR has searched selected national collections of business directories and has collected listings of potential dry cleaner sites that were available to EDR researchers. EDR's review was limited to those categories of sources that might, in EDR's opinion, include dry cleaning establishments. The categories reviewed included, but were not limited to dry cleaners, cleaners, laundry, laundromat, cleaning/laundry, wash & dry etc. This database falls within a category of information EDR classifies as "High Risk Historical Records", or HRHR. EDR's HRHR effort presents unique and sometimes proprietary data about past sites and operations that typically create environmental concerns, but may not show up in current government records searches.

Date of Government Version: N/A
Date Data Arrived at EDR: N/A
Date Made Active in Reports: N/A
Number of Days to Update: N/A

Source: EDR, Inc.
Telephone: N/A
Last EDR Contact: N/A
Next Scheduled EDR Contact: N/A
Data Release Frequency: Varies

EDR RECOVERED GOVERNMENT ARCHIVES

Exclusive Recovered Govt. Archives

RGA LF: Recovered Government Archive Solid Waste Facilities List

The EDR Recovered Government Archive Landfill database provides a list of landfills derived from historical databases and includes many records that no longer appear in current government lists. Compiled from Records formerly available from the Department of Resources Recycling and Recovery in California.

Date of Government Version: N/A
Date Data Arrived at EDR: 07/01/2013
Date Made Active in Reports: 01/13/2014
Number of Days to Update: 196

Source: Department of Resources Recycling and Recovery
Telephone: N/A
Last EDR Contact: 06/01/2012
Next Scheduled EDR Contact: N/A
Data Release Frequency: Varies

RGA LUST: Recovered Government Archive Leaking Underground Storage Tank

The EDR Recovered Government Archive Leaking Underground Storage Tank database provides a list of LUST incidents derived from historical databases and includes many records that no longer appear in current government lists. Compiled from Records formerly available from the State Water Resources Control Board in California.

Date of Government Version: N/A
Date Data Arrived at EDR: 07/01/2013
Date Made Active in Reports: 12/30/2013
Number of Days to Update: 182

Source: State Water Resources Control Board
Telephone: N/A
Last EDR Contact: 06/01/2012
Next Scheduled EDR Contact: N/A
Data Release Frequency: Varies

COUNTY RECORDS

ALAMEDA COUNTY:

CS ALAMEDA: Contaminated Sites

A listing of contaminated sites overseen by the Toxic Release Program (oil and groundwater contamination from chemical releases and spills) and the Leaking Underground Storage Tank Program (soil and ground water contamination from leaking petroleum USTs).

Date of Government Version: 01/09/2019
Date Data Arrived at EDR: 01/11/2019
Date Made Active in Reports: 03/05/2019
Number of Days to Update: 53

Source: Alameda County Environmental Health Services
Telephone: 510-567-6700
Last EDR Contact: 09/27/2022
Next Scheduled EDR Contact: 01/16/2023
Data Release Frequency: Semi-Annually

UST ALAMEDA: Underground Tanks

Underground storage tank sites located in Alameda county.

Date of Government Version: 06/29/2022
Date Data Arrived at EDR: 06/29/2022
Date Made Active in Reports: 07/21/2022
Number of Days to Update: 22

Source: Alameda County Environmental Health Services
Telephone: 510-567-6700
Last EDR Contact: 09/27/2022
Next Scheduled EDR Contact: 01/16/2023
Data Release Frequency: Semi-Annually

AMADOR COUNTY:

CUPA AMADOR: CUPA Facility List
Cupa Facility List

Date of Government Version: 07/22/2022
Date Data Arrived at EDR: 07/27/2022
Date Made Active in Reports: 08/01/2022
Number of Days to Update: 5

Source: Amador County Environmental Health
Telephone: 209-223-6439
Last EDR Contact: 07/26/2022
Next Scheduled EDR Contact: 11/14/2022
Data Release Frequency: Varies

BUTTE COUNTY:

CUPA BUTTE: CUPA Facility Listing
Cupa facility list.

Date of Government Version: 04/21/2017
Date Data Arrived at EDR: 04/25/2017
Date Made Active in Reports: 08/09/2017
Number of Days to Update: 106

Source: Public Health Department
Telephone: 530-538-7149
Last EDR Contact: 09/27/2022
Next Scheduled EDR Contact: 01/16/2023
Data Release Frequency: No Update Planned

CALVERAS COUNTY:

CUPA CALVERAS: CUPA Facility Listing
Cupa Facility Listing

Date of Government Version: 06/14/2022
Date Data Arrived at EDR: 06/15/2022
Date Made Active in Reports: 09/02/2022
Number of Days to Update: 79

Source: Calveras County Environmental Health
Telephone: 209-754-6399
Last EDR Contact: 09/27/2022
Next Scheduled EDR Contact: 01/02/2023
Data Release Frequency: Quarterly

COLUSA COUNTY:

CUPA COLUSA: CUPA Facility List
Cupa facility list.

Date of Government Version: 04/06/2020
Date Data Arrived at EDR: 04/23/2020
Date Made Active in Reports: 07/10/2020
Number of Days to Update: 78

Source: Health & Human Services
Telephone: 530-458-0396
Last EDR Contact: 07/26/2022
Next Scheduled EDR Contact: 11/14/2022
Data Release Frequency: Semi-Annually

CONTRA COSTA COUNTY:

SL CONTRA COSTA: Site List
List includes sites from the underground tank, hazardous waste generator and business plan/2185 programs.

Date of Government Version: 04/21/2022
Date Data Arrived at EDR: 04/22/2022
Date Made Active in Reports: 07/12/2022
Number of Days to Update: 81

Source: Contra Costa Health Services Department
Telephone: 925-646-2286
Last EDR Contact: 07/19/2022
Next Scheduled EDR Contact: 11/07/2022
Data Release Frequency: Semi-Annually

DEL NORTE COUNTY:

CUPA DEL NORTE: CUPA Facility List
Cupa Facility list

Date of Government Version: 05/04/2022
Date Data Arrived at EDR: 05/06/2022
Date Made Active in Reports: 07/28/2022
Number of Days to Update: 83

Source: Del Norte County Environmental Health Division
Telephone: 707-465-0426
Last EDR Contact: 07/19/2022
Next Scheduled EDR Contact: 11/07/2022
Data Release Frequency: Varies

EL DORADO COUNTY:

CUPA EL DORADO: CUPA Facility List
CUPA facility list.

Date of Government Version: 08/08/2022
Date Data Arrived at EDR: 08/09/2022
Date Made Active in Reports: 09/01/2022
Number of Days to Update: 23

Source: El Dorado County Environmental Management Department
Telephone: 530-621-6623
Last EDR Contact: 07/20/2022
Next Scheduled EDR Contact: 11/07/2022
Data Release Frequency: Varies

FRESNO COUNTY:

CUPA FRESNO: CUPA Resources List
Certified Unified Program Agency. CUPA's are responsible for implementing a unified hazardous materials and hazardous waste management regulatory program. The agency provides oversight of businesses that deal with hazardous materials, operate underground storage tanks or aboveground storage tanks.

Date of Government Version: 06/28/2021
Date Data Arrived at EDR: 12/21/2021
Date Made Active in Reports: 03/03/2022
Number of Days to Update: 72

Source: Dept. of Community Health
Telephone: 559-445-3271
Last EDR Contact: 07/01/2022
Next Scheduled EDR Contact: 10/10/2022
Data Release Frequency: Semi-Annually

GLENN COUNTY:

CUPA GLENN: CUPA Facility List
Cupa facility list

Date of Government Version: 01/22/2018
Date Data Arrived at EDR: 01/24/2018
Date Made Active in Reports: 03/14/2018
Number of Days to Update: 49

Source: Glenn County Air Pollution Control District
Telephone: 830-934-6500
Last EDR Contact: 07/12/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: No Update Planned

HUMBOLDT COUNTY:

CUPA HUMBOLDT: CUPA Facility List
CUPA facility list.

Date of Government Version: 08/12/2021
Date Data Arrived at EDR: 08/12/2021
Date Made Active in Reports: 11/08/2021
Number of Days to Update: 88

Source: Humboldt County Environmental Health
Telephone: N/A
Last EDR Contact: 08/09/2022
Next Scheduled EDR Contact: 11/28/2022
Data Release Frequency: Semi-Annually

IMPERIAL COUNTY:

CUPA IMPERIAL: CUPA Facility List
Cupa facility list.

Date of Government Version: 07/13/2022
Date Data Arrived at EDR: 07/14/2022
Date Made Active in Reports: 09/29/2022
Number of Days to Update: 77

Source: San Diego Border Field Office
Telephone: 760-339-2777
Last EDR Contact: 07/13/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Varies

INYO COUNTY:

CUPA INYO: CUPA Facility List
Cupa facility list.

Date of Government Version: 04/02/2018
Date Data Arrived at EDR: 04/03/2018
Date Made Active in Reports: 06/14/2018
Number of Days to Update: 72

Source: Inyo County Environmental Health Services
Telephone: 760-878-0238
Last EDR Contact: 08/09/2022
Next Scheduled EDR Contact: 11/28/2022
Data Release Frequency: Varies

KERN COUNTY:

CUPA KERN: CUPA Facility List
A listing of sites included in the Kern County Hazardous Material Business Plan.

Date of Government Version: 05/06/2022
Date Data Arrived at EDR: 05/12/2022
Date Made Active in Reports: 08/01/2022
Number of Days to Update: 81

Source: Kern County Public Health
Telephone: 661-321-3000
Last EDR Contact: 09/21/2022
Next Scheduled EDR Contact: 11/14/2022
Data Release Frequency: Varies

UST KERN: Underground Storage Tank Sites & Tank Listing
Kern County Sites and Tanks Listing.

Date of Government Version: 05/06/2022
Date Data Arrived at EDR: 05/12/2022
Date Made Active in Reports: 08/01/2022
Number of Days to Update: 81

Source: Kern County Environment Health Services Department
Telephone: 661-862-8700
Last EDR Contact: 09/21/2022
Next Scheduled EDR Contact: 11/14/2022
Data Release Frequency: Quarterly

KINGS COUNTY:

CUPA KINGS: CUPA Facility List
A listing of sites included in the county's Certified Unified Program Agency database. California's Secretary for Environmental Protection established the unified hazardous materials and hazardous waste regulatory program as required by chapter 6.11 of the California Health and Safety Code. The Unified Program consolidates the administration, permits, inspections, and enforcement activities.

Date of Government Version: 12/03/2020
Date Data Arrived at EDR: 01/26/2021
Date Made Active in Reports: 04/14/2021
Number of Days to Update: 78

Source: Kings County Department of Public Health
Telephone: 559-584-1411
Last EDR Contact: 08/09/2022
Next Scheduled EDR Contact: 11/28/2022
Data Release Frequency: Varies

LAKE COUNTY:

CUPA LAKE: CUPA Facility List
Cupa facility list

Date of Government Version: 02/10/2022
Date Data Arrived at EDR: 02/11/2022
Date Made Active in Reports: 05/04/2022
Number of Days to Update: 82

Source: Lake County Environmental Health
Telephone: 707-263-1164
Last EDR Contact: 07/07/2022
Next Scheduled EDR Contact: 10/24/2022
Data Release Frequency: Varies

LASSEN COUNTY:

CUPA LASSEN: CUPA Facility List
Cupa facility list

Date of Government Version: 07/31/2020
Date Data Arrived at EDR: 08/21/2020
Date Made Active in Reports: 11/09/2020
Number of Days to Update: 80

Source: Lassen County Environmental Health
Telephone: 530-251-8528
Last EDR Contact: 07/12/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Varies

LOS ANGELES COUNTY:

AOCONCERN: Key Areas of Concerns in Los Angeles County
San Gabriel Valley areas where VOC contamination is at or above the MCL as designated by region 9 EPA office. Date of Government Version: 3/30/2009 Exide Site area is a cleanup plan of lead-impacted soil surrounding the former Exide Facility as designated by the DTSC. Date of Government Version: 7/17/2017

Date of Government Version: 03/30/2009
Date Data Arrived at EDR: 03/31/2009
Date Made Active in Reports: 10/23/2009
Number of Days to Update: 206

Source: N/A
Telephone: N/A
Last EDR Contact: 09/07/2022
Next Scheduled EDR Contact: 12/26/2022
Data Release Frequency: No Update Planned

HMS LOS ANGELES: HMS: Street Number List
Industrial Waste and Underground Storage Tank Sites.

Date of Government Version: 07/06/2022
Date Data Arrived at EDR: 07/07/2022
Date Made Active in Reports: 09/21/2022
Number of Days to Update: 76

Source: Department of Public Works
Telephone: 626-458-3517
Last EDR Contact: 09/27/2022
Next Scheduled EDR Contact: 01/16/2023
Data Release Frequency: Semi-Annually

LF LOS ANGELES: List of Solid Waste Facilities
Solid Waste Facilities in Los Angeles County.

Date of Government Version: 07/11/2022
Date Data Arrived at EDR: 07/11/2022
Date Made Active in Reports: 09/23/2022
Number of Days to Update: 74

Source: La County Department of Public Works
Telephone: 818-458-5185
Last EDR Contact: 07/11/2022
Next Scheduled EDR Contact: 10/24/2022
Data Release Frequency: Varies

LF LOS ANGELES CITY: City of Los Angeles Landfills
Landfills owned and maintained by the City of Los Angeles.

Date of Government Version: 01/01/2022
Date Data Arrived at EDR: 01/21/2022
Date Made Active in Reports: 04/11/2022
Number of Days to Update: 80

Source: Engineering & Construction Division
Telephone: 213-473-7869
Last EDR Contact: 07/06/2022
Next Scheduled EDR Contact: 10/24/2022
Data Release Frequency: Varies

LOS ANGELES AST: Active & Inactive AST Inventory
A listing of active & inactive above ground petroleum storage tank site locations, located in the City of Los Angeles.

Date of Government Version: 06/01/2019
Date Data Arrived at EDR: 06/25/2019
Date Made Active in Reports: 08/22/2019
Number of Days to Update: 58
Source: Los Angeles Fire Department
Telephone: 213-978-3800
Last EDR Contact: 09/19/2022
Next Scheduled EDR Contact: 01/02/2023
Data Release Frequency: Varies

LOS ANGELES CO LF METHANE: Methane Producing Landfills
This data was created on April 30, 2012 to represent known disposal sites in Los Angeles County that may produce and emanate methane gas. The shapefile contains disposal sites within Los Angeles County that once accepted degradable refuse material. Information used to create this data was extracted from a landfill survey performed by County Engineers (Major Waste System Map, 1973) as well as historical records from CalRecycle, Regional Water Quality Control Board, and Los Angeles County Department of Public Health

Date of Government Version: 01/10/2022
Date Data Arrived at EDR: 01/12/2022
Date Made Active in Reports: 04/04/2022
Number of Days to Update: 82
Source: Los Angeles County Department of Public Works
Telephone: 626-458-6973
Last EDR Contact: 07/06/2022
Next Scheduled EDR Contact: 10/24/2022
Data Release Frequency: No Update Planned

LOS ANGELES HM: Active & Inactive Hazardous Materials Inventory
A listing of active & inactive hazardous materials facility locations, located in the City of Los Angeles.

Date of Government Version: 01/13/2022
Date Data Arrived at EDR: 03/21/2022
Date Made Active in Reports: 06/15/2022
Number of Days to Update: 86
Source: Los Angeles Fire Department
Telephone: 213-978-3800
Last EDR Contact: 09/20/2022
Next Scheduled EDR Contact: 01/02/2023
Data Release Frequency: Varies

LOS ANGELES UST: Active & Inactive UST Inventory
A listing of active & inactive underground storage tank site locations and underground storage tank historical sites, located in the City of Los Angeles.

Date of Government Version: 03/22/2022
Date Data Arrived at EDR: 06/24/2022
Date Made Active in Reports: 09/08/2022
Number of Days to Update: 76
Source: Los Angeles Fire Department
Telephone: 213-978-3800
Last EDR Contact: 09/20/2022
Next Scheduled EDR Contact: 01/02/2023
Data Release Frequency: Varies

SITE MIT LOS ANGELES: Site Mitigation List
Industrial sites that have had some sort of spill or complaint.

Date of Government Version: 05/26/2021
Date Data Arrived at EDR: 07/09/2021
Date Made Active in Reports: 09/29/2021
Number of Days to Update: 82
Source: Community Health Services
Telephone: 323-890-7806
Last EDR Contact: 07/14/2022
Next Scheduled EDR Contact: 10/24/2022
Data Release Frequency: Annually

UST EL SEGUNDO: City of El Segundo Underground Storage Tank
Underground storage tank sites located in El Segundo city.

Date of Government Version: 01/21/2017
Date Data Arrived at EDR: 04/19/2017
Date Made Active in Reports: 05/10/2017
Number of Days to Update: 21
Source: City of El Segundo Fire Department
Telephone: 310-524-2236
Last EDR Contact: 07/06/2022
Next Scheduled EDR Contact: 10/24/2022
Data Release Frequency: No Update Planned

UST LONG BEACH: City of Long Beach Underground Storage Tank
Underground storage tank sites located in the city of Long Beach.

Date of Government Version: 04/22/2019
Date Data Arrived at EDR: 04/23/2019
Date Made Active in Reports: 06/27/2019
Number of Days to Update: 65

Source: City of Long Beach Fire Department
Telephone: 562-570-2563
Last EDR Contact: 07/12/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Varies

UST TORRANCE: City of Torrance Underground Storage Tank
Underground storage tank sites located in the city of Torrance.

Date of Government Version: 04/20/2022
Date Data Arrived at EDR: 04/21/2022
Date Made Active in Reports: 07/12/2022
Number of Days to Update: 82

Source: City of Torrance Fire Department
Telephone: 310-618-2973
Last EDR Contact: 07/13/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Semi-Annually

MADERA COUNTY:

CUPA MADERA: CUPA Facility List
A listing of sites included in the county's Certified Unified Program Agency database. California's Secretary for Environmental Protection established the unified hazardous materials and hazardous waste regulatory program as required by chapter 6.11 of the California Health and Safety Code. The Unified Program consolidates the administration, permits, inspections, and enforcement activities.

Date of Government Version: 08/10/2020
Date Data Arrived at EDR: 08/12/2020
Date Made Active in Reports: 10/23/2020
Number of Days to Update: 72

Source: Madera County Environmental Health
Telephone: 559-675-7823
Last EDR Contact: 08/09/2022
Next Scheduled EDR Contact: 11/28/2022
Data Release Frequency: Varies

MARIN COUNTY:

UST MARIN: Underground Storage Tank Sites
Currently permitted USTs in Marin County.

Date of Government Version: 09/26/2018
Date Data Arrived at EDR: 10/04/2018
Date Made Active in Reports: 11/02/2018
Number of Days to Update: 29

Source: Public Works Department Waste Management
Telephone: 415-473-6647
Last EDR Contact: 09/21/2022
Next Scheduled EDR Contact: 01/10/2023
Data Release Frequency: Semi-Annually

MENDOCINO COUNTY:

UST MENDOCINO: Mendocino County UST Database
A listing of underground storage tank locations in Mendocino County.

Date of Government Version: 09/22/2021
Date Data Arrived at EDR: 11/18/2021
Date Made Active in Reports: 11/22/2021
Number of Days to Update: 4

Source: Department of Public Health
Telephone: 707-463-4466
Last EDR Contact: 08/16/2022
Next Scheduled EDR Contact: 12/05/2022
Data Release Frequency: Annually

MERCED COUNTY:

CUPA MERCED: CUPA Facility List
CUPA facility list.

Date of Government Version: 02/15/2022
Date Data Arrived at EDR: 02/17/2022
Date Made Active in Reports: 05/11/2022
Number of Days to Update: 83

Source: Merced County Environmental Health
Telephone: 209-381-1094
Last EDR Contact: 08/09/2022
Next Scheduled EDR Contact: 11/28/2022
Data Release Frequency: Varies

MONO COUNTY:

CUPA MONO: CUPA Facility List
CUPA Facility List

Date of Government Version: 02/22/2021
Date Data Arrived at EDR: 03/02/2021
Date Made Active in Reports: 05/19/2021
Number of Days to Update: 78

Source: Mono County Health Department
Telephone: 760-932-5580
Last EDR Contact: 08/15/2022
Next Scheduled EDR Contact: 12/05/2022
Data Release Frequency: Varies

MONTEREY COUNTY:

CUPA MONTEREY: CUPA Facility Listing
CUPA Program listing from the Environmental Health Division.

Date of Government Version: 10/04/2021
Date Data Arrived at EDR: 10/06/2021
Date Made Active in Reports: 12/29/2021
Number of Days to Update: 84

Source: Monterey County Health Department
Telephone: 831-796-1297
Last EDR Contact: 09/21/2022
Next Scheduled EDR Contact: 01/10/2023
Data Release Frequency: Varies

NAPA COUNTY:

LUST NAPA: Sites With Reported Contamination
A listing of leaking underground storage tank sites located in Napa county.

Date of Government Version: 01/09/2017
Date Data Arrived at EDR: 01/11/2017
Date Made Active in Reports: 03/02/2017
Number of Days to Update: 50

Source: Napa County Department of Environmental Management
Telephone: 707-253-4269
Last EDR Contact: 08/15/2022
Next Scheduled EDR Contact: 12/05/2022
Data Release Frequency: No Update Planned

UST NAPA: Closed and Operating Underground Storage Tank Sites
Underground storage tank sites located in Napa county.

Date of Government Version: 09/05/2019
Date Data Arrived at EDR: 09/09/2019
Date Made Active in Reports: 10/31/2019
Number of Days to Update: 52

Source: Napa County Department of Environmental Management
Telephone: 707-253-4269
Last EDR Contact: 08/15/2022
Next Scheduled EDR Contact: 12/05/2022
Data Release Frequency: No Update Planned

NEVADA COUNTY:

CUPA NEVADA: CUPA Facility List
CUPA facility list.

Date of Government Version: 07/21/2022
Date Data Arrived at EDR: 07/25/2022
Date Made Active in Reports: 07/28/2022
Number of Days to Update: 3

Source: Community Development Agency
Telephone: 530-265-1467
Last EDR Contact: 07/19/2022
Next Scheduled EDR Contact: 11/07/2022
Data Release Frequency: Varies

ORANGE COUNTY:

IND_SITE ORANGE: List of Industrial Site Cleanups
Petroleum and non-petroleum spills.

Date of Government Version: 04/08/2022
Date Data Arrived at EDR: 05/09/2022
Date Made Active in Reports: 07/28/2022
Number of Days to Update: 80

Source: Health Care Agency
Telephone: 714-834-3446
Last EDR Contact: 07/29/2022
Next Scheduled EDR Contact: 11/14/2022
Data Release Frequency: Annually

LUST ORANGE: List of Underground Storage Tank Cleanups
Orange County Underground Storage Tank Cleanups (LUST).

Date of Government Version: 04/08/2022
Date Data Arrived at EDR: 05/18/2022
Date Made Active in Reports: 08/03/2022
Number of Days to Update: 77

Source: Health Care Agency
Telephone: 714-834-3446
Last EDR Contact: 07/29/2022
Next Scheduled EDR Contact: 11/14/2022
Data Release Frequency: Quarterly

UST ORANGE: List of Underground Storage Tank Facilities
Orange County Underground Storage Tank Facilities (UST).

Date of Government Version: 04/08/2022
Date Data Arrived at EDR: 05/03/2022
Date Made Active in Reports: 07/20/2022
Number of Days to Update: 78

Source: Health Care Agency
Telephone: 714-834-3446
Last EDR Contact: 08/01/2022
Next Scheduled EDR Contact: 11/14/2022
Data Release Frequency: Quarterly

PLACER COUNTY:

MS PLACER: Master List of Facilities
List includes aboveground tanks, underground tanks and cleanup sites.

Date of Government Version: 05/25/2022
Date Data Arrived at EDR: 05/26/2022
Date Made Active in Reports: 06/01/2022
Number of Days to Update: 6

Source: Placer County Health and Human Services
Telephone: 530-745-2363
Last EDR Contact: 08/23/2022
Next Scheduled EDR Contact: 12/12/2022
Data Release Frequency: Semi-Annually

PLUMAS COUNTY:

CUPA PLUMAS: CUPA Facility List
Plumas County CUPA Program facilities.

Date of Government Version: 03/31/2019
Date Data Arrived at EDR: 04/23/2019
Date Made Active in Reports: 06/26/2019
Number of Days to Update: 64

Source: Plumas County Environmental Health
Telephone: 530-283-6355
Last EDR Contact: 07/12/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Varies

RIVERSIDE COUNTY:

LUST RIVERSIDE: Listing of Underground Tank Cleanup Sites
Riverside County Underground Storage Tank Cleanup Sites (LUST).

Date of Government Version: 07/07/2022
Date Data Arrived at EDR: 07/08/2022
Date Made Active in Reports: 09/21/2022
Number of Days to Update: 75
Source: Department of Environmental Health
Telephone: 951-358-5055
Last EDR Contact: 09/07/2022
Next Scheduled EDR Contact: 12/26/2022
Data Release Frequency: Quarterly

UST RIVERSIDE: Underground Storage Tank Tank List
Underground storage tank sites located in Riverside county.

Date of Government Version: 07/07/2022
Date Data Arrived at EDR: 07/08/2022
Date Made Active in Reports: 09/21/2022
Number of Days to Update: 75
Source: Department of Environmental Health
Telephone: 951-358-5055
Last EDR Contact: 09/07/2022
Next Scheduled EDR Contact: 12/26/2022
Data Release Frequency: Quarterly

SACRAMENTO COUNTY:

CS SACRAMENTO: Toxic Site Clean-Up List
List of sites where unauthorized releases of potentially hazardous materials have occurred.

Date of Government Version: 06/18/2021
Date Data Arrived at EDR: 09/28/2021
Date Made Active in Reports: 12/14/2021
Number of Days to Update: 77
Source: Sacramento County Environmental Management
Telephone: 916-875-8406
Last EDR Contact: 06/30/2022
Next Scheduled EDR Contact: 10/10/2022
Data Release Frequency: Quarterly

ML SACRAMENTO: Master Hazardous Materials Facility List
Any business that has hazardous materials on site - hazardous material storage sites, underground storage tanks, waste generators.

Date of Government Version: 05/04/2022
Date Data Arrived at EDR: 06/30/2022
Date Made Active in Reports: 07/05/2022
Number of Days to Update: 5
Source: Sacramento County Environmental Management
Telephone: 916-875-8406
Last EDR Contact: 09/26/2022
Next Scheduled EDR Contact: 01/10/2023
Data Release Frequency: Quarterly

SAN BENITO COUNTY:

CUPA SAN BENITO: CUPA Facility List
Cupa facility list

Date of Government Version: 04/29/2022
Date Data Arrived at EDR: 04/29/2022
Date Made Active in Reports: 05/05/2022
Number of Days to Update: 6
Source: San Benito County Environmental Health
Telephone: N/A
Last EDR Contact: 07/26/2022
Next Scheduled EDR Contact: 11/14/2022
Data Release Frequency: Varies

SAN BERNARDINO COUNTY:

PERMITS SAN BERNARDINO: Hazardous Material Permits
This listing includes underground storage tanks, medical waste handlers/generators, hazardous materials handlers, hazardous waste generators, and waste oil generators/handlers.

Date of Government Version: 05/12/2022
Date Data Arrived at EDR: 05/12/2022
Date Made Active in Reports: 05/18/2022
Number of Days to Update: 6

Source: San Bernardino County Fire Department Hazardous Materials Division
Telephone: 909-387-3041
Last EDR Contact: 07/26/2022
Next Scheduled EDR Contact: 11/14/2022
Data Release Frequency: Quarterly

SAN DIEGO COUNTY:

HMMD SAN DIEGO: Hazardous Materials Management Division Database

The database includes: HE58 - This report contains the business name, site address, business phone number, establishment 'H' permit number, type of permit, and the business status. HE17 - In addition to providing the same information provided in the HE58 listing, HE17 provides inspection dates, violations received by the establishment, hazardous waste generated, the quantity, method of storage, treatment/disposal of waste and the hauler, and information on underground storage tanks. Unauthorized Release List - Includes a summary of environmental contamination cases in San Diego County (underground tank cases, non-tank cases, groundwater contamination, and soil contamination are included.)

Date of Government Version: 05/31/2022
Date Data Arrived at EDR: 05/31/2022
Date Made Active in Reports: 08/18/2022
Number of Days to Update: 79

Source: Hazardous Materials Management Division
Telephone: 619-338-2268
Last EDR Contact: 08/25/2022
Next Scheduled EDR Contact: 12/12/2022
Data Release Frequency: Quarterly

LF SAN DIEGO: Solid Waste Facilities

San Diego County Solid Waste Facilities.

Date of Government Version: 10/27/2021
Date Data Arrived at EDR: 03/04/2022
Date Made Active in Reports: 05/31/2022
Number of Days to Update: 88

Source: Department of Health Services
Telephone: 619-338-2209
Last EDR Contact: 07/12/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Varies

SAN DIEGO CO LOP: Local Oversight Program Listing

A listing of all LOP release sites that are or were under the County of San Diego's jurisdiction. Included are closed or transferred cases, open cases, and cases that did not have a case type indicated. The cases without a case type are mostly complaints; however, some of them could be LOP cases.

Date of Government Version: 07/22/2021
Date Data Arrived at EDR: 10/19/2021
Date Made Active in Reports: 01/13/2022
Number of Days to Update: 86

Source: Department of Environmental Health
Telephone: 858-505-6874
Last EDR Contact: 07/13/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Varies

SAN DIEGO CO SAM: Environmental Case Listing

The listing contains all underground tank release cases and projects pertaining to properties contaminated with hazardous substances that are actively under review by the Site Assessment and Mitigation Program.

Date of Government Version: 03/23/2010
Date Data Arrived at EDR: 06/15/2010
Date Made Active in Reports: 07/09/2010
Number of Days to Update: 24

Source: San Diego County Department of Environmental Health
Telephone: 619-338-2371
Last EDR Contact: 08/23/2022
Next Scheduled EDR Contact: 12/12/2022
Data Release Frequency: No Update Planned

SAN FRANCISCO COUNTY:

CUPA SAN FRANCISCO CO: CUPA Facility Listing

Cupa facilities

Date of Government Version: 05/05/2022
Date Data Arrived at EDR: 05/06/2022
Date Made Active in Reports: 07/28/2022
Number of Days to Update: 83

Source: San Francisco County Department of Environmental Health
Telephone: 415-252-3896
Last EDR Contact: 07/26/2022
Next Scheduled EDR Contact: 11/14/2022
Data Release Frequency: Varies

LUST SAN FRANCISCO: Local Oversite Facilities
A listing of leaking underground storage tank sites located in San Francisco county.

Date of Government Version: 09/19/2008
Date Data Arrived at EDR: 09/19/2008
Date Made Active in Reports: 09/29/2008
Number of Days to Update: 10

Source: Department Of Public Health San Francisco County
Telephone: 415-252-3920
Last EDR Contact: 07/26/2022
Next Scheduled EDR Contact: 11/14/2022
Data Release Frequency: No Update Planned

UST SAN FRANCISCO: Underground Storage Tank Information
Underground storage tank sites located in San Francisco county.

Date of Government Version: 05/05/2022
Date Data Arrived at EDR: 05/06/2022
Date Made Active in Reports: 07/20/2022
Number of Days to Update: 75

Source: Department of Public Health
Telephone: 415-252-3920
Last EDR Contact: 07/26/2022
Next Scheduled EDR Contact: 11/14/2022
Data Release Frequency: Quarterly

SAN FRANCISO COUNTY:

SAN FRANCISCO MAHER: Maher Ordinance Property Listing
a listing of properties that fall within a Maher Ordinance, for all of San Francisco

Date of Government Version: 01/18/2022
Date Data Arrived at EDR: 01/20/2022
Date Made Active in Reports: 04/27/2022
Number of Days to Update: 97

Source: San Francisco Planning
Telephone: 628-652-7483
Last EDR Contact: 07/05/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Varies

SAN JOAQUIN COUNTY:

UST SAN JOAQUIN: San Joaquin Co. UST
A listing of underground storage tank locations in San Joaquin county.

Date of Government Version: 06/22/2018
Date Data Arrived at EDR: 06/26/2018
Date Made Active in Reports: 07/11/2018
Number of Days to Update: 15

Source: Environmental Health Department
Telephone: N/A
Last EDR Contact: 09/07/2022
Next Scheduled EDR Contact: 12/26/2022
Data Release Frequency: Semi-Annually

SAN LUIS OBISPO COUNTY:

CUPA SAN LUIS OBISPO: CUPA Facility List
Cupa Facility List.

Date of Government Version: 05/16/2022
Date Data Arrived at EDR: 05/18/2022
Date Made Active in Reports: 08/04/2022
Number of Days to Update: 78

Source: San Luis Obispo County Public Health Department
Telephone: 805-781-5596
Last EDR Contact: 08/09/2022
Next Scheduled EDR Contact: 11/28/2022
Data Release Frequency: Varies

SAN MATEO COUNTY:

BI SAN MATEO: Business Inventory
List includes Hazardous Materials Business Plan, hazardous waste generators, and underground storage tanks.

Date of Government Version: 02/20/2020
Date Data Arrived at EDR: 02/20/2020
Date Made Active in Reports: 04/24/2020
Number of Days to Update: 64
Source: San Mateo County Environmental Health Services Division
Telephone: 650-363-1921
Last EDR Contact: 09/09/2022
Next Scheduled EDR Contact: 12/19/2022
Data Release Frequency: Annually

LUST SAN MATEO: Fuel Leak List
A listing of leaking underground storage tank sites located in San Mateo county.

Date of Government Version: 03/29/2019
Date Data Arrived at EDR: 03/29/2019
Date Made Active in Reports: 05/29/2019
Number of Days to Update: 61
Source: San Mateo County Environmental Health Services Division
Telephone: 650-363-1921
Last EDR Contact: 08/29/2022
Next Scheduled EDR Contact: 12/19/2022
Data Release Frequency: Semi-Annually

SANTA BARBARA COUNTY:

CUPA SANTA BARBARA: CUPA Facility Listing
CUPA Program Listing from the Environmental Health Services division.

Date of Government Version: 09/08/2011
Date Data Arrived at EDR: 09/09/2011
Date Made Active in Reports: 10/07/2011
Number of Days to Update: 28
Source: Santa Barbara County Public Health Department
Telephone: 805-686-8167
Last EDR Contact: 08/09/2022
Next Scheduled EDR Contact: 11/28/2022
Data Release Frequency: No Update Planned

SANTA CLARA COUNTY:

CUPA SANTA CLARA: Cupa Facility List
Cupa facility list

Date of Government Version: 05/16/2022
Date Data Arrived at EDR: 05/18/2022
Date Made Active in Reports: 08/04/2022
Number of Days to Update: 78
Source: Department of Environmental Health
Telephone: 408-918-1973
Last EDR Contact: 08/09/2022
Next Scheduled EDR Contact: 11/28/2022
Data Release Frequency: Varies

HIST LUST SANTA CLARA: HIST LUST - Fuel Leak Site Activity Report
A listing of open and closed leaking underground storage tanks. This listing is no longer updated by the county. Leaking underground storage tanks are now handled by the Department of Environmental Health.

Date of Government Version: 03/29/2005
Date Data Arrived at EDR: 03/30/2005
Date Made Active in Reports: 04/21/2005
Number of Days to Update: 22
Source: Santa Clara Valley Water District
Telephone: 408-265-2600
Last EDR Contact: 03/23/2009
Next Scheduled EDR Contact: 06/22/2009
Data Release Frequency: No Update Planned

LUST SANTA CLARA: LOP Listing
A listing of leaking underground storage tanks located in Santa Clara county.

Date of Government Version: 03/03/2014
Date Data Arrived at EDR: 03/05/2014
Date Made Active in Reports: 03/18/2014
Number of Days to Update: 13
Source: Department of Environmental Health
Telephone: 408-918-3417
Last EDR Contact: 08/15/2022
Next Scheduled EDR Contact: 12/05/2022
Data Release Frequency: No Update Planned

SAN JOSE HAZMAT: Hazardous Material Facilities
Hazardous material facilities, including underground storage tank sites.

Date of Government Version: 11/03/2020
Date Data Arrived at EDR: 11/05/2020
Date Made Active in Reports: 01/26/2021
Number of Days to Update: 82

Source: City of San Jose Fire Department
Telephone: 408-535-7694
Last EDR Contact: 07/26/2022
Next Scheduled EDR Contact: 11/14/2022
Data Release Frequency: Annually

SANTA CRUZ COUNTY:

CUPA SANTA CRUZ: CUPA Facility List
CUPA facility listing.

Date of Government Version: 01/21/2017
Date Data Arrived at EDR: 02/22/2017
Date Made Active in Reports: 05/23/2017
Number of Days to Update: 90

Source: Santa Cruz County Environmental Health
Telephone: 831-464-2761
Last EDR Contact: 08/09/2022
Next Scheduled EDR Contact: 11/28/2022
Data Release Frequency: Varies

SHASTA COUNTY:

CUPA SHASTA: CUPA Facility List
Cupa Facility List.

Date of Government Version: 06/15/2017
Date Data Arrived at EDR: 06/19/2017
Date Made Active in Reports: 08/09/2017
Number of Days to Update: 51

Source: Shasta County Department of Resource Management
Telephone: 530-225-5789
Last EDR Contact: 08/09/2022
Next Scheduled EDR Contact: 11/28/2022
Data Release Frequency: Varies

SOLANO COUNTY:

LUST SOLANO: Leaking Underground Storage Tanks
A listing of leaking underground storage tank sites located in Solano county.

Date of Government Version: 06/04/2019
Date Data Arrived at EDR: 06/06/2019
Date Made Active in Reports: 08/13/2019
Number of Days to Update: 68

Source: Solano County Department of Environmental Management
Telephone: 707-784-6770
Last EDR Contact: 08/23/2022
Next Scheduled EDR Contact: 12/12/2022
Data Release Frequency: Quarterly

UST SOLANO: Underground Storage Tanks
Underground storage tank sites located in Solano county.

Date of Government Version: 09/15/2021
Date Data Arrived at EDR: 09/16/2021
Date Made Active in Reports: 12/09/2021
Number of Days to Update: 84

Source: Solano County Department of Environmental Management
Telephone: 707-784-6770
Last EDR Contact: 08/23/2022
Next Scheduled EDR Contact: 12/12/2022
Data Release Frequency: Quarterly

SONOMA COUNTY:

CUPA SONOMA: Cupa Facility List
Cupa Facility list

Date of Government Version: 07/02/2021
Date Data Arrived at EDR: 07/06/2021
Date Made Active in Reports: 07/14/2021
Number of Days to Update: 8

Source: County of Sonoma Fire & Emergency Services Department
Telephone: 707-565-1174
Last EDR Contact: 09/13/2022
Next Scheduled EDR Contact: 01/02/2023
Data Release Frequency: Varies

LUST SONOMA: Leaking Underground Storage Tank Sites
A listing of leaking underground storage tank sites located in Sonoma county.

Date of Government Version: 06/30/2021
Date Data Arrived at EDR: 06/30/2021
Date Made Active in Reports: 09/24/2021
Number of Days to Update: 86

Source: Department of Health Services
Telephone: 707-565-6565
Last EDR Contact: 09/13/2022
Next Scheduled EDR Contact: 01/02/2023
Data Release Frequency: Quarterly

STANISLAUS COUNTY:

CUPA STANISLAUS: CUPA Facility List
Cupa facility list

Date of Government Version: 02/08/2022
Date Data Arrived at EDR: 02/10/2022
Date Made Active in Reports: 05/04/2022
Number of Days to Update: 83

Source: Stanislaus County Department of Ennvironmental Protection
Telephone: 209-525-6751
Last EDR Contact: 07/11/2022
Next Scheduled EDR Contact: 10/24/2022
Data Release Frequency: Varies

SUTTER COUNTY:

UST SUTTER: Underground Storage Tanks
Underground storage tank sites located in Sutter county.

Date of Government Version: 05/03/2022
Date Data Arrived at EDR: 05/27/2022
Date Made Active in Reports: 08/11/2022
Number of Days to Update: 76

Source: Sutter County Environmental Health Services
Telephone: 530-822-7500
Last EDR Contact: 08/23/2022
Next Scheduled EDR Contact: 12/12/2022
Data Release Frequency: Semi-Annually

TEHAMA COUNTY:

CUPA TEHAMA: CUPA Facility List
Cupa facilities

Date of Government Version: 01/13/2021
Date Data Arrived at EDR: 01/14/2021
Date Made Active in Reports: 04/06/2021
Number of Days to Update: 82

Source: Tehama County Department of Environmental Health
Telephone: 530-527-8020
Last EDR Contact: 07/26/2022
Next Scheduled EDR Contact: 11/14/2022
Data Release Frequency: Varies

TRINITY COUNTY:

CUPA TRINITY: CUPA Facility List
Cupa facility list

Date of Government Version: 07/13/2022
Date Data Arrived at EDR: 07/14/2022
Date Made Active in Reports: 09/29/2022
Number of Days to Update: 77

Source: Department of Toxic Substances Control
Telephone: 760-352-0381
Last EDR Contact: 07/13/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Varies

TULARE COUNTY:

CUPA TULARE: CUPA Facility List
Cupa program facilities

Date of Government Version: 04/26/2021
Date Data Arrived at EDR: 04/28/2021
Date Made Active in Reports: 07/13/2021
Number of Days to Update: 76

Source: Tulare County Environmental Health Services Division
Telephone: 559-624-7400
Last EDR Contact: 07/12/2022
Next Scheduled EDR Contact: 11/14/2022
Data Release Frequency: Varies

TUOLUMNE COUNTY:

CUPA TUOLUMNE: CUPA Facility List
Cupa facility list

Date of Government Version: 04/23/2018
Date Data Arrived at EDR: 04/25/2018
Date Made Active in Reports: 06/25/2018
Number of Days to Update: 61

Source: Divison of Environmental Health
Telephone: 209-533-5633
Last EDR Contact: 07/12/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Varies

VENTURA COUNTY:

BWT VENTURA: Business Plan, Hazardous Waste Producers, and Operating Underground Tanks
The BWT list indicates by site address whether the Environmental Health Division has Business Plan (B), Waste Producer (W), and/or Underground Tank (T) information.

Date of Government Version: 03/28/2022
Date Data Arrived at EDR: 04/28/2022
Date Made Active in Reports: 07/15/2022
Number of Days to Update: 78

Source: Ventura County Environmental Health Division
Telephone: 805-654-2813
Last EDR Contact: 07/18/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Quarterly

LF VENTURA: Inventory of Illegal Abandoned and Inactive Sites
Ventura County Inventory of Closed, Illegal Abandoned, and Inactive Sites.

Date of Government Version: 12/01/2011
Date Data Arrived at EDR: 12/01/2011
Date Made Active in Reports: 01/19/2012
Number of Days to Update: 49

Source: Environmental Health Division
Telephone: 805-654-2813
Last EDR Contact: 09/21/2022
Next Scheduled EDR Contact: 01/10/2023
Data Release Frequency: No Update Planned

LUST VENTURA: Listing of Underground Tank Cleanup Sites
Ventura County Underground Storage Tank Cleanup Sites (LUST).

Date of Government Version: 05/29/2008
Date Data Arrived at EDR: 06/24/2008
Date Made Active in Reports: 07/31/2008
Number of Days to Update: 37

Source: Environmental Health Division
Telephone: 805-654-2813
Last EDR Contact: 08/02/2022
Next Scheduled EDR Contact: 11/21/2022
Data Release Frequency: No Update Planned

MED WASTE VENTURA: Medical Waste Program List
To protect public health and safety and the environment from potential exposure to disease causing agents, the Environmental Health Division Medical Waste Program regulates the generation, handling, storage, treatment and disposal of medical waste throughout the County.

Date of Government Version: 03/28/2022
Date Data Arrived at EDR: 04/28/2022
Date Made Active in Reports: 07/15/2022
Number of Days to Update: 78

Source: Ventura County Resource Management Agency
Telephone: 805-654-2813
Last EDR Contact: 07/18/2022
Next Scheduled EDR Contact: 10/31/2022
Data Release Frequency: Quarterly

UST VENTURA: Underground Tank Closed Sites List
Ventura County Operating Underground Storage Tank Sites (UST)/Underground Tank Closed Sites List.

Date of Government Version: 05/26/2022
Date Data Arrived at EDR: 06/07/2022
Date Made Active in Reports: 08/24/2022
Number of Days to Update: 78
Source: Environmental Health Division
Telephone: 805-654-2813
Last EDR Contact: 08/31/2022
Next Scheduled EDR Contact: 12/19/2022
Data Release Frequency: Quarterly

YOLO COUNTY:

UST YOLO: Underground Storage Tank Comprehensive Facility Report
Underground storage tank sites located in Yolo county.

Date of Government Version: 06/22/2022
Date Data Arrived at EDR: 06/30/2022
Date Made Active in Reports: 09/14/2022
Number of Days to Update: 76
Source: Yolo County Department of Health
Telephone: 530-666-8646
Last EDR Contact: 09/21/2022
Next Scheduled EDR Contact: 01/10/2023
Data Release Frequency: Annually

YUBA COUNTY:

CUPA YUBA: CUPA Facility List
CUPA facility listing for Yuba County.

Date of Government Version: 05/03/2022
Date Data Arrived at EDR: 05/05/2022
Date Made Active in Reports: 07/28/2022
Number of Days to Update: 84
Source: Yuba County Environmental Health Department
Telephone: 530-749-7523
Last EDR Contact: 08/02/2022
Next Scheduled EDR Contact: 11/07/2022
Data Release Frequency: Varies

OTHER DATABASE(S)

Depending on the geographic area covered by this report, the data provided in these specialty databases may or may not be complete. For example, the existence of wetlands information data in a specific report does not mean that all wetlands in the area covered by the report are included. Moreover, the absence of any reported wetlands information does not necessarily mean that wetlands do not exist in the area covered by the report.

CT MANIFEST: Hazardous Waste Manifest Data
Facility and manifest data. Manifest is a document that lists and tracks hazardous waste from the generator through transporters to a tsd facility.

Date of Government Version: 05/08/2022
Date Data Arrived at EDR: 05/09/2022
Date Made Active in Reports: 07/28/2022
Number of Days to Update: 80
Source: Department of Energy & Environmental Protection
Telephone: 860-424-3375
Last EDR Contact: 08/08/2022
Next Scheduled EDR Contact: 11/21/2022
Data Release Frequency: No Update Planned

NJ MANIFEST: Manifest Information
Hazardous waste manifest information.

Date of Government Version: 12/31/2018
Date Data Arrived at EDR: 04/10/2019
Date Made Active in Reports: 05/16/2019
Number of Days to Update: 36
Source: Department of Environmental Protection
Telephone: N/A
Last EDR Contact: 06/28/2022
Next Scheduled EDR Contact: 10/17/2022
Data Release Frequency: Annually

NY MANIFEST: Facility and Manifest Data

Manifest is a document that lists and tracks hazardous waste from the generator through transporters to a TSD facility.

Date of Government Version: 01/01/2019
Date Data Arrived at EDR: 10/29/2021
Date Made Active in Reports: 01/19/2022
Number of Days to Update: 82

Source: Department of Environmental Conservation
Telephone: 518-402-8651
Last EDR Contact: 07/29/2022
Next Scheduled EDR Contact: 11/07/2022
Data Release Frequency: Quarterly

PA MANIFEST: Manifest Information

Hazardous waste manifest information.

Date of Government Version: 06/30/2018
Date Data Arrived at EDR: 07/19/2019
Date Made Active in Reports: 09/10/2019
Number of Days to Update: 53

Source: Department of Environmental Protection
Telephone: 717-783-8990
Last EDR Contact: 07/06/2022
Next Scheduled EDR Contact: 10/24/2022
Data Release Frequency: Annually

RI MANIFEST: Manifest information

Hazardous waste manifest information

Date of Government Version: 12/31/2020
Date Data Arrived at EDR: 11/30/2021
Date Made Active in Reports: 02/18/2022
Number of Days to Update: 80

Source: Department of Environmental Management
Telephone: 401-222-2797
Last EDR Contact: 08/10/2022
Next Scheduled EDR Contact: 11/28/2022
Data Release Frequency: Annually

WI MANIFEST: Manifest Information

Hazardous waste manifest information.

Date of Government Version: 05/31/2018
Date Data Arrived at EDR: 06/19/2019
Date Made Active in Reports: 09/03/2019
Number of Days to Update: 76

Source: Department of Natural Resources
Telephone: N/A
Last EDR Contact: 08/29/2022
Next Scheduled EDR Contact: 12/19/2022
Data Release Frequency: Annually

Oil/Gas Pipelines

Source: Endeavor Business Media

Petroleum Bundle (Crude Oil, Refined Products, Petrochemicals, Gas Liquids (LPG/NGL), and Specialty Gases (Miscellaneous)) N = Natural Gas Bundle (Natural Gas, Gas Liquids (LPG/NGL), and Specialty Gases (Miscellaneous)). This map includes information copyrighted by Endeavor Business Media. This information is provided on a best effort basis and Endeavor Business Media does not guarantee its accuracy nor warrant its fitness for any particular purpose. Such information has been reprinted with the permission of Endeavor Business Media.

Electric Power Transmission Line Data

Source: Endeavor Business Media

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Sensitive Receptors: There are individuals deemed sensitive receptors due to their fragile immune systems and special sensitivity to environmental discharges. These sensitive receptors typically include the elderly, the sick, and children. While the location of all sensitive receptors cannot be determined, EDR indicates those buildings and facilities - schools, daycares, hospitals, medical centers, and nursing homes - where individuals who are sensitive receptors are likely to be located.

AHA Hospitals:

Source: American Hospital Association, Inc.
Telephone: 312-280-5991

The database includes a listing of hospitals based on the American Hospital Association's annual survey of hospitals.

Medical Centers: Provider of Services Listing

Source: Centers for Medicare & Medicaid Services
Telephone: 410-786-3000

A listing of hospitals with Medicare provider number, produced by Centers of Medicare & Medicaid Services, a federal agency within the U.S. Department of Health and Human Services.

Nursing Homes
Source: National Institutes of Health
Telephone: 301-594-6248
Information on Medicare and Medicaid certified nursing homes in the United States.
Public Schools
Source: National Center for Education Statistics
Telephone: 202-502-7300
The National Center for Education Statistics' primary database on elementary and secondary public education in the United States. It is a comprehensive, annual, national statistical database of all public elementary and secondary schools and school districts, which contains data that are comparable across all states.
Private Schools
Source: National Center for Education Statistics
Telephone: 202-502-7300
The National Center for Education Statistics' primary database on private school locations in the United States.
Daycare Centers: Licensed Facilities
Source: Department of Social Services
Telephone: 916-657-4041

Flood Zone Data: This data was obtained from the Federal Emergency Management Agency (FEMA). It depicts 100-year and 500-year flood zones as defined by FEMA. It includes the National Flood Hazard Layer (NFHL) which incorporates Flood Insurance Rate Map (FIRM) data and Q3 data from FEMA in areas not covered by NFHL.
Source: FEMA
Telephone: 877-336-2627
Date of Government Version: 2003, 2015

NWI: National Wetlands Inventory. This data, available in select counties across the country, was obtained by EDR in 2002, 2005 and 2010 from the U.S. Fish and Wildlife Service.

State Wetlands Data: Wetland Inventory
Source: Department of Fish and Wildlife
Telephone: 916-445-0411

STREET AND ADDRESS INFORMATION

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APPENDIX E
HISTORICAL RECORDS

Aera Belridge CCS Phase I ESA

Aera Belridge CCS Phase I ESA

Lost Hills, CA 93249

Inquiry Number: 7133623.2

September 29, 2022

Certified Sanborn® Map Report

6 Armstrong Road, 4th floor
Shelton, CT 06484
Toll Free: 800.352.0050
www.edrnet.com

Certified Sanborn® Map Report

09/29/22

Site Name:

Aera Belridge CCS Phase I ES
Aera Belridge CCS Phase I ES
Lost Hills, CA 93249
EDR Inquiry # 7133623.2

Client Name:

Stantec
290 Conejo Ridge Avenue
Thousand Oaks, CA 91361
Contact: Emily Medler

The Sanborn Library has been searched by EDR and maps covering the target property location as provided by Stantec were identified for the years listed below. The Sanborn Library is the largest, most complete collection of fire insurance maps. The collection includes maps from Sanborn, Bromley, Perris & Browne, Hopkins, Barlow, and others. Only Environmental Data Resources Inc. (EDR) is authorized to grant rights for commercial reproduction of maps by the Sanborn Library LLC, the copyright holder for the collection. Results can be authenticated by visiting www.edrnet.com/sanborn.

The Sanborn Library is continually enhanced with newly identified map archives. This report accesses all maps in the collection as of the day this report was generated.

Certified Sanborn Results:

Certification # 2744-4AB1-8359

PO # NA

Project 185805372

UNMAPPED PROPERTY

This report certifies that the complete holdings of the Sanborn Library, LLC collection have been searched based on client supplied target property information, and fire insurance maps covering the target property were not found.

Sanborn® Library search results

Certification #: 2744-4AB1-8359

The Sanborn Library includes more than 1.2 million fire insurance maps from Sanborn, Bromley, Perris & Browne, Hopkins, Barlow and others which track historical property usage in approximately 12,000 American cities and towns. Collections searched:

- ✓ Library of Congress
- ✓ University Publications of America
- ✓ EDR Private Collection

The Sanborn Library LLC Since 1866™

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Aera Belridge CCS Phase I ESA

Aera Belridge CCS Phase I ESA

Lost Hills, CA 93249

Inquiry Number: 7133623.1

September 30, 2022

EDR Historical Topo Map Report

with QuadMatch™

6 Armstrong Road, 4th floor
Shelton, CT 06484
Toll Free: 800.352.0050
www.edrnet.com

EDR Historical Topo Map Report

09/30/22

Site Name:	Client Name:
Aera Belridge CCS Phase I ES	Stantec
Aera Belridge CCS Phase I ES	290 Conejo Ridge Avenue
Lost Hills, CA 93249	Thousand Oaks, CA 91361
EDR Inquiry # 7133623.1	Contact: Emily Medler

EDR Topographic Map Library has been searched by EDR and maps covering the target property location as provided by Stantec were identified for the years listed below. EDR's Historical Topo Map Report is designed to assist professionals in evaluating potential liability on a target property resulting from past activities. EDRs Historical Topo Map Report includes a search of a collection of public and private color historical topographic maps, dating back to the late 1800s.

Search Results:		*Coordinates:*	
P.O.#	NA	**Latitude:**	35.50606 35° 30' 22" North
Project:	185805372	**Longitude:**	-119.75565 -119° 45' 20" West
		UTM Zone:	Zone 11 North
		UTM X Meters:	250068.72
		UTM Y Meters:	3932657.81
		Elevation:	605.01' above sea level

Maps Provided:

2018	1950, 1953
2015	1947
2012	1943
1982	1914
1979	1912
1973	1912, 1914
1959	
1953	

Di□□ai□ er□□Co□□ri□□t□and□Trade□ ar□Noti□e

This Report contains certain information obtained from a variety of public and other sources reasonably available to Environmental Data Resources, Inc. It cannot be concluded from this Report that coverage information for the target and surrounding properties does not exist from other sources. NO WARRANTY EXPRESSED OR IMPLIED, IS MADE WHATSOEVER IN CONNECTION WITH THIS REPORT. ENVIRONMENTAL DATA RESOURCES, INC. SPECIFICALLY DISCLAIMS THE MAKING OF ANY SUCH WARRANTIES, INCLUDING WITHOUT LIMITATION, MERCHANTABILITY OR FITNESS FOR A PARTICULAR USE OR PURPOSE. ALL RISK IS ASSUMED BY THE USER. IN NO EVENT SHALL ENVIRONMENTAL DATA RESOURCES, INC. BE LIABLE TO ANYONE, WHETHER ARISING OUT OF ERRORS OR OMISSIONS, NEGLIGENCE, ACCIDENT OR ANY OTHER CAUSE, FOR ANY LOSS OF DAMAGE, INCLUDING, WITHOUT LIMITATION, SPECIAL, INCIDENTAL, CONSEQUENTIAL, OR EXEMPLARY DAMAGES. ANY LIABILITY ON THE PART OF ENVIRONMENTAL DATA RESOURCES, INC. IS STRICTLY LIMITED TO A REFUND OF THE AMOUNT PAID FOR THIS REPORT. Purchaser accepts this Report "AS IS". Any analyses, estimates, ratings, environmental risk levels or risk codes provided in this Report are provided for illustrative purposes only, and are not intended to provide, nor should they be interpreted as providing any facts regarding, or prediction or forecast of, any environmental risk for any property. Only a Phase I Environmental Site Assessment performed by an environmental professional can provide information regarding the environmental risk for any property. Additionally, the information provided in this Report is not to be construed as legal advice.

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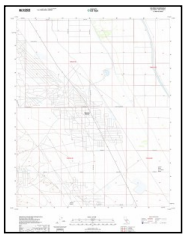
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2018 Source Sheets



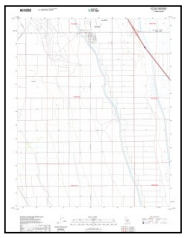
Carneros Rocks
2018
7.5-minute, 24000



Belridge
2018
7.5-minute, 24000

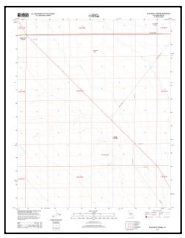


Blackwells Corner
2018
7.5-minute, 24000

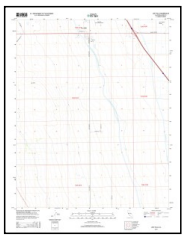


Lost Hills
2018
7.5-minute, 24000

2015 Source Sheets



Blackwells Corner
2015
7.5-minute, 24000



Lost Hills
2015
7.5-minute, 24000



Carneros Rocks
2015
7.5-minute, 24000

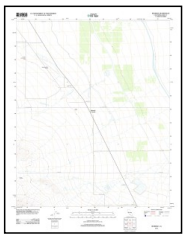


Belridge
2015
7.5-minute, 24000

2012 Source Sheets



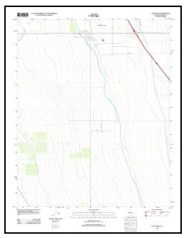
Carneros Rocks
2012
7.5-minute, 24000



Belridge
2012
7.5-minute, 24000

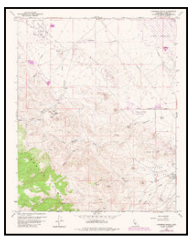


Blackwells Corner
2012
7.5-minute, 24000



Lost Hills
2012
7.5-minute, 24000

1982 Source Sheets



Carneros Rocks
1982
7.5-minute, 24000
Aerial Photo Revised 1980



Blackwells Corner
1982
7.5-minute, 24000
Aerial Photo Revised 1978

Topo Sheet Key

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1979 Source Sheets



MCKITTRICK
1979
15-minute, 50000

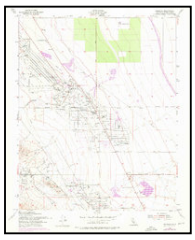
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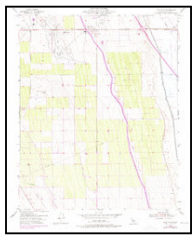
Blackwells Corner
1973
7.5-minute, 24000
Aerial Photo Revised 1973



Carneros Rocks
1973
7.5-minute, 24000
Aerial Photo Revised 1973



Belridge
1973
7.5-minute, 24000
Aerial Photo Revised 1973



Lost Hills
1973
7.5-minute, 24000
Aerial Photo Revised 1973

1959 Source Sheets



Carneros Rocks
1959
7.5-minute, 24000
Aerial Photo Revised 1953

1953 Source Sheets



Blackwells Corner
1953
7.5-minute, 24000
Aerial Photo Revised 1950



Belridge
1953
7.5-minute, 24000
Aerial Photo Revised 1950

Topo Sheet Key

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1950, 1953 Source Sheets

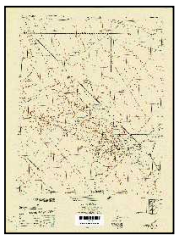


West of Goose Lake
1950
7.5-minute, 24000

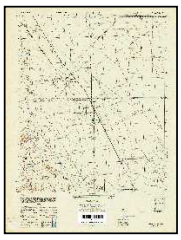


Lost Hills
1953
7.5-minute, 24000
Aerial Photo Revised 1950

1947 Source Sheets



BLACKWELLS CORNER
1947
7.5-minute, 25000



BELRIDGE
1947
7.5-minute, 25000

1943 Source Sheets



Blackwell
1943
7.5-minute, 31680



Belridge
1943
7.5-minute, 31680

1914 Source Sheets



Lost Hills
1914
30-minute, 125000

Topo Sheet Key

□□□□ □DR □□□□□ M□□ R□□□r□□□ □□□□d □□□□□ □□□□ □□□□□□□ □□□□ □ □□ □ □□□□□□r□□□□□□ □ □□□ □□□□□□□□□

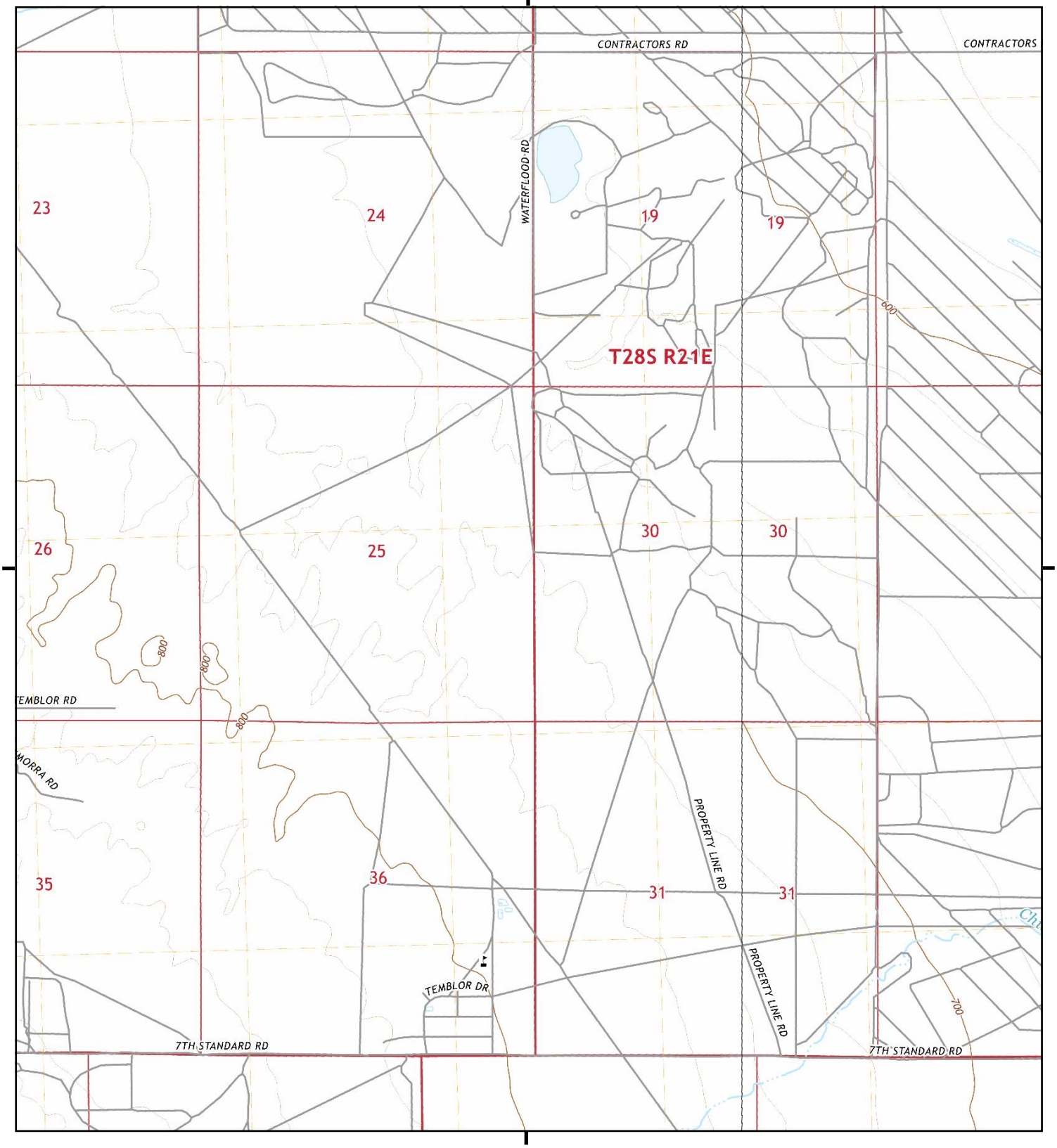
1912 Source Sheets



McKittrick
1912
30-minute, 125000

Historical Topo Map

2018



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0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, Carneros Rocks, 2018, 7.5-minute
E, Belridge, 2018, 7.5-minute

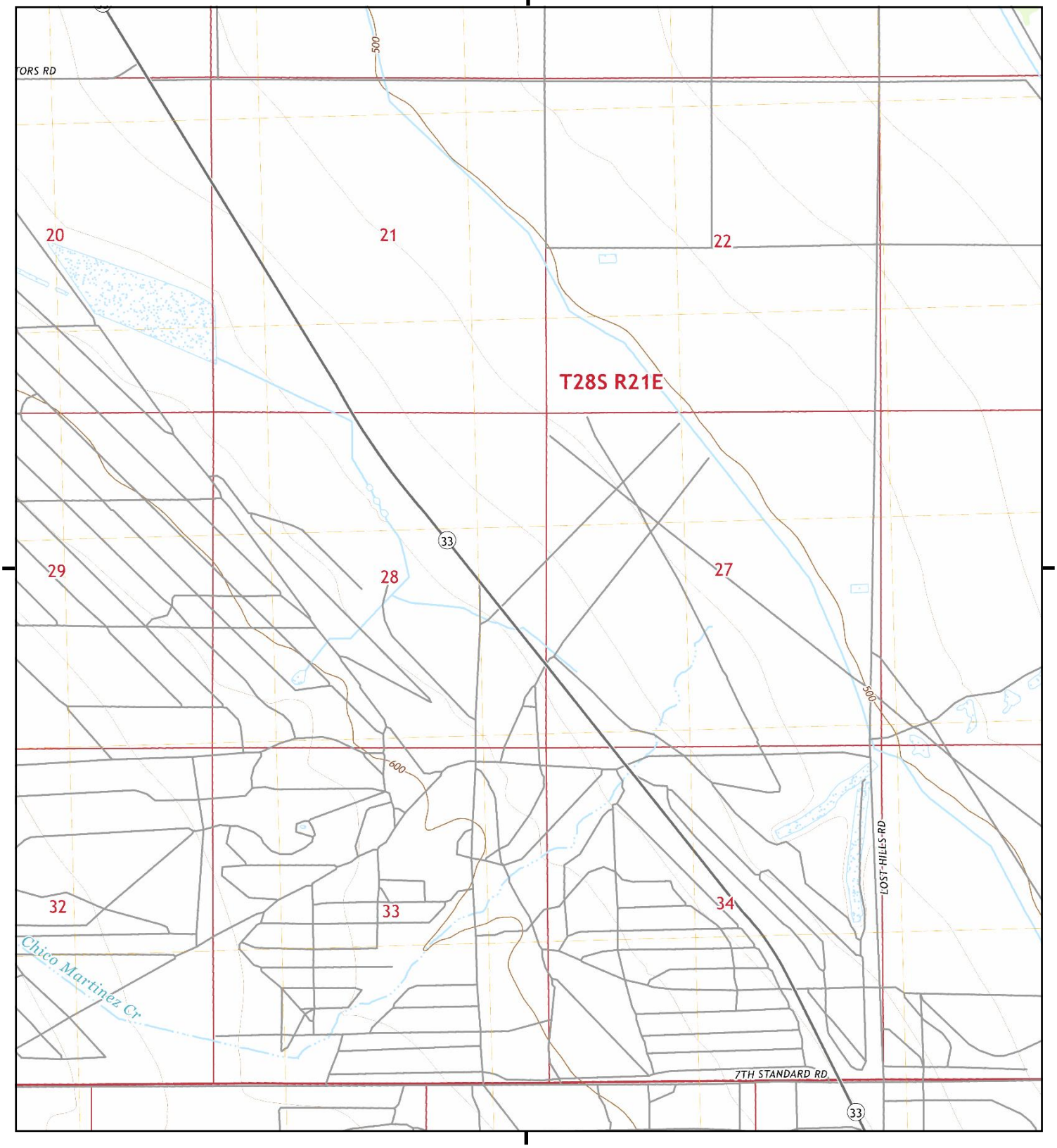
□□□□ □□M□□ Aera Belridge CCS Phase I ESA
□DDR□□□□ Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
□□□□□□□ Stantec

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7133623 - 1 □□□□ 7

Historical Topo Map

2018



0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, Belridge, 2018, 7.5-minute

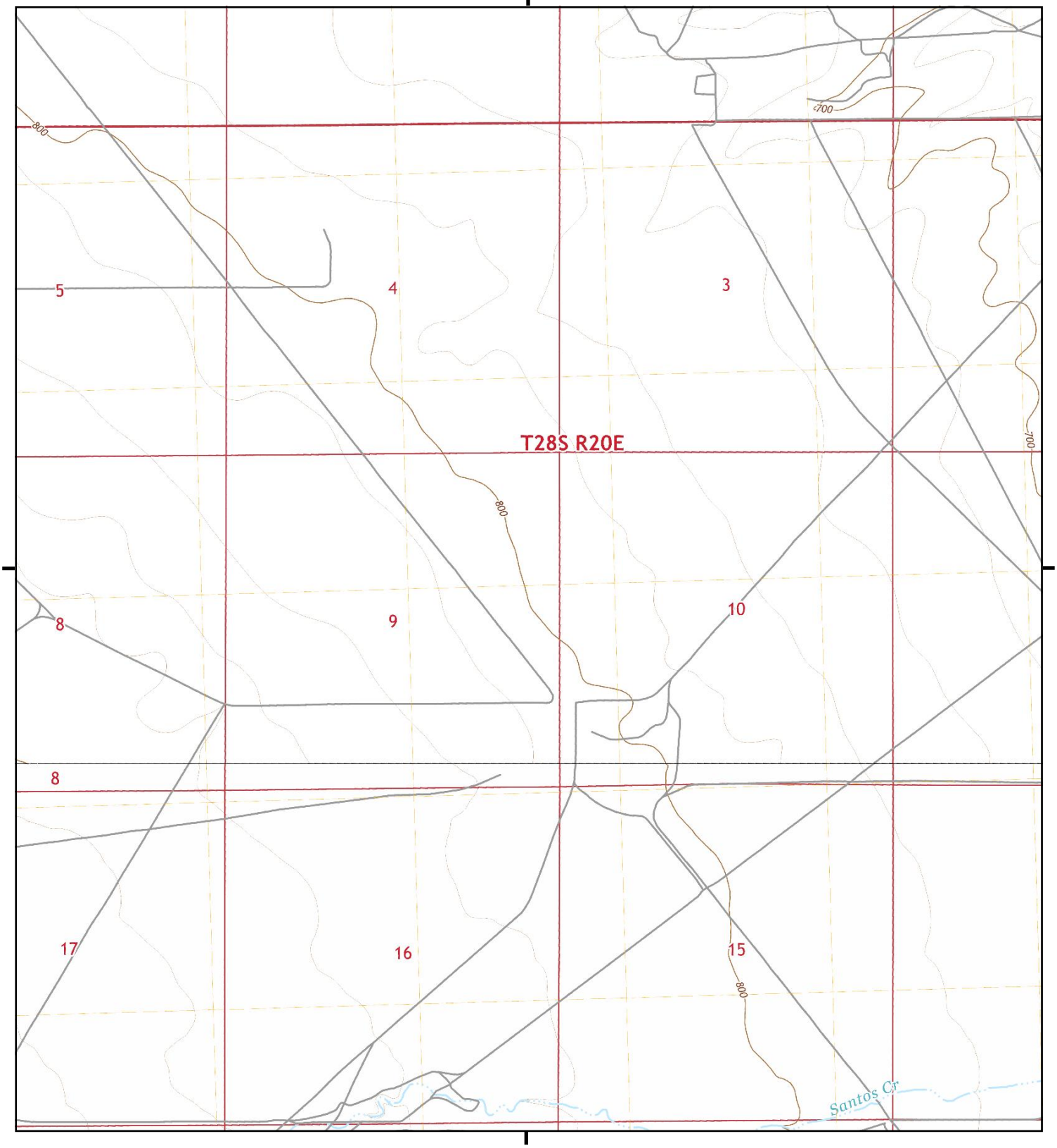
Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
Stantec

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7133623 - 1 8

Historical Topo Map

2018



0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, Blackwells Corner, 2018, 7.5-minute
S, Carneros Rocks, 2018, 7.5-minute

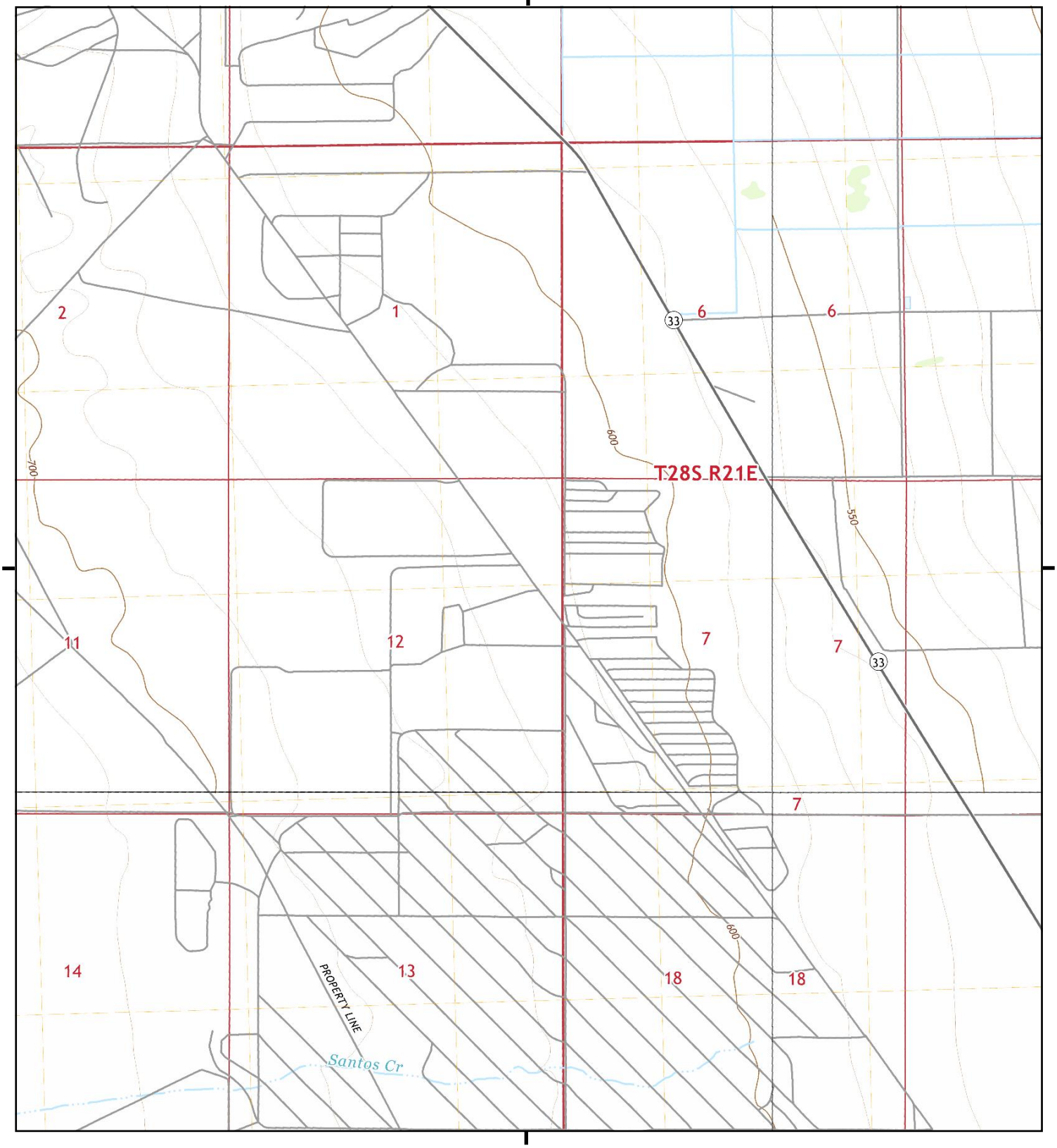
Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
Stantec

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7133623 - 1 9

Historical Topo Map

2018



0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, Blackwells Corner, 2018, 7.5-minute
NE, Lost Hills, 2018, 7.5-minute
S, Belridge, 2018, 7.5-minute
SW, Carneros Rocks, 2018, 7.5-minute

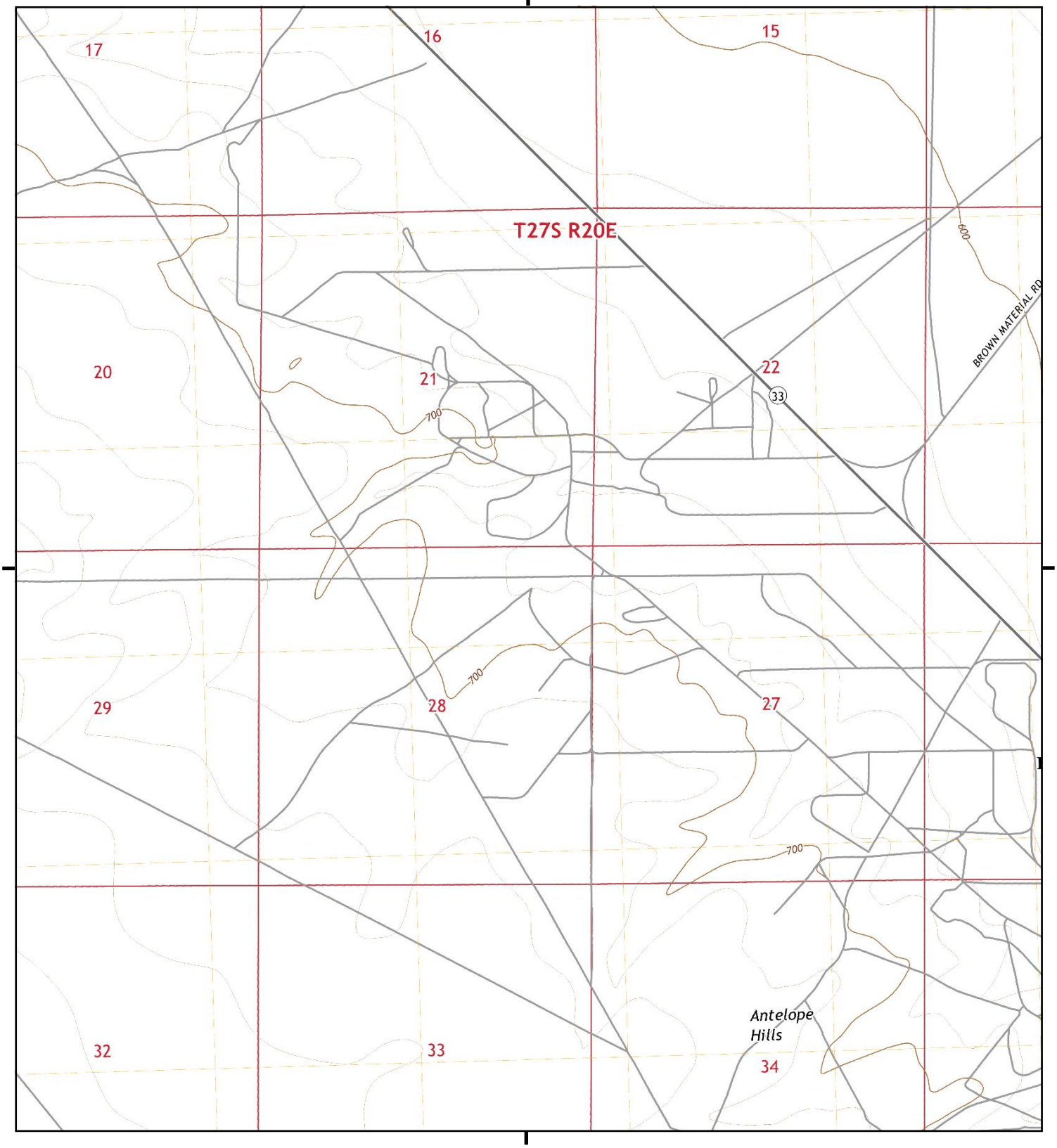
Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
Stantec

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7133623 - 1 10

Historical Topo Map

2018



0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, Blackwells Corner, 2018, 7.5-minute

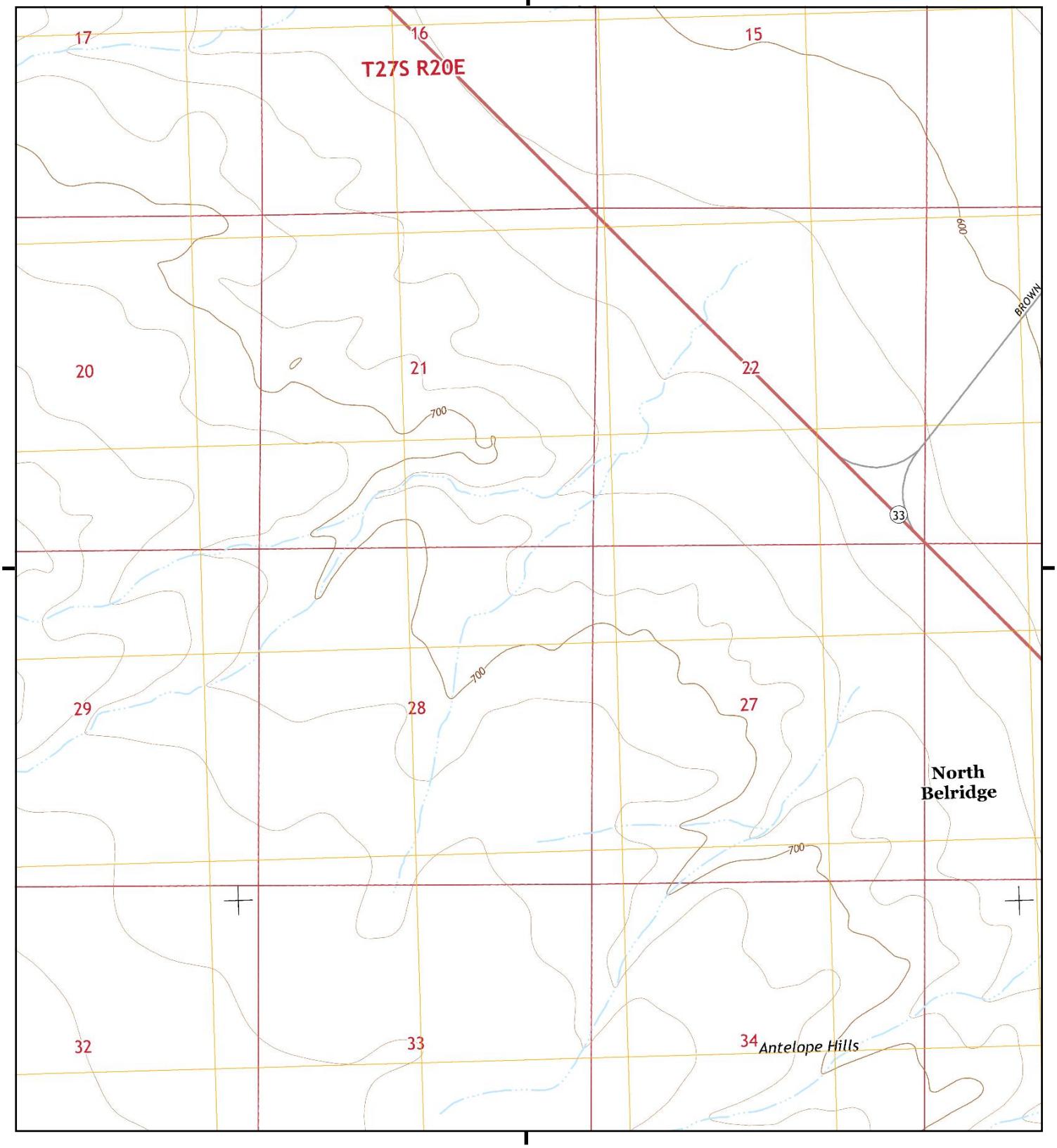
Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
Stantec

N

7133623 - 1 11

Historical Topo Map

2015



0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, Blackwells Corner, 2015, 7.5-minute

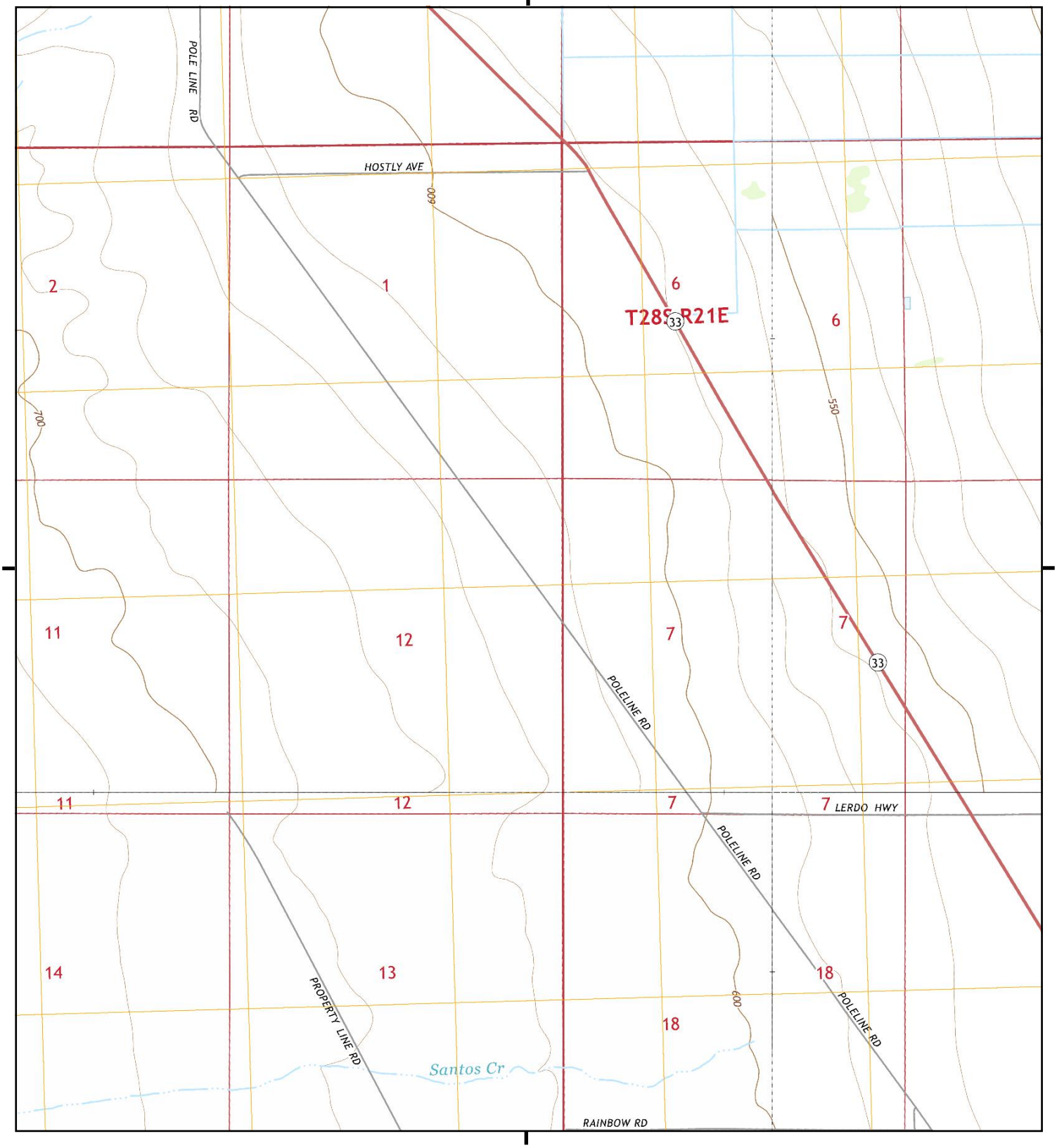
Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
Stantec

N

7133623 - 1 12

Historical Topo Map

2015



0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, Blackwells Corner, 2015, 7.5-minute
NE, Lost Hills, 2015, 7.5-minute
S, Belridge, 2015, 7.5-minute
SW, Carneros Rocks, 2015, 7.5-minute

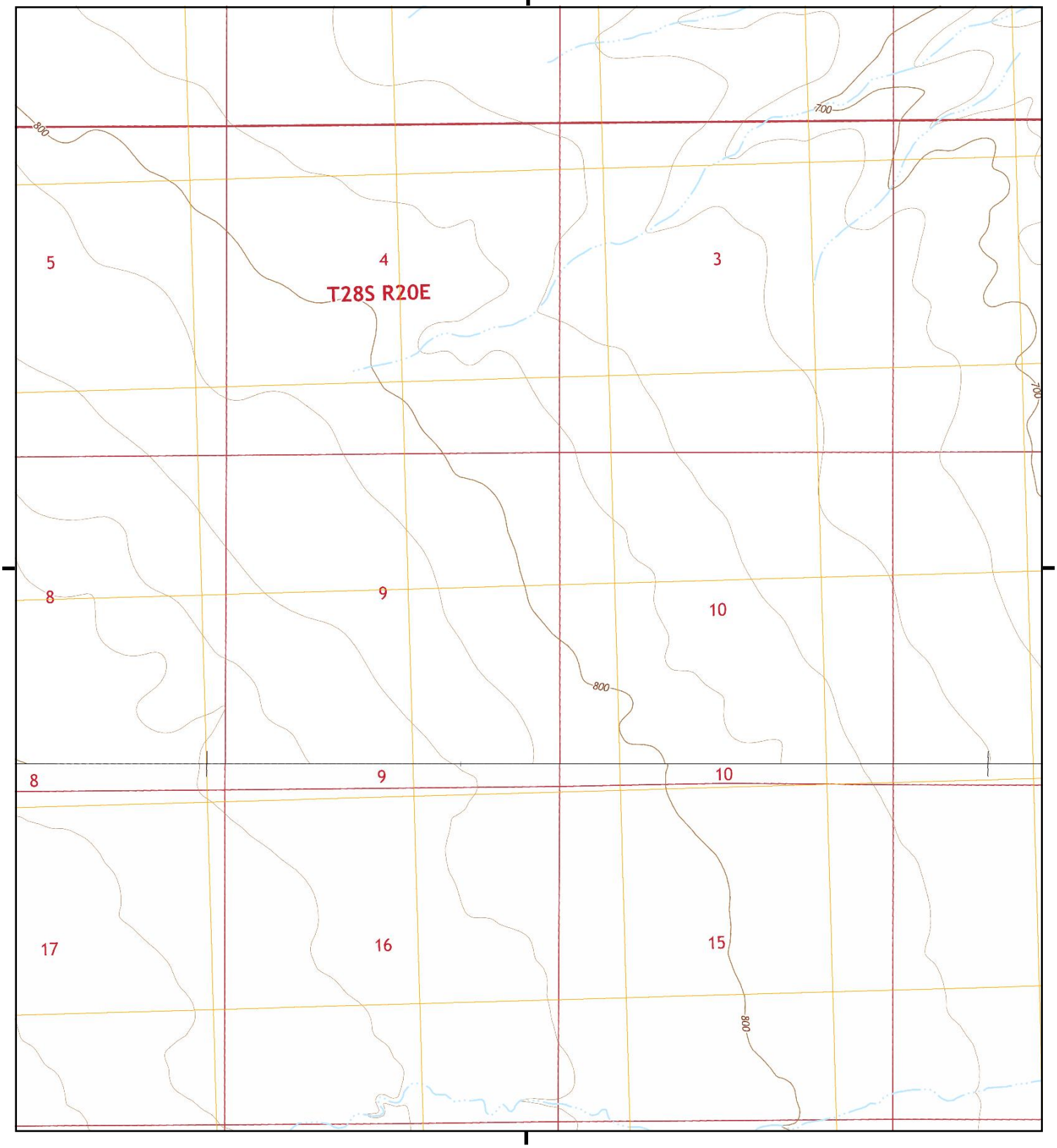
Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
Stantec

N

7133623 - 1 13

Historical Topo Map

2015



0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, Blackwells Corner, 2015, 7.5-minute
S, Carneros Rocks, 2015, 7.5-minute

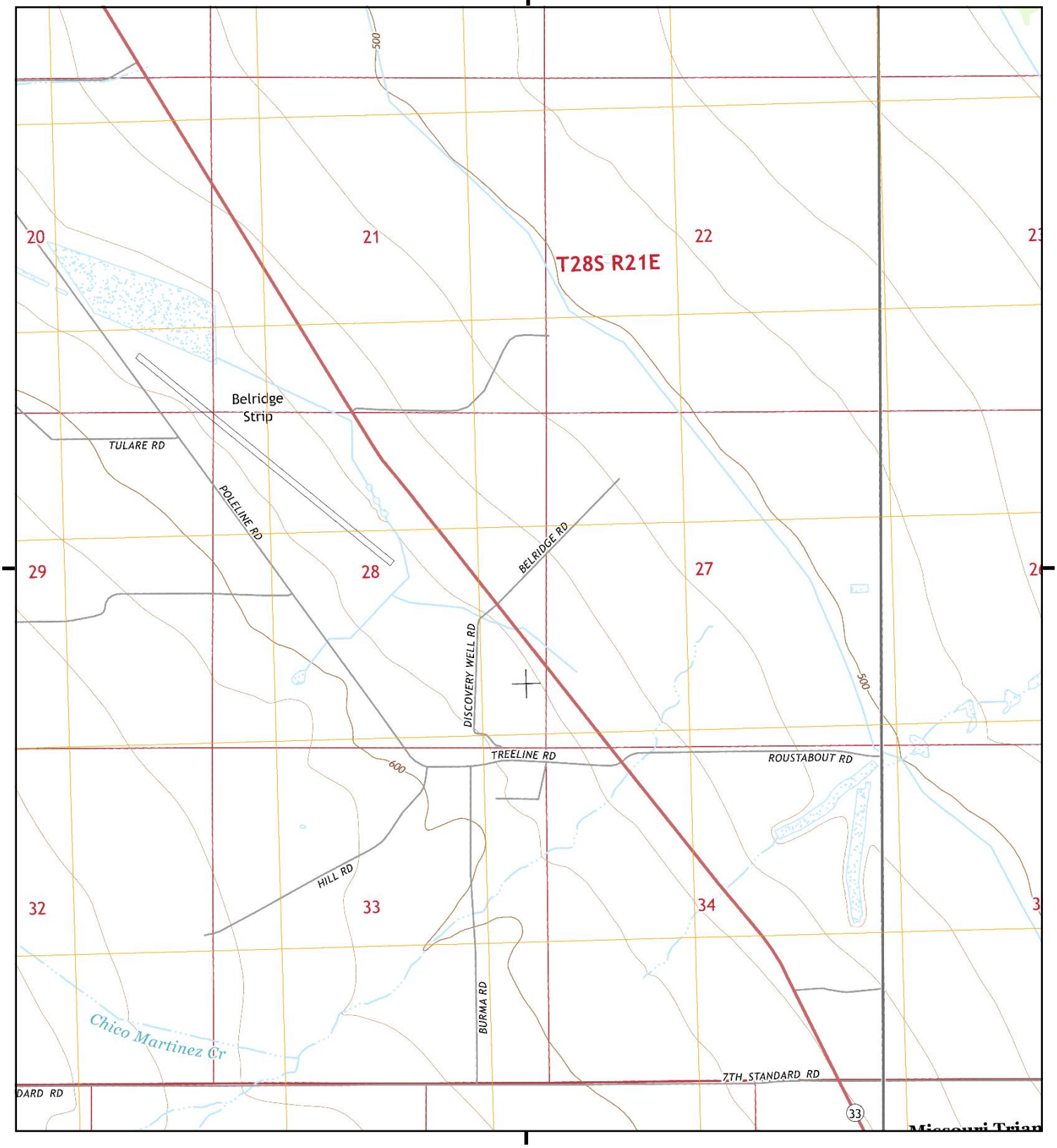
Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
Stantec

N

7133623 - 1 14

Historical Topo Map

2015



0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, Belridge, 2015, 7.5-minute

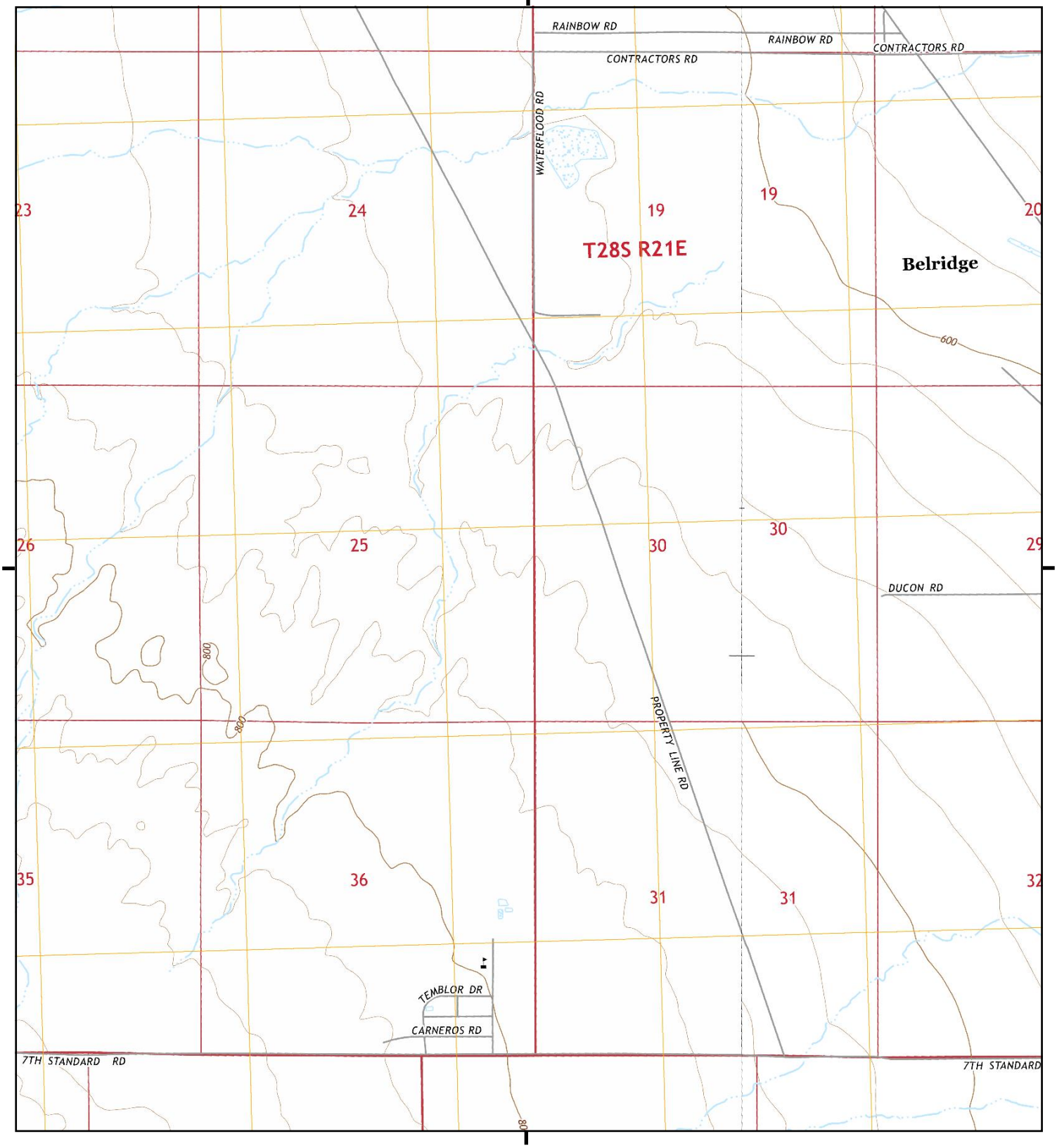
Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
Stantec

N

7133623 - 1 15

Historical Topo Map

2015



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0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, Carneros Rocks, 2015, 7.5-minute
E, Belridge, 2015, 7.5-minute

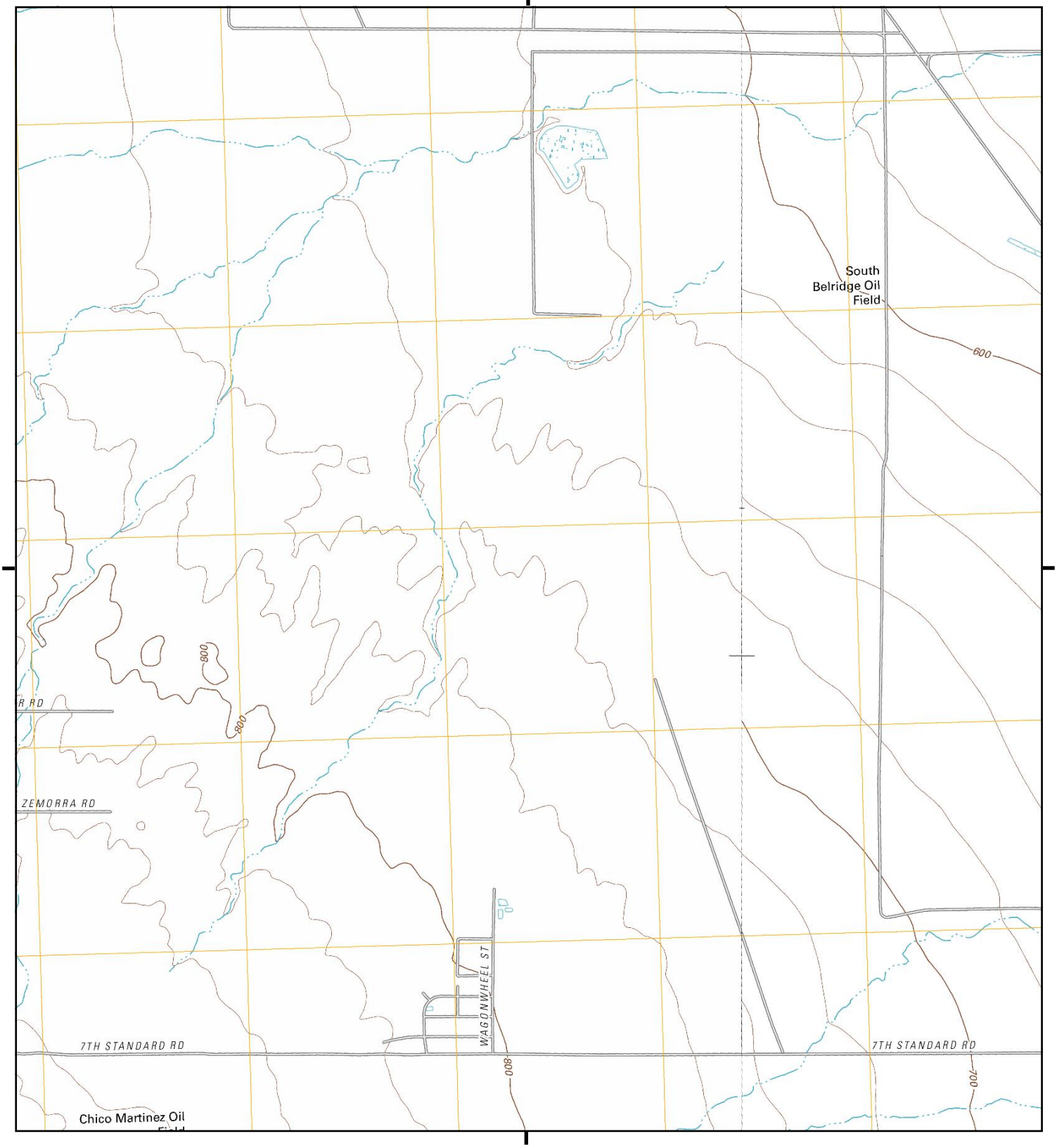
□□□□ □□M□□ Aera Belridge CCS Phase I ESA
□DDR□□□□ Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
□□□□□□□ Stantec

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Historical Topo Map

2012



0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, Carneros Rocks, 2012, 7.5-minute
E, Belridge, 2012, 7.5-minute

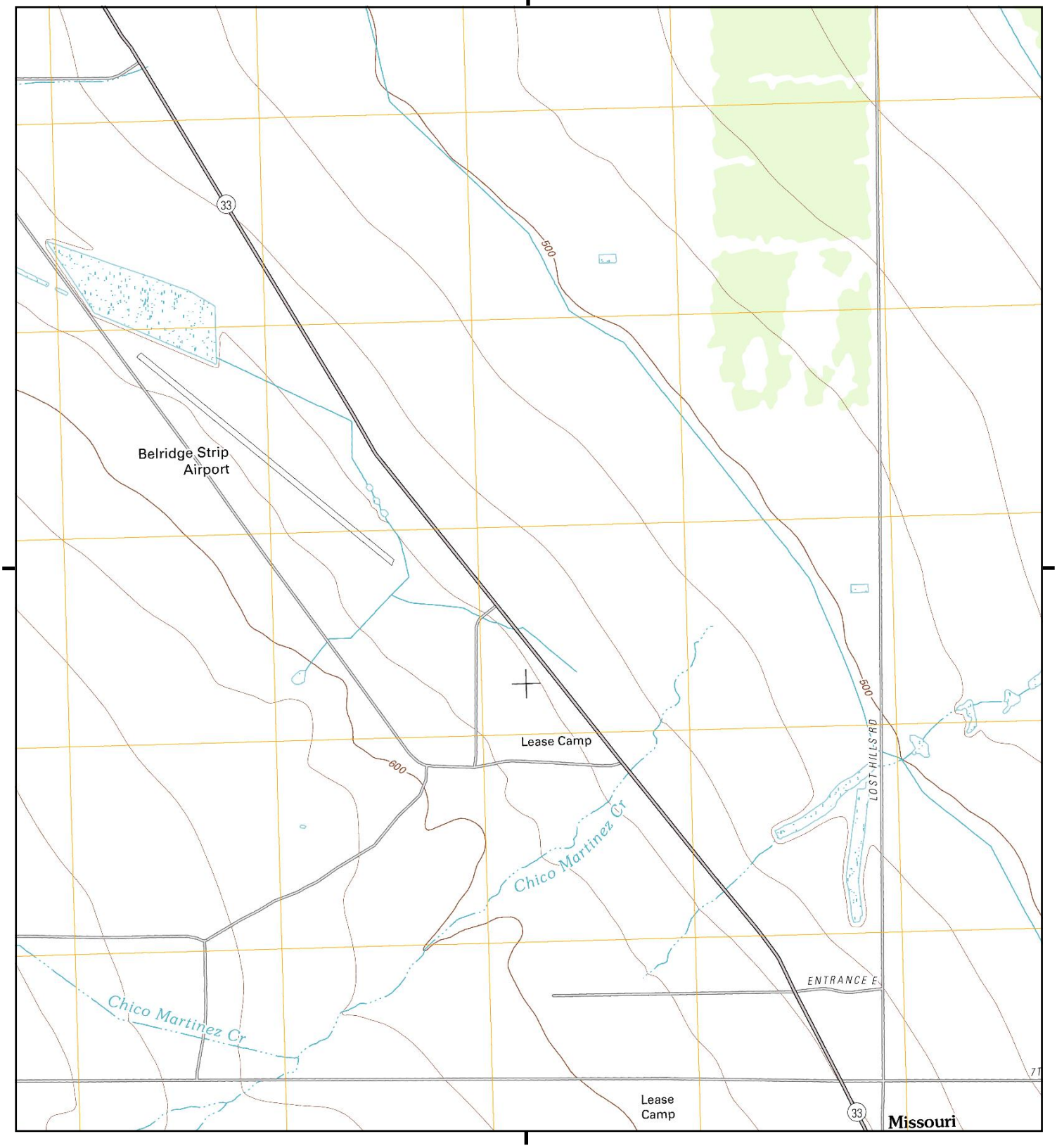
Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
Stantec

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7133623 - 1 17

Historical Topo Map

2012



0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, Belridge, 2012, 7.5-minute

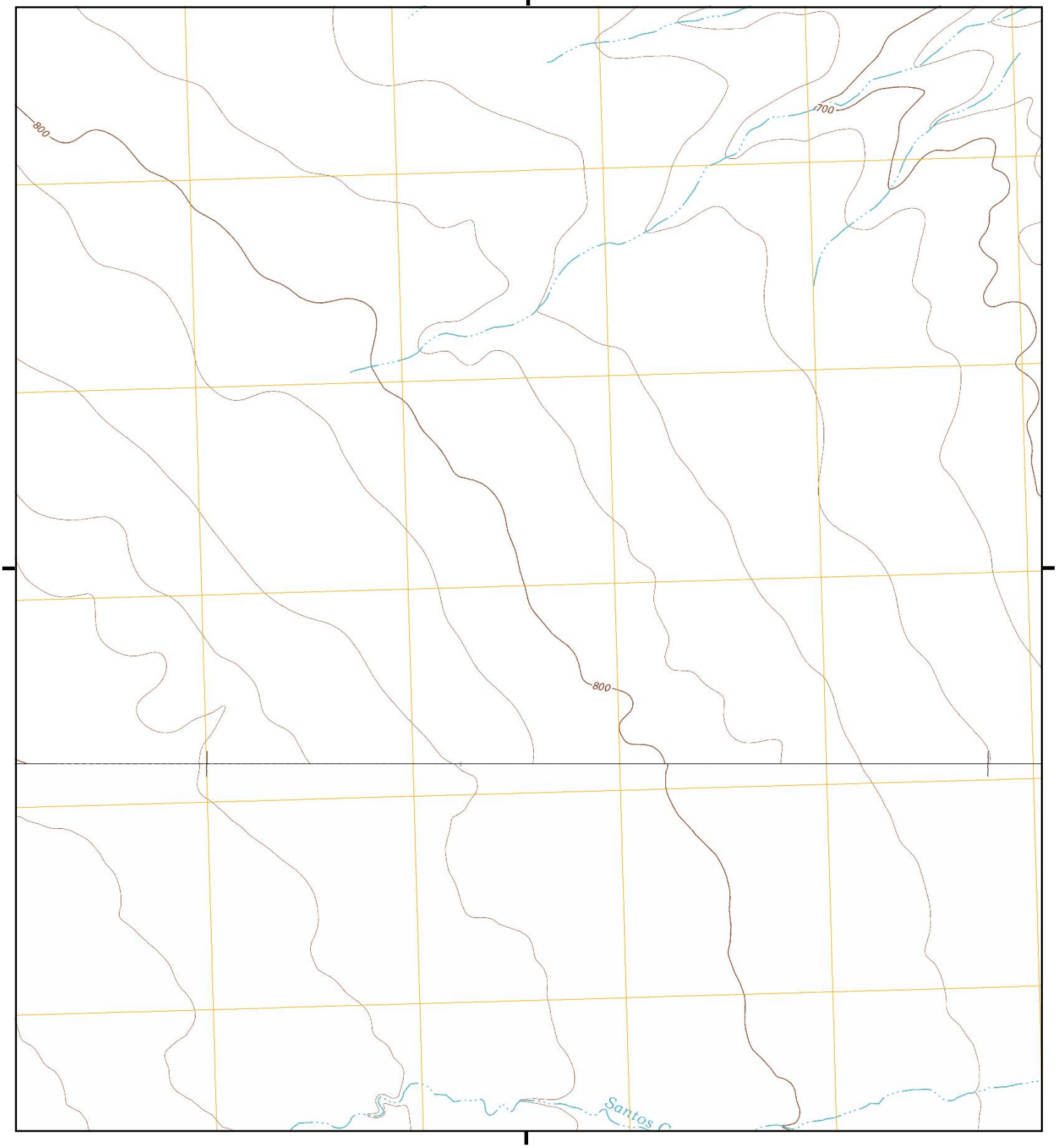
Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
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Historical Topo Map

2012



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0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, Blackwells Corner, 2012, 7.5-minute
S, Carneros Rocks, 2012, 7.5-minute

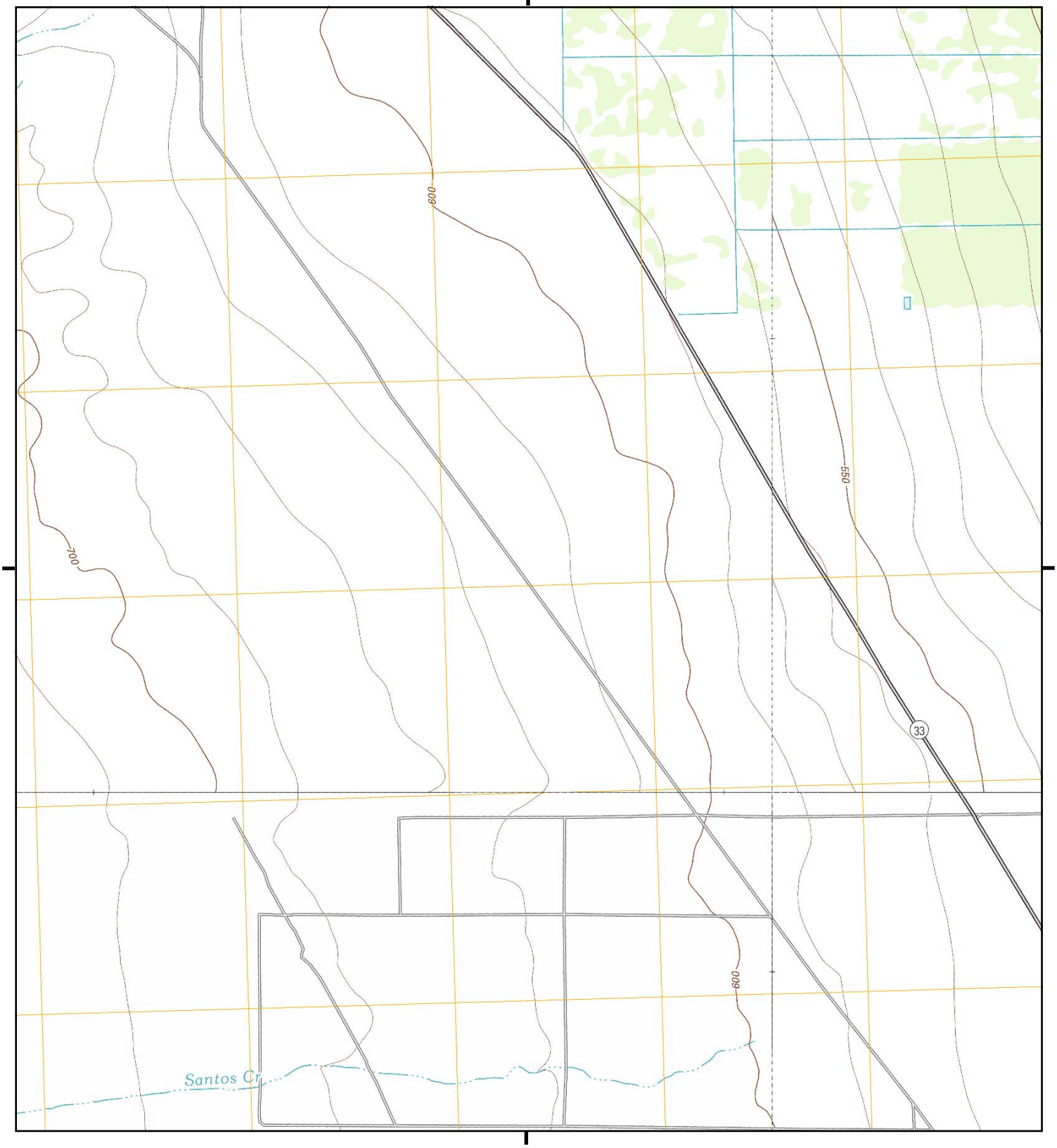
□□□□ □□M□□ Aera Belridge CCS Phase I ESA
□DDR□□□□ Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
□□□□□□□ Stantec

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Historical Topo Map

2012



0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, Blackwells Corner, 2012, 7.5-minute
NE, Lost Hills, 2012, 7.5-minute
S, Belridge, 2012, 7.5-minute
SW, Carneros Rocks, 2012, 7.5-minute

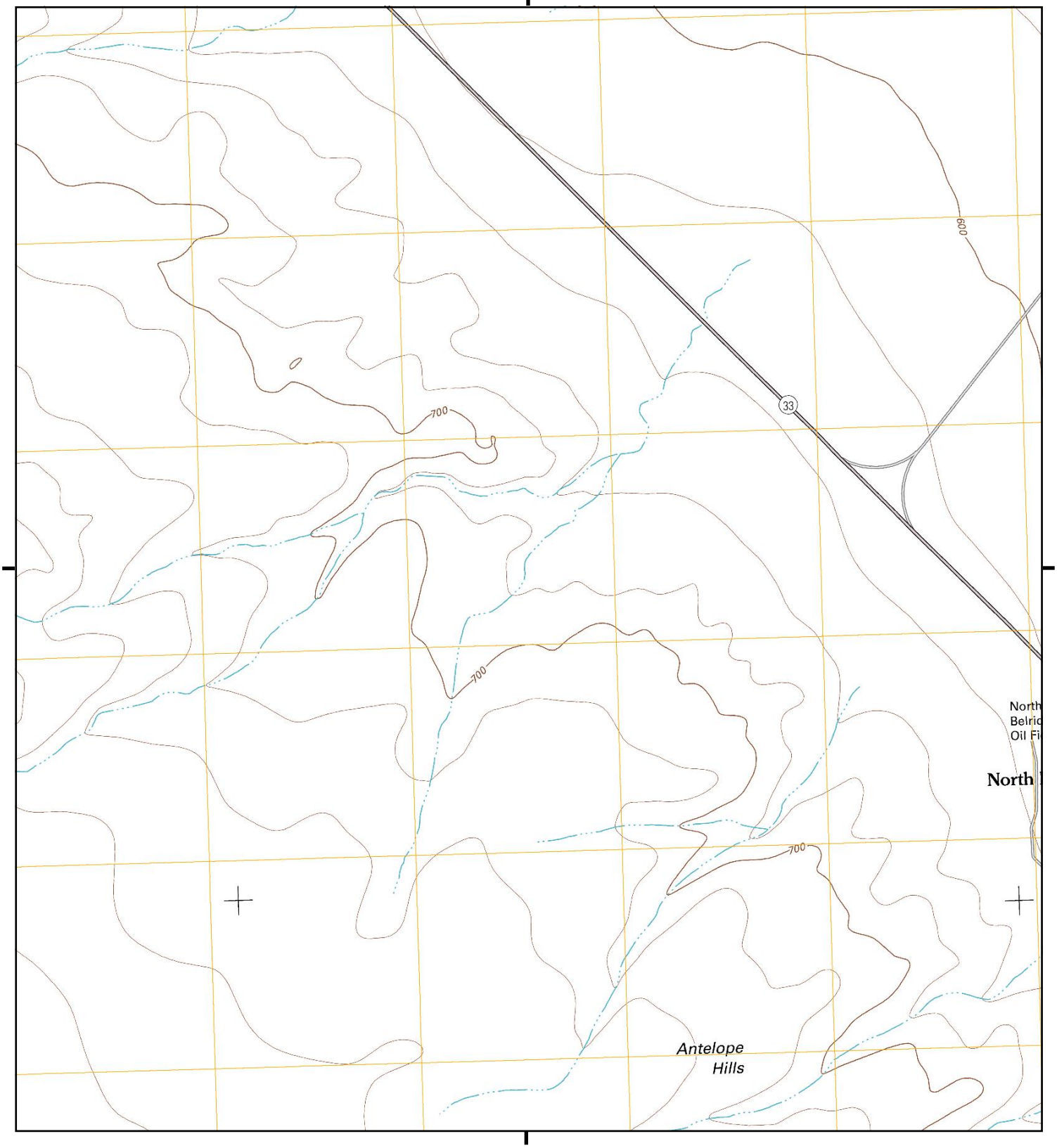
Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
Stantec

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Historical Topo Map

2012



0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, Blackwells Corner, 2012, 7.5-minute

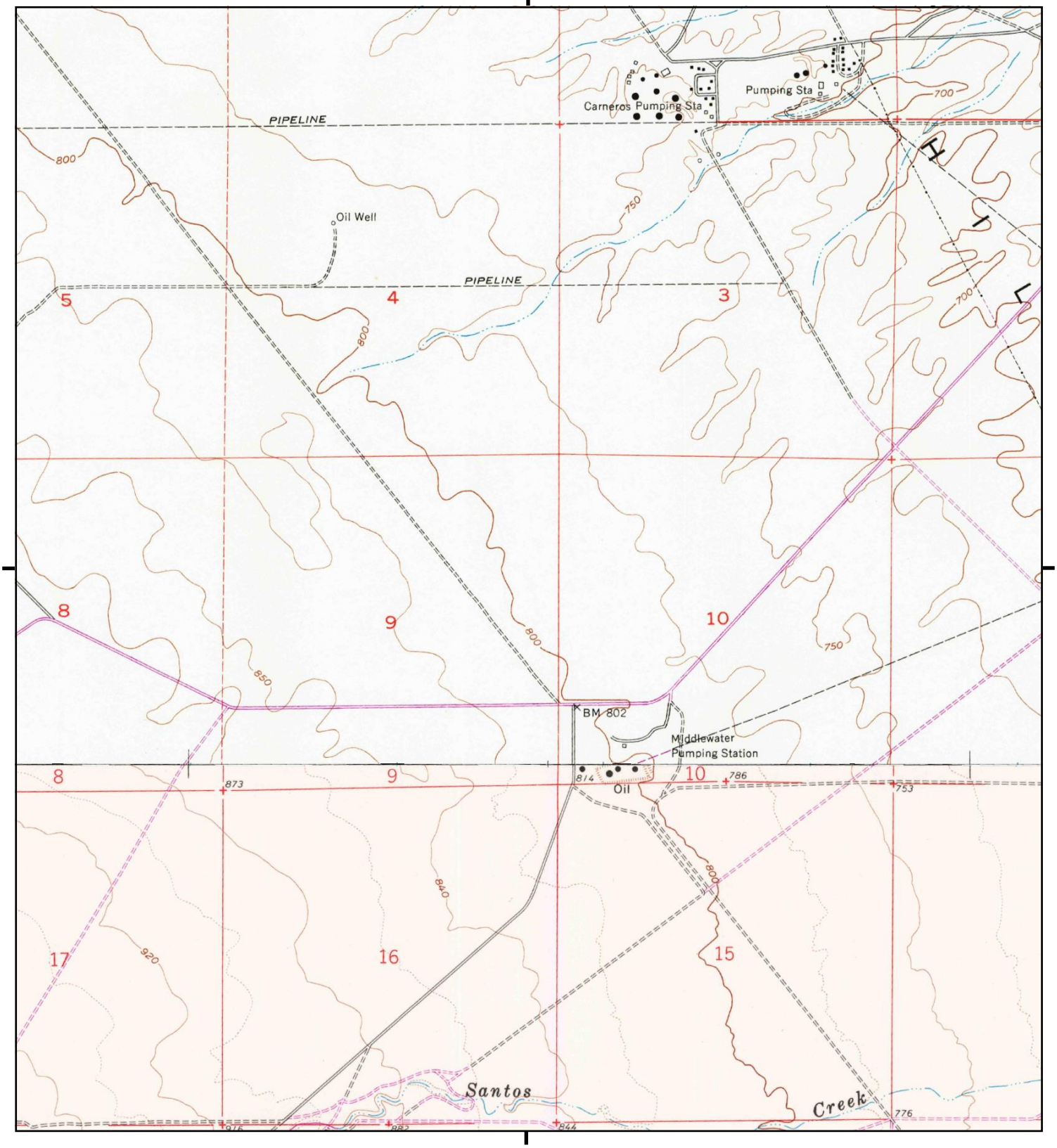
Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
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Historical Topo Map

1982



0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, Blackwells Corner, 1982, 7.5-minute
S, Carneros Rocks, 1982, 7.5-minute

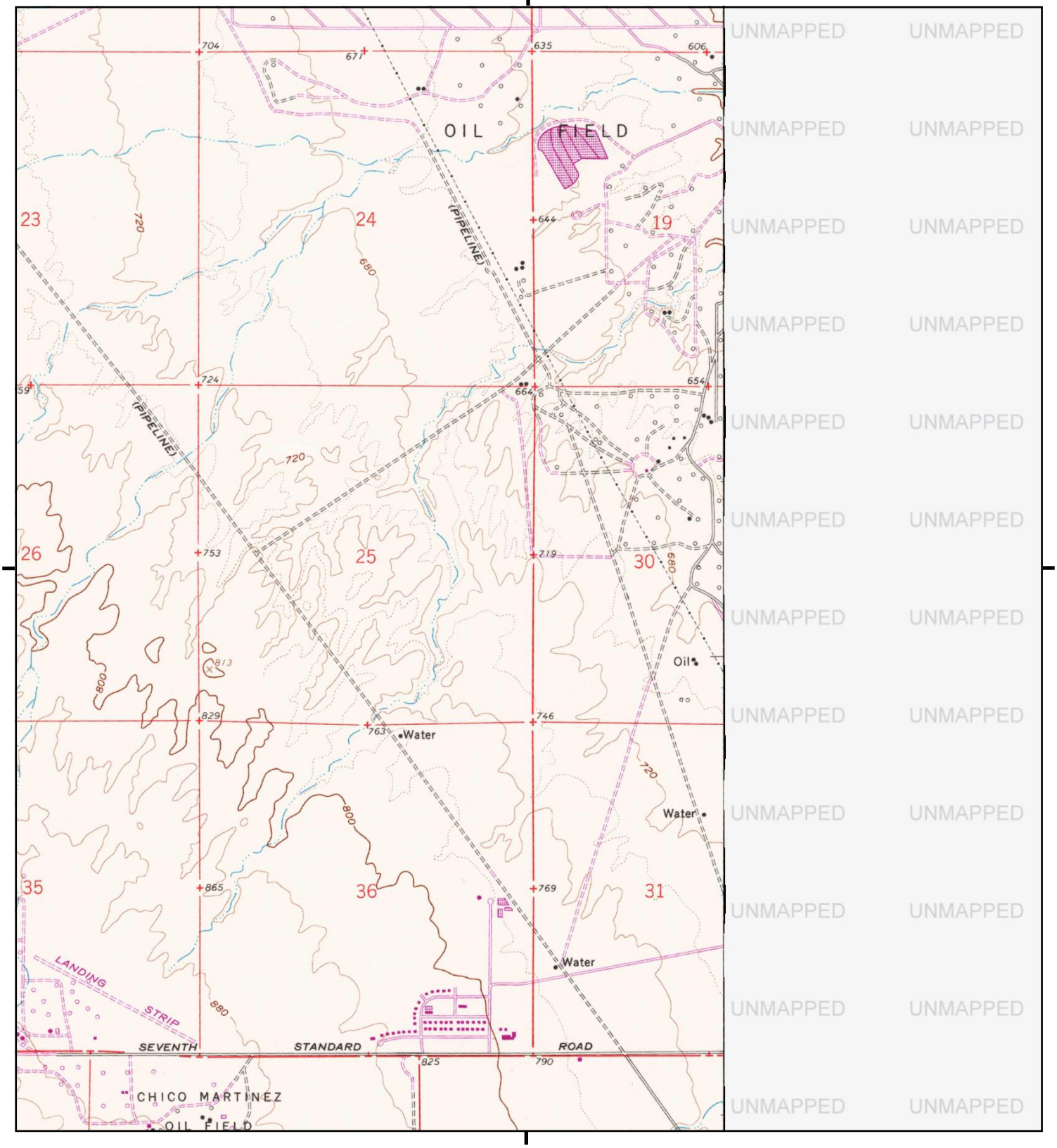
Aera Belridge CCS Phase I ESA
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Historical Topo Map

1982



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NW N NE
W E
SW S SE

TP, Carneros Rocks, 1982, 7.5-minute

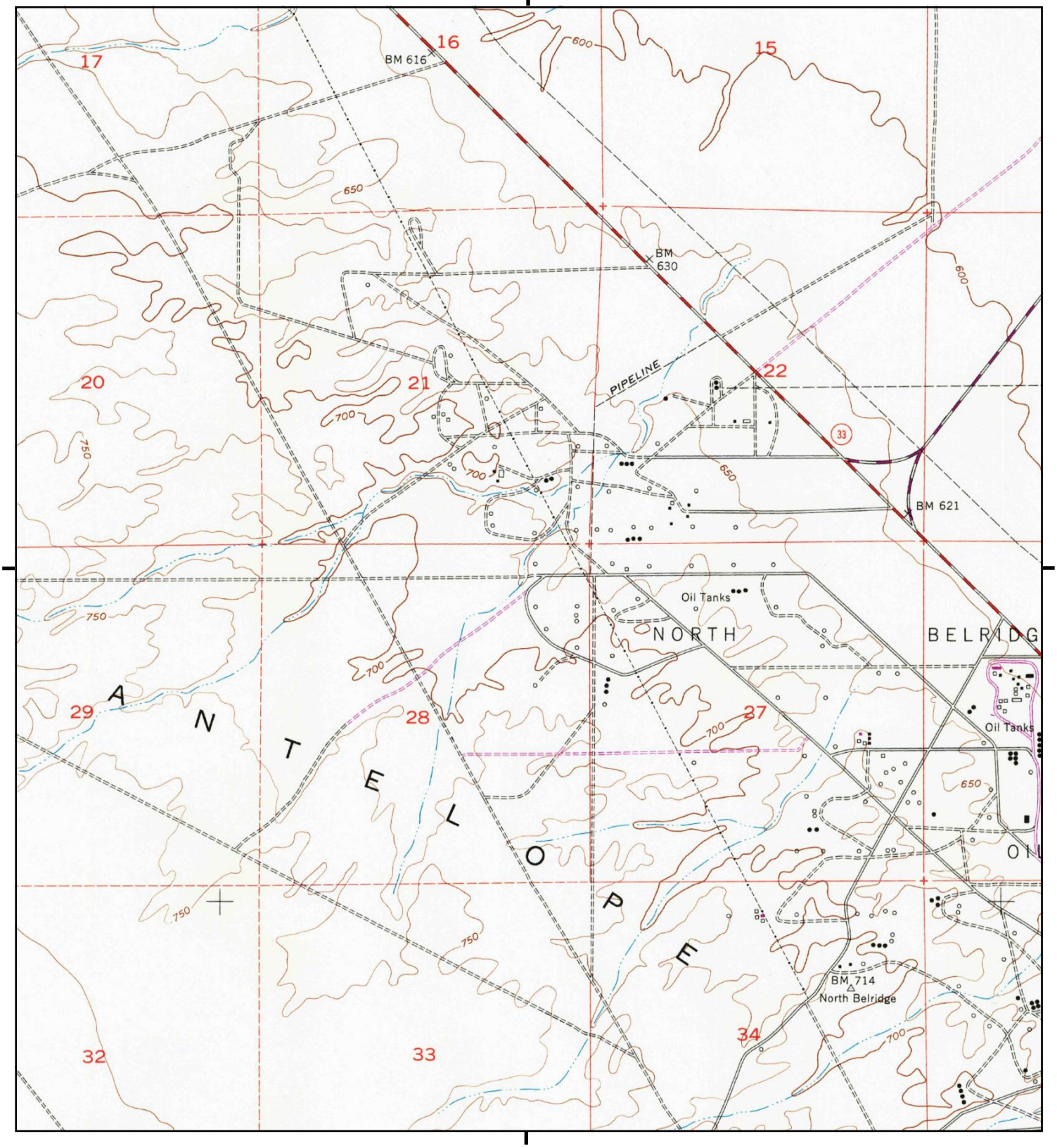
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□DDR□□□□ Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
□□□□□□□ Stantec

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Historical Topo Map

1982



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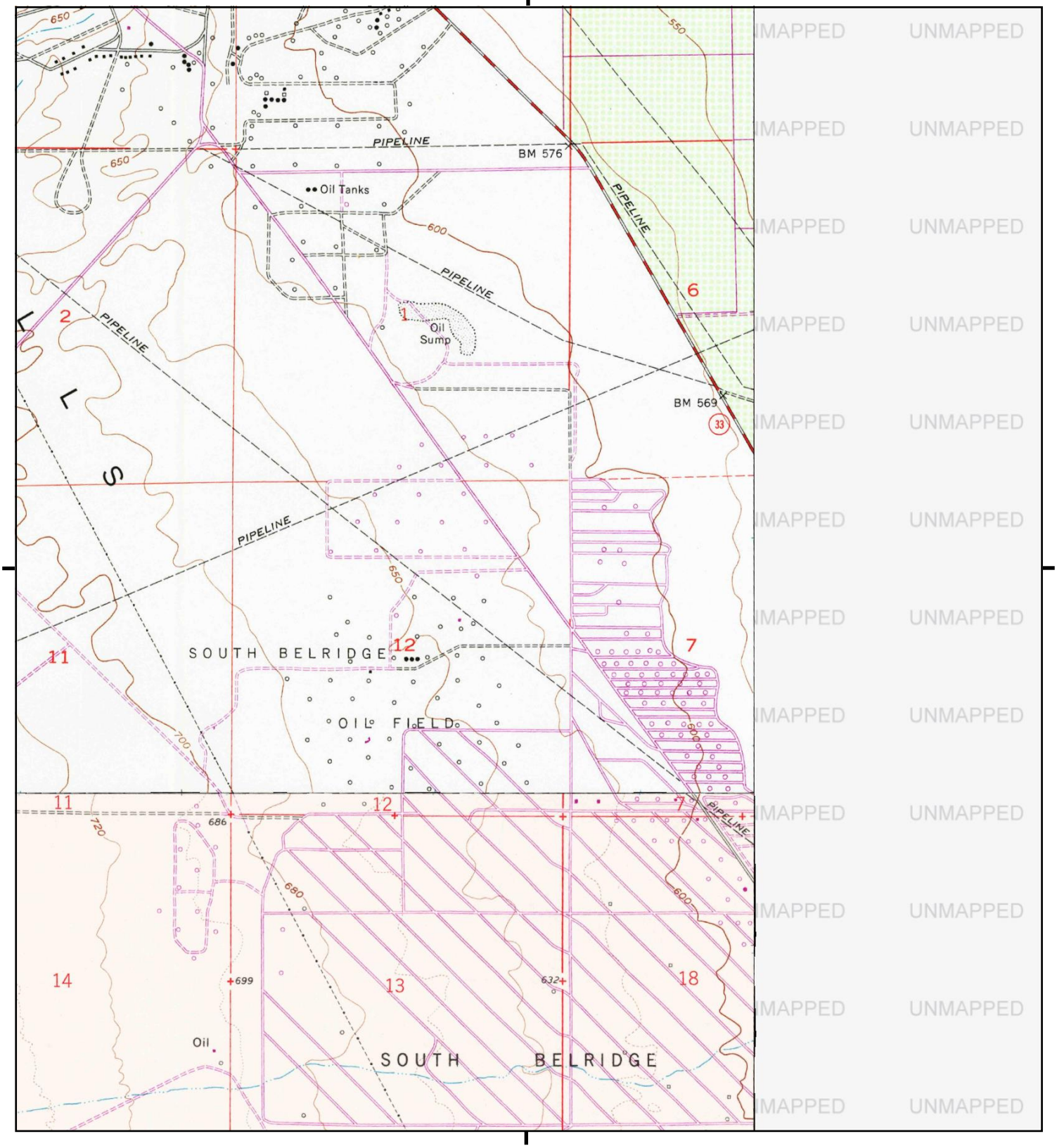
0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, Blackwells Corner, 1982, 7.5-minute

□□□□ □□M□□ Aera Belridge CCS Phase I ESA
□DDR□□□□ Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
□□□□□□□ Stantec

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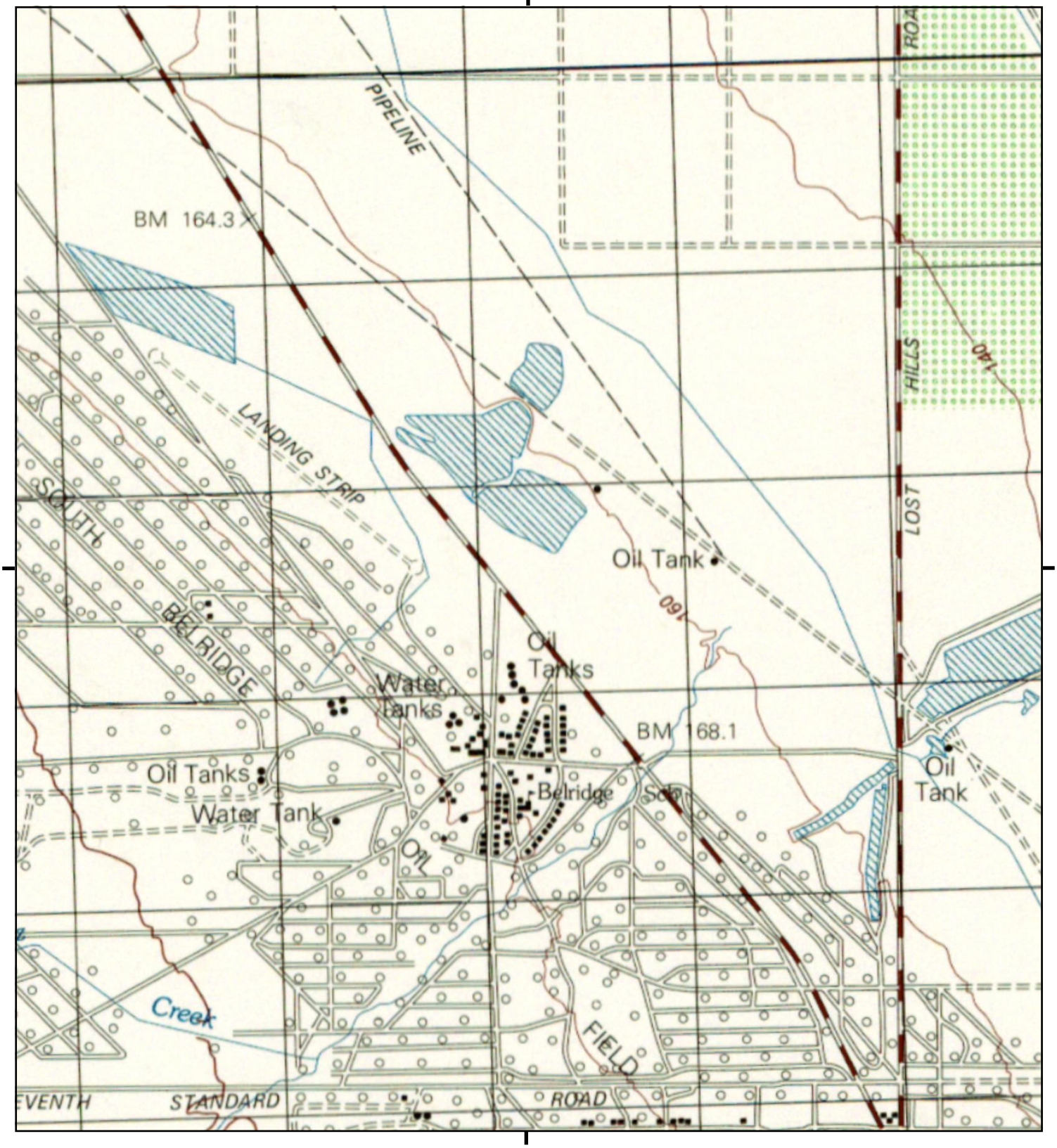
0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, Blackwells Corner, 1982, 7.5-minute
SW, Carneros Rocks, 1982, 7.5-minute

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0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

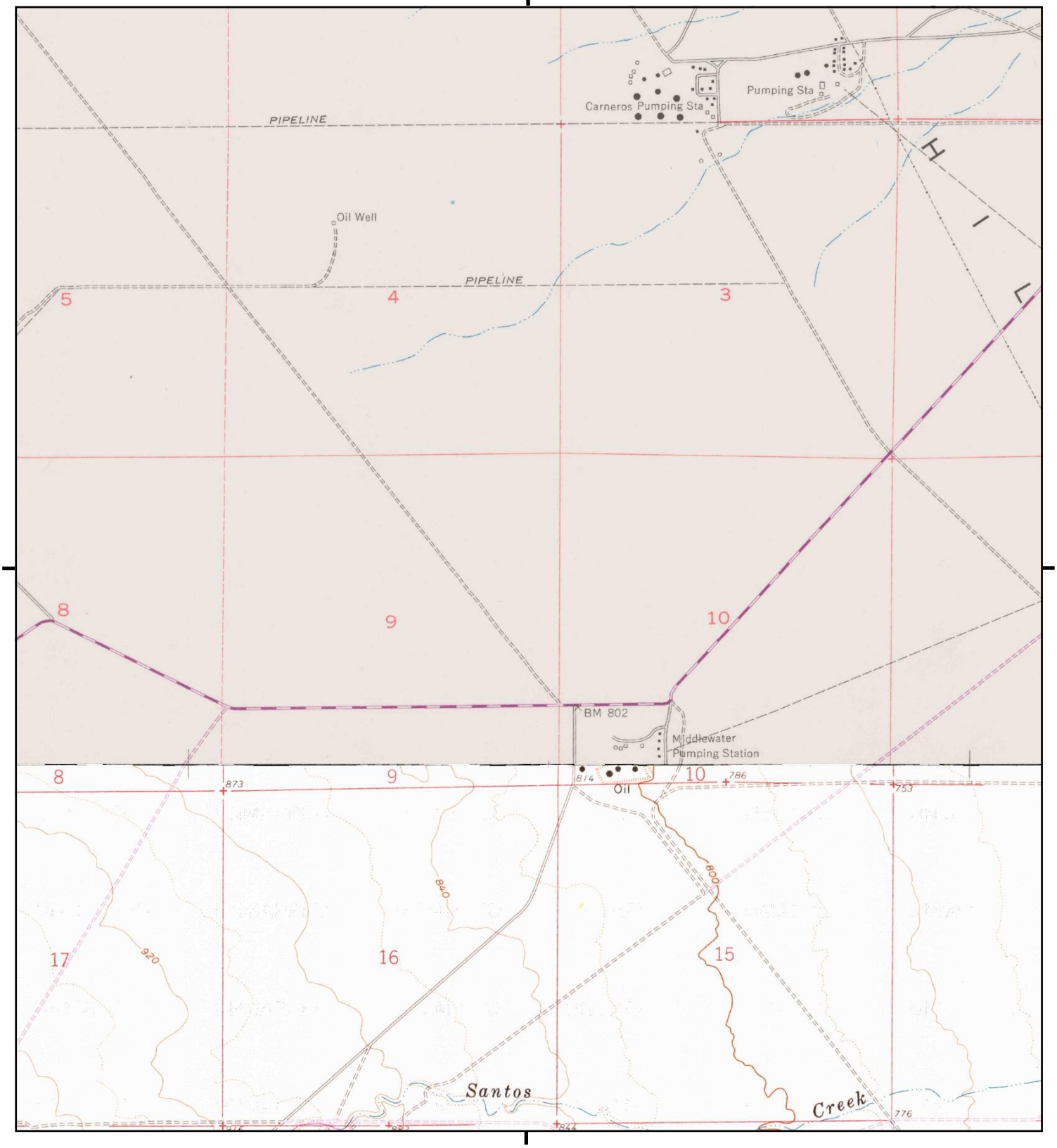
TP, MCKITTRICK, 1979, 15-minute

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Historical Topo Map

1973



0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, Blackwells Corner, 1973, 7.5-minute
S, Carneros Rocks, 1973, 7.5-minute

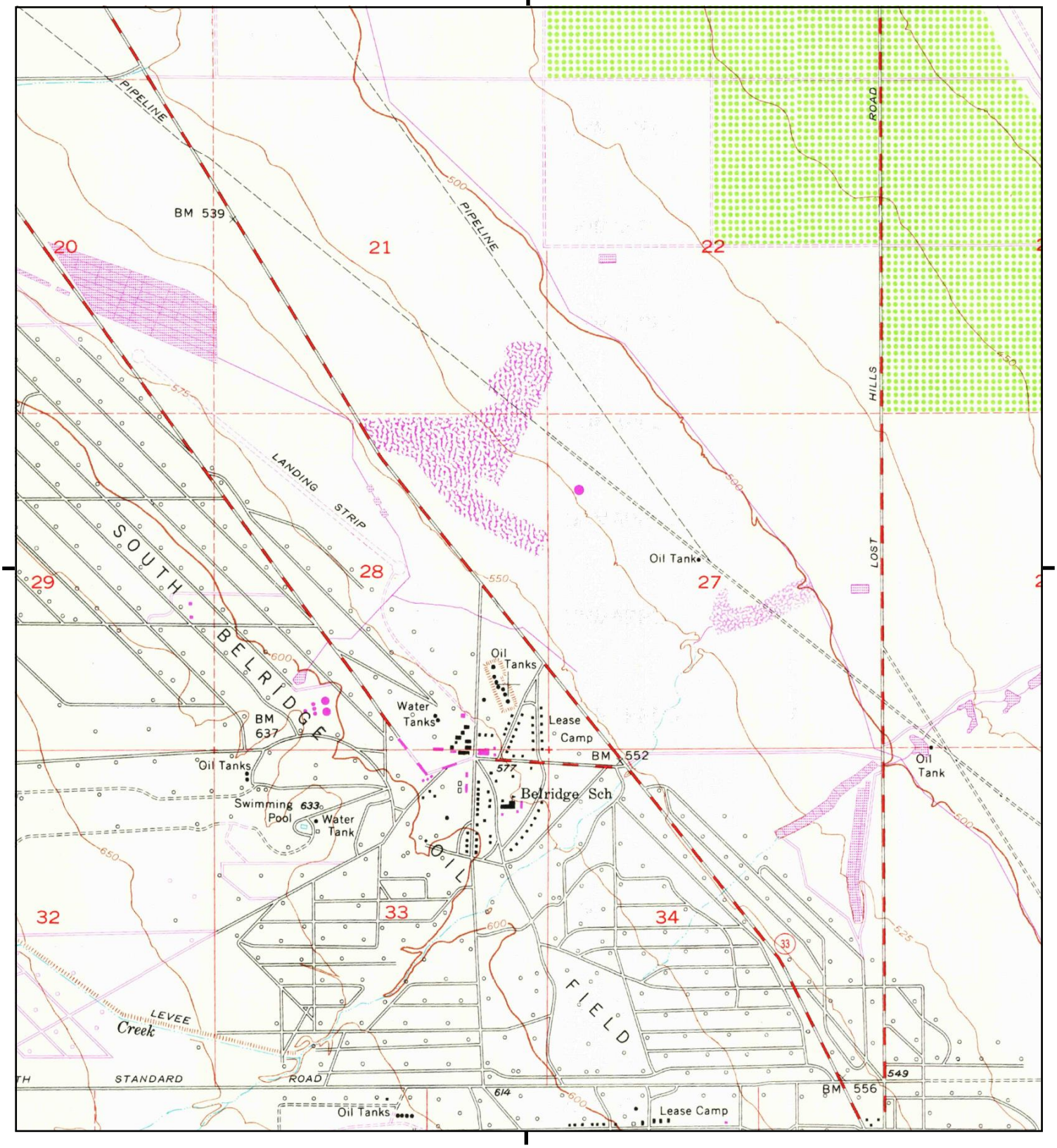
Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
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Historical Topo Map

1973



0 Miles 0.25 0.5 1 1.5

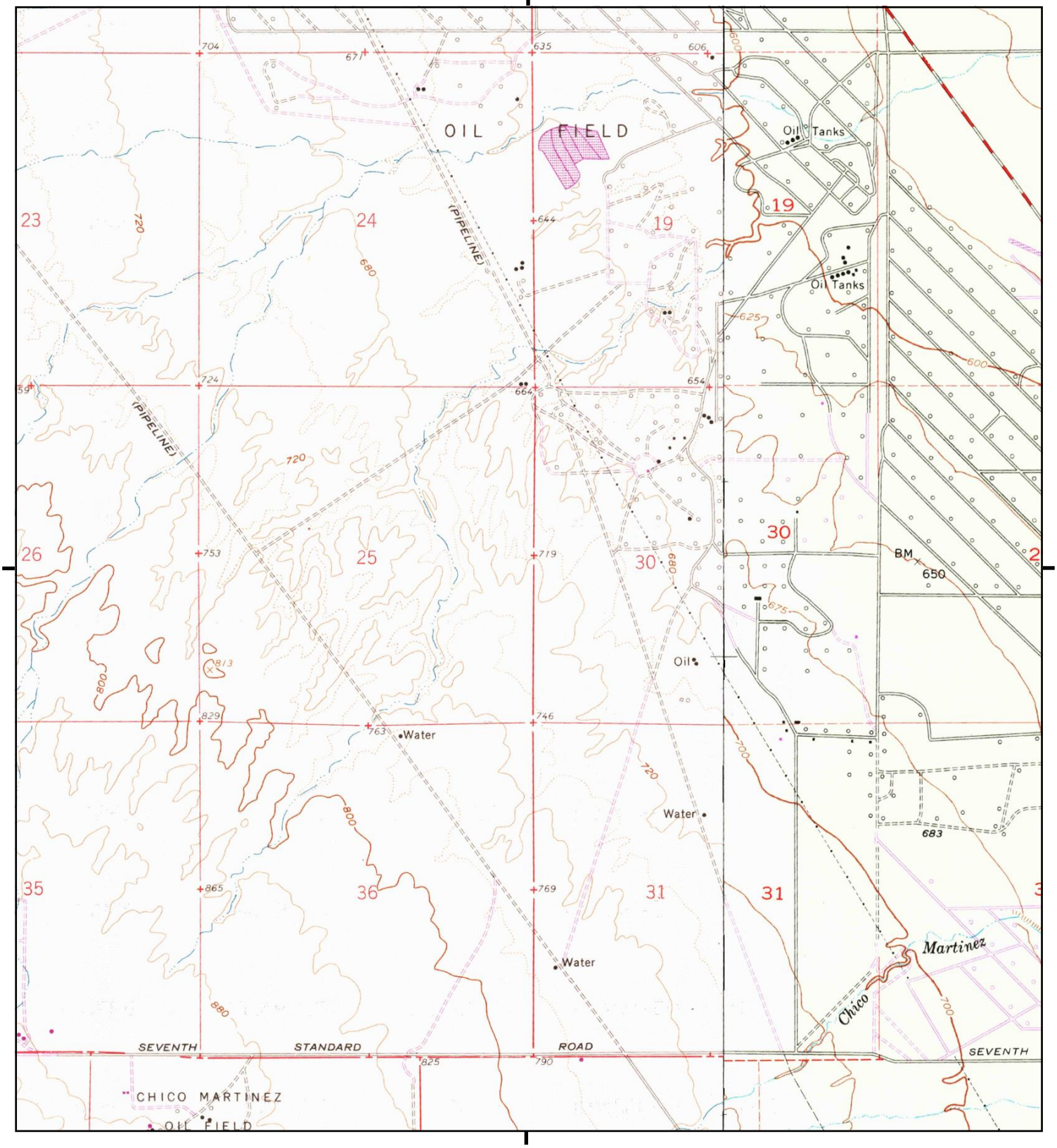
NW N NE
W E
SW S SE

TP, Belridge, 1973, 7.5-minute

Aera Belridge CCS Phase I ESA
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Lost Hills, CA 93249
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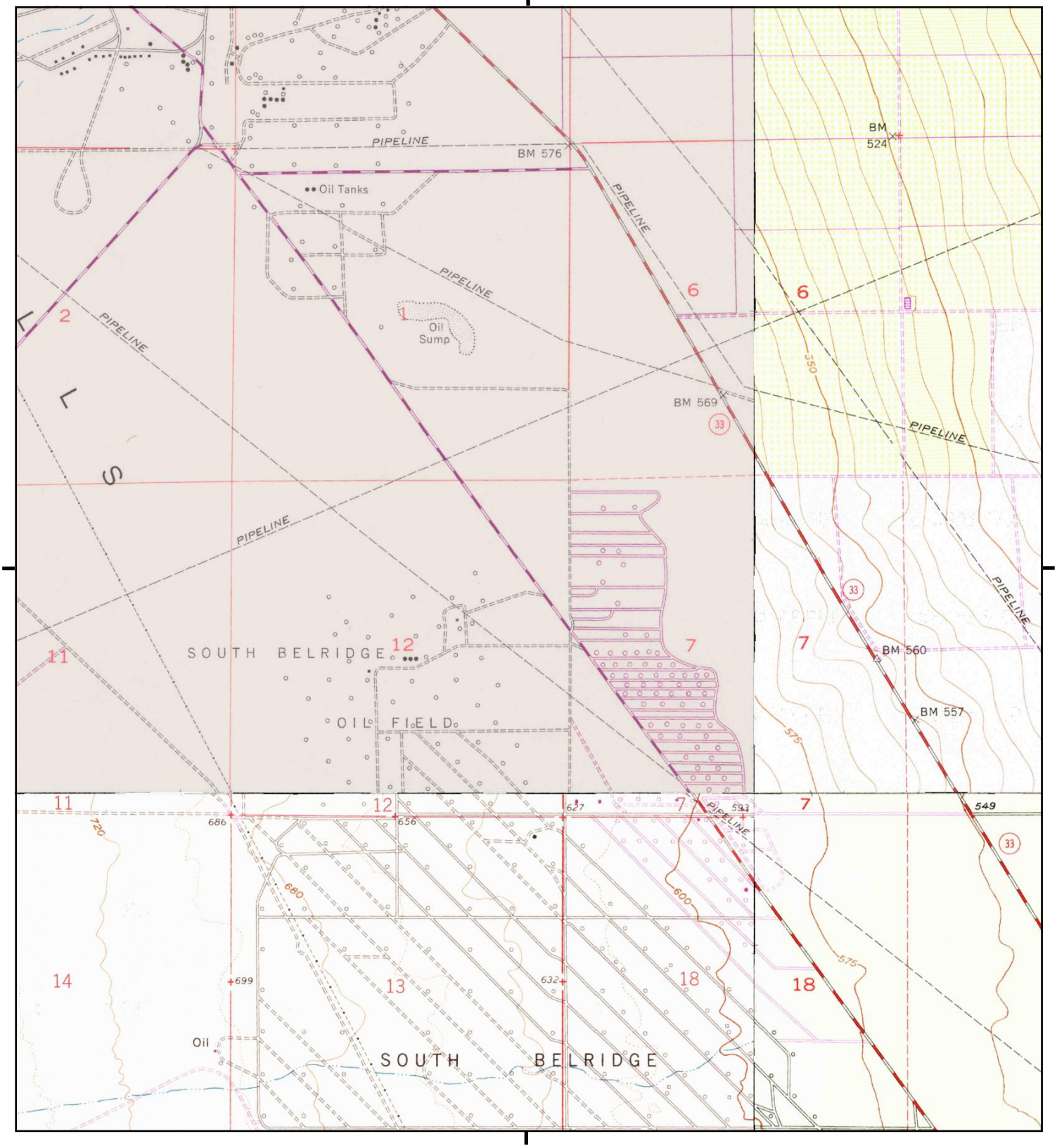
0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, Carneros Rocks, 1973, 7.5-minute
E, Belridge, 1973, 7.5-minute

Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
Stantec

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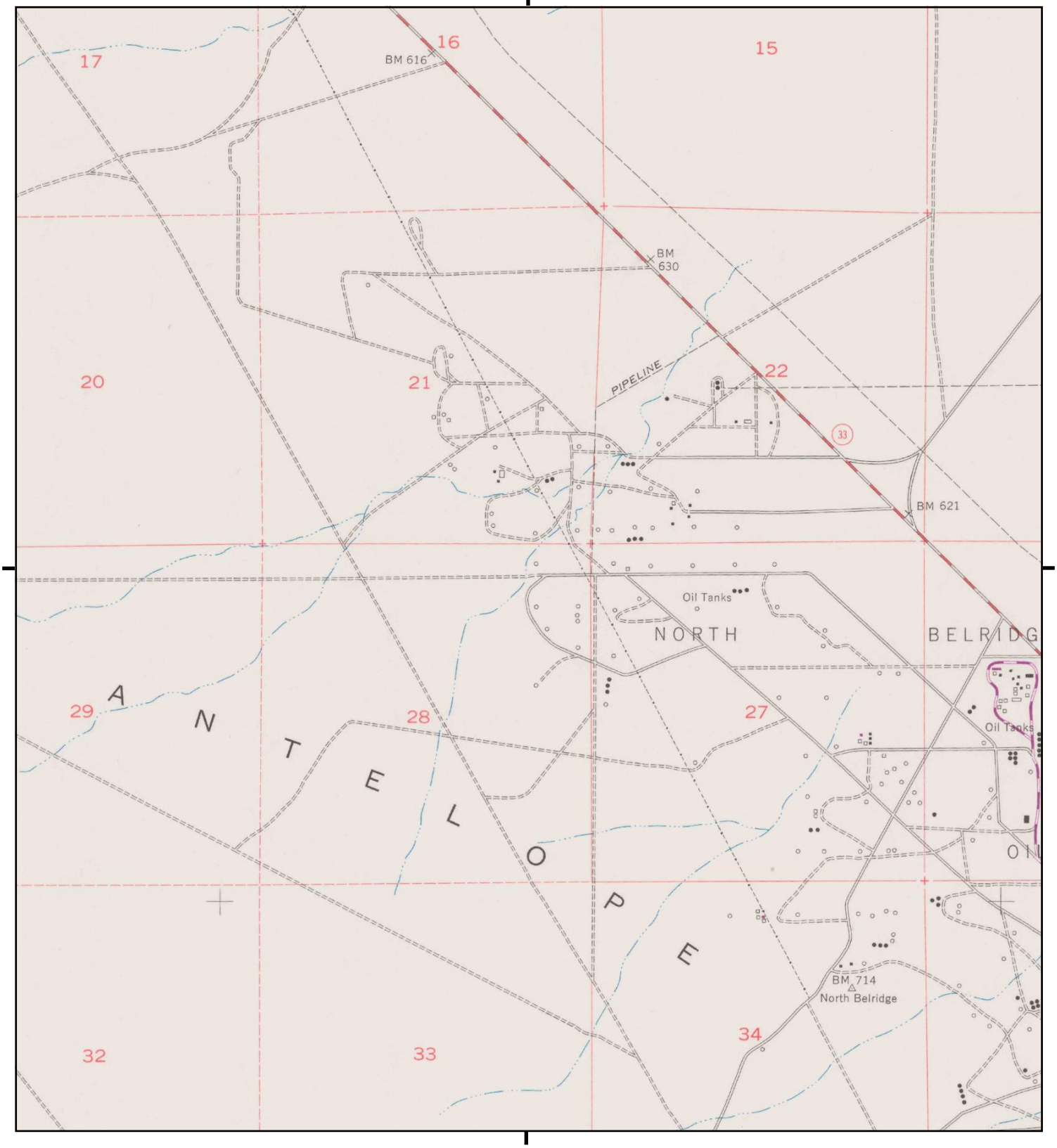
0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, Blackwells Corner, 1973, 7.5-minute
N, Lost Hills, 1973, 7.5-minute
SE, Belridge, 1973, 7.5-minute
SW, Carneros Rocks, 1973, 7.5-minute

Aera Belridge CCS Phase I ESA
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0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

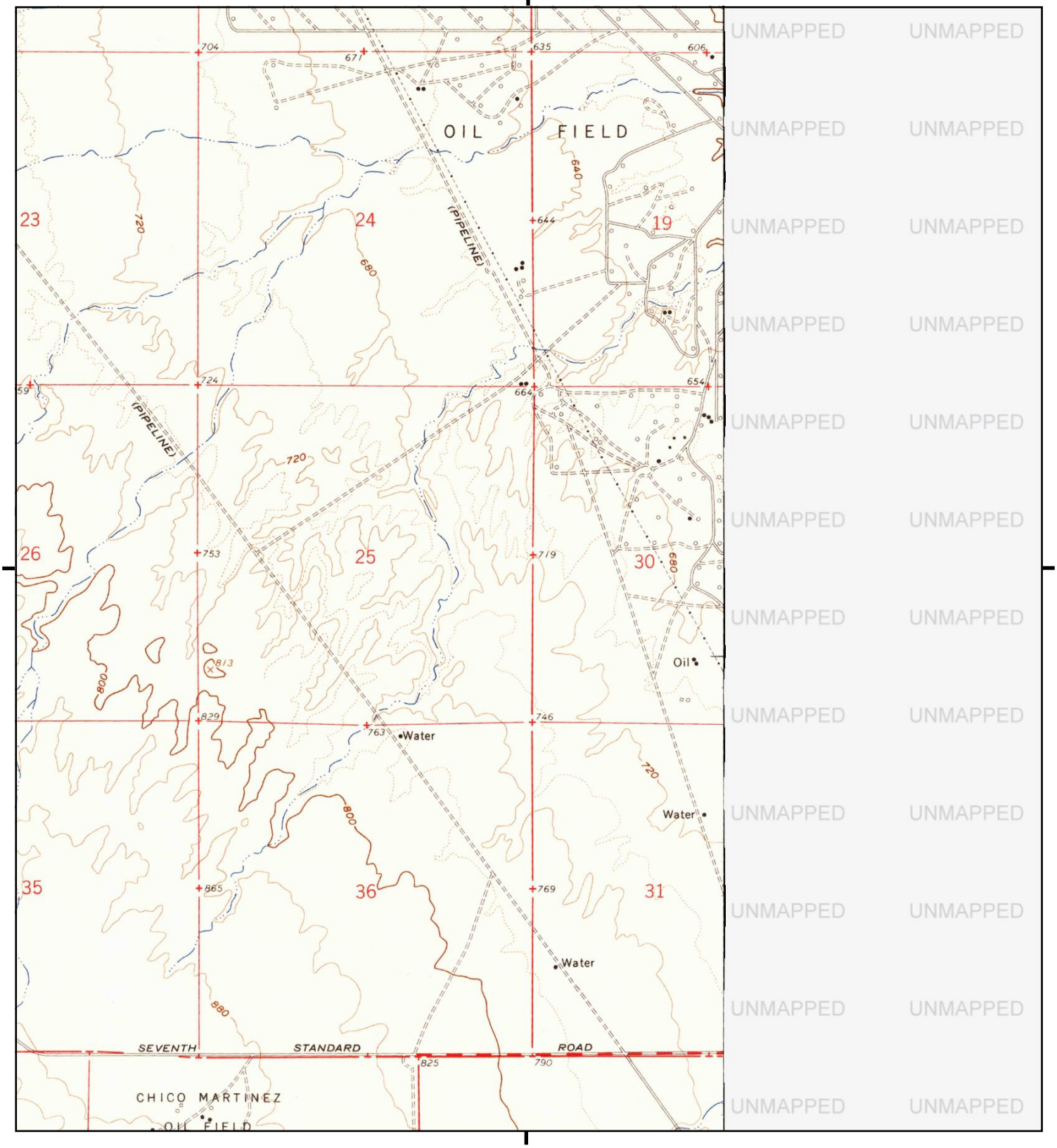
TP, Blackwells Corner, 1973, 7.5-minute

Aera Belridge CCS Phase I ESA
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Lost Hills, CA 93249
Stantec

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Historical Topo Map

1959



0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

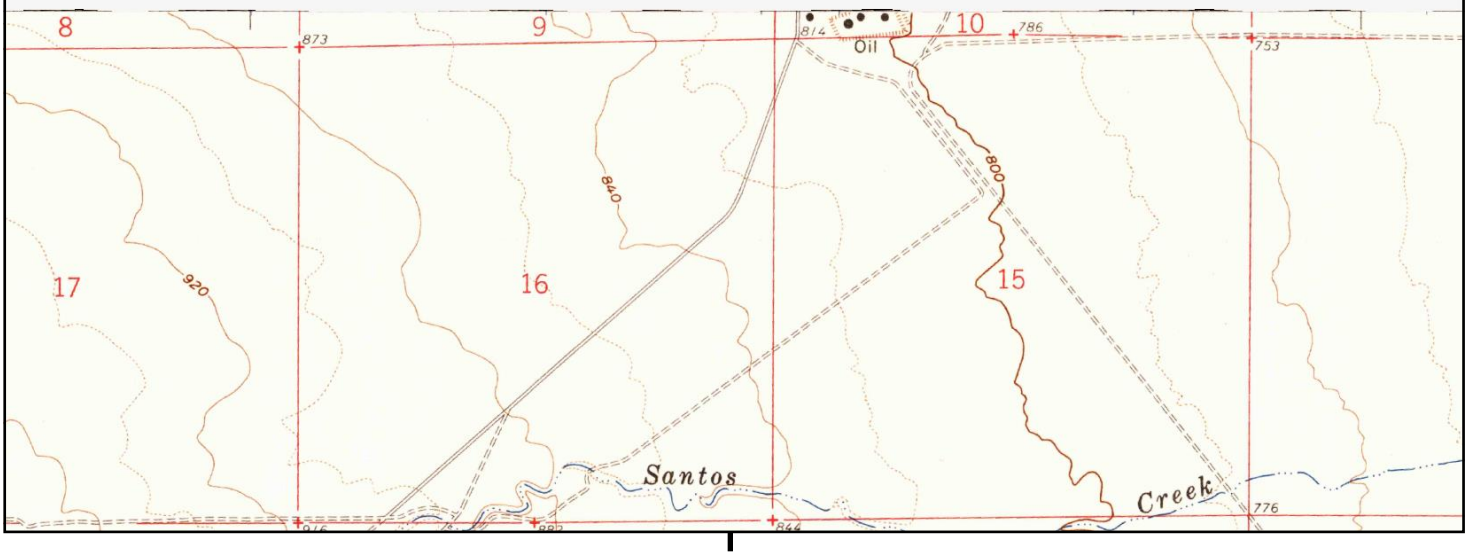
TP, Carneros Rocks, 1959, 7.5-minute

Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
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0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

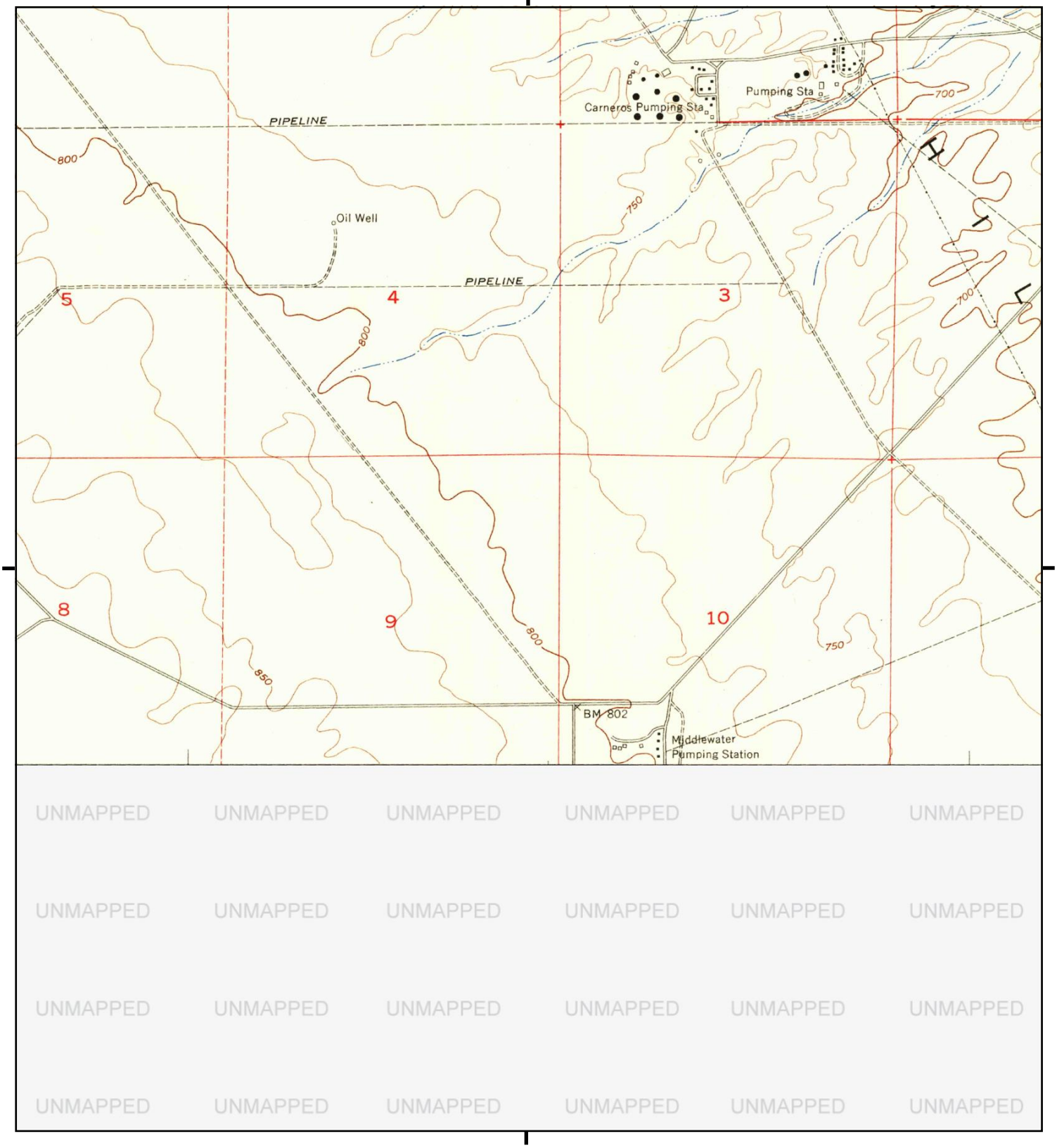
S, Carneros Rocks, 1959, 7.5-minute

Aera Belridge CCS Phase I ESA
DDR Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
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Historical Topo Map

1953



0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, Blackwells Corner, 1953, 7.5-minute

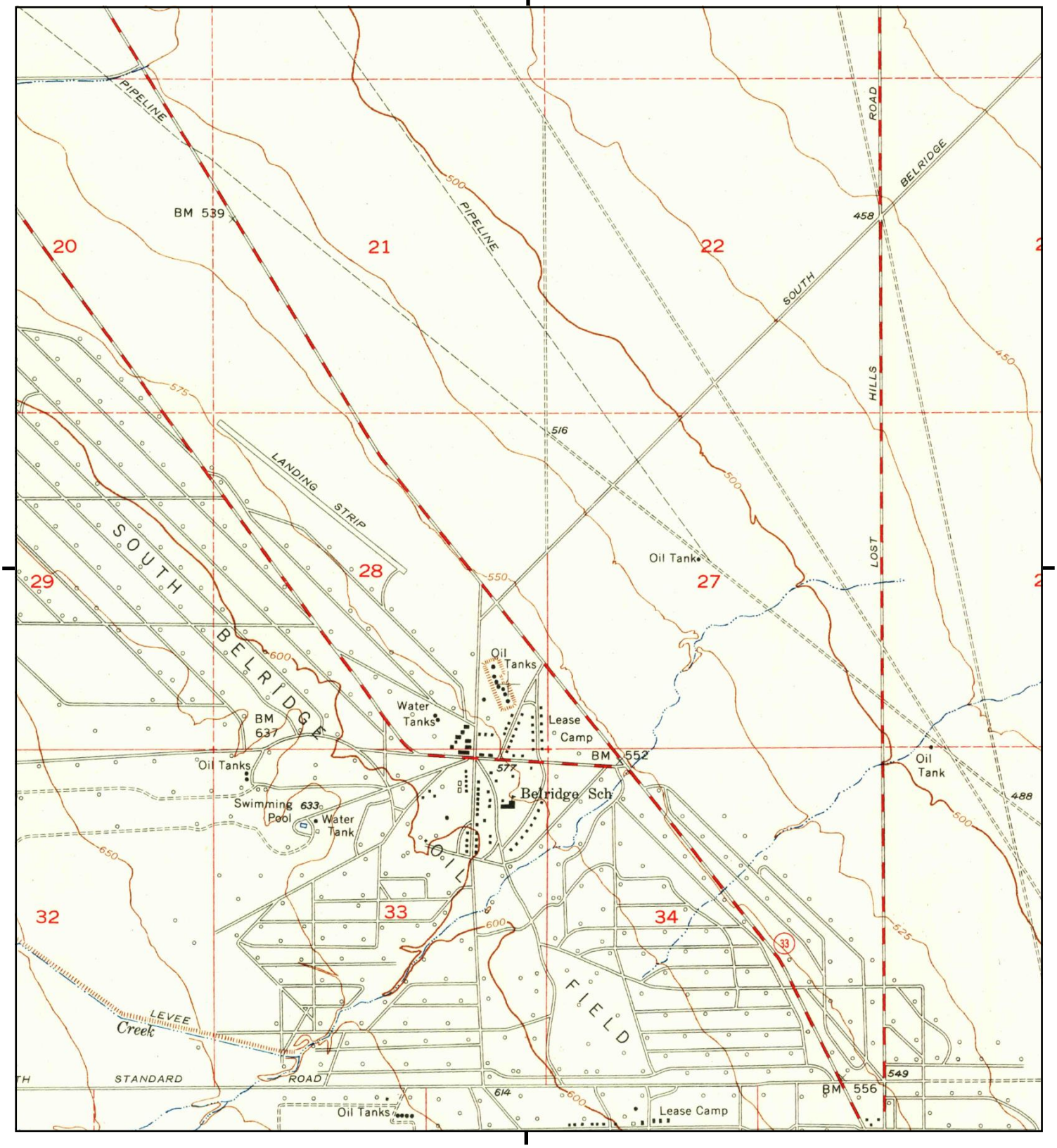
Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
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Historical Topo Map

1953



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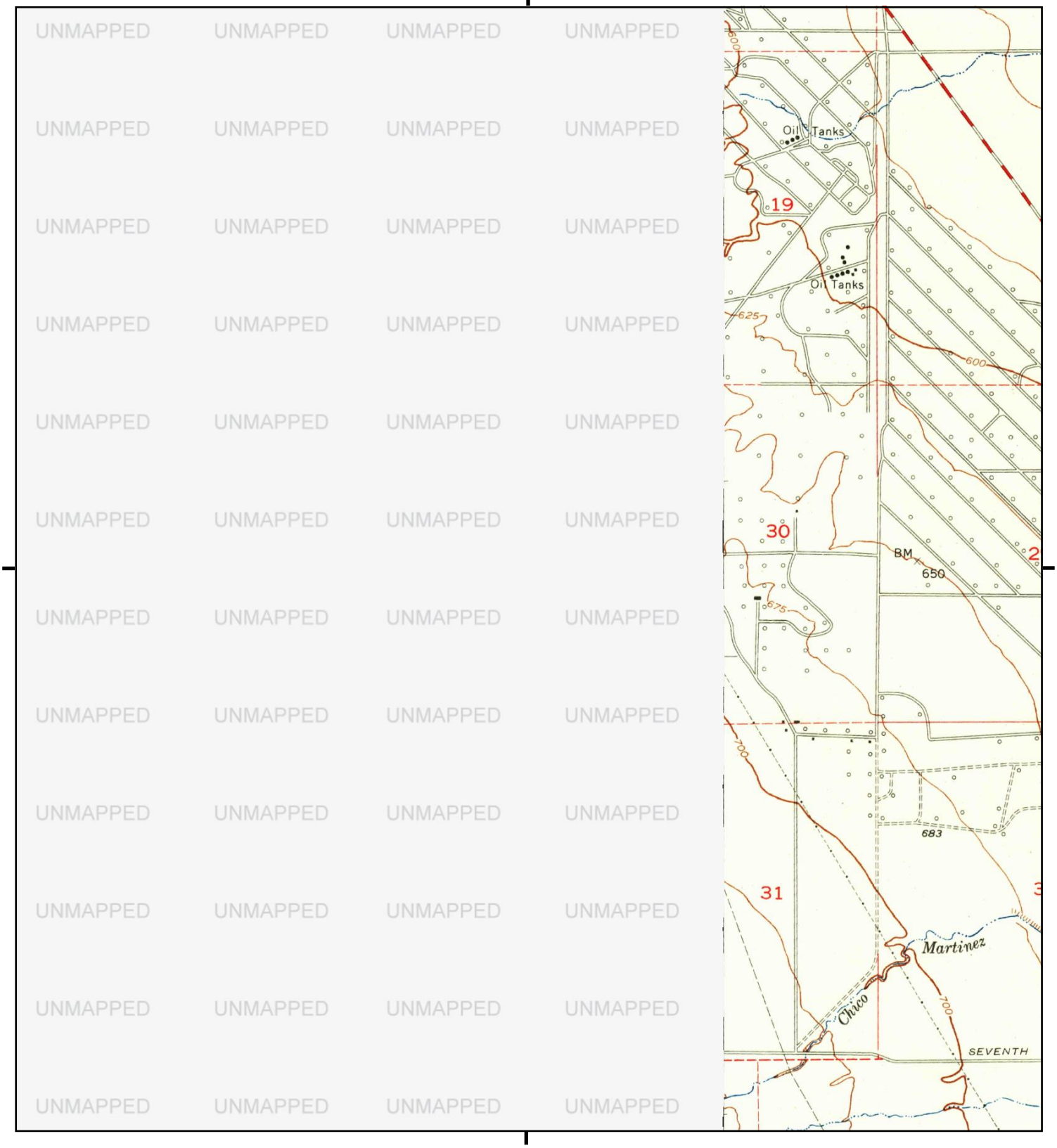
0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, Belridge, 1953, 7.5-minute

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□DDR□□□□ Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
□□□□□□□ Stantec

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0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

E, Belridge, 1953, 7.5-minute

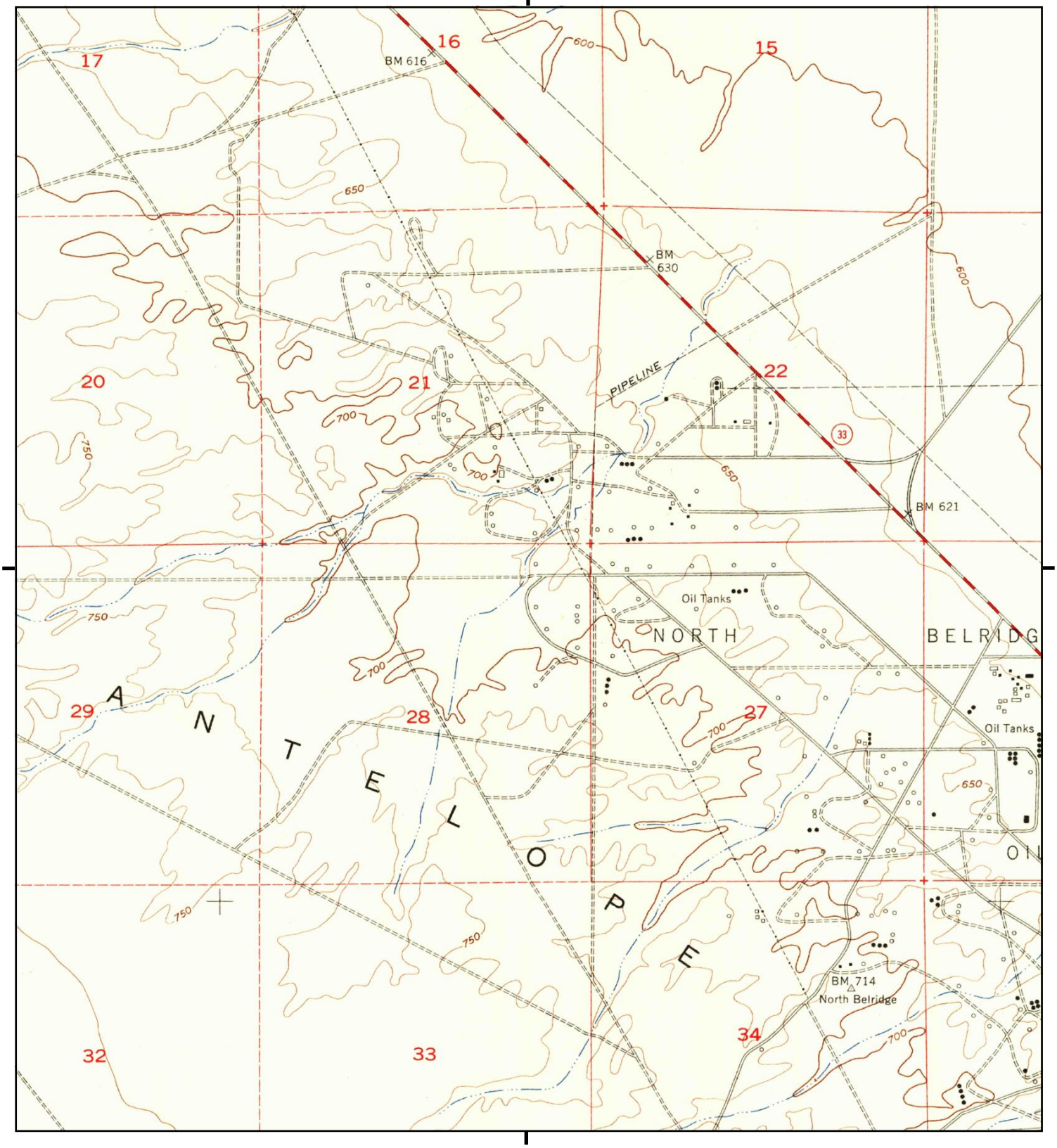
Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
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Historical Topo Map

1953



0 Miles 0.25 0.5 1 1.5

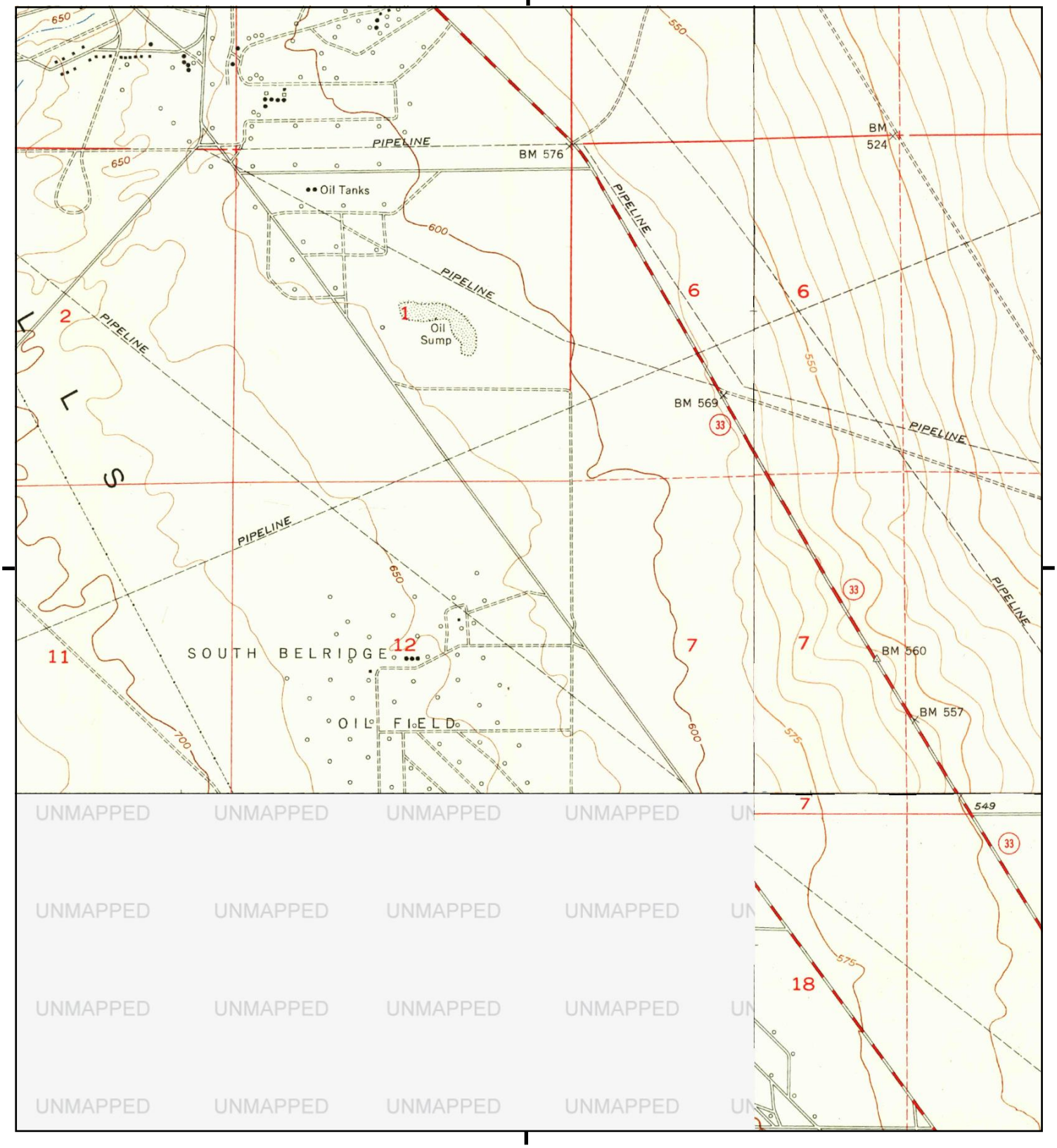
NW N NE
W E
SW S SE

TP, Blackwells Corner, 1953, 7.5-minute

Aera Belridge CCS Phase I ESA
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Lost Hills, CA 93249
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0 Miles 0.25 0.5 1 1.5

NW N NE
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SW S SE

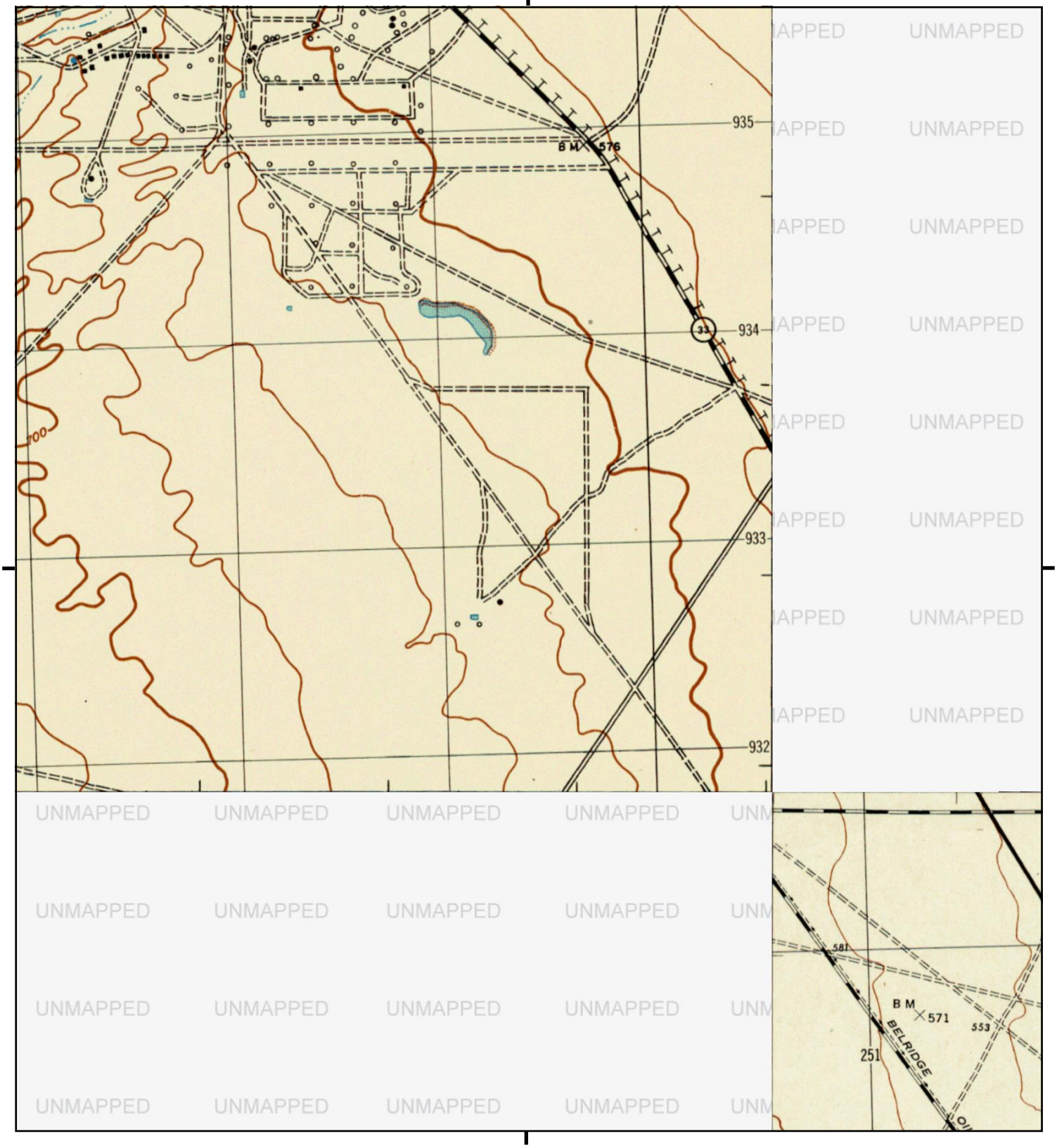
NE, West of Goose Lake, 1950, 7.5-minute
NE, Lost Hills, 1953, 7.5-minute
SE, Belridge, 1953, 7.5-minute
T, Blackwells Corner, 1953, 7.5-minute

□□□□ □□M□□ Aera Belridge CCS Phase I ESA
□DDR□□□□ Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
□□□□□□□ Stantec

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Historical Topo Map

1947



UNMAPPED

0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, BLACKWELLS CORNER, 1947, 7.5-minute
SE, BELRIDGE, 1947, 7.5-minute

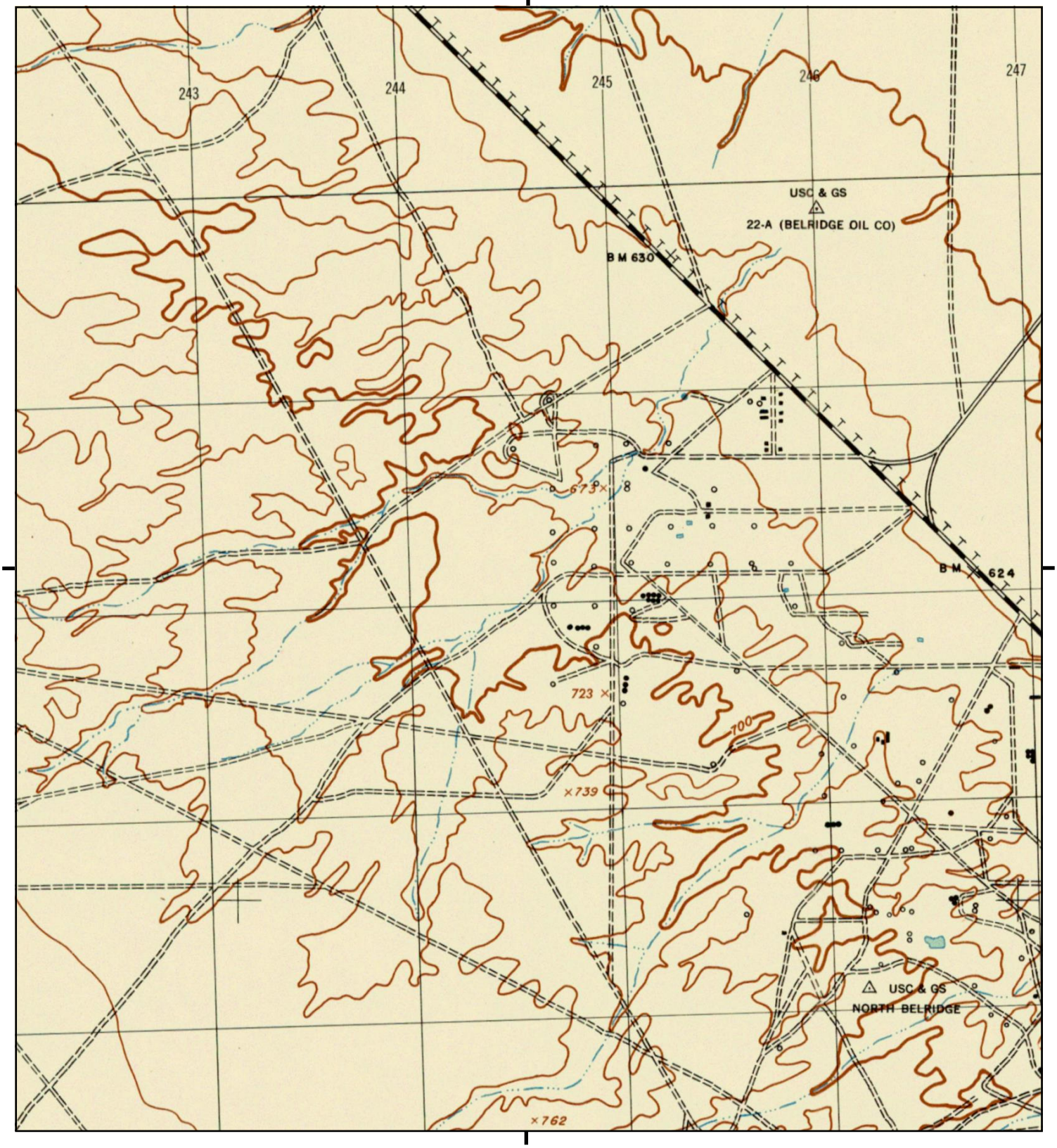
Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
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Historical Topo Map

1947



0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, BLACKWELLS CORNER, 1947, 7.5-minute

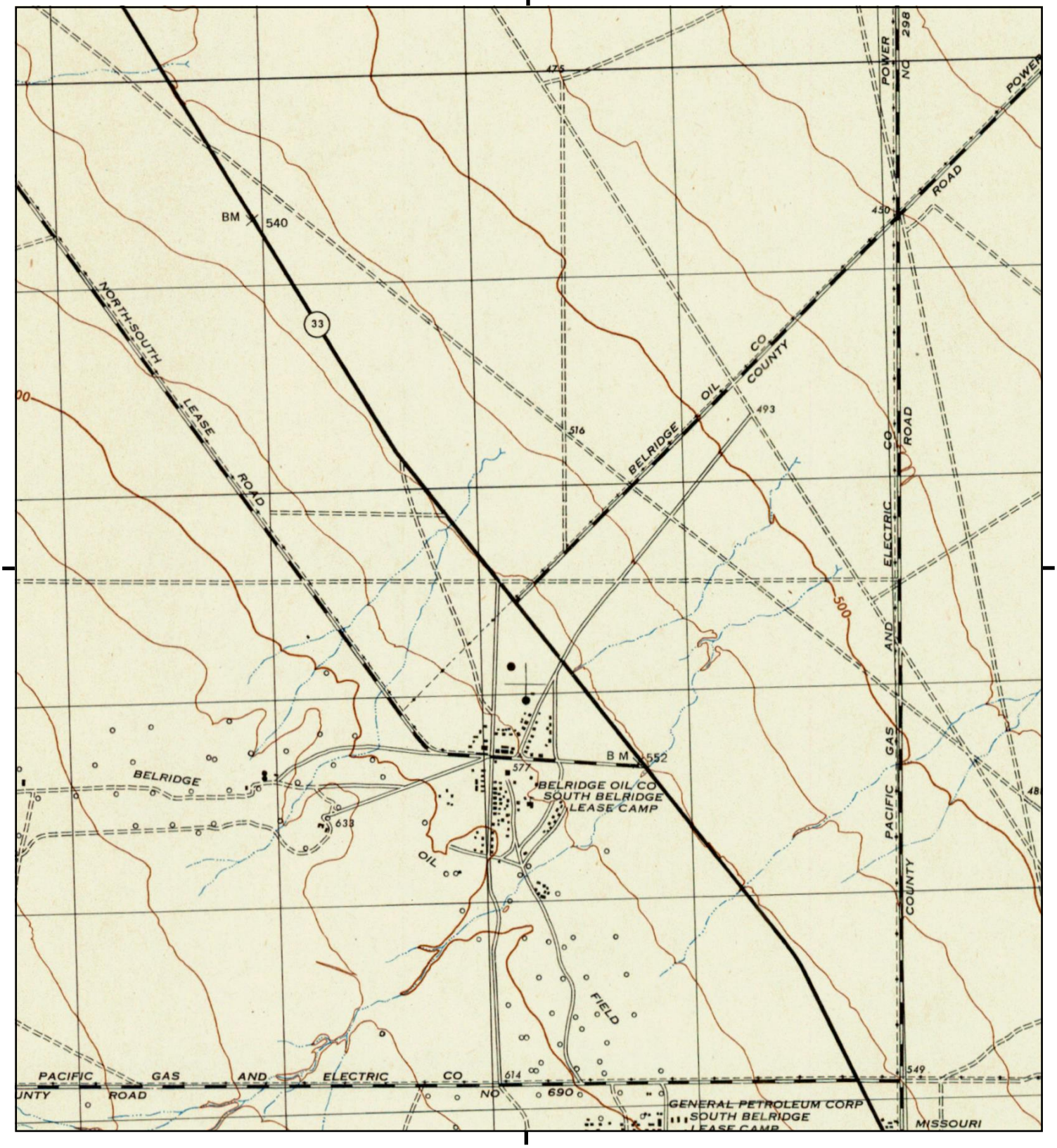
Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
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Historical Topo Map

1947



0 Miles 0.25 0.5 1 1.5

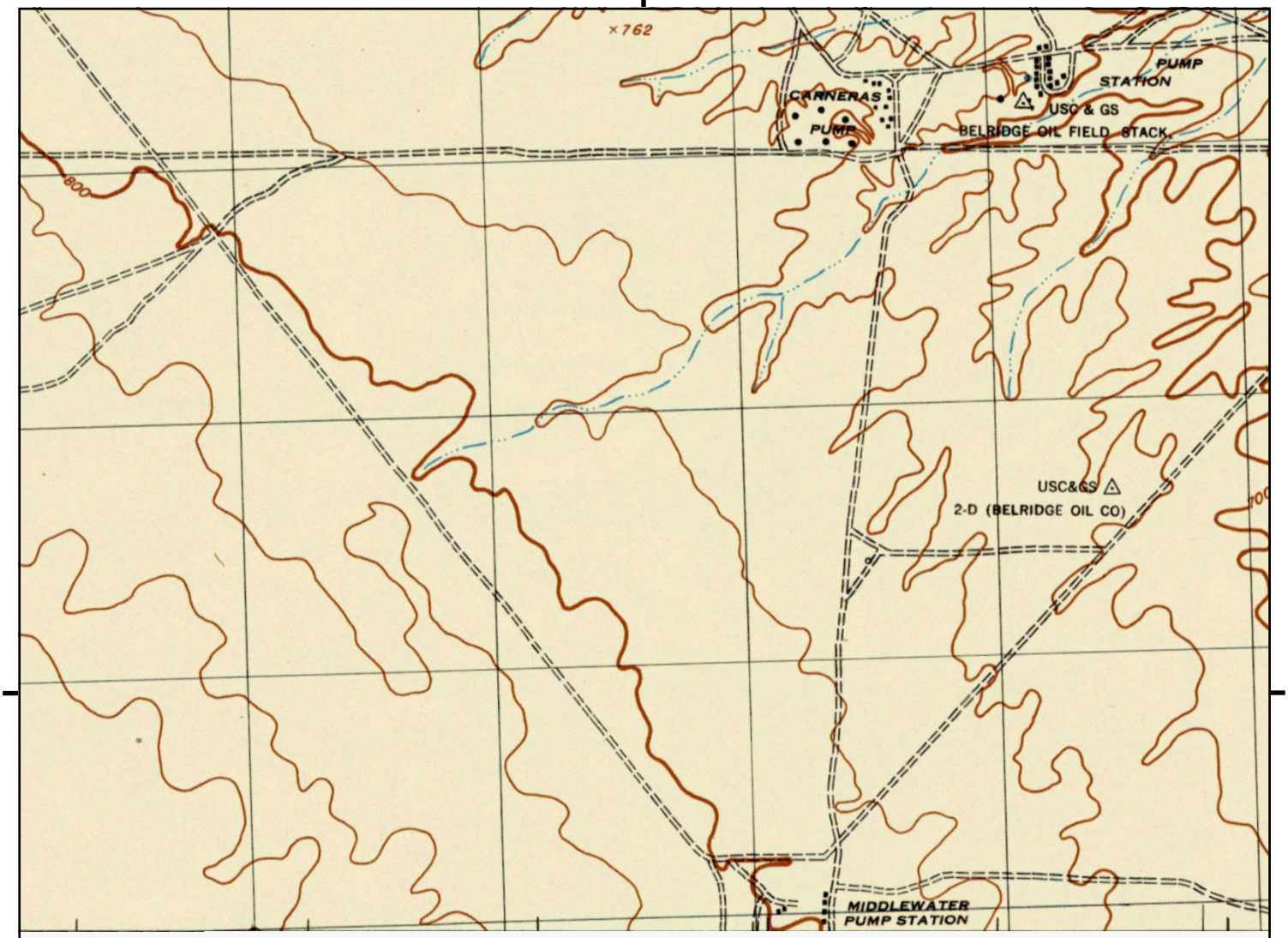
NW N NE
W E
SW S SE

TP, BELRIDGE, 1947, 7.5-minute

Aera Belridge CCS Phase I ESA
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Lost Hills, CA 93249
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W E
SW S SE

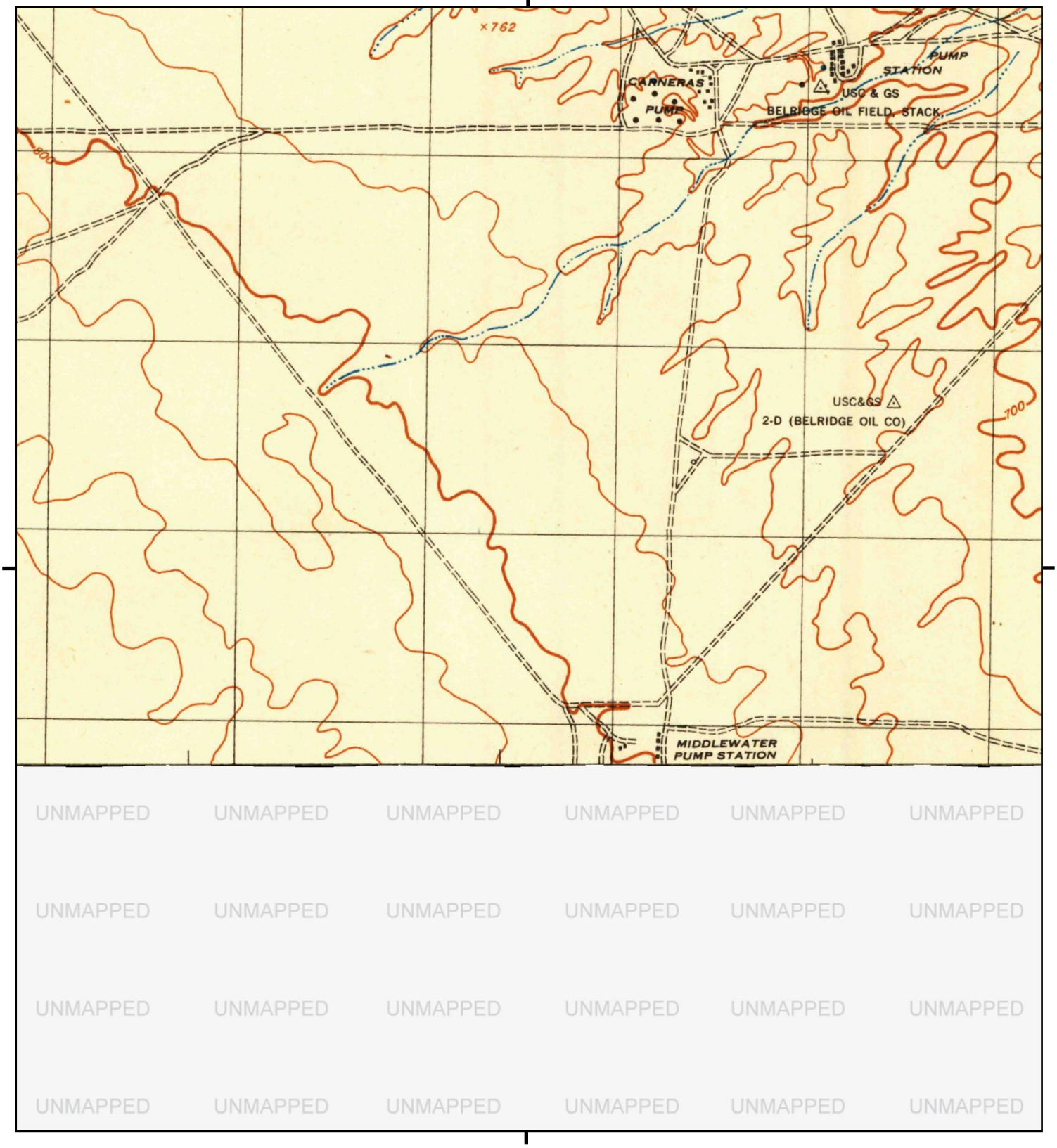
TP, BLACKWELLS CORNER, 1947, 7.5-minute

Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
Stantec

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Historical Topo Map

1943



UNMAPPED

0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, Blackwell, 1943, 7.5-minute

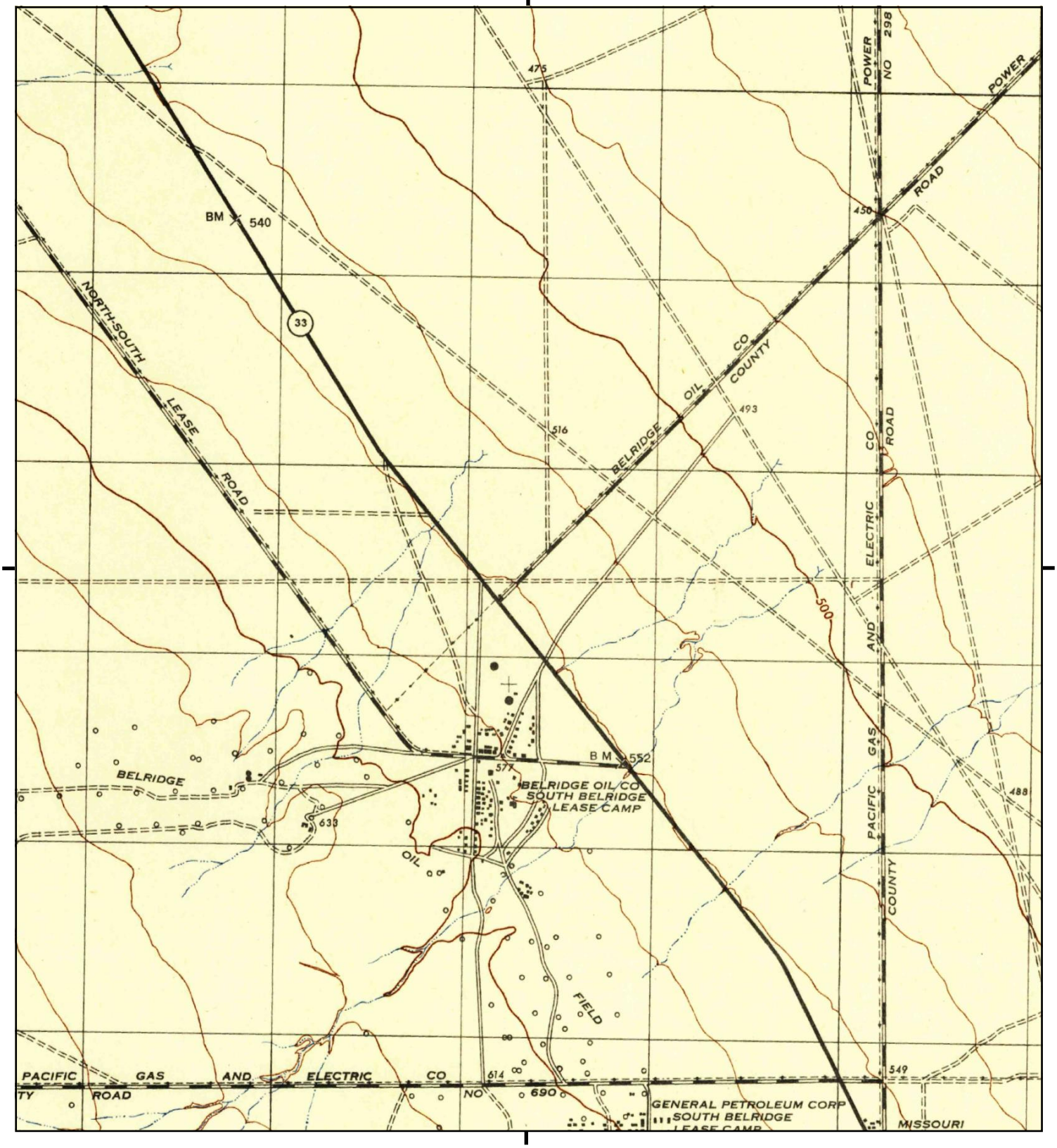
Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
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Historical Topo Map

1943



0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

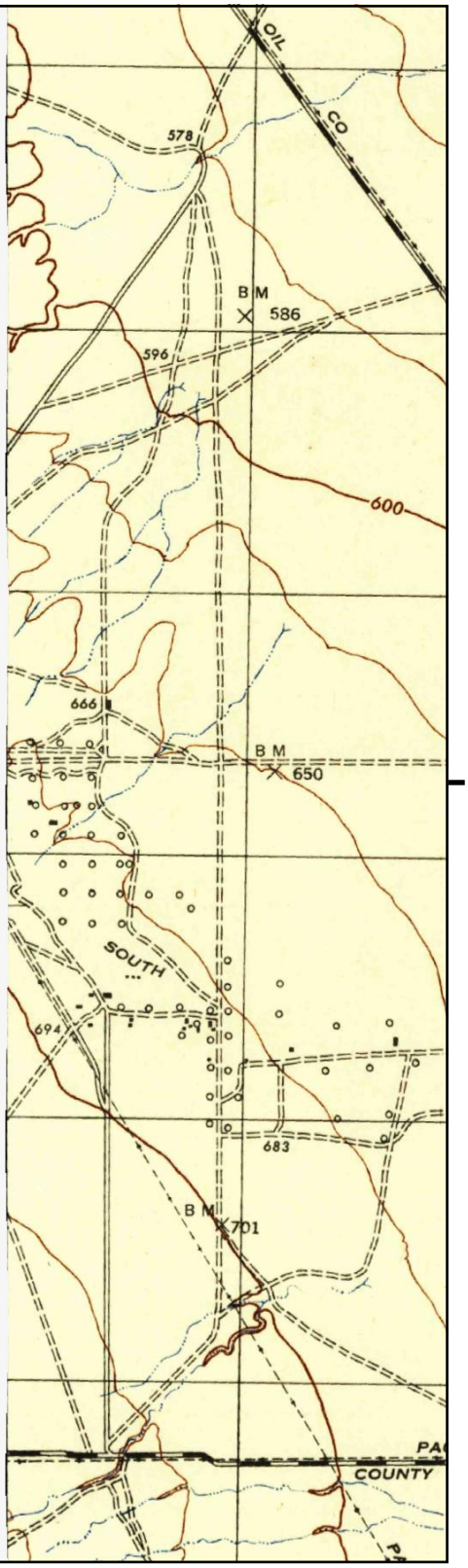
TP, Belridge, 1943, 7.5-minute

Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
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UNMAPPED UNMAPPED UNMAPPED UNMAPPED



0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

E, Belridge, 1943, 7.5-minute

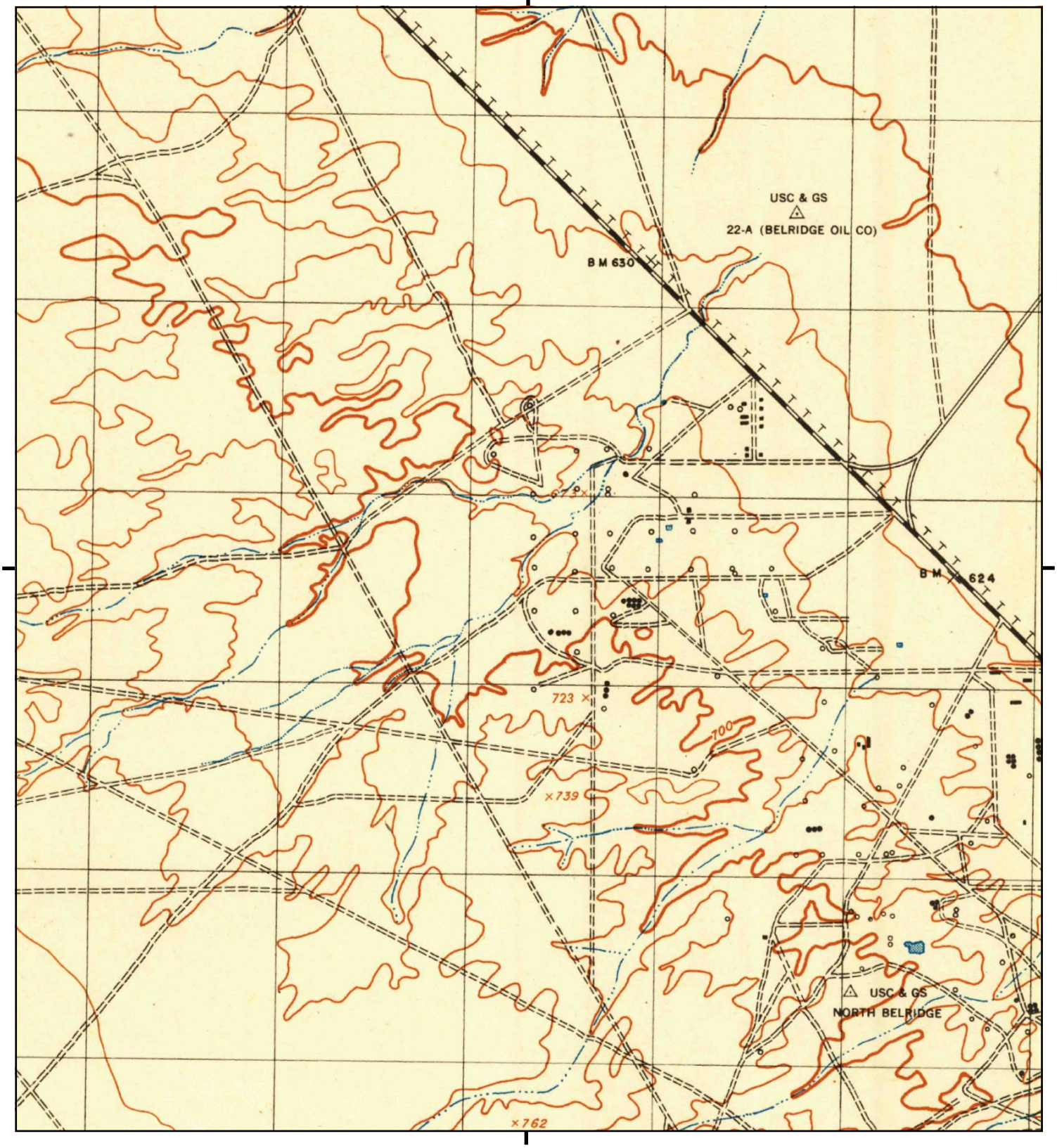
Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
Stantec

N

7133623 - 1 45

Historical Topo Map

1943



0 Miles 0.25 0.5 1 1.5

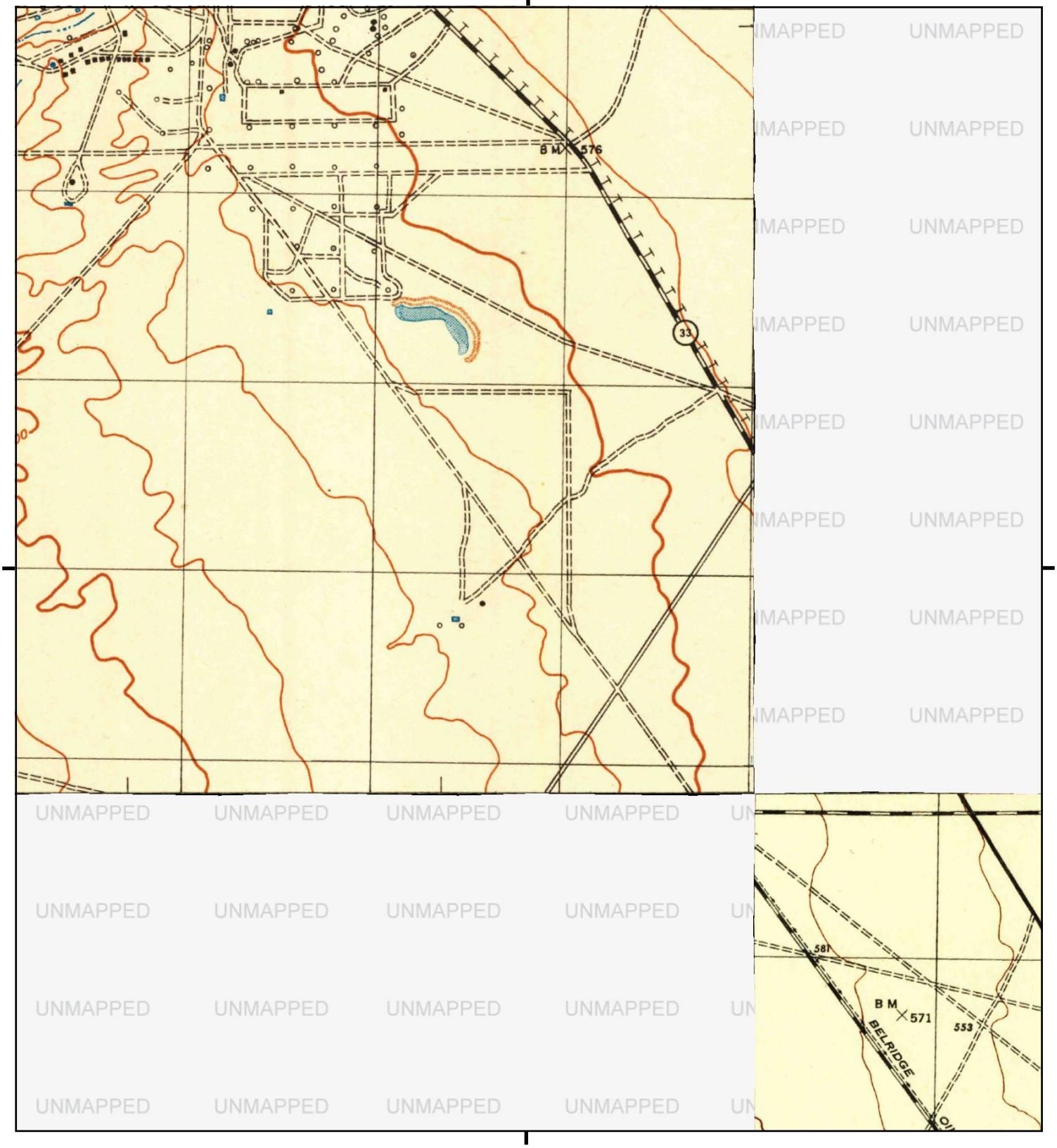
NW N NE
W E
SW S SE

TP, Blackwell, 1943, 7.5-minute

Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
Stantec

N

7133623 - 1 46



UNMAPPED

0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, Blackwell, 1943, 7.5-minute
SE, Belridge, 1943, 7.5-minute

Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
Stantec

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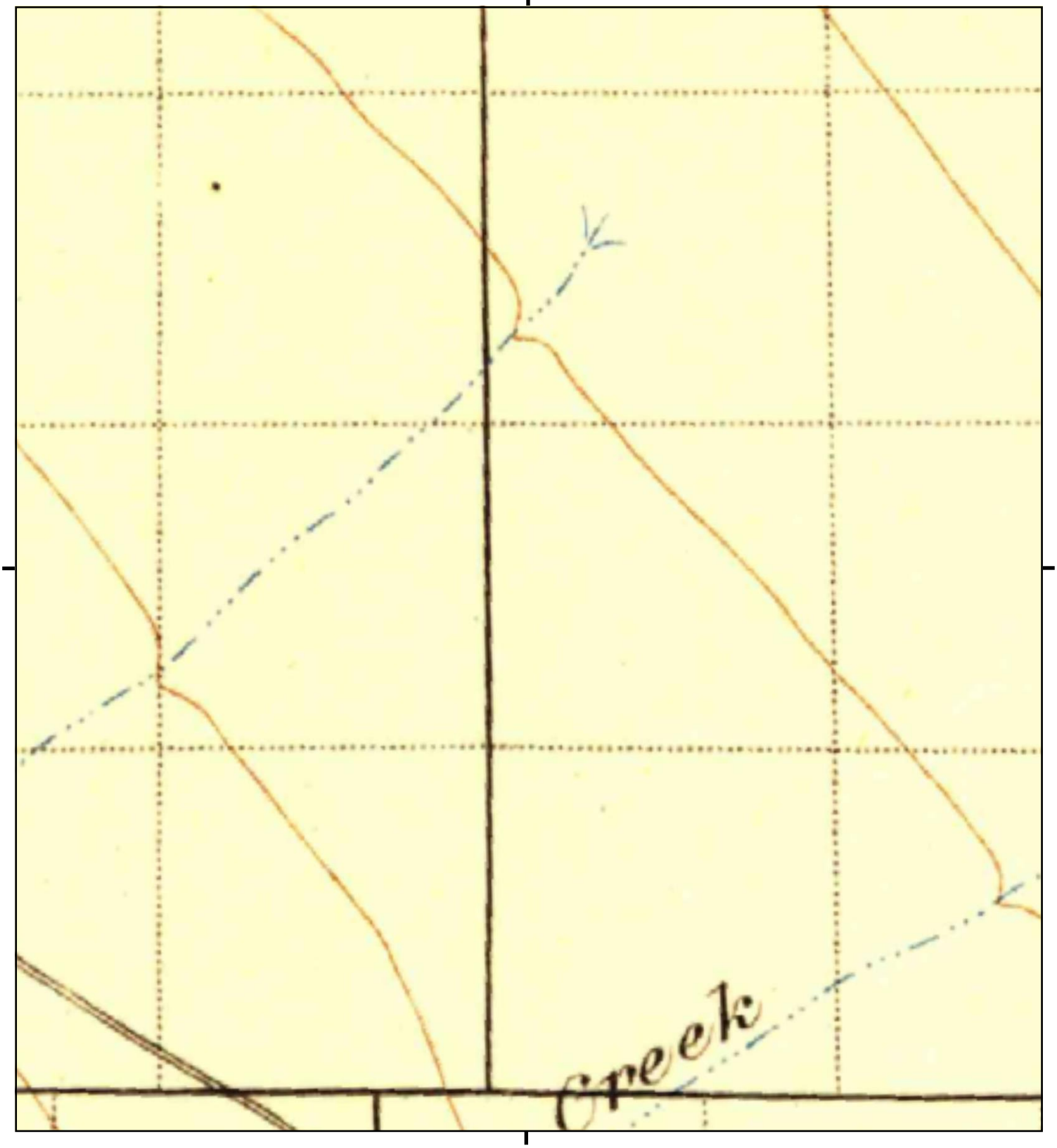
0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, Lost Hills, 1914, 30-minute

□□□□ □□M□□ Aera Belridge CCS Phase I ESA
□DDR□□□□ Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
□□□□□□□ Stantec

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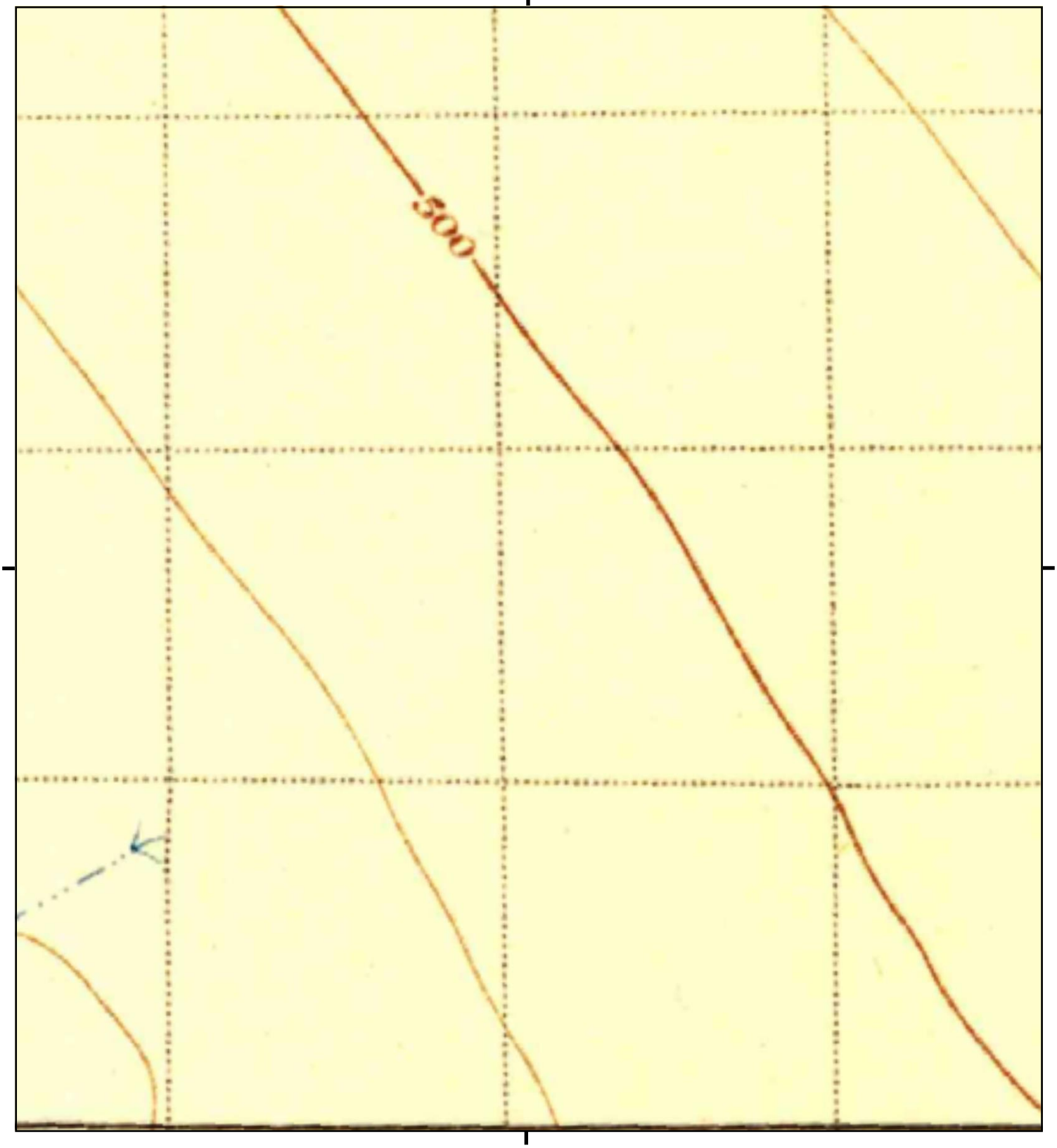
0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, McKittrick, 1912, 30-minute

□□□□ □□M□□ Aera Belridge CCS Phase I ESA
□DDR□□□□□ Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
□□□□□□□□ Stantec

N



0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, McKittrick, 1912, 30-minute

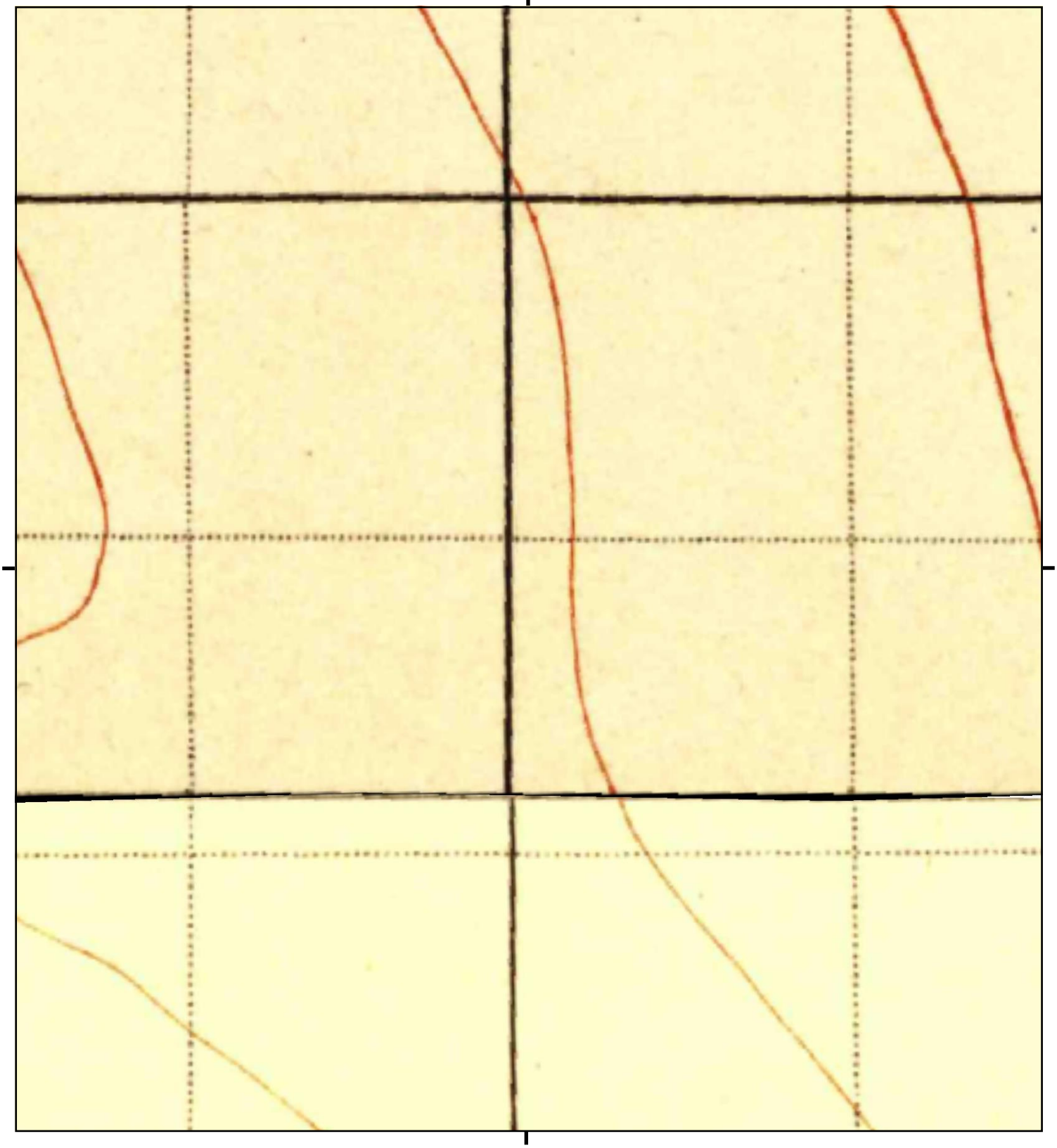
Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
Stantec

N

7133623 - 1 50

Historical Topo Map

1912, 1914



0 Miles 0.25 0.5 1 1.5

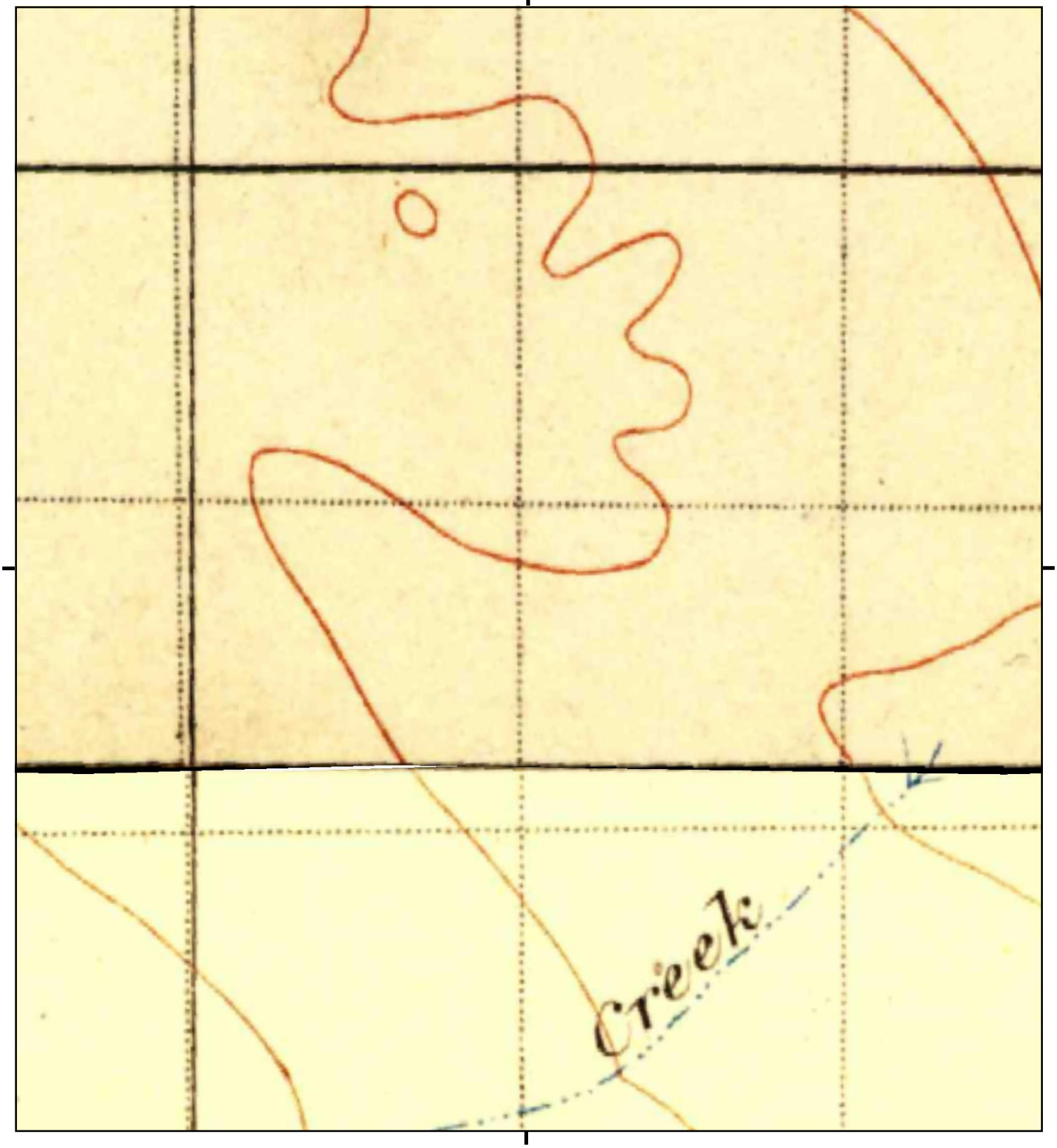
NW N NE
W E
SW S SE

TP, Lost Hills, 1914, 30-minute
S, McKittrick, 1912, 30-minute

Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
Stantec

N

7133623 - 1 51



0 Miles 0.25 0.5 1 1.5

NW N NE
W E
SW S SE

TP, Lost Hills, 1914, 30-minute
S, McKittrick, 1912, 30-minute

Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249
Stantec

N

Aera Belridge CCS Phase I ESA
Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249

Inquiry Number: 7133623.5
October 04, 2022

The EDR-City Directory Image Report

EDR® Environmental Data Resources Inc

6 Armstrong Road
Shelton, CT 06484
800.352.0050
www.edrnet.com

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SECTION

Executive Summary

Findings

City Directory Images

Thank you for your business.
Please contact EDR at 1-800-352-0050
with any questions or comments.

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EXECUTIVE SUMMARY

DESCRIPTION

Environmental Data Resources, Inc.'s (EDR) City Directory Report is a screening tool designed to assist environmental professionals in evaluating potential liability on a target property resulting from past activities. EDR's City Directory Report includes a search of available city directory data at 5 year intervals.

RECORD SOURCES

EDR's Digital Archive combines historical directory listings from sources such as Cole Information and Dun & Bradstreet. These standard sources of property information complement and enhance each other to provide a more comprehensive report.

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Data by
infoUSA®
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RESEARCH SUMMARY

The following research sources were consulted in the preparation of this report. A check mark indicates where information was identified in the source and provided in this report.

Year	Target Street	Cross Street	Source
2017	☐	☐	EDR Digital Archive
2014	☐	☐	EDR Digital Archive
2010	☐	☐	EDR Digital Archive
2005	☐	☐	EDR Digital Archive
2000	☐	☐	EDR Digital Archive
1996	☐	☐	Polk's City Directory
1995	☐	☐	EDR Digital Archive
1992	☐	☐	EDR Digital Archive
1990	☐	☐	Haines Criss-Cross Directory
1985	☐	☐	Haines Criss-Cross Directory
1980	☐	☐	Haines Criss-Cross Directory
1976	☐	☐	Haines Criss-Cross Directory
1973	☐	☐	Haines Criss-Cross Directory

FINDINGS

TARGET PROPERTY STREET

Aera Belridge CCS Phase I ESA
Lost Hills, CA 93249

Year	CD Image	Source	

DUCON RD

2017	-	EDR Digital Archive	Street not listed in Source
2014	-	EDR Digital Archive	Street not listed in Source
2010	-	EDR Digital Archive	Street not listed in Source
2005	-	EDR Digital Archive	Street not listed in Source
2000	-	EDR Digital Archive	Street not listed in Source
1996	-	Polk's City Directory	Street not listed in Source
1995	-	EDR Digital Archive	Street not listed in Source
1992	-	EDR Digital Archive	Street not listed in Source
1990	-	Haines Criss-Cross Directory	Street not listed in Source
1985	-	Haines Criss-Cross Directory	Street not listed in Source
1980	-	Haines Criss-Cross Directory	Street not listed in Source
1976	-	Haines Criss-Cross Directory	Street not listed in Source
1973	-	Haines Criss-Cross Directory	Street not listed in Source

FINDINGS

CROSS STREETS

Year	*CD Image*	*Source*	
POLE LINE RD			
2017	-	EDR Digital Archive	Street not listed in Source
2014	-	EDR Digital Archive	Street not listed in Source
2010	-	EDR Digital Archive	Street not listed in Source
2005	-	EDR Digital Archive	Street not listed in Source
2000	-	EDR Digital Archive	Street not listed in Source
1996	-	Polk's City Directory	Street not listed in Source
1995	-	EDR Digital Archive	Street not listed in Source
1992	-	EDR Digital Archive	Street not listed in Source
1990	-	Haines Criss-Cross Directory	Street not listed in Source
1985	-	Haines Criss-Cross Directory	Street not listed in Source
1980	-	Haines Criss-Cross Directory	Street not listed in Source
1976	-	Haines Criss-Cross Directory	Street not listed in Source
1973	-	Haines Criss-Cross Directory	Street not listed in Source

APPENDIX F
AGENCY RECORDS

Kern County Fire Department

Permit

2820 M St., Bakersfield, CA 93301
Telephone (661) 391-3310 Fax (661) 636-0466 or 636-0467
Website: kerncountyfire.org

Permit Number	2006-FA-022	**Date of Permit**	6/14/2006	Station No.	
Type of Permit	Fire Alarm Permit			Inspection Number	
Project Name	Exxon Mobile			Assessor's Number	
Project Street Address	**18271**	**Hwy. 33**		City	Bakersfield
Description of Project	Install fire alarm system.				

NOTE: KCFD REQUIRES TWO (2) FULL WORKING DAYS NOTICE FOR INSPECTION.

Issued to: (Applicant)	Darrell V. Feliz	App. Ph. No.	(661) 588-4357
Contractor/Company	Kern Security Systems Inc.	Cont. Ph. No.	(661) 588-4357
Business Address Contractor/Company	2701 Fruitvale Ave.	Fax No.	
City, State, Zip	Bakersfield, CA		
License No.	11312		

Fee Code 1.2

THIS PERMIT DOES NOT TAKE THE PLACE OF ANY LICENSE REQUIRED BY LAW. PERMIT IS NOT TRANSFERABLE*THIS IS NOT A FIRE AND LIFE SAFETY CLEARANCE

Plans Approved Signature	Johnston, D.
Project Final Signature	Johnston, D.
Final Inspection Date	4/10/2007

For Office Use Only

Date Picked Up	6 /16/06
Date Faxed	
Date Mailed	
Date Paid	6/14/2006
Amount Paid	$270.00

THIS PERMIT MUST AT ALL TIMES BE POSTED ON THE PREMISES MENTIONED ABOVE

This Permit will expire if an inspection is not requested within 180 days.

KCFD 205 Rev. 6/15

Kern County Fire Department

Permit

2820 M St., Bakersfield, CA 93301
Telephone (661) 391-3310 Fax (661) 636-0466 or 636-0467
Website: kerncountyfire.org

Permit Number	2012-FPS-047	**Date of Permit**	4/17/2012	Station No.	24-McKittrick
Type of Permit	Fire Protection System Permit			Inspection Number	
Project Name	Aera Energy			Assessor's Number	
Project Street Address	**19091**	**Hwy. 33**		City	McKittrick
Description of Project	Install Ansul I-101 system in spray booth.				

NOTE: KCFD REQUIRES TWO (2) FULL WORKING DAYS NOTICE FOR INSPECTION.

Issued to: (Applicant)	Jorgensen Co.	App. Ph. No.	(661) 327-4352
Contractor/Company	Jorgensen Co.	Cont. Ph. No.	(661) 327-4352
Business Address Contractor/Company	2345 Fruitvale Avenue	Fax No.	(661) 327-5309
City, State, Zip	Bakersfield, CA		
License No.	C16 262995		

Fee Code: 1.3

THIS PERMIT DOES NOT TAKE THE PLACE OF ANY LICENSE REQUIRED BY LAW. PERMIT IS NOT TRANSFERABLE*THIS IS NOT A FIRE AND LIFE SAFETY CLEARANCE

Plans Approved Signature	Nicholas, M.
Project Final Signature	Davis, L.
Final Inspection Date	10/3/2012

For Office Use Only

Date Picked Up	
Date Faxed	
Date Mailed	
Date Paid	4/17/2012
Amount Paid	$250.00

THIS PERMIT MUST AT ALL TIMES BE POSTED ON THE PREMISES MENTIONED ABOVE

This Permit will expire if an inspection is not requested within 180 days.

KCFD 205 Rev. 6/15

Kern County Fire Department

Permit

2820 M St., Bakersfield, CA 93301
Telephone (661) 391-3310 Fax (661) 636-0466 or 636-0467
Website: kerncountyfire.org

Permit Number	2015-FA-052	**Date of Permit**	6/15/2015	Station No.	
Type of Permit	Fire Alarm Permit			Inspection Number	
Project Name	Linn Energy			Assessor's Number	
Project Street Address	**18271**	**Hwy. 33**		City	McKittrick
Description of Project	Install fire alarm system				

NOTE: KCFD REQUIRES TWO (2) FULL WORKING DAYS NOTICE FOR INSPECTION.

Issued to: (Applicant)	M&S Security Services	App. Ph. No.	(661) 397-9616
Contractor/Company	M&S Security Services	Cont. Ph. No.	(661) 397-9616
Business Address Contractor/Company	2900 C St.	Fax No.	
City, State, Zip	Bakersfield, CA		
License No.	C10 807015		

Fee Code 1.5

THIS PERMIT DOES NOT TAKE THE PLACE OF ANY LICENSE REQUIRED BY LAW. PERMIT IS NOT TRANSFERABLE*THIS IS NOT A FIRE AND LIFE SAFETY CLEARANCE

Plans Approved Signature	Nicholas, M.
Project Final Signature	Redstone, M.
Final Inspection Date	7/22/2015

For Office Use Only

Date Picked Up	
Date Faxed	
Date Mailed	
Date Paid	6/15/2015
Amount Paid	$270.00

THIS PERMIT MUST AT ALL TIMES BE POSTED ON THE PREMISES MENTIONED ABOVE

This Permit will expire if an inspection is not requested within 180 days.

KCFD 205 Rev. 6/15

Occupancy Detail Report

Kern County

SHELL PIPELINE CO-CARNERAS

BASIC DATA	
Identification	
Number	S2626-11785
Name	SHELL PIPELINE CO-CARNERAS
Occupancy Type	Commercial
- Number of Commercial Units	1
PrePlan on File	No
Location	
Street	16435 HWY 33 ENTRANCE H
City,State,Zip	LOST HILLS CA 93249
District	010
Station	26
Phone Numbers	
Phone Number	(661)979-5273
Map Info	
Map Page	051-34C

CONTACTS - 1	
Business	
Business	SHELL PIPELINE CO-CARNERAS
Name	
Last	Control Center
Involvement	
Occupant	No
Owner	No
Other	No
Contact	
Keyholder	No
Phone	
AfterHours	(832)337-8404

CONTACTS - 2	
Business	
Business	SHELL PIPELINE CO-CARNERAS
Name	
Last	McWhorter
First	Joe
Involvement	
Occupant	Yes

Owner	No
Other	No
Contact	
Keyholder	No
Phone	
DayTime	(661)477-7103

BUILDING

Building Classifications	
Structure Type	Enclosed building
Building Status	In normal use
Wall Construction	
Wall Insulated	No
Combustible	Not Selected
Other	
Stairways	No
Elevators	No
Attic	No

MORE BUILDING

Use Classifications	
Property Use One	Property Use, other
Occupancy Use	Office, Professional or Service Business
On-Site Materials or Products	
None	No
Storage/warehousing	No
Repair or service	No
Processing/manufacturing	No
Packaged Goods	No
Storage/warehousing	No
Repair or service	No
Processing/manufacturing	No
Packaged goods	No
Storage/warehousing	No
Repair or service	No
Processing/manufacturing	No
Packaged goods	No

ACTIONS - 1

Action	
Action	Regular Inspection
Assigned to	Station, 26, E26, B

Assignment date	10/24/2019 08:00:01
Scheduled date	11/01/2019 00:00:00
Fee	90.00
Duration in hours	0.00

ACTIONS - 2

Action

Action	Regular Inspection - No Fee
Activity Status	Granted
Assigned to	Station, 26, E26, A
Assignment date	11/19/2019 00:00:00
Scheduled date	11/19/2019 00:00:00
Completion date	11/19/2019 08:00:00
Completed by	GERL, Peter
Fee	0.00
Duration in hours	0.50
Comments	Everything looks good at this time.

ACTIONS - 3

Action

Action	Regular Inspection
Activity Status	Granted
Assigned to	Station, 26, E26, B
Assignment date	10/24/2015 08:00:06
Scheduled date	11/01/2015 00:00:00
Completion date	12/06/2018 08:00:00
Completed by	GUERRA, Luis
Fee	90.00
Duration in hours	0.00

ACTIONS - 4

Action

Action	Regular Inspection
Assigned to	Station, 26, E26, B
Assignment date	10/24/2017 08:00:06
Scheduled date	11/01/2017 00:00:00
Completion date	12/05/2017 08:00:00
Completed by	GIBBINS, Paul
Fee	90.00
Duration in hours	1.00

ACTIONS - 5

Action

Action	Regular Inspection - No Fee
Assigned to	Station, 26, E26, B

Assignment date	12/03/2014 00:00:00
Scheduled date	12/03/2014 00:00:00
Completion date	12/03/2014 08:00:00
Completed by	NEILSON, Jeremiah
Fee	0.00
Duration in hours	0.50

ACTIONS - 6

Action

Action	Regular Inspection
Assigned to	Station, 26, E26, A
Assignment date	03/30/2011 07:41:31
Scheduled date	11/17/2011 00:00:00
Completion date	11/17/2011 08:00:00
Completed by	KLUBNIKIN, Nicholas
Fee	90.00
Duration in hours	1.00

ACTIONS - 7

Action

Action	Regular Inspection
Assigned to	Station, 26, E26, A
Assignment date	03/24/2010 08:00:09
Scheduled date	04/01/2010 00:00:00
Completion date	05/13/2010 08:00:00
Completed by	HUERTA, Khris
Fee	90.00
Duration in hours	1.00

ACTIONS - 8

Action

Action	Regular Inspection
Assigned to	Station, 26, E26, B
Completion date	03/11/2008 08:00:00
Completed by	RODRIQUEZ, Jessie
Fee	0.00
Duration in hours	1.00

VIOLATIONS - 1

Identification

Violation	G-Granted

Violations

Found on	12/05/2017 00:00:00
Found by	GIBBINS, Paul

Clear date	12/05/2017 00:00:00
Cleared by	GIBBINS, Paul

Comments

Comments	Automated pump station unmanned, Looks Good.

VIOLATIONS - 2

Identification

Violation	G-Granted

Violations

Found on	11/17/2011 00:00:00
Found by	GIRGIS, Peter
Clear date	11/17/2011 00:00:00
Cleared by	GIRGIS, Peter

VIOLATIONS - 3

Identification

Violation	20-Other (see Remarks)

Violations

Found on	05/13/2010 00:00:00
Found by	HUERTA, Khris
Clear date	05/13/2010 00:00:00
Cleared by	HUERTA, Khris

VIOLATIONS - 4

Identification

Violation	G-Granted

Violations

Found on	05/13/2010 00:00:00
Found by	HUERTA, Khris
Clear date	05/13/2010 00:00:00
Cleared by	HUERTA, Khris

VIOLATIONS - 5

Identification

Violation	G-Granted

Violations

Found on	03/11/2008 00:00:00
Found by	RODRIQUEZ, Jessie
Clear date	03/11/2008 00:00:00
Cleared by	RODRIQUEZ, Jessie

End of Report

Occupancy Detail Report

Kern County

AERA ENR

BASIC DATA	
Identification	
Number	S2424-07012
Name	AERA ENR
Occupancy Type	Commercial
- Number of Commercial Units	7
PrePlan on File	No
Location	
Street	19651 33 HWY
City,State,Zip	MCKITTRICK CA 93251
District	010
Station	24
Phone Numbers	
Phone Number	(661)665-7596
Map Info	
Map Page	075-33

BUILDING	
Wall Construction	
Wall Insulated	No
Combustible	Not Selected
Other	
Stairways	No
Elevators	No
Attic	No

MORE BUILDING	
Use Classifications	
Occupancy Use	Office, Professional or Service Business
On-Site Materials or Products	
None	No
Storage/warehousing	No
Repair or service	No
Processing/manufacturing	No
Packaged Goods	No
Storage/warehousing	No
Repair or service	No
Processing/manufacturing	No
Packaged goods	No
Storage/warehousing	No
Repair or service	No
Processing/manufacturing	No
Packaged goods	No

ACTIONS - 1

Action

Action	Regular Inspection
Assigned to	Station, 24, E24, A
Assignment date	12/24/2019 08:00:09
Scheduled date	01/01/2020 00:00:00
Fee	90.00
Duration in hours	0.00

ACTIONS - 2

Action

Action	Regular Inspection
Assigned to	Station, 24, E24, A
Assignment date	12/24/2018 08:05:21
Scheduled date	01/01/2019 00:00:00
Fee	90.00
Duration in hours	0.00

ACTIONS - 3

Action

Action	Regular Inspection
Assigned to	Station, 24, E24, A
Assignment date	12/24/2017 08:05:45
Scheduled date	01/01/2018 00:00:00
Fee	90.00
Duration in hours	0.00

ACTIONS - 4

Action

Action	Regular Inspection
Assigned to	Station, 24, E24, A
Assignment date	12/24/2016 08:04:40
Scheduled date	01/01/2017 00:00:00
Fee	90.00
Duration in hours	0.00

ACTIONS - 5

Action

Action	Regular Inspection
Assigned to	Station, 24, E24, A
Assignment date	11/23/2016 08:00:05
Scheduled date	12/01/2016 00:00:00
Fee	90.00

Duration in hours	0.00

ACTIONS - 6

Action

Action	Regular Inspection
Assigned to	Station, 24, E24, A
Assignment date	11/23/2015 08:00:07
Scheduled date	12/01/2015 00:00:00
Fee	90.00
Duration in hours	0.00

ACTIONS - 7

Action

Action	Regular Inspection
Assigned to	Station, 24, E24, A
Assignment date	11/23/2014 08:00:01
Scheduled date	12/01/2014 00:00:00
Fee	90.00
Duration in hours	0.00

ACTIONS - 8

Action

Action	Regular Inspection
Assigned to	Station, 24, E24, A
Assignment date	11/23/2012 08:00:01
Scheduled date	01/01/1900 00:00:00
Fee	90.00
Duration in hours	0.00

End of Report

San Joaquin Valley
Air Pollution Control District

**FACI□IT□ □□□□

11. The operator shall submit reports of any required monitoring at least every six months unless a different frequency is required by an applicable requirement. All instances of deviations from permit requirements must be clearly identified in such reports. [District Rule 2520, 9.5.1] Federally Enforceable Through Title V Permit

12. Deviations from permit conditions must be promptly reported, including deviations attributable to upset conditions, as defined in the permit. For the purpose of this condition, promptly means as soon as reasonably possible, but no later than 10 days after detection. The report shall include the probable cause of such deviations, and any corrective actions or preventive measures taken. All required reports must be certified by a responsible official consistent with section 10.0 of District Rule 2520 (6/21/01). [District Rules 2520, 9.5.2 and 1100, 7.0] Federally Enforceable Through Title V Permit

13. If for any reason a permit requirement or condition is being challenged for its constitutionality or validity by a court of competent jurisdiction, the outcome of such challenge shall not affect or invalidate the remainder of the conditions or requirements in that permit. [District Rule 2520, 9.7] Federally Enforceable Through Title V Permit

14. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. [District Rule 2520, 9.8.2] Federally Enforceable Through Title V Permit

15. The permit may be modified, revoked, reopened and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance does not stay any permit condition. [District Rule 2520, 9.8.3] Federally Enforceable Through Title V Permit

16. The permit does not convey any property rights of any sort, or any exclusive privilege. [District Rule 2520, 9.8.4] Federally Enforceable Through Title V Permit

17. The Permittee shall furnish to the District, within a reasonable time, any information that the District may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the District copies of records required to be kept by the permit or, for information claimed to be confidential, the permittee may furnish such records directly to EPA along with a claim of confidentiality. [District Rule 2520, 9.8.5] Federally Enforceable Through Title V Permit

18. The permittee shall pay annual permit fees and other applicable fees as prescribed in Regulation III of the District Rules and Regulations. [District Rule 2520, 9.9] Federally Enforceable Through Title V Permit

19. Upon presentation of appropriate credentials, a permittee shall allow an authorized representative of the District to enter the permittee's premises where a permitted source is located or emissions related activity is conducted, or where records must be kept under condition of the permit. [District Rule 2520, 9.13.2.1] Federally Enforceable Through Title V Permit

20. Upon presentation of appropriate credentials, a permittee shall allow an authorized representative of the District to have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit. [District Rule 2520, 9.13.2.2] Federally Enforceable Through Title V Permit

21. Upon presentation of appropriate credentials, a permittee shall allow an authorized representative of the District to inspect at reasonable times any facilities, equipment, practices, or operations regulated or required under the permit. [District Rule 2520, 9.13.2.3] Federally Enforceable Through Title V Permit

22. Upon presentation of appropriate credentials, a permittee shall allow an authorized representative of the District to sample or monitor, at reasonable times, substances or parameters for the purpose of assuring compliance with the permit or applicable requirements. [District Rule 2520, 9.13.2.4] Federally Enforceable Through Title V Permit

23. No air contaminants shall be discharged into the atmosphere for a period or periods aggregating more than 3 minutes in any one hour which is as dark or darker than Ringelmann #1 or equivalent to 20% opacity and greater, unless specifically exempted by District Rule 4101 (02/17/05). If the equipment or operation is subject to a more stringent visible emission standard as prescribed in a permit condition, the more stringent visible emission limit shall supersede this condition. [District Rule 4101, and County Rules 401 (in all eight counties in the San Joaquin Valley)] Federally Enforceable Through Title V Permit

24. No person shall manufacture, blend, repackage, supply, sell, solicit or apply any architectural coating with a VOC content in excess of the corresponding limit specified in Table of Standards 1 effective until 12/30/10 or Table of Standards 2 effective on and after 1/1/11 of District Rule 4601 (12/17/09) for use or sale within the District. [District Rule 4601, 5.1] Federally Enforceable Through Title V Permit

25. All VOC-containing materials subject to Rule 4601 (12/17/09) shall be stored in closed containers when not in use. [District Rule 4601, 5.4] Federally Enforceable Through Title V Permit

26. The permittee shall comply with all the Labeling and Test Methods requirements outlined in Rule 4601 sections 6.1 and 6.3 (12/17/09). [District Rule 4601, 6.1 and 6.3] Federally Enforceable Through Title V Permit

27. With each report or document submitted under a permit requirement or a request for information by the District or EPA, the permittee shall include a certification of truth, accuracy, and completeness by a responsible official. [District Rule 2520, 9.13.1 and 10.0] Federally Enforceable Through Title V Permit

28. If the permittee performs maintenance on, or services, repairs, or disposes of appliances, the permittee shall comply with the standards for Recycling and Emissions Reduction pursuant to 40 CFR Part 82, Subpart F. [40 CFR 82 Subpart F] Federally Enforceable Through Title V Permit

29. If the permittee performs service on motor vehicles when this service involves the ozone-depleting refrigerant in the motor vehicle air conditioner (MVAC), the permittee shall comply with the standards for Servicing of Motor Vehicle Air Conditioners pursuant to all the applicable requirements as specified in 40 CFR Part 82, Subpart B. [40 CFR Part 82, Subpart B] Federally Enforceable Through Title V Permit

30. Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 (8/19/2004) or Rule 8011 (8/19/2004). [District Rules 8011 and 8021] Federally Enforceable Through Title V Permit

31. Outdoor handling, storage and transport of any bulk material which emits dust shall comply with the requirements of District Rule 8031, unless specifically exempted under Section 4.0 of Rule 8031 (8/19/2004) or Rule 8011 (8/19/2004). [District Rules 8011 and 8031] Federally Enforceable Through Title V Permit

32. An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/2004) or Rule 8011 (8/19/2004). [District Rules 8011 and 8041] Federally Enforceable Through Title V Permit

33. Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 (8/19/2004) or Rule 8011 (8/19/2004). [District Rules 8011 and 8051] Federally Enforceable Through Title V Permit

34. Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 (8/19/2004) or Rule 8011 (8/19/2004). [District Rules 8011 and 8061] Federally Enforceable Through Title V Permit

35. Any unpaved vehicle/equipment area that anticipates more than 50 Average annual daily Trips (AADT) shall comply with the requirements of Section 5.1.1 of District Rule 8071. Any unpaved vehicle/equipment area that anticipates more than 150 vehicle trips per day (VDT) shall comply with the requirements of Section 5.1.2 of District Rule 8071. On each day that 25 or more VDT with 3 or more axles will occur on an unpaved vehicle/equipment traffic area, the owner/operator shall comply with the requirements of Section 5.1.3 of District Rule 8071. On each day when a special event will result in 1,000 or more vehicles that will travel/park on an unpaved area, the owner/operator shall comply with the requirements of Section 5.1.4 of District Rule 8071. All sources shall comply with the requirements of Section 5.0 of District Rule 8071 unless specifically exempted under Section 4.0 of Rule 8071 (9/16/2004) or Rule 8011 (8/19/2004). [District Rules 8011 and 8071] Federally Enforceable Through Title V Permit

36. Any owner or operator of a demolition or renovation activity, as defined in 40 CFR 61.141, shall comply with the applicable inspection, notification, removal, and disposal procedures for asbestos containing materials as specified in 40 CFR 61.145 (Standard for Demolition and Renovation). [40 CFR 61 Subpart M] Federally Enforceable Through Title V Permit

37. The permittee shall submit certifications of compliance with the terms and standards contained in Title V permits, including emission limits, standards and work practices, to the District and the EPA annually (or more frequently as specified in an applicable requirement or as specified by the District). The certification shall include the identification of each permit term or condition, the compliance status, whether compliance was continuous or intermittent, the methods used for determining the compliance status, and any other facts required by the District to determine the compliance status of the source. [District Rule 2520, 9.16] Federally Enforceable Through Title V Permit

38. The permittee shall submit an application for Title V permit renewal to the District at least six months, but not greater than 18 months, prior to the permit expiration date. [District Rule 2520, 5.2] Federally Enforceable Through Title V Permit

39. When a term is not defined in a Title V permit condition, the definition in the rule cited as the origin and authority for the condition in a Title V permits shall apply. [District Rule 2520, 9.1.1] Federally Enforceable Through Title V Permit

40. Compliance with permit conditions in the Title V permit shall be deemed in compliance with the following outdated SIP requirements: Rule 401 (Madera, Fresno, Kern, Kings, San Joaquin, Stanislaus, Tulare and Merced), Rule 110 (Fresno, Stanislaus, San Joaquin), Rule 109 (Merced), Rule 113 (Madera), Rule 111 (Kern, Tulare, Kings), and Rule 202 (Fresno, Kern, Tulare, Kings, Madera, Stanislaus, Merced, San Joaquin). A permit shield is granted from these requirements. [District Rule 2520, 13.2] Federally Enforceable Through Title V Permit

41. Compliance with permit conditions in the Title V permit shall be deemed in compliance with the following applicable requirements: SJVUAPCD Rules 1100, sections 6.1 and 7.0 (12/17/92); 2010, sections 3.0 and 4.0 (12/17/92); 2031 (12/17/92); 2040 (12/17/92); 2070, section 7.0 (12/17/92); 2080 (12/17/92); 4101 (2/17/05); 4601 (12/17/09); 8021 (8/19/2004); 8031 (8/19/2004); 8041 (8/19/2004); 8051 (8/19/2004); 8061 (8/19/2004); and 8071 (9/16/2004). A permit shield is granted from these requirements. [District Rule 2520, 13.2] Federally Enforceable Through Title V Permit

42. On December 31, 2012 the initial Title V permit was issued. The reporting periods for the Report of Required Monitoring and the Compliance Certification Report begin January 1 of every year, unless alternative dates are approved by the District Compliance Division. These reports are due within 30 days after the end of the reporting period. [District Rule 2520] Federally Enforceable Through Title V Permit

San Joaquin Valley
Air Pollution Control District

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1. No modification to this unit shall be performed without an Authority to Construct for such modification(s), except for changes specified in conditions below. [District Rule 2010] Federally Enforceable Through Title V Permit
2. The fuel supply line shall be physically disconnected from this unit. [District Rules 4306 and 4320] Federally Enforceable Through Title V Permit
3. This equipment shall not be operated for any reason until an Authority to Construct permit is issued approving all necessary retrofits required to comply with the applicable requirements of District Rule 4306 and all other applicable District regulations. [District Rule 4306 and 4320] Federally Enforceable Through Title V Permit
4. Unit shall be maintained and operated in accordance with the manufacturer's specifications and recommendations. [District Rule 4305] Federally Enforceable Through Title V Permit
5. Heater shall be fueled only on natural gas or LPG. [District Rule 4305] Federally Enforceable Through Title V Permit
6. Total heat input to this unit shall be less than 30 billion Btu per calendar year. [District Rule 4305] Federally Enforceable Through Title V Permit
7. Unit shall be tuned within 30 days of startup and at least once each calendar year in which it operates thereafter, by a qualified technician in accordance with Rule 4304. [District Rules 2201, 4304, and 4305] Federally Enforceable Through Title V Permit
8. Unit shall be equipped with a non-resettable fuel flow meter. A master meter which serves more than one unit may be used, provided either: (1) the total heat input to all of the units is less than 30 billion Btu/yr, or (2) the permittee monitors the operation of each unit to determine the amount of fuel consumed by each unit. [District Rule 4305] Federally Enforceable Through Title V Permit
9. Permittee shall maintain accurate records of monthly and annual fuel usage, and of dates tuning is performed for a period of five years and shall make such records readily available for District inspection upon request. [District Rule 4305] Federally Enforceable Through Title V Permit
10. Particulate matter emissions shall not exceed either of the following limits: 0.1 grain/dscf at operating conditions or 0.1 grain/dscf calculated to 12% CO2, nor 10 lb/hr. [District Rules 4201 and 4301] Federally Enforceable Through Title V Permit
11. Sulfur compound emissions shall not exceed 0.2% by volume, 2000 ppmv, on a dry basis averaged over 15 consecutive minutes. [District Rule 4801] Federally Enforceable Through Title V Permit

San Joaquin Valley
Air Pollution Control District

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1. The true vapor pressure of liquid stored shall not exceed 11.0 psia. [District Rule 2201] Federally Enforceable Through Title V Permit
2. Total throughput of organic liquid with TVP greater than 5.9 psia and less than or equal to 11.0 psia shall not exceed either of the following limits: 190,000 bbl/day or 85,000 bbl/day on a monthly average basis. [District Rule 2201] Federally Enforceable Through Title V Permit
3. Total throughput of organic liquid with TVP less than or equal to 5.9 psia shall not exceed either of the following limits: 360,000 bbl/day or 180,000 bbl/day on a monthly average basis. [District Rule 2201] Federally Enforceable Through Title V Permit
4. Combined total throughput of permits S-77-9, '-11, and '-14 shall not exceed either of the following limits: 550,000 bbl/day or 265,000 bbl/day on a monthly average basis. [District Rule 2201] Federally Enforceable Through Title V Permit
5. VOC emission rate from permits S-77-9, '-11, and '-14 shall not exceed 227.1 lb/day. [District Rule 2201] Federally Enforceable Through Title V Permit
6. VOC emission rate from permits S-77-9, '-11, and '-14 shall not exceed 41,913 lb/yr. [District Rule 2201] Federally Enforceable Through Title V Permit
7. VOC emission rate shall not exceed 152.8 lb/day. [District Rule 2201] Federally Enforceable Through Title V Permit
8. Tank shall be equipped with operational temperature indicator. [District Rule 2201] Federally Enforceable Through Title V Permit
9. Permittee shall maintain a record of the liquid stored, the period of storage, and the maximum true vapor pressure of that liquid during the respective storage period. [District Rule 2201] Federally Enforceable Through Title V Permit
10. Permittee shall maintain records of maximum daily throughput and monthly average daily throughput. [District Rule 2201] Federally Enforceable Through Title V Permit
11. When storing organic liquids with true vapor pressure less than 0.5 psia, the requirements of Sections 5.3, 5.5 and 6.1 of District Rule 4623 (Amended May 19, 2005) shall not apply to this unit. This exemption applies to all conditions in this permit referencing Rule 4623 Sections 5.3, 5.5 or 6.1 only. [District Rule 4623] Federally Enforceable Through Title V Permit
12. Before switching to the storage of organic liquids with true vapor pressure greater than or equal to 0.5 psia, all covers, seals, and lids shall be inspected by the facility operator to ensure compliance with the provisions of this permit. This includes all conditions containing District Rule 4623 reference. [District Rule 2520] Federally Enforceable Through Title V Permit

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13. The internal floating roof shall rest or float on the liquid surface (but not necessarily in complete contact with it) inside a storage vessel that has a fixed roof. The internal roof shall be floating on the liquid surface except during initial fill and when the storage vessel is completely emptied or subsequently emptied and refilled. When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible. Whenever the permittee intends to land the roof on it's legs, the permittee shall notify the APCO in writing at least five days prior to performing the work. [District Rule 4623] Federally Enforceable Through Title V Permit
14. Gaps between the tank shell and the primary seal shall not exceed 2 1/2 inches. [District Rule 4623] Federally Enforceable Through Title V Permit
15. The cumulative length of all primary seal gaps greater than 1 1/2 inches shall not exceed 10% of the circumference of the tank. [District Rule 4623] Federally Enforceable Through Title V Permit
16. The cumulative length of all primary seal gaps greater than 1/8 inch shall not exceed 30% of the circumference of the tank. [District Rule 4623] Federally Enforceable Through Title V Permit
17. No continuous gap in the primary seal greater than 1/8 inch wide shall exceed 10% of the tank circumference. [District Rule 4623] Federally Enforceable Through Title V Permit
18. No gap between the tank shell and the secondary seal shall exceed 1/2 inch. [District Rule 4623] Federally Enforceable Through Title V Permit
19. The cumulative length of all gaps between the tank shell and the secondary seal, greater than 1/8 inch shall not exceed 5% of the tank circumference. [District Rule 4623] Federally Enforceable Through Title V Permit
20. The metallic shoe-type seal shall be installed so that one end of the shoe extends into the stored liquid and the other end extends a minimum vertical distance of 18 inches above the stored liquid surface. [District Rule 4623] Federally Enforceable Through Title V Permit
21. The geometry of the metallic-shoe type seal shall be such that the maximum gap between the shoe and the tank shell shall be no greater than 5 inches for a length of at least 18 inches in the vertical plane above the liquid. [District Rule 4623] Federally Enforceable Through Title V Permit
22. There shall be no holes, tears, or openings in the secondary seal or in the primary seal envelope that surrounds the annular vapor space enclosed by the roof edge, seal fabric, and secondary seal. [District Rule 4623] Federally Enforceable Through Title V Permit
23. The secondary seal shall allow easy insertion of probes up to 2 1/2 inches in width in order to measure gaps in the primary seal. [District Rule 4623] Federally Enforceable Through Title V Permit
24. The secondary seal shall extend from the roof to the tank shell and shall not be attached to the primary seal. [District Rule 4623] Federally Enforceable Through Title V Permit
25. All openings in the roof used for sampling and gauging, except pressure-vacuum valves which shall be set to within 10% of the maximum allowable working pressure of the roof, shall provide a projection below the liquid surface to prevent belching of liquid and to prevent entrained or formed organic vapor from escaping from the liquid contents of the tank and shall be equipped with a cover, seal or lid that shall be in a closed position at all times, with no visible gaps and be gas tight, except when the device or appurtenance is in use. [District Rule 4623] Federally Enforceable Through Title V Permit
26. A gas-tight condition is defined as a condition without a gas leak. A gas leak is defined as a reading in excess of 10,000 ppmv, above background, as measured by a portable hydrocarbon detection instrument in accordance with the procedures specified in EPA Test Method 21. A reading in excess of 10,000 ppmv above background is a violation of this permit and Rule 4623 and shall be reported as a deviation. [District Rule 4623] Federally Enforceable Through Title V Permit

27. A leak-free condition is defined as a condition without a gas leak or a liquid leak. A liquid leak is defined as the dripping of organic liquid at a rate of more than 3 drops per minute. A gas leak is defined as a reading in excess of 10,000 ppmv, above background, as measured by a portable hydrocarbon detection instrument in accordance with the procedures specified in EPA Test Method 21. A liquid leak or reading in excess of 10,000 ppmv above background is a violation of this permit and Rule 4623 and shall be reported as a deviation. [District Rule 4623] Federally Enforceable Through Title V Permit

28. Each opening in a non-contact internal floating roof, except for automatic bleeder vents (vacuum breaker vents) and rim space vents, shall provide a projection below the liquid surface. [District Rule 4623] Federally Enforceable Through Title V Permit

29. Each opening in the internal floating roof except for leg sleeves, automatic bleeder vents, rim space vents, column wells, ladder wells, sample wells, and stub drains is to be equipped with a cover or lid which is to be maintained in a closed position at all times (i.e., no visible gap) except when the device is in actual use. The cover or lid shall be equipped with a gasket. Covers on each access hatch and automatic gauge float well shall be bolted except when they are in use. [District Rule 4623] Federally Enforceable Through Title V Permit

30. Automatic bleeder vents shall be equipped with a gasket and shall be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports. [District Rule 4623] Federally Enforceable Through Title V Permit

31. Rim vents shall be equipped with a gasket and are to be set to open only when the internal floating roof is not floating or at the manufacturer's recommended setting. [District Rule 4623] Federally Enforceable Through Title V Permit

32. Each penetration of the internal floating roof for the purpose of sampling shall be a sample well. The well shall have a slit fabric cover that covers at least 90% of the opening. The fabric cover must be impermeable. [District Rule 4623] Federally Enforceable Through Title V Permit

33. Each penetration of the internal floating roof that allows for passage of a column supporting the fixed roof shall have a flexible fabric sleeve seal or a gasketed sliding cover. The fabric sleeve must be impermeable. [District Rule 4623] Federally Enforceable Through Title V Permit

34. The permittee shall visually inspect the internal floating roof, and its appurtenant parts, fittings, etc. and measure the gaps of the primary seal and/or secondary seal prior to filling the tank for newly constructed, repair, or rebuilt internal floating roof tanks. If holes, tears, or openings in the primary seal, the secondary seal, the seal fabric or defects in the internal floating roof or its appurtenant parts, components, fittings, etc., are found, they shall be repaired prior to filling the tank. [District Rule 4623] Federally Enforceable Through Title V Permit

35. The permittee shall visually inspect, through the manholes, roof hatches, or other openings on the fixed roof, the internal floating roof and its appurtenant parts, fittings, etc., and the primary seal and/or secondary seal at least once every 12 months after the tank is initially filled with an organic liquid. There should be no visible organic liquid on the roof, tank walls, or anywhere. Other than the gap criteria specified by this rule, no holes, tears, or other openings are allowed that would permit the escape of vapors. Any defects found are violations of this rule. [District Rule 4623] Federally Enforceable Through Title V Permit

36. The permittee shall conduct actual gap measurements of the primary seal and/or secondary seal at least once every 60 months. [District Rule 4623] Federally Enforceable Through Title V Permit

37. Permittee shall submit the reports of the floating roof tank inspections to the APCO within five calendar days after the completion of the inspection only for those tanks that failed to meet the applicable requirements of Rule 4623, Sections 5.2 through 5.5. The inspection report for tanks that that have been determined to be in compliance with the requirements of Sections 5.2 through 5.5 need not be submitted to the APCO, but the inspection report shall be kept on-site and made available upon request by the APCO. The inspection report shall contain all necessary information to demonstrate compliance with the provisions of Rule 4623. [District Rule 4623] Federally Enforceable Through Title V Permit

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38. Permittee shall maintain the records of the internal floating roof landing activities that are performed pursuant to Rule 4623, Sections 5.3.1.3 and 5.4.3. The records shall include information on the true vapor pressure (TVP), API gravity, storage temperature, type of organic liquid stored in the tank, the purpose of landing the roof on its legs, the date of roof landing, duration the roof was on its legs, the level or height at which the tank roof was set to land on its legs, and the lowest liquid level in the tank. [District Rule 4623] Federally Enforceable Through Title V Permit

39. The tank pressure-vacuum (PV) relief valve shall be set to within 10% of the maximum allowable working pressure of the tank. The PV relief valve shall be permanently labeled with the operating pressure settings. The PV relief valve shall be properly installed and maintained in good operating order in accordance with the manufacturer's instructions, and shall remain in leak-free condition except when the operating pressure exceeds the valve's set pressure. [District Rule 4623] Federally Enforceable Through Title V Permit

40. Permittee shall notify District at least 7 days prior to the date when unobstructed primary and secondary seal/gap testing will occur. [District Rule 1070]

41. All records required to be maintained by this permit shall be maintained for a period of at least five years and shall be made readily available for District inspection upon request. [District Rule 4623] Federally Enforceable Through Title V Permit

42. This unit was constructed prior to 1973 and has not been modified (as defined in 40 CFR 60.14) or reconstructed (as defined in 40 CFR 60.15) since 1973. Therefore, the requirements of 40 CFR 60 are not applicable to this unit. A permit shield is granted from these requirements. [District Rule 2520] Federally Enforceable Through Title V Permit

43. Permittee shall conduct true vapor pressure (TVP) testing of the organic liquid stored in this tank at least once every 24 months and/or whenever there is a change in the source or type of organic liquid stored in the tank. The TVP of any organic liquid shall be determined by measuring the Reid Vapor Pressure (RVP) using ASTM D 323 (Test Method for Vapor Pressure for Petroleum Products), and converting the RVP to TVP at the tank's maximum organic liquid storage temperature. The conversion of RVP to TVP shall be done in accordance with the procedures in appendix B of District Rule 4623. Records of TVP testing shall be maintained. [District Rules 2520 and 4623] Federally Enforceable Through Title V Permit

San Joaquin Valley
Air Pollution Control District

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1. This tank shall only store liquid with a true vapor pressure (TVP) of 5.9 psia or less under all storage conditions. [District Rules 2201and 4623 and 40 CFR 60.110b(a), 112b(a)] Federally Enforceable Through Title V Permit
2. Total throughput of organic liquid with TVP less than or equal to 5.9 psia shall not exceed either of the following limits: 360,000 bbl/day or 180,000 bbl/day on a monthly average basis. [District Rule 2201] Federally Enforceable Through Title V Permit
3. Combined total throughput of permits S-77-9, '-11, and '-14 shall not exceed either of the following limits: 550,000 bbl/day or 265,000 bbl/day on a monthly average basis. [District Rule 2201] Federally Enforceable Through Title V Permit
4. VOC emission rate from permits S-77-9, '-11, and '-14 shall not exceed 227.1 lb/day. [District Rule 2201] Federally Enforceable Through Title V Permit
5. VOC emission rate from permits S-77-9, '-11, and '-14 shall not exceed 41,913 lb/yr. [District Rule 2201] Federally Enforceable Through Title V Permit
6. VOC emission rate shall not exceed 119.4 lb/day. [District Rule 2201] Federally Enforceable Through Title V Permit
7. Permittee shall maintain a record of the liquid stored, the period of storage, and the maximum true vapor pressure of that liquid during the respective storage period. [District Rule 2201 and 40 CFR 60.116b(c)] Federally Enforceable Through Title V Permit
8. Permittee shall maintain records of maximum daily throughput and monthly average daily throughput. [District Rule 2201] Federally Enforceable Through Title V Permit
9. When storing organic liquids with true vapor pressure less than 0.5 psia, the requirements of Sections 5.3, 5.5 and 6.1 of District Rule 4623 (Amended May 19, 2005) shall not apply to this unit. This exemption applies to all conditions in this permit referencing Rule 4623 Sections 5.3, 5.5 or 6.1 only. [District Rule 4623] Federally Enforceable Through Title V Permit
10. When storing organic liquids with true vapor pressure less than 0.75 psia, the requirements of 40 CFR 60 Subpart Kb shall not apply to this unit. This exemption applies to all conditions in this permit referencing 40 CFR 60 Subpart Kb only. [40 CFR 60.112b(a)] Federally Enforceable Through Title V Permit
11. Before switching to the storage of organic liquids with true vapor pressure greater than or equal to 0.5 psia, all covers, seals, and lids shall be inspected by the facility operator to ensure compliance with the provisions of this permit. This includes all conditions containing District Rule 4623 reference. [District Rule 2520] Federally Enforceable Through Title V Permit

12. Before switching to the storage of organic liquids with true vapor pressure greater than or equal to 0.75 psia, all covers, seals, and lids shall be inspected by the facility operator to ensure compliance with the provisions of this permit. This includes all conditions containing District Rule 4623 or 40 CFR 60 Subpart Kb reference. [District Rule 2520] Federally Enforceable Through Title V Permit

13. This tank shall be equipped with a closure device between the tank shell and roof edge consisting of two seals mounted one above the other; the one below shall be referred to as the primary seal, and the one above shall be referred as the secondary seal. [District Rules 2201 and 4623 and 40 CFR 60.112b(a)(2)(i)] Federally Enforceable Through Title V Permit

14. The external floating roof shall float on the surface of the stored liquid at all times (i.e., off the roof leg supports) except during the initial fill until the roof is lifted off the leg supports and when the tank is completely emptied and subsequently refilled. When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible. Whenever the permittee intends to land the roof on its legs, the permittee shall notify the APCO in writing at least five calendar days prior to performing the work. The tank must be in compliance with this rule before it may land on its legs. [District Rule 4623 and 40 CFR 60.112b(a)(2)(iii)] Federally Enforceable Through Title V Permit

15. Gaps between the tank shell and the primary seal shall not exceed 1 1/2 inches. [District Rule 4623 and 40 CFR 60.113b(b)(4)(i)] Federally Enforceable Through Title V Permit

16. The cumulative length of all gaps between the tank shell and the primary seal greater than 1/2 inch shall not exceed 10% of the circumference of the tank. [District Rule 4623 and 40 CFR 60.113b(b)(4)(i)] Federally Enforceable Through Title V Permit

17. The cumulative length of all primary seal gaps greater than 1/8 inch shall not exceed 30% of the circumference of the tank. [District Rule 4623 and 40 CFR 60.113b(b)(4)(i)] Federally Enforceable Through Title V Permit

18. No continuous gap in the primary seal greater than 1/8 inch wide shall exceed 10% of the tank circumference. [District Rule 4623 and 40 CFR 60.113b(b)(4)(i)] Federally Enforceable Through Title V Permit

19. No gap between the tank shell and the secondary seal shall exceed 1/2 inch. [District Rule 4623 and 40 CFR 60.113b(b)(4)(ii)(B)] Federally Enforceable Through Title V Permit

20. The cumulative length of all gaps between the tank shell and the secondary seal, greater than 1/8 inch shall not exceed 5% of the tank circumference. [District Rule 4623 and 40 CFR 60.113b(b)(4)(ii)(B)] Federally Enforceable Through Title V Permit

21. The metallic shoe-type seal shall be installed so that one end of the shoe extends into the stored liquid and the other end extends a minimum vertical distance of 24 inches above the stored liquid surface. [District Rule 4623 and 40 CFR 60.113b(b)(4)(i)(A)] Federally Enforceable Through Title V Permit

22. The geometry of the metallic-shoe type seal shall be such that the maximum gap between the shoe and the tank shell shall be no greater than 3 inches for a length of at least 18 inches in the vertical plane above the liquid. [District Rule 4623] Federally Enforceable Through Title V Permit

23. There shall be no holes, tears, or openings in the secondary seal or in the primary seal envelope that surrounds the annular vapor space enclosed by the roof edge, seal fabric, and secondary seal. Except for gaps meeting permit requirements, the primary seal shall completely cover the annular space between the edge of the floating roof and tank wall. [District Rule 4623 and 40 CFR 60.112b(a)(2)(i)(A), 40 CFR 60.113b(b)(4)(i)(B) and 60.113b(b)(4)(ii)(C)] Federally Enforceable Through Title V Permit

24. The secondary seal shall allow easy insertion of probes of up to 1 1/2 inches in width in order to measure gaps in the primary seal. [District Rule 4623] Federally Enforceable Through Title V Permit

25. The secondary seal shall extend from the roof to the tank shell and shall not be attached to the primary seal. Except for gaps meeting permit requirements, the secondary seal shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion. [District Rule 4623 and 40 CFR 60.112b(a)(2)(i)(B) and 40 CFR 60.113b(b)(4)(ii)(A)] Federally Enforceable Through Title V Permit

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26. All openings in the roof used for sampling and gauging, except pressure-vacuum valves which shall be set to within 10% of the maximum allowable working pressure of the roof, shall provide a projection below the liquid surface to prevent belching of liquid and to prevent entrained or formed organic vapor from escaping from the liquid contents of the tank and shall be equipped with a cover, seal or lid that shall be in a closed position at all times, with no visible gaps and be gas tight, except when the device or appurtenance is in use. [District Rule 4623] Federally Enforceable Through Title V Permit

27. A gas-tight condition is defined as a condition without a gas leak. A gas leak is defined as a reading in excess of 10,000 ppmv, above background, as measured by a portable hydrocarbon detection instrument in accordance with the procedures specified in EPA Test Method 21. A reading in excess of 10,000 ppmv above background is a violation of this permit and Rule 4623 and shall be reported as a deviation. [District Rule 4623] Federally Enforceable Through Title V Permit

28. Except for automatic bleeder vents, rim vents, and pressure relief vents, each opening in a non-contact external floating roof shall provide a projection below the liquid surface. [District Rule 4623 and 40 CFR 60.112b(a)(2)(ii)] Federally Enforceable Through Title V Permit

29. Except for automatic bleeder vents and rim vents, roof drains, and leg sleeves, each opening in the roof shall be equipped with a gasketed cover, seal, or lid that shall be maintained in a closed position at all times (i.e., no visible gap) except when in actual use. [District Rule 4623 and 40 CFR 60.112b(a)(2)(ii)] Federally Enforceable Through Title V Permit

30. Automatic bleeder vents shall be equipped with a gasket and shall be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports. [District Rule 4623 and 40 CFR 60.112b(a)(2)(ii)] Federally Enforceable Through Title V Permit

31. Rim vents shall be equipped with a gasket and shall be set to open when the roof is being floated off the roof leg supports or at the manufacturer's recommended setting. [District Rule 4623 and 40 CFR 60.112b(a)(2)(ii)] Federally Enforceable Through Title V Permit

32. Each emergency roof drain shall be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening. The fabric cover must be impermeable if the liquid is drained into the contents of the tanks. [District Rule 4623 and 40 CFR 60.112b(a)(2)(ii)] Federally Enforceable Through Title V Permit

33. External floating roof legs shall be equipped with vapor socks or vapor barriers in order to maintain a gas-tight condition so as to prevent VOC emissions from escaping through the roof leg opening. [District Rule 4623] Federally Enforceable Through Title V Permit

34. All wells and similar fixed projections through the floating roof shall provide a projection below the liquid surface. [District Rule 4623] Federally Enforceable Through Title V Permit

35. The solid guidepole well shall be equipped with a pole wiper and a gasketed cover, seal or lid which shall be in a closed position at all times (i.e., no visible gap) except when the well is in use. [District Rule 4623] Federally Enforceable Through Title V Permit

36. The gap between the pole wiper and the solid guidepole shall be added to the gaps measured to determine compliance with the secondary seal requirement, and in no case shall exceed 1/2 inch. [District Rule 4623] Federally Enforceable Through Title V Permit

37. The slotted guidepole well on a external floating roof shall be equipped with the following: a sliding cover, a well gasket, a pole sleeve, a pole wiper, and an internal float and float wiper designed to minimize the gap between the float and the well, and provided the gap shall not exceed 1/8 inch; or shall be equipped with a well gasket, a zero gap pole wiper seal and a pole sleeve that projects below the liquid surface. [District Rule 4623] Federally Enforceable Through Title V Permit

38. The gap between the pole wiper and the slotted guidepole shall be added to the gaps measured to determine compliance with the secondary seal requirement, and in no case shall exceed 1/8 inch. [District Rule 4623] Federally Enforceable Through Title V Permit

39. The permittee of external floating roof tanks shall make the primary seal envelope available for unobstructed inspection by the APCO on an annual basis at locations selected along its circumference at random by the APCO. In the case of riveted tanks with toroid-type seals, a minimum of eight locations shall be made available; in all other cases, a minimum of four locations shall be made available. If the APCO suspects a violation may exist the APCO may require such further unobstructed inspection of the primary seal as may be necessary to determine the seal condition for its entire circumference. [District Rule 4623] Federally Enforceable Through Title V Permit

40. Measurements of gaps between the tank wall and the primary and secondary seal shall be performed during the hydrostatic testing of the vessel or within 60 days of the initial fill with a volatile organic liquid. [40 CFR 60.113b(b)(1)(i)] Federally Enforceable Through Title V Permit

41. If any source ceases to store volatile organic liquid for a period of 1 year or more, subsequent introduction of volatile organic liquid into the vessel shall be considered an initial fill. [40 CFR 60.113b(b)(1)(iii)] Federally Enforceable Through Title V Permit

42. The permittee shall inspect all floating roof tanks at least once every 12 months to determine compliance with the requirements of this rule. The actual gap measurements of the floating roof primary and secondary seals shall be recorded. Permittee shall measure seal gaps, at one or more floating roof levels when the roof is floating off the roof leg supports, around the entire circumference of the tank in each place where a 0.32-cm diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the storage vessel and measure the circumferential distance of each such location. The inspection results shall be submitted to the APCO as specified in Section 6.3.5. [County Rule 107 (40 CFR 60.113b(b)(1)(i) & (ii); and 40 CFR 60.113b(b)(2)(i) & (ii)] Federally Enforceable Through Title V Permit

43. The permittee shall inspect the primary and secondary seals for compliance with the requirements of this rule every time a tank is emptied or degassed. Actual gap measurements shall be performed when the liquid level is static but not more than 48 hours after the tank roof is re-floated. If the external floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, the owner or operator shall repair the items as necessary before filling or refilling the storage vessel. The owner or operator shall notify the APCO in writing at least 30 days prior to the filling or refilling of each storage vessel to afford the APCO the opportunity to inspect the storage vessel prior to refilling. [District Rule 4623 and 40 CFR 60.113b(b)(6)] Federally Enforceable Through Title V Permit

44. Permittee shall submit the reports of the floating roof tank inspections to the APCO within five calendar days after the completion of the inspection only for those tanks that failed to meet the applicable requirements of Rule 4623, Sections 5.2 through 5.5. The inspection report for tanks that that have been determined to be in compliance with the requirements of Sections 5.2 through 5.5 need not be submitted to the APCO, but the inspection report shall be kept on-site and made available upon request by the APCO. The inspection report shall contain all necessary information to demonstrate compliance with the provisions of Rule 4623. [District Rule 4623 and 40 CFR 60.115b(b)] Federally Enforceable Through Title V Permit

45. Permittee shall maintain the records of the external floating roof landing activities that are performed pursuant to Rule 4623, Sections 5.3.1.3 and 5.4.3. The records shall include information on the true vapor pressure (TVP), API gravity, storage temperature, type of organic liquid stored in the tank, the purpose of landing the roof on its legs, the date of roof landing, duration the roof was on its legs, the level or height at which the tank roof was set to land on its legs, and the lowest liquid level in the tank. [District Rule 4623] Federally Enforceable Through Title V Permit

46. All records required to be maintained by this permit shall be maintained for a period of at least five years and shall be made readily available for District inspection upon request. [District Rule 4623 and 40 CFR 60.116b(a)] Federally Enforceable Through Title V Permit

47. Permittee shall notify District at least 30 days prior to the date when unobstructed primary and secondary seal/gap measurements will occur to afford the APCO the opportunity to have an observer present. [40 CFR 60.113b(b)(5)] Federally Enforceable Through Title V Permit

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48. Permittee shall make necessary repairs or empty the storage vessel within 45 days of identification in any inspection for seals not meeting the requirements listed in 40 CFR 60.113b(b)(4)(i) and (ii). If necessary repairs cannot be made within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the APCO. Such an extension request must include a demonstration of unavailability of alternate storage capacity and a specification of a schedule that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible. [40 CFR 60.113b(b)(4)] Federally Enforceable Through Title V Permit

49. The owner or operator of each storage vessel shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel. Such records shall be retained for the life of the source. [40 CFR 60.116b(b)] Federally Enforceable Through Title V Permit

50. Permittee shall maintain records of daily throughput. [District Rule 2520] Federally Enforceable Through Title V Permit

51. Permittee shall conduct true vapor pressure (TVP) testing of the organic liquid stored in this tank at least once every 24 months and/or whenever there is a change in the source or type of organic liquid stored in the tank. The TVP of any organic liquid shall be determined by measuring the Reid Vapor Pressure (RVP) using ASTM D 323 (Test Method for Vapor Pressure for Petroleum Products), and converting the RVP to TVP at the tank's maximum organic liquid storage temperature. The conversion of RVP to TVP shall be done in accordance with the procedures in appendix B of District Rule 4623. Records of TVP testing shall be maintained. [District Rule 2520 and 4623] Federally Enforceable Through Title V Permit

52. Compliance with permit conditions in the Title V permit shall be deemed compliance with District Rule 4623 (amended may 19, 2005) and 40CFR60 Subpart Kb. A permit shield is granted form this requirement. [District Rule 2520] Federally Enforceable Through Title V Permit

San Joaquin Valley
Air Pollution Control District

PERMIT TO OPERATE **FACILITY ADDRESS:**

LOCATION: **MODIFICATION:**

EQUIPMENT DESCRIPTION:

PERMIT UNIT REQUIREMENTS

1. This engine shall be equipped with either a positive crankcase ventilation (PCV) system that recirculates crankcase emissions into the air intake system for combustion, or a crankcase emissions control device of at least 90% control efficiency. [District Rule 2201] Federally Enforceable Through Title V Permit
2. The engine shall be equipped with a turbocharger and with an aftercooler or intercooler. [District Rule 2201] Federally Enforceable Through Title V Permit
3. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201] Federally Enforceable Through Title V Permit
4. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101] Federally Enforceable Through Title V Permit
5. This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems". Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 100 hours per calendar year. [District Rule 4702 and 17 CCR 93115 and 40 CFR 63 Subpart ZZZZ] Federally Enforceable Through Title V Permit
6. The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115] Federally Enforceable Through Title V Permit
7. An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702] Federally Enforceable Through Title V Permit
8. The permittee shall maintain monthly records of the type of fuel purchased, the amount of fuel purchased, date when the fuel was purchased, signature of the permittee who received the fuel, and signature of the fuel supplier indicating that the fuel was delivered. [Rule 2520 and 17 CCR 93115] Federally Enforceable Through Title V Permit
9. If this engine is located on the grounds of a K-12 school, or if this engine is located within 500 feet of the property boundary of a K-12 school, the engine shall not be operated for non-emergency purposes, including maintenance and testing, between 7:30 a.m. and 3:30 p.m. on days when school is in session. [Rule 2520 and 17 CCR 93115] Federally Enforceable Through Title V Permit

10. If this engine is located on the grounds of a K-12 school, the engine shall not be operated for non-emergency purposes, including maintenance and testing, whenever there is a school sponsored activity. [Rule 2520 and 17 CCR 93115] Federally Enforceable Through Title V Permit

11. Compliance with permit conditions in the Title V permit shall be deemed compliance with the following applicable requirements of SJVUAPCD Rule 4201 (Amended December 17, 1992) and Kern County Rule 407. A permit shield is granted from these requirements. [District Rule 2520] Federally Enforceable Through Title V Permit

12. All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115] Federally Enforceable Through Title V Permit

13. This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702 and 17 CCR 93115, and 40 CFR 63 Subpart ZZZZ] Federally Enforceable Through Title V Permit

14. This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702 and 40 CFR 63 Subpart ZZZZ] Federally Enforceable Through Title V Permit

15. Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4702 and 17 CCR 93115] Federally Enforceable Through Title V Permit

16. During periods of operation for maintenance, testing, and required regulatory purposes, the permittee shall monitor the operational characteristics of the engine as recommended by the manufacturer or emission control system supplier (for example: check engine fluid levels, battery, cables and connections; change engine oil and filters; replace engine coolant; and/or other operational characteristics as recommended by the manufacturer or supplier). [District Rule 4702 and 40 CFR 63 Subpart ZZZZ] Federally Enforceable Through Title V Permit

17. This engine shall not be used to produce power for the electrical distribution system, as part of a voluntary utility demand reduction program, or for an interruptible power contract. [District Rule 4702 and 40 CFR 63, Subpart ZZZZ] Federally Enforceable Through Title V Permit

18. The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.) and records of operational characteristics monitoring. For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115 and 40 CFR 63, Subpart ZZZZ] Federally Enforceable Through Title V Permit

19. All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 1070, 4702, 2520 and 17 CCR 93115, and 40 CFR 63 Subpart ZZZZ] Federally Enforceable Through Title V Permit

20. The engine shall be in full compliance with 40 CFR Part 63, Subpart ZZZZ (National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines). [40 CFR 63, Subpart ZZZZ] Federally Enforceable Through Title V Permit

21. The permittee must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes. [40 CFR 63, Subpart ZZZZ] Federally Enforceable Through Title V Permit

22. The engine's oil and filter shall be changed every 500 hours of operation or every 12 months, whichever comes first. [40 CFR 63, Subpart ZZZZ] Federally Enforceable Through Title V Permit

23. The engine's air filter shall be inspected every 1,000 hours of operation or every 12 months, whichever comes first, and replaced as necessary. [40 CFR 63, Subpart ZZZZ] Federally Enforceable Through Title V Permit

24. The engine's hoses and belts shall be inspected every 500 hours of operation or every 12 months, whichever comes first, and replaced as necessary. [40 CFR 63, Subpart ZZZZ] Federally Enforceable Through Title V Permit

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25. The permittee shall maintain records of performance tests and performance evaluations as required in §63.10(b)(2)(viii) and records of required maintenance performed on the air pollution control and monitoring equipment. [40 CFR 63, Subpart ZZZZ] Federally Enforceable Through Title V Permit

26. The permittee shall maintain records of the occurrence and duration of each malfunction of operation (i.e., process equipment) or the air pollution control and monitoring equipment. The permittee shall also maintain records of action taken during periods of malfunction to minimize emissions in accordance with §63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation. [40 CFR 63, Subpart ZZZZ] Federally Enforceable Through Title V Permit

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT REQUIREMENTS FOR: **EFFECTIVE DATE:**

ATTACHMENTS: **PERMIT UNIT REQUIREMENTS:**

PERMIT UNIT REQUIREMENTS

THE FOLLOWING TERMS AND CONDITIONS HAVE BEEN ESTABLISHED BY THE DISTRICT TO ENSURE COMPLIANCE WITH DISTRICT, STATE AND FEDERAL RULES AND REGULATIONS. FAILURE TO COMPLY WITH ANY OF THESE TERMS AND CONDITIONS MAY RESULT IN ENFORCEMENT ACTION.

PERMIT UNIT REQUIREMENTS

1. The true vapor pressure of liquid stored shall not exceed 11.0 psia. [District Rule 2201] Federally Enforceable Through Title V Permit
2. Total throughput of organic liquid with TVP greater than 5.9 psia and less than or equal to 11.0 psia shall not exceed either of the following limits: 190,000 bbl/day or 85,000 bbl/day on a monthly average basis. [District Rule 2201] Federally Enforceable Through Title V Permit
3. Total throughput of organic liquid with TVP less than or equal to 5.9 psia shall not exceed either of the following limits: 360,000 bbl/day or 180,000 bbl/day on a monthly average basis. [District Rule 2201] Federally Enforceable Through Title V Permit
4. Combined total throughput of permits S-77-9, '-11, and '-14 shall not exceed either of the following limits: 550,000 bbl/day or 265,000 bbl/day on a monthly average basis. [District Rule 2201] Federally Enforceable Through Title V Permit
5. VOC emission rate from permits S-77-9, '-11, and '-14 shall not exceed 227.1 lb/day. [District Rule 2201] Federally Enforceable Through Title V Permit
6. VOC emission rate from permits S-77-9, '-11, and '-14 shall not exceed 41,913 lb/yr. [District Rule 2201] Federally Enforceable Through Title V Permit
7. VOC emission rate shall not exceed 129.9 lb/day. [District Rule 2201] Federally Enforceable Through Title V Permit
8. Permittee shall maintain a record of the liquid stored, the period of storage, and the maximum true vapor pressure of that liquid during the respective storage period. [District Rule 2201 and 40 CFR 60.116b(c)] Federally Enforceable Through Title V Permit
9. Permittee shall maintain records of maximum daily throughput and monthly average daily throughput. [District Rule 2201] Federally Enforceable Through Title V Permit
10. When storing organic liquids with true vapor pressure less than 0.5 psia, the requirements of Sections 5.3, 5.5 and 6.1 of District Rule 4623 (Amended May 19, 2005) shall not apply to this unit. This exemption applies to all conditions in this permit referencing Rule 4623 Sections 5.3, 5.5 or 6.1 only. [District Rule 4623] Federally Enforceable Through Title V Permit
11. When storing organic liquids with true vapor pressure less than 0.75 psia, the requirements of 40 CFR 60 Subpart Kb shall not apply to this unit. This exemption applies to all conditions in this permit referencing 40 CFR 60 Subpart Kb only. [40 CFR 60.112b(a)] Federally Enforceable Through Title V Permit

12. Before switching to the storage of organic liquids with true vapor pressure greater than or equal to 0.5 psia, all covers, seals, and lids shall be inspected by the facility operator to ensure compliance with the provisions of this permit. This includes all conditions containing District Rule 4623 reference. [District Rule 2520] Federally Enforceable Through Title V Permit

13. Before switching to the storage of organic liquids with true vapor pressure greater than or equal to 0.75 psia, all covers, seals, and lids shall be inspected by the facility operator to ensure compliance with the provisions of this permit. This includes all conditions containing District Rule 4623 or 40 CFR 60 Subpart Kb reference. [District Rule 2520] Federally Enforceable Through Title V Permit

14. This tank shall be equipped with a closure device between the tank shell and roof edge consisting of two seals mounted one above the other; the one below shall be referred to as the primary seal, and the one above shall be referred as the secondary seal. [District Rules 2201 and 4623 and 40 CFR 60.112b(a)(2)(i)] Federally Enforceable Through Title V Permit

15. The external floating roof shall float on the surface of the stored liquid at all times (i.e., off the roof leg supports) except during the initial fill until the roof is lifted off the leg supports and when the tank is completely emptied and subsequently refilled. When the roof is resting on the leg supports, the process of filling, emptying, or refilling shall be continuous and shall be accomplished as rapidly as possible. Whenever the permittee intends to land the roof on its legs, the permittee shall notify the APCO in writing at least five calendar days prior to performing the work. The tank must be in compliance with this rule before it may land on its legs. [District Rule 4623 and 40 CFR 60.112b(a)(2)(iii)] Federally Enforceable Through Title V Permit

16. Gaps between the tank shell and the primary seal shall not exceed 1 1/2 inches. [District Rule 4623 and 40 CFR 60.113b(b)(4)(i)] Federally Enforceable Through Title V Permit

17. The cumulative length of all gaps between the tank shell and the primary seal greater than 1/2 inch shall not exceed 10% of the circumference of the tank. [District Rule 4623 and 40 CFR 60.113b(b)(4)(i)] Federally Enforceable Through Title V Permit

18. The cumulative length of all primary seal gaps greater than 1/8 inch shall not exceed 30% of the circumference of the tank. [District Rule 4623 and 40 CFR 60.113b(b)(4)(i)] Federally Enforceable Through Title V Permit

19. No continuous gap in the primary seal greater than 1/8 inch wide shall exceed 10% of the tank circumference. [District Rule 4623 and 40 CFR 60.113b(b)(4)(i)] Federally Enforceable Through Title V Permit

20. No gap between the tank shell and the secondary seal shall exceed 1/2 inch. [District Rule 4623 and 40 CFR 60.113b(b)(4)(ii)(B)] Federally Enforceable Through Title V Permit

21. The cumulative length of all gaps between the tank shell and the secondary seal, greater than 1/8 inch shall not exceed 5% of the tank circumference. [District Rule 4623 and 40 CFR 60.113b(b)(4)(ii)(B)] Federally Enforceable Through Title V Permit

22. The metallic shoe-type seal shall be installed so that one end of the shoe extends into the stored liquid and the other end extends a minimum vertical distance of 24 inches above the stored liquid surface. [District Rule 4623 and 40 CFR 60.113b(b)(4)(i)(A)] Federally Enforceable Through Title V Permit

23. The geometry of the metallic-shoe type seal shall be such that the maximum gap between the shoe and the tank shell shall be no greater than 3 inches for a length of at least 18 inches in the vertical plane above the liquid. [District Rule 4623] Federally Enforceable Through Title V Permit

24. There shall be no holes, tears, or openings in the secondary seal or in the primary seal envelope that surrounds the annular vapor space enclosed by the roof edge, seal fabric, and secondary seal. Except for gaps meeting permit requirements, the primary seal shall completely cover the annular space between the edge of the floating roof and tank wall. [District Rule 4623 and 40 CFR 60.112b(a)(2)(i)(A), 40 CFR 60.113b(b)(4)(i)(B) and 60.113b(b)(4)(ii)(C)] Federally Enforceable Through Title V Permit

25. The secondary seal shall allow easy insertion of probes of up to 1 1/2 inches in width in order to measure gaps in the primary seal. [District Rule 4623] Federally Enforceable Through Title V Permit

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26. The secondary seal shall extend from the roof to the tank shell and shall not be attached to the primary seal. Except for gaps meeting permit requirements, the secondary seal shall completely cover the annular space between the external floating roof and the wall of the storage vessel in a continuous fashion. [District Rule 4623 and 40 CFR 60.112b(a)(2)(i)(B) and 40 CFR 60.113b(b)(4)(ii)(A)] Federally Enforceable Through Title V Permit

27. All openings in the roof used for sampling and gauging, except pressure-vacuum valves which shall be set to within 10% of the maximum allowable working pressure of the roof, shall provide a projection below the liquid surface to prevent belching of liquid and to prevent entrained or formed organic vapor from escaping from the liquid contents of the tank and shall be equipped with a cover, seal or lid that shall be in a closed position at all times, with no visible gaps and be gas tight, except when the device or appurtenance is in use. [District Rule 4623] Federally Enforceable Through Title V Permit

28. A gas-tight condition is defined as a condition without a gas leak. A gas leak is defined as a reading in excess of 10,000 ppmv, above background, as measured by a portable hydrocarbon detection instrument in accordance with the procedures specified in EPA Test Method 21. A reading in excess of 10,000 ppmv above background is a violation of this permit and Rule 4623 and shall be reported as a deviation. [District Rule 4623] Federally Enforceable Through Title V Permit

29. Except for automatic bleeder vents, rim vents, and pressure relief vents, each opening in a non-contact external floating roof shall provide a projection below the liquid surface. [District Rule 4623 and 40 CFR 60.112b(a)(2)(ii)] Federally Enforceable Through Title V Permit

30. Except for automatic bleeder vents and rim vents, roof drains, and leg sleeves, each opening in the roof shall be equipped with a gasketed cover, seal, or lid that shall be maintained in a closed position at all times (i.e., no visible gap) except when in actual use. [District Rule 4623 and 40 CFR 60.112b(a)(2)(ii)] Federally Enforceable Through Title V Permit

31. Automatic bleeder vents shall be equipped with a gasket and shall be closed at all times when the roof is floating except when the roof is being floated off or is being landed on the roof leg supports. [District Rule 4623 and 40 CFR 60.112b(a)(2)(ii)] Federally Enforceable Through Title V Permit

32. Rim vents shall be equipped with a gasket and shall be set to open when the roof is being floated off the roof leg supports or at the manufacturer's recommended setting. [District Rule 4623 and 40 CFR 60.112b(a)(2)(ii)] Federally Enforceable Through Title V Permit

33. Each emergency roof drain shall be provided with a slotted membrane fabric cover that covers at least 90 percent of the area of the opening. The fabric cover must be impermeable if the liquid is drained into the contents of the tanks. [District Rule 4623 and 40 CFR 60.112b(a)(2)(ii)] Federally Enforceable Through Title V Permit

34. External floating roof legs shall be equipped with vapor socks or vapor barriers in order to maintain a gas-tight condition so as to prevent VOC emissions from escaping through the roof leg opening. [District Rule 4623] Federally Enforceable Through Title V Permit

35. All wells and similar fixed projections through the floating roof shall provide a projection below the liquid surface. [District Rule 4623] Federally Enforceable Through Title V Permit

36. The solid guidepole well shall be equipped with a pole wiper and a gasketed cover, seal or lid which shall be in a closed position at all times (i.e., no visible gap) except when the well is in use. [District Rule 4623] Federally Enforceable Through Title V Permit

37. The gap between the pole wiper and the solid guidepole shall be added to the gaps measured to determine compliance with the secondary seal requirement, and in no case shall exceed 1/2 inch. [District Rule 4623] Federally Enforceable Through Title V Permit

38. The slotted guidepole well on a external floating roof shall be equipped with the following: a sliding cover, a well gasket, a pole sleeve, a pole wiper, and an internal float and float wiper designed to minimize the gap between the float and the well, and provided the gap shall not exceed 1/8 inch; or shall be equipped with a well gasket, a zero gap pole wiper seal and a pole sleeve that projects below the liquid surface. [District Rule 4623] Federally Enforceable Through Title V Permit

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39. The gap between the pole wiper and the slotted guidepole shall be added to the gaps measured to determine compliance with the secondary seal requirement, and in no case shall exceed 1/8 inch. [District Rule 4623] Federally Enforceable Through Title V Permit

40. The permittee of external floating roof tanks shall make the primary seal envelope available for unobstructed inspection by the APCO on an annual basis at locations selected along its circumference at random by the APCO. In the case of riveted tanks with toroid-type seals, a minimum of eight locations shall be made available; in all other cases, a minimum of four locations shall be made available. If the APCO suspects a violation may exist the APCO may require such further unobstructed inspection of the primary seal as may be necessary to determine the seal condition for its entire circumference. [District Rule 4623] Federally Enforceable Through Title V Permit

41. Measurements of gaps between the tank wall and the primary and secondary seal shall be performed during the hydrostatic testing of the vessel or within 60 days of the initial fill with a volatile organic liquid. [40 CFR 60.113b(b)(1)(i)] Federally Enforceable Through Title V Permit

42. If any source ceases to store volatile organic liquid for a period of 1 year or more, subsequent introduction of volatile organic liquid into the vessel shall be considered an initial fill. [40 CFR 60.113b(b)(1)(iii)] Federally Enforceable Through Title V Permit

43. The permittee shall inspect all floating roof tanks at least once every 12 months to determine compliance with the requirements of this rule. The actual gap measurements of the floating roof primary and secondary seals shall be recorded. Permittee shall measure seal gaps, at one or more floating roof levels when the roof is floating off the roof leg supports, around the entire circumference of the tank in each place where a 0.32-cm diameter uniform probe passes freely (without forcing or binding against seal) between the seal and the wall of the storage vessel and measure the circumferential distance of each such location. The inspection results shall be submitted to the APCO as specified in Section 6.3.5. [County Rule 107 (40 CFR 60.113b(b)(1)(i) & (ii); and 40 CFR 60.113b(b)(2)(i) & (ii)] Federally Enforceable Through Title V Permit

44. The permittee shall inspect the primary and secondary seals for compliance with the requirements of this rule every time a tank is emptied or degassed. Actual gap measurements shall be performed when the liquid level is static but not more than 48 hours after the tank roof is re-floated. If the external floating roof has defects, the primary seal has holes, tears, or other openings in the seal or the seal fabric, or the secondary seal has holes, tears, or other openings in the seal or the seal fabric, the owner or operator shall repair the items as necessary before filling or refilling the storage vessel. The owner or operator shall notify the APCO in writing at least 30 days prior to the filling or refilling of each storage vessel to afford the APCO the opportunity to inspect the storage vessel prior to refilling. [District Rule 4623 and 40 CFR 60.113b(b)(6)] Federally Enforceable Through Title V Permit

45. Permittee shall submit the reports of the floating roof tank inspections to the APCO within five calendar days after the completion of the inspection only for those tanks that failed to meet the applicable requirements of Rule 4623, Sections 5.2 through 5.5. The inspection report for tanks that that have been determined to be in compliance with the requirements of Sections 5.2 through 5.5 need not be submitted to the APCO, but the inspection report shall be kept on-site and made available upon request by the APCO. The inspection report shall contain all necessary information to demonstrate compliance with the provisions of Rule 4623. [District Rule 4623 and 40 CFR 60.115b(b)] Federally Enforceable Through Title V Permit

46. Permittee shall maintain the records of the external floating roof landing activities that are performed pursuant to Rule 4623, Sections 5.3.1.3 and 5.4.3. The records shall include information on the true vapor pressure (TVP), API gravity, storage temperature, type of organic liquid stored in the tank, the purpose of landing the roof on its legs, the date of roof landing, duration the roof was on its legs, the level or height at which the tank roof was set to land on its legs, and the lowest liquid level in the tank. [District Rule 4623] Federally Enforceable Through Title V Permit

47. All records required to be maintained by this permit shall be maintained for a period of at least five years and shall be made readily available for District inspection upon request. [District Rule 4623 and 40 CFR 60.116b(a)] Federally Enforceable Through Title V Permit

48. Permittee shall notify District at least 30 days prior to the date when unobstructed primary and secondary seal/gap measurements will occur to afford the APCO the opportunity to have an observer present. [40 CFR 60.113b(b)(5)] Federally Enforceable Through Title V Permit

49. Permittee shall make necessary repairs or empty the storage vessel within 45 days of identification in any inspection for seals not meeting the requirements listed in 40 CFR 60.113b(b)(4)(i) and (ii). If necessary repairs cannot be made within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the APCO. Such an extension request must include a demonstration of unavailability of alternate storage capacity and a specification of a schedule that will assure that the control equipment will be repaired or the vessel will be emptied as soon as possible. [40 CFR 60.113b(b)(4)] Federally Enforceable Through Title V Permit

50. The owner or operator of each storage vessel shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel. Such records shall be retained for the life of the source. [40 CFR 60.116b(b)] Federally Enforceable Through Title V Permit

51. Permittee shall maintain records of daily throughput. [District Rule 2520] Federally Enforceable Through Title V Permit

52. Permittee shall conduct true vapor pressure (TVP) testing of the organic liquid stored in this tank at least once every 24 months and/or whenever there is a change in the source or type of organic liquid stored in the tank. The TVP of any organic liquid shall be determined by measuring the Reid Vapor Pressure (RVP) using ASTM D 323 (Test Method for Vapor Pressure for Petroleum Products), and converting the RVP to TVP at the tank's maximum organic liquid storage temperature. The conversion of RVP to TVP shall be done in accordance with the procedures in appendix B of District Rule 4623. Records of TVP testing shall be maintained. [District Rule 2520] Federally Enforceable Through Title V Permit

53. Compliance with permit conditions in the Title V permit shall be deemed compliance with District Rule 4623 (amended may 19, 2005) and 40CFR60 Subpart Kb. A permit shield is granted form this requirement. [District Rule 2520] Federally Enforceable Through Title V Permit

San Joaquin Valley
Air Pollution Control District

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1. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
2. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
3. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
4. This engine shall be equipped with either a positive crankcase ventilation (PCV) system that recirculates crankcase emissions into the air intake system for combustion, or a crankcase emissions control device of at least 90% control efficiency. [District Rule 2201]
5. The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]
6. This engine shall be equipped with a non-resettable hour meter with a minimum display capability of 9,999 hours, unless the District determines that a non-resettable hour meter with a different minimum display capability is appropriate in consideration of the historical use of the engine and the owner or operator's compliance history. [District Rule 4702 and 17 CCR 93115]
7. Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801, and 17 CCR 93115]
8. Emissions from this IC engine shall not exceed 6.713 g-NOx/bhp-hr. [District Rule 2201 and 17 CCR 93115]
9. Emissions from this IC engine shall not exceed 0.369 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102, and 17 CCR 93115]
10. This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
11. During periods of operation for maintenance, testing, and required regulatory purposes, the permittee shall monitor the operational characteristics of the engine as recommended by the manufacturer or emission control system supplier (for example: check engine fluid levels, battery, cables and connections; change engine oil and filters; replace engine coolant; and/or other operational characteristics as recommended by the manufacturer or supplier). [District Rule 4702]
12. An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702 and 17 CCR 93115]
13. This engine shall not be used to produce power for the electrical distribution system, as part of a voluntary utility demand reduction program, or for an interruptible power contract. [District Rule 4702 and 17 CCR 93115]

14. This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 30 hours per calendar year. [District Rule 4702 and 17 CCR 93115]

15. The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.) and records of operational characteristics monitoring. For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

16. The permittee shall maintain monthly records of the type of fuel purchased. [District Rule 4702 and 17 CCR 93115]

17. If this engine is located on the grounds of a K-12 school, or if this engine is located within 500 feet of the property boundary of a K-12 school, the engine shall not be operated for non-emergency purposes, including maintenance and testing, between 7:30 a.m. and 3:30 p.m. on days when school is in session. [17 CCR 93115]

18. If this engine is located on the grounds of a K-12 school, the engine shall not be operated for non-emergency purposes, including maintenance and testing, whenever there is a school sponsored activity. [17 CCR 93115]

19. All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

NOV Report

Action Type: prior to
Sorted By Date, Source Name

Source: TEXACO TRADING & TRANSPORTATION INC. / KAREN LE\
SEC 32 T27S R20E CARNERAS PUMP STATION
LOST HILLS

Facility ID: S-77
Notice of Violation #: 002447
Violation Issued: 12/7/94
Violation Discovered: 12/7/94

Rule/Reg.: 2070

Pollutants:

Violation Description:
I.C. ENGINE NOT EQUIPPED W/POSITIVE CRANKCASE VENTILATION (PCV) SYSTEM/A CRANKCASE EMISSION CTRL DEVICE OF AT LEAST 90%

Compliance Achieved: 1/30/95

Verification Method(s): Other

Date : 04/25/1995

Mutual Settlement **Case Number:** S95-0096

Penalty Paid: $ 187.50

Source: TEXACO TRADING & TRANSFORMATION
SEC 34, T275 R 20E
LOST HILLS

Facility ID: S-77
Notice of Violation #: 010069
Violation Issued: 5/9/93
Violation Discovered: 5/9/93

Rule/Reg.: 4623

Pollutants:

Violation Description:
BETWEEN TANK SHELL AND THE SECONDARY SEAL WERE EXCESSIVE.

Compliance Achieved: 6/17/96

Verification Method(s): Other

Date : 10/28/1996

Mutual Settlement **Case Number:** S96-0403

Penalty Paid: $ 500.00

Source: TEXACO TRADING & TRANSPORTATION
5005 BUSINESS PARK NORTH SUITE 200
93309

Facility ID: S-77
Notice of Violation #: 010312
Violation Issued: 1/30/97
Violation Discovered: 1/30/97

Rule/Reg.: 4623

Pollutants:

Violation Description:
WHILE STORING ORGANIC LIQUID WITH TVP>1.5 THE ROOFS WERE ALLOW ED TO REST ON THEIR LEGS. A VAPOR SPACE WAS CREAT

Compliance Achieved: **Verification Method(s):**

Date : 05/02/1997

Mutual Settlement **Case Number:** S97-0094 **Penalty Paid:** $ 2,600.00

Source: EQUILON PIPELINE CO/GORDON JONES
SEC34, T27S, R20E, CARNERAS PUMP STAT.

Facility ID: S-77
Notice of Violation #: 16284
Violation Issued: 3/14/00
Violation Discovered: 3/14/00

Rule/Reg.: 4623 **Pollutants:**

Violation Description:
BLEEDER VENT OPEN & VENTING HYDROCARBONS INTO THE ATMOSPHERE

Compliance Achieved: 3/22/00 **Verification Method(s):** Other

Date : 04/30/2001

Mutual Settlement **Case Number:** S01-0107 **Penalty Paid:** $ 8,970.00

Source: SHELL PIPELINE CO/NOEL KURAI
CARNERAS PUMP STATION
LOST HILLS

Facility ID: S-77
Notice of Violation #: 17984
Violation Issued: 4/15/03
Violation Discovered: 4/15/03

Rule/Reg.: 2070 **Pollutants:**

Violation Description:
ALL OPENINGS IN TANK ROOF EXCEPT FOR PRESSURE VACUUM VALVES SHALL BE EQUIPPED WITH A GAS TIGHT COVER

Compliance Achieved: 4/16/03 **Verification Method(s):** Other

Date : 11/17/2003

Mutual Settlement **Case Number:** S03-0501 **Penalty Paid:** $ 2,000.00

Source: SHELL PIPELINE CO/NOEL KURAI
CARNERAS PUMP STATION
LOST HILLS

Facility ID: S-77
Notice of Violation #: 17986
Violation Issued: 1/31/02
Violation Discovered: 1/31/02

Rule/Reg.: 2070

Pollutants:

Violation Description:
THROUGHPUT EXCEEDED 30,000 BBL/DAY

Compliance Achieved: 3/31/03

Verification Method(s): Other

Date : 02/17/2004

Mutual Settlement **Case Number:** S03-0554 **Penalty Paid:** $ 4,500.00

Source: SHELL PIPELINE COMPANY LP
Carneras Pump Station
Lost Hills CA

Facility ID: S-77
Notice of Violation #: 22697
Violation Issued: 6/28/07
Violation Discovered: 6/20/07

Rule/Reg.: 4623

Pollutants:

Violation Description:
Rule 4623 section 5.3.2.1.2
The gap between the tank shell and secondary seal exceeded 1/2 inch.

Compliance Achieved: 6/20/07

Verification Method(s): Inspection

Date : 11/13/2007

Mutual Settlement **Case Number:** S07-0809 **Penalty Paid:** $ 4,500.00

Source: SHELL PIPELINE COMPANY LP
Carneras Pump Station
Lost Hills CA

Facility ID: S-77
Notice of Violation #: 22696
Violation Issued: 6/27/07
Violation Discovered: 6/20/07

Rule/Reg.: 4623

Pollutants: VOC

Violation Description:
Rule 4623 section 5.1.3
A gas leak in excess of 10,000 ppm was detected from the vacuum breaker.

Compliance Achieved: 7/18/07 **Verification Method(s):** Inspection

Date : 11/26/2007

Mutual Settlement **Case Number:** S07-0839 **Penalty Paid:** $ 12,000.00

Source: Shell Pipeline Company Lp
Carneras Pump Station
Lost Hills CA

Facility ID: S-77
Notice of Violation #: 5002275
Violation Issued: 6/18/08
Violation Discovered: 6/18/08

Rule/Reg.: 2070, 4623

Pollutants:

Violation Description:
Holes in the primary seal envelope was found. Breakdown relief was denied. Rule 2070 section 7, Rule 4623 section 5.3.2.1.5, and condition No. 14 on PTO S-77-11-4 were violated.

Compliance Achieved: 6/5/08 **Verification Method(s):** Inspection

Date : 09/18/2008

Mutual Settlement **Case Number:** S08-0900 **Penalty Paid:** $ 3,000.00

Source: Shell Pipeline Company Lp
Carneras Pump Station
Lost Hills CA

Facility ID: S-77
Notice of Violation #: 37551
Violation Issued: 7/9/08
Violation Discovered: 7/9/08

Rule/Reg.: 2070, 4623

Pollutants: VOC

Violation Description:
A gas leak of 20,000 ppm was detected from the intake valve on the Varec pressure/vacuum vent located opposite of the stairway.

Compliance Achieved: 7/11/08 **Verification Method(s):** Inspection

Date : 12/04/2008

Mutual Settlement **Case Number:** S08-1111 **Penalty Paid:** $ 5,000.00

Source: Shell Pipeline Company LP
Carneras Pump Station
Lost Hills CA

Facility ID: S-77
Notice of Violation #: 5011331
Violation Issued: 11/18/13
Violation Discovered: 11/1/13

Rule/Reg.: 2070, 2520, 4623

Pollutants:

Violation Description:
Torn wiper on secondary seal.

Compliance Achieved: 10/25/13 **Verification Method(s):** Records Review

Date : 03/10/2014

Mutual Settlement **Case Number:** S14-0136 **Penalty Paid:** $ 2,250.00

Source: Shell Pipeline Company LP
Carneras Pump Station
Lost Hills CA

Facility ID: S-77
Notice of Violation #: 5016633
Violation Issued: 9/29/16
Violation Discovered: 9/29/16

Rule/Reg.: 2070, 2520

Pollutants:

Violation Description:
Failure to inspect tank once every 12 months.

Compliance Achieved: 4/18/16 **Verification Method(s):** Records Review

Date : 12/30/2016

Mutual Settlement **Case Number:** S16-0621 **Penalty Paid:** $ 2,000.00

Source: Shell Pipeline Co LP
Carneras Pump Station
Lost Hills CA

Facility ID: S-77
Notice of Violation #: 5020411
Violation Issued: 9/12/18
Violation Discovered: 9/10/18

Rule/Reg.: 2070, 2520, 4623

Pollutants:

Violation Description:
Failure to maintain the secondary seal free of openings in a continuous fashion as required by permit -14-9, Conditions 24 and 26.

Failure to submit a deviation for a compromised secondary seal as required by Permit -0-1, Condition 12.

Compliance Achieved: 10/13/17 **Verification Method(s):** Records Review

Date : 04/09/2019

Mutual Settlement **Case Number:** S19-0136 **Penalty Paid:** $ 5,600.00

Department of Toxic Substances Control

Meredith Williams, Ph.D., Director
9211 Oakdale Avenue
Chatsworth, California 91311

Yana Garcia
Secretary for
Environmental Protection

Gavin Newsom
Governor

October 13, 2022

Tom Stanley
Stantec
tom.stanley@stantec.com

Public Records Request Number: PR3-101022-11

Locations: 20576, 20322, 20310 Seventh Standard RD, Mc Kittrick, CA 93251
20118 Lerdo Hy, Lost Hills, CA 93249
19683 Lost Hills Rd, Mc Kittrick, CA 93251
19662,19651, 19644, 19091, 19030, 18271 Hwy 33, Mc Kittrick, CA 93251
18667 Waterflood Rd, Mc Kittrick, CA 93251
18426 Pole Line Rd, Mc Kittrick, CA 93251
18271 Hwy 33, Belridge, CA 93249
17811, 17450, 17030Pole Line Rd, Lost Hills, CA 93249
16878,16864, 16631, 16435 Hwy 33, Lost Hills, CA 93249

APNs: 085-230-07, 085-230-09, 085-230-05, 085-190-19, 098-111-03, 098-112-26, 098-111-01, 098-112-02, 085-230-26, 085-220-37, 085-210-21, 085-210-18, 085-210-24, 085-210-23, 085-110-32,085-110-13, 068-220-09, 068-220-29, 068-220-30, 068-220-55, 068-220-18, 068-220-13

Dear Mr. Stanley:

On October 10, 2022, the Department of Toxic Substances Control (DTSC) received your email of the same date requesting records under the Public Records Act. After a thorough review of our files, no site records were found pertaining to the sites/facilities referenced above.

Many of our records are available on EnviroStor, an online database that provides non-confidential, public access to DTSC's data management system. It tracks our cleanup, permitting, enforcement, and investigation efforts at hazardous waste facilities and sites with known or suspected contamination issues. EnviroStor is available 24/7, 365 days a year. The data reflects the latest updates as they are entered in the system. Access it from your computer or smartphone, the local library – anywhere Internet access is

available. Just go to www.envirostor.dtsc.ca.gov. You will find a step-by-step tour of EnviroStor under the "How to Use EnviroStor" menu on the website.

If you have any questions or would like further information regarding your request, please contact me at 747-249-1019 or via email at ChatsworthFileRoom@dtsc.ca.gov.

Sincerely,
Roya Riahi Nejad
Roya Riahi Nejad
Records Mgmt. Asst. Coordinator

Melanie Briggs

From: "Information Request" <noreply@kernpublichealth.com>
Sent: Friday, October 7, 2022 4:50 PM
To: EH
Subject: New submission from Environmental Health: Information Request

CAUTION: This email originated from outside of the organization. Do not click links, open attachments, or provide information unless you recognize the sender and know the content is safe.

Describe the records you are requesting in as much detail (business name, address, type of record desired, etc.) as possible:

Stantec is completing a Phase I Environmental Site Assessment of multiple parcels located in western Kern County. Our client is proposing to construct a pipeline that will span (approximately) from North Belridge, southwards to Missouri Triangle; an approximate distance of 12 miles. The purpose is to evaluate the parcels from when they were undeveloped, what the parcels were historically used for, and their current use. We then identify potential risks associated with those activities and provide recommendations to our client.

The regulations put forth by the Environmental Protection Agency require us to follow All Appropriate Inquiry practices (Title 40 of the Code of Federal Regulations, Part 312), which involves requesting information held by regulatory bodies that pertain to environmental matters at our subject property. As such, Stantec kindly requests that you review the attached spreadsheet which contains a list of parcels identified by Assessor Parcel Number that the proposed pipeline will pass through, with street addresses included where present.

Once reviewed, we would be grateful if you could let us know of any records associated with the parcels which may be of environmental importance to our assessment, including but not limited to:
• Records of above/underground storage tanks (past and present);
• Records of spills/releases of hazardous materials
• Records of the storage of hazardous materials and/or inspections that have been completed
• Records of past site assessments, such as Phase I ESA reports or Phase II soil/groundwater/soil vapor sampling reports
• Records of public nuisances due to site activities (noise, odors, illegal or unpermitted processes)
• Records of current or past planning/building permits, particularly for commercial or industrial uses.

We understand that you may not hold records sorted by APN, so below is a list of parcels for which we have identified formal street addresses:

20576 SEVENTH STANDARD RD MC KITTRICK
20322 SEVENTH STANDARD RD MC KITTRICK
20310 SEVENTH STANDARD RD MC KITTRICK
20118 LERDO HY LOST HILLS
19683 LOST HILLS RD MC KITTRICK
19662 HIGHWAY 33 MC KITTRICK
19651 HWY 33 MC KITTRICK
19644 HIGHWAY 33 MC KITTRICK
19091 HIGHWAY 33 MC KITTRICK
19030 HIGHWAY 33 MC KITTRICK
18667 WATERFLOOD RD BELRIDGE
18426 POLE LINE RD MC KITTRICK
18271 HWY 33 MC KITTRICK
18271 HIGHWAY 33 HW BELRIDGE
17811 POLE LINE RD LOST HILLS
17450 POLELINE RD LOST HILLS
17030 POLE LINE RD LOST HILLS
16878 HIGHWAY 33 LOST HILLS
16864 HWY 33 LOST HILLS
16864 HWY 33 LOST HILLS

16631 HWY 33 LOST HILLS
16435 HIGHWAY 33 HY LOST HILLS

We appreciate your assistance with this request. Please feel free to contact me should you have any questions or concerns.

Name

Thomas Stanley

Address

290 Conejo Ridge Avenue
Thousand Oaks, CA 91361
United States
Map It

Email

TOM.STANLEY@STANTEC.COM

Phone

(805) 358-3145

File

- addresses.pdf

ENVIRONMENTAL HEALTH SERVICES DEPARTMENT

MATTHEW CONSTANTINE, R.E.H.S., Director

2700 "M" STREET, SUITE 300
BAKERSFIELD, CA 93301-2370
Voice: (661) 862-8700
Fax: (661) 862-8701
TTY Relay: (800) 735-2929
Web: www.co.kern.ca.us/eh
E-mail: *eh@co.kern.ca.us*

RESOURCE MANAGEMENT AGENCY

DAVID PRICE III, RMA DIRECTOR

Animal Control Department
Community and Economic Development Department
Engineering and Survey Services Department
Environmental Health Services Department
Planning Department
Roads Department

September 14, 2009

CERTIFIED UNIFIED PROGRAM AGENCY (CUPA)
HAZARDOUS MATERIAL INSPECTION FORM

Date: 09/14/2009 Facility ID: FA0004246 File #: 000314

Facility Name: RSC EQUIPMENTAL RENTAL 684			**Inspection Type**		
Site Address: 19091 HIGHWAY 33 MCKITTRICK, CA 93251			☒ **Routine**		
			☐ **Reinspection**		
Phone: (661)762-9156			☐ **Complaint**		
PROGRAMS INSPECTED:	☒ Business Plan	☒ HW Generator	☐ UST	☒ AGT	☐ CalARP
REINSPECTION REQUIRED:	☐ Business Plan	☐ HW Generator	☐ UST	☐ AGT	☐ CalARP

VIOLATION

YES	NO/NA	VIOL. #	BUSINESS PLAN REQUIREMENTS
☐	☒	BP01	Inventory of hazardous materials is accurate, up to date, and complete [HSC 6.95, 25504, Title 19 CCR 2729].
☐	☒	BP02	Site layout/facility maps are accurate [HSC 6.95,25504; Title 19 CCR 2729].
☒	☐	BP03	Hazardous materials are stored in properly labeled and non-detoriated containers [HSC 25124(b)(3)(A & B)].
☐	☒	ER01	Contingency Plan is complete, updated, and maintained on site [HSC 6.95, 25504;Title 19 CCR 2731 Title 22 CCR 66265.53-54].
☐	☒	ER02	Facility is operated and maintained to prevent/mitigate fire, explosion, or releases of hazardous material or waste which could threaten human health or the environment [Title 22 CCR 66265.31; Title 19 CCR 2731].
☐	☒	ER03	Business has equipment required to, or appropriate for, safely handling hazardous materials [Title 22 CCR 66265.32 & .34].
☐	☒	TR01	Facility has a training program appropriate for the size and complexity of business and nature of hazardous materials handled [Title 19 CCR 2732; Title 22 CCR 66265.16].
☐	☒	TR02	Training documentation is maintained on site for current personnel. [Title 19 CCR 2732;22 CCR 66265.16].

VIOLATION

ABOVE GROUND STORAGE TANKS

☐	☒	AT01	SPCC Plan prepared, reviewed, and certified by a registered engineer within last 5 years [HSC 6.67 S25270].

COMMENTS: **Go to http://www.co.kern.ca.us/eh/cupaprogram.asp for forms and information.**

GPS Coordinates: Latitude: **Longtitude:**

INSPECTOR: WAQAR RUSTAM **DATE:** 09/14/2009

HAZARDOUS WASTE GENERATOR

EPA ID NUMBER: CAL 000 237 885

VIOLATIONS

YES	NO/NA	VIOL. #	GENERATOR REQUIREMENTS
☐	☒	GR01	Generator has an EPA Identification number to treat, store, dispose, transport, or transfer hazardous waste [Title 22, CCR 66262.12].
☐	☒	GR02	The facility has made an appropriate waste determination for hazardous based on own knowledge or analysis or other [Title 22, CCR 66262.11]
☐	☒	GR03	Facility Personnel demonstrate awareness of proper(legal) hazardous-waste handling procedures. [Title 22, CCR, 66262.34(d)(2)].
☐	☒	GA01	Hazardous waste has not accumulated for more than 90/180/270 days(depending upon volume/circumstances) without the facility having a hazardous waste storage permit [Title 22,CCR, 66262.34(a).]
☐	☒	GA02	Empty containers or inner liners greater than 5 gallons have dates when emptied and are managed properly within one year of date emptied [Title 22, CCR, 66261.7(f)].
☐	☒	GA03	Universal waste is not accumulated at facility for more than one year [Title 22, CCR, 66273.15(a);66273.35(a)].
☐	☒	GA04	The facility disposes used oil filters within 180 days of generation (or one year if less than 1 ton are accumulated) [Title 22, CCR, 66266.130(c)(4)].
☐	☒	GA05	The facility disposes lead-acid batteries within 180 days of generation (or one year if less than 1 ton are accumulated) [Title 22, CCR, 66268.81(a)(6)]
☐	☒	GC01	Hazardous waste storage containers are in good condition [Title 22, CCR, 66262.34(a)(1)(A)].
☐	☒	GC02	Containers holding hazardous waste are closed/sealed except when adding/removing waste [Title 22, CCR, 66262.34(a)(1)(A)].]
☐	☒	GC03	The facility documents weekly inspections of hazardous waste storage area/containers [Title 22, CCR, 66265.15(d) and 66262.34(a)(1)(A)].
☐	☒	GC04	The facility documents daily inspections of tanks where hazardous waste is stored [Title 22, CCR 66262.34(a)(1)(A)].
☐	☒	GC05	The facility has adequate secondary containment for hazardous waste tank systems [Title 22, CCR 66262.34(a)(1)(A)].
☐	☒	GC06	Containers utilizing satellite accumulation rules are at or near the point of generation [Title 22, CCR 66262.34(e)(1)(A)].
☐	☒	GC07	Satellite wastes are managed according to the regulations (complete labeling, accumulation times, 55-gallon or 1 quart volume limits, etc.). [Title 22, CCR, 66262.34(e)].
☐	☒	GR04	Manifests or LDRs are properly completed and/or retained by generator for 3 years [Title 22, CCR 66262.23(a)(1); 66263.42;66263.24;66262.34(a)(4)].
☐	☒	GR05	The facility filed an exception report to DTSC after not receiving the signed TSDF copy of a manifest within 35 days [Title 22, CCR, 66262.42].
☐	☒	GR06	The facility has copies of bills of lading or receipts for removal of hazardous wastes [HSC 25160.2-Consolidated manifests/ 66266.81(a)(6)(B)-lead acid batteries/66266.130- oil filters]. The facility shall maintain copies of receipts for at least three years.
☐	☒	GR07	The facility submitted a hazardous waste recycling report [HSC 25143.10]
☐	☒	GT01	The facility is conducting on-site treatment of hazardous waste with a tiered permit [HSC 25189.5(d)]
☐	☒	GT02	Authorized, licensed, and certified hazardous waste haulers are used to transport hazardous waste to appropriate facilities [H&S Code Chapter 6.5 Section 25163].
☐	☒	GT03	Hazardous wastes are sent to authorized disposal facilities [HSC 25189.5].
☐	☒	GT04	Hazardous waste is not disposed to ground, water, or air [HSC 25189.5].

INSPECTOR: WAQAR RUSTAM **DATE:** 09/14/2009

VIOLATIONS

YES	NO/NA	VIOL. #	GENERATOR REQUIREMENTS
☐	☒	GL01	Containers of hazardous waste are properly labeled (includes appropriate accumulation date, the words "HAZARDOUS WASTE," the waste composition/physical state, the hazardous properties, and name/address of generator) [Title 22, CCR, 66262.34(f)].
☐	☒	GL02	Containers of excluded recyclable materials are properly labeled [HSC 25143.9(a)].
☐	☒	GL03	Containers of universal waste are properly labeled. [Title 22, CCR, 66273.14 for SQH or 66273.34 for LQH].
☐	☒	GL04	Containers of drained used oil filters are labeled with the words "DRAINED USED OIL FILTERS" [Title 22, CCR, 66266.130(c)(3)].
☐	☒	GL05	Accumulation dates are marked on spent lead-acid batteries [22CCR 66266.81]
☐	☒	GL06	Tanks/containers of used oil destined for recycling are clearly marked with the words "USED OIL" [HSC 25143.9(a)].
☐	☒	GL07	Empty contaminated containers are clearly marked with the date they were emptied [Title 22, CCR, 66261.7(f)].

SUMMARY OF OBSERVATIONS/VIOLATIONS

☐ **No violations of underground storage tank, hazardous materials, or hazardous waste laws/regulations were discovered. KERN CUPA greatly appreciates your efforts to comply with all the laws and regulations**

☒ **Violations were observed/discovered as listed below. All violations must be corrected by implementing the corrective action listed by each violation. If you disagree with any of the violations or corrective actions required, please inform the CUPA in writing.**

ALL VIOLATIONS MUST BE CORRECTED WITHIN 30 DAYS OR AS SPECIFIED. CUPA must be informed in writing with a certification that compliance has been achieved. A false statement that compliance has been achieved is a violation of the law and punishable by a fine of not less than $2,000 or more than $25,000 for each violation. Your facility may be reinspected any time during normal business hours. If a second reinspection becomes necessary due to non compliance, a reinspection charge of $85.00 per hour may be charged to the facility.

You may request a meeting with the Program Manager to discuss the inspection findings and/or the proposed corrective actions. The issuance of this Summary of Violations does not preclude the CUPA from taking administrative, civil, or criminal action.

FACILITY NAME: RSC EQUIPMENTAL RENTAL 684 **ADDRESS:** 19091 HIGHWAY 33 MCKITTRICK, CA 93251 **FA ID:** FA0004246 **FILE ID:** 000314

VIOLATIONS

VIOL. NO	VIOL. TYPE	CORRECTIVE ACTION REQUIRED
BP03	MINOR VIOLATION	Hazardous materials can become discarded material and potentially hazardous waste if stored in improperly labeled containers or in deteriorated containers. Improperly labeled containers are to be properly labeled within ten days. Hazardous materials in deteriorated or leaking containers are to be placed in overpack containers or appropriate non-deteriorated containers within 96 hours. Otherwise the materials may be considered a waste. **PLEASE LABEL ALL THE CONTAINERS CONTAINING HAZARDOUS MATERIALS.**

INSPECTION COMMENTS:

INSPECTOR: WAQAR RUSTAM
DATE: 09/14/2009

SIGNATURE OF FACILITY REP:

Certification: I certify under penalty of perjury that this facility has complied with the corrective actions listed on this inspection form.
Signature of Owner/Operator: _____ **Title:** _____ **Date:**

ENVIRONMENTAL HEALTH SERVICES DEPARTMENT

MATTHEW CONSTANTINE, R.E.H.S., Director

2700 "M" STREET, SUITE 300
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September 14, 2009

CERTIFIED UNIFIED PROGRAM AGENCY (CUPA)
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INSPECTOR: WAQAR RUSTAM **DATE:** 09/14/2009

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FACILITY NAME: RSC EQUIPMENTAL RENTAL 684 **ADDRESS:** 19091 HIGHWAY 33 MCKITTRICK, CA 93251 **FA ID:** FA0004246 **FILE ID:** 000314

VIOLATIONS

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INSPECTION COMMENTS:

INSPECTOR: WAQAR RUSTAM
DATE: 09/14/2009

SIGNATURE OF FACILITY REP:

Certification: I certify under penalty of perjury that this facility has complied with the corrective actions listed on this inspection form.
Signature of Owner/Operator: _____ **Title:** _____ **Date:**

KERN COUNTY
Public Health Services
DEPARTMENT

ENVIRONMENTAL HEALTH DIVISION
UNIFIED PROGRAM AGENCY (UPA)

MATTHEW CONSTANTINE
DIRECTOR

2700 M STREET, SUITE 300 BAKERSFIELD, CALIFORNIA 93301-2370 VOICE: 661-862-8740 FAX: 661-862-8701 KERNPUBLICHEALTH.COM

HAZARDOUS MATERIALS BUSINESS PLAN (HMBP) INSPECTION REPORT

Facility Name: Torrance Valley Pipeline Company LLC - BELRIDGE		**Facility ID:** FA0000222
Site Address: 19662 HIGHWAY 33 RD MCKITTRICK, CA 93251		**CERS ID:** 10230871
Phone: (661) 763-7641	**Consent Granted By:** Scott Hedlund	**Inspection Date:** 01/17/2019
Inspection Type: ☒ Routine ☐ Reinspection	**Reinspection required:** ☐ Yes ☒ No	
Inspection Element: BUS PLAN LARGE LOW RISK 1 UNIT		

File/CERS Review Violations

V	Viol #	Summary	Code
	H335	Failure to adequately submit a complete HMBP into the California Environmental Reporting System (CERS)	HSC 6.95 25505, 25508(a)(1)
	F001	Failure to pay the HMBP annual permit fees	KCOC 8.04.030
	H344	Failure to complete and submit the Business Activities page and/or Business Owner/Operator Identification page in CERS	HSC 6.95 25508(a)(1); 19 CCR 4 2729.2(a)(1);
	H342	Failure to complete and submit Hazardous Materials Inventory information for all hazardous materials at or above reportable quantities in CERS	HSC 6.95 25505(a)(1), 25506, 25508(a)(1)
	H341	Failure to annually review and electronically certify that the HMBP is complete and accurate on or before the annual due date	HSC 6.95 25508(c), 25508.2
	H346	Failure to complete and submit Site Map with all required content in CERS	HSC 6.95 25505(a)(2), 25508(a)(1)
	H347	Failure to submit an adequate Emergency Response/Contingency plan in CERS	HSC 6.95 25505(a)(3), 25508(a)(1)
	H353	Failure to submit an adequate Employee Training Plan in CERS	HSC 6.95 25505(a)(4), 25508(a)(1)
	H340	Failure to notify property owner in writing that a HMBP is required	HSC 6.95 25505.1
	H336	Failure to provide property owner a copy of the HMBP upon request	HSC 6.95 25505.1

Onsite Inspection Violations

V	Viol #	Summary	Code
	H334	Failure to adequately establish and implement a HMBP	HSC 6.95 25507
	H345	Failure to revise HMBP in CERS within 30 days upon a change of information, inventory, address, ownership, or operation.	HSC 6.95 25508.1(a)-(f)
	H348	Failure to provide initial and annual safety training to all employees and/or failure to document and maintain training records for 3 years	HSC 6.95 25505(a)(4)
	H338	Failure to report a release or threatened release of a hazardous material to the CUPA and to California Office of Emergency Services	HSC 6.95 25510(a)
	H761	Failure to have the HMBP readily available to personnel of the business/facility	HSC 6.95 25505(c)

Inspector: Lana Elfstrom **Inspection Date:** 01/17/2019

CONDITIONAL EXEMPTIONS FROM REPORTING REQUIREMENTS

Agricultural handlers are conditionally exempt from electronically submitting Emergency Response and Employee Training Plans in CERS if the following requirements are met:

- Owner/Operator annually submits the Facility Information and Hazardous Materials Inventory electronically into CERS
- Each location/building, where hazardous materials (i.e. pesticides, petroleum products, fertilizers, etc.) are stored, is posted with warning signs that meet the following requirements:
  - Shall be conspicuous and visible from any direction of probable approach
  - Shall be of such size that it is readable from 25 feet and shall be labeled as follows:

> DANGER HAZARDOUS MATERIAL STORAGE AREA
> (the hazardous materials stored within shall be noted by category
> [i.e. pesticides, petroleum products, fertilizers, etc.])
> ALL UNAUTHORIZED PERSONS-KEEP OUT - IN AN EMERGENCY, CONTACT:
> (list the name and phone number of an emergency contact person(s))

  - Shall be repeated in an appropriate language other than English when persons who do not understand the English language may enter the posted location/building
- Owner/Operator provides training for all new employees and annual training, including refresher courses, for all employees in safety

Exempt Facility Violations

V	Viol #	Summary	Code
	H760	Failure to submit Emergency Response/Contingency Plan in CERS when not meeting agricultural handler exemption requirements	HSC 6.95 25507.1, 25508(a)(1); 19 CCR 4 2670, 2671
	H758	Failure to submit Employee Training Plan in CERS when not meeting agricultural handler exemption requirements	HSC 6.95 25507.1, 25508(a)(1); 19 CCR 4 2670, 2671
	H759	Failure to establish and submit a HMBP in CERS when not meeting remote unstaffed facility exemption requirements	HSC 6.95 25505, 25506, 25507.2, 25508(a)(1)

SUMMARY OF OBSERVATIONS/VIOLATIONS

☒ **No violations of hazardous materials business plan laws/regulations were discovered. Kern County UPA greatly appreciates your efforts to comply with all the laws and regulations applicable to your facility.**

☐ **Violations were observed/discovered as listed below. ALL VIOLATIONS MUST BE CORRECTED WITHIN 30 DAYS OR AS SPECIFIED. UPA must be informed in writing with a certification that compliance has been achieved. A false statement that compliance has been achieved is a violation of the law and punishable by a fine of not less than $2,000 or more than $25,000 for each violation. Your facility may be reinspected any time during normal business hours. If a second reinspection becomes necessary due to non compliance, a reinspection charge of $115.00 per hour may be charged to the facility.**

You may request a meeting with the Program Manager to discuss the inspection findings and/or the proposed corrective actions. The issuance of this Summary of Violations does not preclude the CUPA from taking administrative, civil, or criminal action.

INSPECTION COMMENTS:

COMMENTS: **Go to http://www.kernpublichealth.com/hazardous-materials for forms and information.**

Inspector: Lana Elfstrom **Signature of Facility Representative:**

Inspection Date: 01/17/2019

KERN COUNTY
Public Health Services
DEPARTMENT

ENVIRONMENTAL HEALTH DIVISION
UNIFIED PROGRAM AGENCY (UPA)

MATTHEW CONSTANTINE
DIRECTOR

2700 M STREET, SUITE 300 BAKERSFIELD, CALIFORNIA 93301-2370 VOICE: 661-862-8740 FAX: 661-862-8701 KERNPUBLICHEALTH.COM

HAZARDOUS MATERIALS BUSINESS PLAN (HMBP) INSPECTION REPORT

Facility Name: Torrance Valley Pipeline Company LLC - BELRIDGE		**Facility ID:** FA0000222
Site Address: 19662 HIGHWAY 33 RD MCKITTRICK, CA 93251		**CERS ID:** 10230871
Phone: (661) 763-7641	**Consent Granted By:** Scott Hedlund	**Inspection Date:** 01/17/2019
Inspection Type: ☒ Routine ☐ Reinspection	**Reinspection required:** ☐ Yes ☒ No	
Inspection Element: BUS PLAN LARGE LOW RISK 1 UNIT		

File/CERS Review Violations

V	Viol #	Summary	Code
	H335	Failure to adequately submit a complete HMBP into the California Environmental Reporting System (CERS)	HSC 6.95 25505, 25508(a)(1)
	F001	Failure to pay the HMBP annual permit fees	KCOC 8.04.030
	H344	Failure to complete and submit the Business Activities page and/or Business Owner/Operator Identification page in CERS	HSC 6.95 25508(a)(1); 19 CCR 4 2729.2(a)(1);
	H342	Failure to complete and submit Hazardous Materials Inventory information for all hazardous materials at or above reportable quantities in CERS	HSC 6.95 25505(a)(1), 25506, 25508(a)(1)
	H341	Failure to annually review and electronically certify that the HMBP is complete and accurate on or before the annual due date	HSC 6.95 25508(c), 25508.2
	H346	Failure to complete and submit Site Map with all required content in CERS	HSC 6.95 25505(a)(2), 25508(a)(1)
	H347	Failure to submit an adequate Emergency Response/Contingency plan in CERS	HSC 6.95 25505(a)(3), 25508(a)(1)
	H353	Failure to submit an adequate Employee Training Plan in CERS	HSC 6.95 25505(a)(4), 25508(a)(1)
	H340	Failure to notify property owner in writing that a HMBP is required	HSC 6.95 25505.1
	H336	Failure to provide property owner a copy of the HMBP upon request	HSC 6.95 25505.1

Onsite Inspection Violations

V	Viol #	Summary	Code
	H334	Failure to adequately establish and implement a HMBP	HSC 6.95 25507
	H345	Failure to revise HMBP in CERS within 30 days upon a change of information, inventory, address, ownership, or operation.	HSC 6.95 25508.1(a)-(f)
	H348	Failure to provide initial and annual safety training to all employees and/or failure to document and maintain training records for 3 years	HSC 6.95 25505(a)(4)
	H338	Failure to report a release or threatened release of a hazardous material to the CUPA and to California Office of Emergency Services	HSC 6.95 25510(a)
	H761	Failure to have the HMBP readily available to personnel of the business/facility	HSC 6.95 25505(c)

Inspector: Lana Elfstrom **Inspection Date:** 01/17/2019

CONDITIONAL EXEMPTIONS FROM REPORTING REQUIREMENTS

Agricultural handlers are conditionally exempt from electronically submitting Emergency Response and Employee Training Plans in CERS if the following requirements are met:

- Owner/Operator annually submits the Facility Information and Hazardous Materials Inventory electronically into CERS
- Each location/building, where hazardous materials (i.e. pesticides, petroleum products, fertilizers, etc.) are stored, is posted with warning signs that meet the following requirements:
  - Shall be conspicuous and visible from any direction of probable approach
  - Shall be of such size that it is readable from 25 feet and shall be labeled as follows:

> DANGER HAZARDOUS MATERIAL STORAGE AREA
> (the hazardous materials stored within shall be noted by category
> [i.e. pesticides, petroleum products, fertilizers, etc.])
> ALL UNAUTHORIZED PERSONS-KEEP OUT - IN AN EMERGENCY, CONTACT:
> (list the name and phone number of an emergency contact person(s))

  - Shall be repeated in an appropriate language other than English when persons who do not understand the English language may enter the posted location/building
- Owner/Operator provides training for all new employees and annual training, including refresher courses, for all employees in safety

Exempt Facility Violations

V	Viol #	Summary	Code
	H760	Failure to submit Emergency Response/Contingency Plan in CERS when not meeting agricultural handler exemption requirements	HSC 6.95 25507.1, 25508(a)(1); 19 CCR 4 2670, 2671
	H758	Failure to submit Employee Training Plan in CERS when not meeting agricultural handler exemption requirements	HSC 6.95 25507.1, 25508(a)(1); 19 CCR 4 2670, 2671
	H759	Failure to establish and submit a HMBP in CERS when not meeting remote unstaffed facility exemption requirements	HSC 6.95 25505, 25506, 25507.2, 25508(a)(1)

SUMMARY OF OBSERVATIONS/VIOLATIONS

☒ **No violations of hazardous materials business plan laws/regulations were discovered. Kern County UPA greatly appreciates your efforts to comply with all the laws and regulations applicable to your facility.**

☐ **Violations were observed/discovered as listed below. ALL VIOLATIONS MUST BE CORRECTED WITHIN 30 DAYS OR AS SPECIFIED. UPA must be informed in writing with a certification that compliance has been achieved. A false statement that compliance has been achieved is a violation of the law and punishable by a fine of not less than $2,000 or more than $25,000 for each violation. Your facility may be reinspected any time during normal business hours. If a second reinspection becomes necessary due to non compliance, a reinspection charge of $115.00 per hour may be charged to the facility.**

You may request a meeting with the Program Manager to discuss the inspection findings and/or the proposed corrective actions. The issuance of this Summary of Violations does not preclude the CUPA from taking administrative, civil, or criminal action.

INSPECTION COMMENTS:

COMMENTS: **Go to http://www.kernpublichealth.com/hazardous-materials for forms and information.**

Inspector: Lana Elfstrom **Signature of Facility Representative:**

Inspection Date: 01/17/2019

KERN COUNTY
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HAZARDOUS WASTE GENERATOR INSPECTION REPORT

Facility Name: Torrance Valley Pipeline Company LLC - BELRIDGE		**Facility ID:** FA0000222
Site Address: 19662 HIGHWAY 33 RD MCKITTRICK, CA 93251		**CERS ID:** 10230871 **EPA ID #:**
Phone: (661) 763-7641	**Consent Granted By:** Scott Hedlund	**Inspection Date:** 01/17/2019
Inspection Type: ☒ Routine ☐ Reinspection		**Reinspection required:** ☐ Yes ☒ No

Small Quantity Generator (SQG)	Large Quantity Generator (LQG)
22 CCR § 66262.34(d), 66262.34(d)(3); HSC § 25123.3(h)(1)	22 CCR § 66262.34; HSC § 25123.3
≤1,000 kg or ≤2,240 lbs or ≤270 gal per month	≥1000 kg or ≥2,240 lbs or ≥270 gal per month
Acute or Extremely Hazardous Waste	
≤1 kg or ≤2.2 lbs or ≤0.3 gals per month	≥1 kg or ≥2.2 lbs or ≥0.3 gals per month
Acute Spill Residue or Soil	
	≥100 kg or ≥220 lbs or ≥27 gals per month
Accumulation Time Limits	
22 CCR § 66262.34(b)*, 66262.34(d)(2), 66262.34(d)(3)	22 CCR 66262.34(a)
≤180 days or ≤270 days (if greater than 200 miles) *90 days from date 100 kg limit is reached	≤90 days

General Violations - All Generators

V	VIOL #	Summary	Code
	H804	Failure to report data electronically when required	HSC 6.11 25404(e)(4)
	F004	Failure to pay Hazardous Waste Generator permit fees	KCOC 8.04.030
	H236	Failure to obtain/maintain an active/correct EPA ID number	22 CCR 12 66262.12
	H251	Improper hazardous waste determination	22 CCR 12 66262.11
	H248	Failure to comply with all consolidated manifest procedures	22 CCR 12 66262.40(a); HSC 6.5 25160.2
	H239	Failure to properly complete the Uniform Hazardous Waste Manifest	22 CCR 12 66262.23(a)
	H243	Failure to properly prepare manifests for transportation	22 CCR 12 66262.20
	H246	Failure of owner/operator to send generator manifest copies to DTSC within 30 days	22 CCR 12 66262.23(a)(4)
	H241	Failure to maintain signed copies of manifests for 3 years	22 CCR 12 66262.40(a)
	H297	Hazardous waste not transported by registered hauler	22 CCR 13 66263.41; HSC 6.5 25163(a)
	H260	Improper labeling of hazardous waste containers/portable tanks	22 CCR 12 66262.34(f)
	H810	Failure mark stationary tanks with "Hazardous Waste" and/or accumulation start date	22 CCR 12 66262.34(f)

Inspector: Lana Elfstrom **Inspection Date:** 01/17/2019

General Violations - All Generators (continued)

V	VIOL #	Summary	Code
	H298	Disposal of hazardous waste at an unauthorized location	HSC 6.5 25189.5(a), 25201(a)
	H302	Failure to manage recyclable materials according to requirements	HSC 6.5 25143.2, 25143.9
	H296	Failure to properly manage used oil and fuel filters	22 CCR 16 66266.130; HSC 6.5 25250.22
	H812	Failure to properly manage empty containers > 5 gallons	22 CCR 11 66261.7
	H811	Failure to follow all requirements for hazardous waste satellite accumulation	22 CCR 12 66262.34(e)
	H808	Failure to properly manage soiled/contaminated rages before being sent for laundering	HSC 6.5 25144.6(b)

Small Quantity Generator - Violations

V	VIOL #	Summary	Code
	H242	Failure to conduct employee training on waste handling and emergency procedures	22 CCR 12 66262.34(d)(2); 40 CFR 262.34(d)(5)(iii)
	H256	Hazardous waste accumulation time limit exceeded	HSC 6.5 25123.3(h)(1); 22 CCR 12 66262.34(d)
	H259	Acutely/extremely hazardous waste accumulation time limit exceeded	HSC 6.5 25123.3(c), 25123.3(h)(1)(C); 22 CCR 12 66262.34(b)(1)
	H267	Failure to accumulate hazardous waste in containers that are in good condition	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(1), 262.34(d)(2), 265.171
	H269	Failure to store hazardous waste in containers made of or lined with a material compatible with the hazardous waste to be stored	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(2), 265.172
	H271	Failure to keep hazardous waste tank/container closed	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(2), 265.173
	H276	Failure to separate incompatible waste during storage	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(2), 265.17(b), 265.177
	H273	Failure to conduct weekly hazardous waste storage area inspections	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(2), 265.174
	H281	Failure to conduct daily inspections of hazardous waste tank systems	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(3), 265.201(c)(1), 265.201(c)(2), 265.201(c)(3)
	H299	Failure to post emergency information	22 CCR 12 66262.34(d)(2); 40 CFR 262.34(d)(5)(ii)
	H303	Failure to maintain facility to prevent fire, explosion, and/or release	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(4), 265.31
	H306	Failure to have all required emergency equipment	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(4), 265.32
	H305	Failure to maintain all required emergency equipment	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(4), 265.33
	H308	Failure to maintain adequate aisle space	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(4), 265.35
	H798	Failure to complete Uniform Hazardous Waste Manifest exception report when required	HSC 6.5 25123.3(h); 22 CCR 12 66262.42 (a),(c),(d)

Large Quantity Generator - Violations

V	VIOL #	Summary	Code
	H245	Failure to conduct annual employee training and maintain documentation until facility closure	22 CCR 12 66262.34(a)(4); 22 CCR 15 66265.16
	H237	Failure to prepare and implement a contingency plan	22 CCR 12 66262.34(a)(4); 22 CCR 15 66265.51
	H240	Failure to include all required information in the contingency plan	22 CCR 12 66262.34(a)(4); 22 CCR 15 66265.52

Large Quantity Generator - Violations (continued)

V	VIOL #	Summary	Code
	H238	Failure to maintain a copy of the contingency plan on site and/or submit a copy to all responding agencies	22 CCR 12, 66262.34(a)(4); 22 CCR 15 66265.53
	H258	Failure to dispose of hazardous waste within 90 days of accumulation start	HSC 6.5 25123.3(b)(1), 25201; 22 CCR 12 66262.34(a)
	H268	Failure to accumulate hazardous waste in containers that are in good condition	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.171
	H270	Failure to store hazardous waste in containers made of or lined with a material compatible with the hazardous waste to be stored	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.172
	H272	Failure to keep hazardous waste tank/container closed	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.173
	H274	Failure to conduct weekly hazardous waste storage area inspections	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.174
	H289	Failure to conduct daily inspections of hazardous waste tank systems	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.195(a), 66265.195(c)
	H309	Failure to maintain adequate aisle space	22 CCR 12 66262.34(a)(4); 22 CCR 15 66265.35
	H275	Failure to locate reactive and ignitable waste at least 15 meters (50 feet) from the facility's property line	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.176
	H279	Failure to separate incompatible waste during storage	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.17(b), 66265.177
	H304	Failure to maintain facility to prevent fire, explosion, and/or release	22 CCR 12 66262.34(a)(4); 22 CCR 15 66265.31
	H291	Failure to meet secondary containment requirements for hazardous waste tank systems or components	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.193
	H294	Failure to immediately remove from service a tank system which is unfit for use and/or comply with applicable requirements	22 CCR 15 66265.196
	H292	Failure to meet tank system closure requirements	22 CCR 15 66265.111, 66265.114, 66265.197
	H286	Failure to obtain and/or maintain a new hazardous waste tank assessment by a professional engineer	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.192(a)
	H800	Failure to complete an assessment or reassessment of a hazardous waste tank as required	22 CCR 15 66265.192(h)
	H312	Failure to conduct hazardous waste tank system cathodic protection system inspections as required	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.195(b), 66265.195(c)
	H815	Failure to comply with air emmisions requirements for hazardous waste in containers	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.178
	H816	Failure to comply with air emmisions requirements for hazardous waste in tanks	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.202
	H307	Failure to have all required emergency equipment	22 CCR 12 66262.34(a)(4); 22 CCR 15 66265.32
	H301	Failure to inspect and/or maintain all safety/emergency equipment as required	22 CCR 12 66262.34(a)(4); 22 CCR 15 66265.33
	H244	Failure to complete Uniform Hazardous Waste Manifest exception report when required	22 CCR 12 66262.42(a),(b),(d)
	H799	Failure to complete certification of waste minimization on all manifests	22 CCR 12 66262.27(a)
	H257	Failure to adequately complete, and maintain for review, all requirements of the source reduction evaluation review and plan (SB-14)	HSC 6.5 25244.19, 25244.21; 22 CCR 31 67100.5
	H254	Failure to properly prepare a source reduction evaluation review and plan every four years	HSC 6.5 25244.19; 22 CCR 31 67100.7, 67100.8
	H255	Failure to prepare a summary progress report and submitted it to DTSC every four years	22 CCR 31 67100.9

Universal Waste Generator - Violations

V	VIOL #	Summary	Code
	H318	Failure to comply with all universal waste training requirements	22 CCR 23 66273.36
	H321	Faillure to meet universal waste labeling requirements	22 CCR 23 66273.34
	H330	Universal waste accumulation exceeded the 1 year limit	22 CCR 23 66273.35
	H329	Failure to disposal of universal waste at an appropriate destination facility	22 CCR 23 66273.31(a)
	H320	Failure to properly prepare and/or retain shipping papers for all universal waste shipped	22 CCR 23 66273.38; 49 CFR 1 172.201(e)
	H325	Failure to handle waste aerosol cans to prevent fire, explosion, and/or release	HSC 6.5 25201.16(e)
	H328	Failure to meet accumulation standards for aerosol cans	HSC 6.5 25201.16(f)
	H326	Failure to properly clean up and/or contain spills of electronic devices, CRTs and/or CRT glass	22 CCR 23 66273.33.5

Waste Lead Acid Battery Generator - Violations

V	VIOL #	Summary	Code
	H290	Failure to meet requirements for handling, storing, and/or transporting lead acid batteries	22 CCR 16 66266.81(a)(1)
	H293	Failure to properly manage, store, and/or label damaged lead acid batteries	22 CCR 16 66266.81(b)
	H250	Failure to maintain documentation for disposal of lead acid batteries for 3 years	22 CCR 16 66266.81(a)(4)(B)
	H261	Failure to meet all requirements when accepting spent lead acid batteries	22 CCR 16 66266.81(a)(3)

SUMMARY OF OBSERVATIONS/VIOLATIONS

☒ **No violations of hazardous waste laws/regulations were discovered. KERN CUPA greatly appreciates your efforts to comply with all the laws and regulations applicable to your facility.**

☐ **Violations were observed/discovered as listed below. All violations must be corrected by implementing the corrective action listed by each violation. If you disagree with any of the violations or corrective actions required, please inform the CUPA in writing.**

ALL VIOLATIONS MUST BE CORRECTED WITHIN 30 DAYS OR AS SPECIFIED. CUPA must be informed in writing with a certification that compliance has been achieved. A false statement that compliance has been achieved is a violation of the law and punishable by a fine of not less than $2,000 or more than $25,000 for each violation. Your facility may be reinspected any time during normal business hours. If a second reinspection becomes necessary due to non compliance, a reinspection charge of $115.00 per hour may be charged to the facility.

You may request a meeting with the Program Manager to discuss the inspection findings and/or the proposed corrective actions. The issuance of this Summary of Violations does not preclude the CUPA from taking administrative, civil, or criminal action.

INSPECTION COMMENTS:

COMMENTS: **Go to http://www.kernpublichealth.com/hazardous-materials for forms and information.**

Inspector: Lana Elfstrom
Inspection Date: 01/17/2019

Signature of Facility Representative:

KERN COUNTY
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HAZARDOUS WASTE GENERATOR INSPECTION REPORT

Facility Name: Torrance Valley Pipeline Company LLC - BELRIDGE		**Facility ID:** FA0000222
Site Address: 19662 HIGHWAY 33 RD MCKITTRICK, CA 93251		**CERS ID:** 10230871 **EPA ID #:**
Phone: (661) 763-7641	**Consent Granted By:** Scott Hedlund	**Inspection Date:** 01/17/2019
Inspection Type: ☒ Routine ☐ Reinspection		**Reinspection required:** ☐ Yes ☒ No

Small Quantity Generator (SQG)	Large Quantity Generator (LQG)
22 CCR § 66262.34(d), 66262.34(d)(3); HSC § 25123.3(h)(1)	22 CCR § 66262.34; HSC § 25123.3
≤1,000 kg or ≤2,240 lbs or ≤270 gal per month	≥1000 kg or ≥2,240 lbs or ≥270 gal per month
Acute or Extremely Hazardous Waste	
≤1 kg or ≤2.2 lbs or ≤0.3 gals per month	≥1 kg or ≥2.2 lbs or ≥0.3 gals per month
Acute Spill Residue or Soil	
	≥100 kg or ≥220 lbs or ≥27 gals per month
Accumulation Time Limits	
22 CCR § 66262.34(b)*, 66262.34(d)(2), 66262.34(d)(3)	22 CCR 66262.34(a)
≤180 days or ≤270 days (if greater than 200 miles) *90 days from date 100 kg limit is reached	≤90 days

General Violations - All Generators

V	VIOL #	Summary	Code
	H804	Failure to report data electronically when required	HSC 6.11 25404(e)(4)
	F004	Failure to pay Hazardous Waste Generator permit fees	KCOC 8.04.030
	H236	Failure to obtain/maintain an active/correct EPA ID number	22 CCR 12 66262.12
	H251	Improper hazardous waste determination	22 CCR 12 66262.11
	H248	Failure to comply with all consolidated manifest procedures	22 CCR 12 66262.40(a); HSC 6.5 25160.2
	H239	Failure to properly complete the Uniform Hazardous Waste Manifest	22 CCR 12 66262.23(a)
	H243	Failure to properly prepare manifests for transportation	22 CCR 12 66262.20
	H246	Failure of owner/operator to send generator manifest copies to DTSC within 30 days	22 CCR 12 66262.23(a)(4)
	H241	Failure to maintain signed copies of manifests for 3 years	22 CCR 12 66262.40(a)
	H297	Hazardous waste not transported by registered hauler	22 CCR 13 66263.41; HSC 6.5 25163(a)
	H260	Improper labeling of hazardous waste containers/portable tanks	22 CCR 12 66262.34(f)
	H810	Failure mark stationary tanks with "Hazardous Waste" and/or accumulation start date	22 CCR 12 66262.34(f)

Inspector: Lana Elfstrom **Inspection Date:** 01/17/2019

General Violations - All Generators (continued)

V	VIOL #	Summary	Code
	H298	Disposal of hazardous waste at an unauthorized location	HSC 6.5 25189.5(a), 25201(a)
	H302	Failure to manage recyclable materials according to requirements	HSC 6.5 25143.2, 25143.9
	H296	Failure to properly manage used oil and fuel filters	22 CCR 16 66266.130; HSC 6.5 25250.22
	H812	Failure to properly manage empty containers > 5 gallons	22 CCR 11 66261.7
	H811	Failure to follow all requirements for hazardous waste satellite accumulation	22 CCR 12 66262.34(e)
	H808	Failure to properly manage soiled/contaminated rages before being sent for laundering	HSC 6.5 25144.6(b)

Small Quantity Generator - Violations

V	VIOL #	Summary	Code
	H242	Failure to conduct employee training on waste handling and emergency procedures	22 CCR 12 66262.34(d)(2); 40 CFR 262.34(d)(5)(iii)
	H256	Hazardous waste accumulation time limit exceeded	HSC 6.5 25123.3(h)(1); 22 CCR 12 66262.34(d)
	H259	Acutely/extremely hazardous waste accumulation time limit exceeded	HSC 6.5 25123.3(c), 25123.3(h)(1)(C); 22 CCR 12 66262.34(b)(1)
	H267	Failure to accumulate hazardous waste in containers that are in good condition	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(1), 262.34(d)(2), 265.171
	H269	Failure to store hazardous waste in containers made of or lined with a material compatible with the hazardous waste to be stored	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(2), 265.172
	H271	Failure to keep hazardous waste tank/container closed	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(2), 265.173
	H276	Failure to separate incompatible waste during storage	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(2), 265.17(b), 265.177
	H273	Failure to conduct weekly hazardous waste storage area inspections	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(2), 265.174
	H281	Failure to conduct daily inspections of hazardous waste tank systems	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(3), 265.201(c)(1), 265.201(c)(2), 265.201(c)(3)
	H299	Failure to post emergency information	22 CCR 12 66262.34(d)(2); 40 CFR 262.34(d)(5)(ii)
	H303	Failure to maintain facility to prevent fire, explosion, and/or release	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(4), 265.31
	H306	Failure to have all required emergency equipment	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(4), 265.32
	H305	Failure to maintain all required emergency equipment	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(4), 265.33
	H308	Failure to maintain adequate aisle space	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(4), 265.35
	H798	Failure to complete Uniform Hazardous Waste Manifest exception report when required	HSC 6.5 25123.3(h); 22 CCR 12 66262.42 (a),(c),(d)

Large Quantity Generator - Violations

V	VIOL #	Summary	Code
	H245	Failure to conduct annual employee training and maintain documentation until facility closure	22 CCR 12 66262.34(a)(4); 22 CCR 15 66265.16
	H237	Failure to prepare and implement a contingency plan	22 CCR 12 66262.34(a)(4); 22 CCR 15 66265.51
	H240	Failure to include all required information in the contingency plan	22 CCR 12 66262.34(a)(4); 22 CCR 15 66265.52

Large Quantity Generator - Violations (continued)

V	VIOL #	Summary	Code
	H238	Failure to maintain a copy of the contingency plan on site and/or submit a copy to all responding agencies	22 CCR 12, 66262.34(a)(4); 22 CCR 15 66265.53
	H258	Failure to dispose of hazardous waste within 90 days of accumulation start	HSC 6.5 25123.3(b)(1), 25201; 22 CCR 12 66262.34(a)
	H268	Failure to accumulate hazardous waste in containers that are in good condition	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.171
	H270	Failure to store hazardous waste in containers made of or lined with a material compatible with the hazardous waste to be stored	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.172
	H272	Failure to keep hazardous waste tank/container closed	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.173
	H274	Failure to conduct weekly hazardous waste storage area inspections	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.174
	H289	Failure to conduct daily inspections of hazardous waste tank systems	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.195(a), 66265.195(c)
	H309	Failure to maintain adequate aisle space	22 CCR 12 66262.34(a)(4); 22 CCR 15 66265.35
	H275	Failure to locate reactive and ignitable waste at least 15 meters (50 feet) from the facility's property line	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.176
	H279	Failure to separate incompatible waste during storage	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.17(b), 66265.177
	H304	Failure to maintain facility to prevent fire, explosion, and/or release	22 CCR 12 66262.34(a)(4); 22 CCR 15 66265.31
	H291	Failure to meet secondary containment requirements for hazardous waste tank systems or components	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.193
	H294	Failure to immediately remove from service a tank system which is unfit for use and/or comply with applicable requirements	22 CCR 15 66265.196
	H292	Failure to meet tank system closure requirements	22 CCR 15 66265.111, 66265.114, 66265.197
	H286	Failure to obtain and/or maintain a new hazardous waste tank assessment by a professional engineer	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.192(a)
	H800	Failure to complete an assessment or reassessment of a hazardous waste tank as required	22 CCR 15 66265.192(h)
	H312	Failure to conduct hazardous waste tank system cathodic protection system inspections as required	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.195(b), 66265.195(c)
	H815	Failure to comply with air emmisions requirements for hazardous waste in containers	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.178
	H816	Failure to comply with air emmisions requirements for hazardous waste in tanks	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.202
	H307	Failure to have all required emergency equipment	22 CCR 12 66262.34(a)(4); 22 CCR 15 66265.32
	H301	Failure to inspect and/or maintain all safety/emergency equipment as required	22 CCR 12 66262.34(a)(4); 22 CCR 15 66265.33
	H244	Failure to complete Uniform Hazardous Waste Manifest exception report when required	22 CCR 12 66262.42(a),(b),(d)
	H799	Failure to complete certification of waste minimization on all manifests	22 CCR 12 66262.27(a)
	H257	Failure to adequately complete, and maintain for review, all requirements of the source reduction evaluation review and plan (SB-14)	HSC 6.5 25244.19, 25244.21; 22 CCR 31 67100.5
	H254	Failure to properly prepare a source reduction evaluation review and plan every four years	HSC 6.5 25244.19; 22 CCR 31 67100.7, 67100.8
	H255	Failure to prepare a summary progress report and submitted it to DTSC every four years	22 CCR 31 67100.9

Universal Waste Generator - Violations

V	VIOL #	Summary	Code
	H318	Failure to comply with all universal waste training requirements	22 CCR 23 66273.36
	H321	Faillure to meet universal waste labeling requirements	22 CCR 23 66273.34
	H330	Universal waste accumulation exceeded the 1 year limit	22 CCR 23 66273.35
	H329	Failure to disposal of universal waste at an appropriate destination facility	22 CCR 23 66273.31(a)
	H320	Failure to properly prepare and/or retain shipping papers for all universal waste shipped	22 CCR 23 66273.38; 49 CFR 1 172.201(e)
	H325	Failure to handle waste aerosol cans to prevent fire, explosion, and/or release	HSC 6.5 25201.16(e)
	H328	Failure to meet accumulation standards for aerosol cans	HSC 6.5 25201.16(f)
	H326	Failure to properly clean up and/or contain spills of electronic devices, CRTs and/or CRT glass	22 CCR 23 66273.33.5

Waste Lead Acid Battery Generator - Violations

V	VIOL #	Summary	Code
	H290	Failure to meet requirements for handling, storing, and/or transporting lead acid batteries	22 CCR 16 66266.81(a)(1)
	H293	Failure to properly manage, store, and/or label damaged lead acid batteries	22 CCR 16 66266.81(b)
	H250	Failure to maintain documentation for disposal of lead acid batteries for 3 years	22 CCR 16 66266.81(a)(4)(B)
	H261	Failure to meet all requirements when accepting spent lead acid batteries	22 CCR 16 66266.81(a)(3)

SUMMARY OF OBSERVATIONS/VIOLATIONS

☒ **No violations of hazardous waste laws/regulations were discovered. KERN CUPA greatly appreciates your efforts to comply with all the laws and regulations applicable to your facility.**

☐ **Violations were observed/discovered as listed below. All violations must be corrected by implementing the corrective action listed by each violation. If you disagree with any of the violations or corrective actions required, please inform the CUPA in writing.**

ALL VIOLATIONS MUST BE CORRECTED WITHIN 30 DAYS OR AS SPECIFIED. CUPA must be informed in writing with a certification that compliance has been achieved. A false statement that compliance has been achieved is a violation of the law and punishable by a fine of not less than $2,000 or more than $25,000 for each violation. Your facility may be reinspected any time during normal business hours. If a second reinspection becomes necessary due to non compliance, a reinspection charge of $115.00 per hour may be charged to the facility.

You may request a meeting with the Program Manager to discuss the inspection findings and/or the proposed corrective actions. The issuance of this Summary of Violations does not preclude the CUPA from taking administrative, civil, or criminal action.

INSPECTION COMMENTS:

COMMENTS: **Go to http://www.kernpublichealth.com/hazardous-materials for forms and information.**

Inspector: Lana Elfstrom
Inspection Date: 01/17/2019

Signature of Facility Representative:

EMPLOYEE TRAINING PLAN REQUIREMENTS AND TEMPLATE

All facilities are required to create and implement an employee training plan. Below is a template of requirements for the Hazardous Materials Business Plan and Hazardous Waste Generator program elements. This template will help facilities ensure that all requirements for each program are covered and will help draft a site-specific plan for your facility. Training requirements for the Hazardous Materials Business Plan and Hazardous Waste Generator programs can be found in Health and Safety Code Chapter 6.95 Article 1, Chapter 6.5, Title 19 § 2732, and Chapter 22 of California Code of Regulations § 66265.16. This template may be uploaded onto CERS and will satisfy the above mentioned regulations.

1. Programs
   a. Facility maintains hazardous materials at or above the reporting quantities of 55 gallons of a liquid, 500 pounds of a solid, and/or 200 cubic feet of a compressed gas

      [X] YES Complete section 1b

   b. Hazardous Materials Business Plan Requirements (HSC § 25504(c))
      i. Methods of safe handling of hazardous materials

Employees follow Personal Protective Equipment (PPE) requirements listed on all hazardous material Safety Data Sheets (SDS).

      ii. Safety procedures in the event of a release or threatened release of a hazardous material as described in Emergency Action/Contingency Plan

Emergency Response Objectives & Strategies:
1. Ensure the Safety of Citizens & Response Personnel
2. Control the Source of Release
3. Manage Coordinated Response Effort
4. Maximize Protection of Environmentally- Sensitive Areas
5. Contain and Recover Spilled Material
6. Recover and Rehabilitate Injured Wildlife
7. Remove Hazardous Material from Impacted Areas

      iii. Procedures for coordination with local emergency organizations

The Incident Command System (ICS) structure will be used to manage all emergency response organizations during any incident.

iv. Communication and alarm systems

Verbal alarm will be made at site and and emergency page will be sent to all employees cellular devices during emergency.

v. Use of emergency response equipment and supplies employees may use

Hand held fire extinguishers are present throughout each site. Emergency response to include standard PPE and air monitoring equipment

vi. Procedures for using, inspection of, repairing, and/or replacing facility emergency and monitoring equipment

All emergency monitoring equipment is inspected monthly and before each use.

vii. Evacuation/re-entry procedures and assembly point locations

During emergency, employees will muster at front gate at facility and will not re-enter until emergency situation has been resolved and all are accounted for.

c. Facility stores/generates hazardous waste

- [x] YES — Complete section 1d
- [ ] NO — Do not complete section 1d

d. Hazardous Waste Generator Requirements (HSC Chapter 6.5, 22 CCR § 66265.16)

i. Proper packaging and labeling of all waste

All hazardous waste is stored in Main Storage Area or designated Satellite Storage Area. Hazardous waste must be labeled with contents and accumulation date.

ii. On-site management and storage requirements

All hazardous waste is stored in Main Storage Area or designated Satellite Storage Area. Hazardous waste must be labeled with contents and accumulation date. Waste shipments are tracked and accounted for through Corporate Waste Advisor.

iii. Proper use of safety equipment and hazardous waste management supplies

PPE requirements are determined by materials SDS and the Company Safety Manual.

iv. Off-site transportation requirements

All off-site transportation is done by Contractor to an approved waste facility.

v. Interaction with waste haulers and disposal sites including manifesting

Done on an as needed basis. All waste goes to facilities on an approved waste list. All manifests are sent to the Department of Toxic Substances Control (DTSC) and are kept at facility.

vi. Conducting and documentation off periodic inspections

Documentation of inspections are located on the Weekly Hazardous & Universal Waste Inspection Log.

Frequency of inspections: (Defined as every 7 Days)

2. Required Training Topics – By Job Title

While all topics in section 1 must be covered, not every individual must be trained in each topic for respective program(s). Training given to each individual will commensurate with the tasks assigned to that employee.

Example: An employee who physically handles hazardous wastes but does not fill out or manage manifests needs training in handling not manifesting, while the clerical person responsible for the manifests needs training in manifesting but not handling the wastes.

Training on MSDS (Material Safety Data Sheets) including specific hazard(s) of each chemical to which employees may be exposed, including routes of exposure (i.e. inhalation, ingestion, absorption, etc.) is required.

Procedures for specific job titles (optional):

All company employees complete Hazardous Waste Awareness and Hazard Communication training on an annual basis.

3. Personal Responsibilities

   Responsibility for ensuring the training plan is compliant to all requirements and implementation is assigned to: Field Regulatory Specialist

   Special Responsibilities are as follows:

TRAINING TASK	ASSIGNED TO
Hazardous Waste Awareness	Web Based Training (WebCAT)
Hazard Communication	Web Based Training (WebCAT)
First Aid and Automated External	American Red Cross
Defibrillator	

4. Training Frequency

   New employees will successfully complete training within 6 months after date of employment or assignment to a new position at facility. All employees are to receive at least annual training, including refresher courses. In the event of new assignments or changes in operation, training will be provided before the new assignment or change in operation takes place. Employees will not handle hazardous materials and/or hazardous waste without supervision until trained.

   Date of last training: Completed Annually

   Date of next training: Completed Annually

   Additional dates for refresher courses (optional):

COURSE	DATE

5. Training Documentation

   All training must be documented. Training records on current personnel shall be kept until closure of the facility. Training records on former employees shall be kept for at least three years from the date the employee last worked at the facility. Records that document that the requirements, trainings, and job experience have met must be kept and maintained.

Training records are kept: within the internal Web based training program

CALIFORNIA ENVIRONMENTAL REPORTING SYSTEM (CERS)

CONSOLIDATED EMERGENCY RESPONSE / CONTINGENCY PLAN

Prior to completing this Plan, please refer to the INSTRUCTIONS FOR COMPLETING A CONSOLIDATED CONTINGENCY PLAN

FACILITY ID # A1.	CERS ID # A2.	DATE OF PLAN PREPARATION/REVISION (MM/DD/YYYY) A3.
	10230871	01/14/2022

BUSINESS NAME *(Same as Facility Name or DBA - Doing Business As)* A4.
Torrance Valley Pipeline Company LLC

BUSINESS SITE ADDRESS A5.
19662 Highway 33 Rd.

BUSINESS SITE CITY A6.		ZIP CODE A7.
Mckittrick	CA	93251

TYPE OF BUSINESS (e.g., Painting Contractor) A8.	INCIDENTAL OPERATIONS (e.g., Fleet Maintenance) A9.
Pipeline Operator	Pipeline Maintenance

THIS PLAN COVERS CHEMICAL SPILLS, FIRES, AND EARTHQUAKES INVOLVING (Check all that apply): A10.

☒ 1. HAZARDOUS MATERIALS; ☒ 2. HAZARDOUS WASTES

INTERNAL FACILITY EMERGENCY RESPONSE WILL OCCUR BY (Check all that apply): B1.

☒ 1. CALLING PUBLIC EMERGENCY RESPONDERS (e.g., 9-1-1)
☒ 2. CALLING HAZARDOUS WASTE CONTRACTOR
☒ 3. ACTIVATING IN-HOUSE EMERGENCY RESPONSE TEAM

In the event of an emergency involving hazardous materials and/or hazardous waste, all facilities must IMMEDIATELY:

1. Notify facility personnel and evacuate if necessary in accordance with the Emergency Action Plan (Title 8 California Code of Regulations §3220);
2. Notify local emergency responders by calling 9-1-1;
3. Notify the local Unified Program Agency (UPA) at the phone number below; and
4. Notify the State Warning Center at (800) 852-7550.

Facilities that generate, treat, store or dispose of hazardous waste have additional responsibilities to notify and coordinate with other response agencies. Whenever there is an imminent or actual emergency situation such as an explosion, fire, or release, the Emergency Coordinator must follow the appropriate requirements for the category of facility and type of release involved:

1. Title 22 California Code of Regulations §66265.56. Emergency Procedures for generators of 1,000 kilograms or more of hazardous waste in any calendar month.
2. Title 22 California Code of Regulations §66265.196. Response to Leaks or Spills and Disposition of Leaking or Unfit-for-Use Tank Systems.
3. Title 40 Code of Federal Regulations §302.6. Notification requirements for a release of a hazardous substance equal to or greater than the reportable quantity.
4. Title 22 California Code of Regulations §66262.34(d)(2) and Title 40 Code of Federal Regulations §262.34(d)(5)(ii) for generators of less than 1000 kilograms of hazardous waste in any calendar month.

Following notification and before facility operations are resumed in areas of the facility affected by the incident, the Emergency Coordinator shall notify the local UPA and the local fire department's hazardous materials program, if necessary, that the facility is in compliance with requirements to:

1. Provide for proper storage and disposal of recovered waste, contaminated soil or surface water, or any other material that results from an explosion, fire, or release at the facility; and
2. Ensure that no material that is incompatible with the released material is transferred, stored, or disposed of in areas of the facility affected by the incident until cleanup procedures are completed.

EMERGENCY RESPONSE PHONE NUMBERS:		
AMBULANCE, FIRE, POLICE AND CHP		9-1-1
CALIFORNIA STATE WARNING CENTER (CSWC)/CAL OES.		(800) 852-7550
NATIONAL RESPONSE CENTER (NRC)		(800) 424-8802
POISON CONTROL CENTER		(800) 222-1222
LOCAL UNIFIED PROGRAM AGENCY (UPA)		(661) 549-9927 C1.
OTHER (Specify):	Patriot Environmental Serviec C2.	(800) 624-9136 C3.
NEAREST MEDICAL FACILITY / HOSPITAL NAME:	Mercy Southwest Hospital C4.	(661) 663-6000 C5.

AGENCY NOTIFICATION PHONE NUMBERS:		
CALIFORNIA DEPT. OF TOXIC SUBSTANCES CONTROL (DTSC)		(916) 255-3545
REGIONAL WATER QUALITY CONTROL BOARD (RWQCB).		(559) 445-5116 C6.
U.S. ENVIRONMENTAL PROTECTION AGENCY (US EPA)		(800) 300-2193
CALIFORNIA DEPT. OF FISH AND WILDLIFE (CDFW)		(916) 358-2900
U.S. COAST GUARD (USCG)		(202) 267-2180
CAL OSHA		(916) 263-2800
CAL FIRE OFFICE OF THE STATE FIRE MARSHAL (OSFM)		(916) 323-7390
OTHER (Specify):	National Response Center C7.	(800) 424-8802 C8.
OTHER (Specify):	C9.	C10.

INTERNAL FACILITY EMERGENCY COMMUNICATIONS OR ALARM NOTIFICATION WILL OCCUR BY (Check all that apply): C11.

- ☑ 1. VERBAL WARNINGS;
- ☐ 2. PUBLIC ADDRESS OR INTERCOM SYSTEM;
- ☑ 3. TELEPHONE;
- ☐ 4. PAGERS;
- ☐ 5. ALARM SYSTEM;
- ☐ 6. PORTABLE RADIO

NOTIFICATIONS TO NEIGHBORING FACILITIES THAT MAY BE AFFECTED BY AN OFF-SITE RELEASE WILL OCCUR BY (Check all that apply): C12.

- ☑ 1. VERBAL WARNINGS;
- ☐ 2. PUBLIC ADDRESS OR INTERCOM SYSTEM;
- ☑ 3. TELEPHONE;
- ☐ 4. PAGERS;
- ☐ 5. ALARM SYSTEM;
- ☐ 6. PORTABLE RADIO

EMERGENCY COORDINATOR CONTACT INFORMATION: Scott Hedlund (661) 381-8038 C13.

PRIMARY EMERGENCY COORDINATOR NAME: Anthony Mooney PHONE NO.: (661) 763-7641 PHONE NO.: (661) 345-7643

ALTERNATE EMERGENCY COORDINATOR NAME: Cory Engle PHONE NO.: (805) 503-0787 PHONE NO.: (805) 503-0787

☐ Check if additional Emergency Coordinator contact and address information is available onsite or by calling PHONE NO.:

Note: If more than one alternate emergency coordinator is designated, attach a list in order of responsibility.

D. EMERGENCY CONTAINMENT AND CLEANUP PROCEDURES

Check the applicable boxes to indicate your facility's procedures for containing spills and preventing and mitigating releases, fires and/or explosions.

D1.

- ☑ 1. MONITOR FOR LEAKS, RUPTURES, PRESSURE BUILD-UP, ETC.;
- ☑ 2. PROVIDE STRUCTURAL PHYSICAL BARRIERS (e.g., Portable spill containment walls, built-in berms);
- ☑ 3. PROVIDE ABSORBENT PHYSICAL BARRIERS (e.g., Pads, spill pigs, spill pillows);
- ☑ 4. COVER OR BLOCK FLOOR AND/OR STORM DRAINS;
- ☑ 5. LINED TRENCH DRAINS AND/OR SUMPS;
- ☐ 6. AUTOMATIC FIRE SUPPRESSION SYSTEM;
- ☑ 7. ELIMINATE SOURCES OF IGNITION FOR FLAMMABLE HAZARDS;
- ☑ 8. STOP PROCESSES AND/OR OPERATIONS;
- ☑ 9. AUTOMATIC / ELECTRONIC EQUIPMENT SHUT-OFF SYSTEM;
- ☑ 10. SHUT OFF WATER, GAS, ELECTRICAL UTILITIES;
- ☑ 11. CALL 9-1-1 FOR PUBLIC EMERGENCY RESPONDER ASSISTANCE AND/OR MEDICAL AID;
- ☑ 12. NOTIFY AND EVACUATE PERSONS IN ALL THREATENED AND/OR IMPACTED AREAS;
- ☑ 13. ACCOUNT FOR EVACUATED PERSONS IMMEDIATELY AFTER EVACUATION;
- ☑ 14. PROVIDE PROTECTIVE EQUIPMENT FOR ON-SITE EMERGENCY RESPONSE TEAM;
- ☑ 15. REMOVE CONTAINERS AND/OR ISOLATE AREAS;
- ☑ 16. HIRE LICENSED HAZARDOUS WASTE CONTRACTOR;
- ☑ 17. USE ABSORBENT MATERIAL FOR SPILL CONTAINMENT;
- ☑ 18. VACUUM SUCTION USING APPROPRIATE VACUUM (e.g., Intrinsically safe) FOR SPILL CONTROL AND/OR CLEANUP;
- ☑ 19. DECONTAMINATE PERSONNEL AND EQUIPMENT WITHIN DESIGNATED AREA AND DISPOSE OF WASTEWATER AS HAZARDOUS WASTE;
- ☑ 20. PROVIDE SAFE TEMPORARY STORAGE OF HAZARDOUS WASTE GENERATED DURING EMERGENCY ACTIONS;
- ☐ 21. OTHER (Specify): D2.

E. FACILITY EVACUATION

THE FOLLOWING ALARM SIGNAL(S) WILL BE USED TO BEGIN EVACUATION OF THE FACILITY (Check all that apply): E1.

E2.

- ☐ 1. BELLS;
- ☐ 2. HORNS/SIRENS;
- ☑ 3. VERBAL (i.e., Shouting);
- ☐ 4. OTHER (Specify):

THE FOLLOWING LOCATION(S) WILL BE USED FOR AN EMERGENCY ASSEMBLY AREA(S) (e.g., Parking lot, street corner): E3.

Main entrance gate south of the facility by Highway 166.

Note: The Emergency Coordinator must account for all onsite employees and visitors after evacuation.

EVACUATION ROUTE S AND ALTERNATE EVACUATION ROUTES ARE DESCRIBED AS FOLLOWS: E4.

- ☑ 1. WRITTEN PROCEDURES DESCRIBING ROUTES, EXITS, AND ASSEMBLY AREAS;
- ☑ 2. EVACUATION MAP(S) DEPICTING ROUTES, EXITS, AND ASSEMBLY AREAS;
- ☐ 3. OTHER (Specify): E5.

Note: Evacuation procedures and/or maps should be posted in visible facility locations and must be included in the Contingency Plan.

F. ARRANGEMENTS FOR EMERGENCY SERVICES

ADVANCE ARRANGEMENTS FOR LOCAL EMERGENCY SERVICES (Check one of the following): F1.

- ☐ 1. HAVE BEEN DETERMINED NOT NECESSARY;
- ☑ 2. THE FOLLOWING ARRANGEMENTS HAVE BEEN MADE (Specify): OSRO contracts our in place with Clean Harbors and Patriot Environmental as listed in our Integrated Contingency Plan. F2.

Note: Advance arrangements with local fire and police departments, hospitals, state and local emergency response teams, and/or emergency services contractors should be made for your facility, if necessary. Large Quantity Generators must describe arrangements in the Contingency Plan.

G. EMERGENCY EQUIPMENT

Check the applicable boxes to list emergency response equipment available at the facility, identify the location(s) where the equipment is kept, and indicate the equipment's capability, if applicable.

TYPE	EQUIPMENT AVAILABLE G1.	LOCATION G2.	CAPABILITY G3.
EXAMPLE	☒ *CHEMICAL PROTECTIVE GLOVES*	*SPILL RESPONSE KIT*	*SINGLE USE, OIL RESISTANT ONLY*
Safety and First Aid	1. ▣ CHEMICAL PROTECTIVE SUITS, APRONS, AND/OR VESTS	Located at Continental Station	Single Use
	2. ▣ CHEMICAL PROTECTIVE GLOVES	Located at Continental Station	Single Use
	3. ▣ CHEMICAL PROTECTIVE BOOTS	Located at Continental Station	Single Use
	4. ▣ SAFETY GLASSES, GOGGLES, AND FACE SHIELDS	In all company vehicles	
	5. ▣ HARD HATS	In all company vehicles	
	6. ▣ AIR-PURIFYING RESPIRATORS		Single Use
	7. ☐ SELF-CONTAINED BREATHING APPARATUS (SCBA)		
	8. ▣ FIRST AID KITS	In company vehicles and control room	Single Use, < 25 employees
	9. ☐ PLUMBED EYEWASH FOUNTAIN AND/OR SHOWER		
	10. ▣ PORTABLE EYEWASH KITS AND/OR STATION	Outside control room exit	Single Use
	11. ☐ OTHER		
Fire Fighting	12. ▣ PORTABLE FIRE EXTINGUISHERS	In company vehicles/see facility maps	Single Use, 25 lb extinguisher
	13. ☐ FIXED FIRE SUPPRESSION SYSTEMS AND/ OR SPRINKLERS		
	14. ☐ FIRE ALARM BOXES		
	15. ☐ OTHER		
Spill Control and Clean-Up	16. ▣ ALL-IN-ONE SPILL KIT	At control room spill kit	Single Use, 95 gallon capacity
	17. ▣ ABSORBENT MATERIAL	At control room spill kit	Single Use, 95 gallon capacity
	18. ▣ CONTAINER FOR USED ABSORBENT	At control room spill kit	Single Use, 95 gallon capacity
	19. ☐ BERM AND/OR DIKING EQUIPMENT		
	20. ☐ BROOM		
	21. ■ SHOVEL	At Continental Station	
	22. ■ VACUUM	Patriot/Clean Harbors	130 BBL per truck
	23. ☐ EXHAUST HOOD		
	24. ☐ SUMP AND/OR HOLDING TANK		
	25. ☐ CHEMICAL NEUTRALIZERS		
	26. ☐ GAS CYLINDER LEAK REPAIR KIT		
	27. ▣ SPILL OVERPACK DRUMS		1-95 gallon overpack at each facility
	28. ☐ OTHER		
Communi-cations and Alarm Systems	29. ▣ TELEPHONES (e.g., Cellular)		
	30. ☐ INTERCOM AND/OR PA SYSTEM		
	31. ☐ PORTABLE RADIOS		
	32. ☐ AUTOMATIC ALARM CHEMICAL MONITORING EQUIPMENT		
Other	33. ☐ OTHER		
	34. ☐ OTHER		

H. EARTHQUAKE VULNERABILITY

Identify areas of the facility that are vulnerable to hazardous materials releases due to seismic motion. These areas require immediate isolation and inspection.

VULNERABLE AREAS (Check all that apply): H1.

- ☐ 1. HAZARDOUS MATERIALS AND/OR WASTE STORAGE AREAS
- ☒ 2. PROCESS LINES AND PIPING
- ☐ 3. LABORATORY
- ☐ 4. WASTE TREATMENT AREA

LOCATIONS (e.g., Shop, outdoor shed, lab): H2.

Throughout facility, below and above ground.

Identify mechanical systems vulnerable to releases / spills due to earthquake-related motion. These systems require immediate isolation and inspection.

VULNERABLE SYSTEMS AND/OR EQUIPMENT (Check all that apply): H3.

- ☐ 1. SHELVES, CABINETS AND/OR RACKS
- ☐ 2. TANKS AND SHUT-OFF VALVES
- ☐ 3. PORTABLE GAS CYLINDERS
- ☒ 4. EMERGENCY SHUT-OFF AND/OR UTILITY VALVES
- ☐ 5. SPRINKLER SYSTEMS
- ☐ 6. STATIONARY PRESSURIZED CONTAINERS (e.g., Propane tank)

LOCATIONS: H4.

Facility is equipped with seismic detection equipment which shuts facility down at 6.0 or above earthquake

I. EMPLOYEE TRAINING

Employee training is required for all employees and/or contractors handling hazardous materials and/or hazardous wastes during normal and/or emergency operations. Most facilities will need to submit a separate Training Plan. However, your CUPA may accept this section as the Training Plan for some small facilities.
Employee training plans may include the following content:

- Applicable laws and regulations;
- Emergency response plans and procedures;
- Safety Data Sheets;
- Hazard communication related to health and safety;
- Methods for safe handling of hazardous substances;
- Hazards of materials and processes (e.g., fire, explosion, asphyxiation);
- Hazard mitigation, prevention and abatement procedures;
- Coordination of emergency response actions;
- Notification procedures for local emergency responders, CUPA, Cal OES, and onsite personnel;
- Communication and alarm systems;
- Personal protective equipment;
- Use and maintenance of emergency response equipment and supplies (e.g. Fire extinguishers, respirators, spill control materials);
- Decontamination procedures;
- Evacuation procedures and evacuation staging locations;
- Identification of facility areas, equipment, and systems vulnerable to earthquakes and other natural disasters.
- OTHER (Specify): Training is web based

Check the applicable boxes below to indicate how the employee training program is administered.

☐ 1. FORMAL CLASSROOM ☐ 2. VIDEOS ☐ 3. SAFETY MEETINGS ☐ 4. STUDY GUIDES / MANUALS I1.

☐ 5. OTHER (Specify): _____ I2.

☒ 6. NOT APPLICABLE SINCE FACILITY HAS NO EMPLOYEES

☐ 7. CHECK IF A SEPARATE EMPLOYEE TRAINING PLAN IS USED AND UPLOADED TO CERS AS A PDF DOCUMENT I3.

☐ 8. CHECK IF EMPLOYEE TRAINING IS COVERED BY THE ABOVE REFERENCED CONTENT AND OTHER DOCUMENTS ONSITE I4.

EMPLOYEE TRAINING FREQUENCY AND RECORDKEEPING TRAINING MUST BE:

- Provided initially for new employees as soon as possible following the date of hire. New employees should not work in an unsupervised position that involves hazardous materials handling and/or hazardous waste management without proper training;
- Provided within six months from the date of hire for new employees at a large quantity generator;
- Ongoing and provided at least annually;
- Amended prior to a change in process or work assignment;
- Given upon modification to the Emergency Response/Contingency Plan.

Large Quantity Generator Training: Large quantity generators (1,000 kg or more) must retain written plan and documentation of employee training which includes:

- A written description of the type and amount of both initial and ongoing training that will be given to persons filling each job position having responsibility for hazardous waste management and/or emergency response.
- The name, job title and job description for each position at the facility related to hazardous waste management.
- Current employee training records must be retained until closure of the facility and former employee training records must be retained for at least three years after termination of employment.

Small Quantity Generator Training: Small quantity generators (less than 1,000 kg) must include basic hazardous waste management and emergency response procedures but a written employee training plan and training records are not required. In order to show that the facility has met the small quantity generator employee training requirement, an employee training plan and training records may be made available.

Hazardous Materials Business Plan Training: Businesses must provide initial and annual employee training that includes the content referenced above. The training may be based on the job position and training records must be made available for a period of at least three years.

J. LIST OF ATTACHMENTS

Check one of the following: J1.

☒ 1. NO ATTACHMENTS ARE REQUIRED; or

☐ 2. THE FOLLOWING DOCUMENTS ARE ATTACHED: J2.

KERN COUNTY
Public Health Services
DEPARTMENT

MATTHEW CONSTANTINE
DIRECTOR

ENVIRONMENTAL HEALTH DIVISION
INSPECTION CONSENT AND ACKNOWLEDGEMENT CERTIFICATION

Facility Name: Exxonmobil Inspection Date: [illegible]

Facility ID: FA0000222 CERS ID: _____

Consent: By signing this document, you are consenting to an inspection of the above referenced facility by the Kern County Public Health Services Department, Environmental Health Division, Certified Unified Program Agency (CUPA) for the county of Kern. The State of California has authorized the CUPA to conduct business facility inspections for compliance with the programs listed below. These inspections may include the inspection of all business areas on the property, the review and copying of records, the taking of photographs, and the taking of samples to evaluate compliance with CUPA requirements. The following Health and Safety Code (HSC) sections give the CUPA the authority to inspect:

- Hazardous Waste (Health & Safety Code [HSC § 25185, subd. (a)];
- California Accidental Release Prevention (HSC § 25534.5);
- Hazardous Materials Release Response Plans [HSC § 25508, subd. (a)];
- Underground Storage Tanks – (HSC § 25289); and
- Aboveground Storage Tanks – [HSC § 25270.5, subd. (a)].

_____ _____ _____

Signature Facility Representative | Print Name and Title | Date Signed

☐ Declined to sign, verbal consent to inspect given. ☐ Inspection Refused

Acknowledgement of Method to Receive Inspection Report:

☐ E-mail to: ☐ Mail to: _____

☐ Fax to:

_____ _____ _____

Signature Inspector | Print Name and Title | Date Signed

Printed on Recycled Paper

KERN COUNTY
Public Health Services
DEPARTMENT

ENVIRONMENTAL HEALTH DIVISION
CERTIFIED UNIFIED PROGRAM AGENCY (CUPA)

MATTHEW CONSTANTINE
DIRECTOR

2700 M STREET, SUITE 300 BAKERSFIELD, CALIFORNIA 93301-2370 VOICE: 661-862-8740 FAX: 661-862-8701 WWW.CO.KERN.CA.US/EH

HAZARDOUS MATERIALS BUSINESS PLAN (HMBP) INSPECTION REPORT

Facility Name: EXXONMOBIL OIL CORP - BELRIDGE		**Facility ID:** FA0000222
Site Address: 19662 HIGHWAY 33 RD MCKITTRICK, CA 93251		**CERS ID:** 10230871
Phone: (661) 763-7641	**Consent Granted By:** Scott Hedlund	**Inspection Date:** 02/18/2016
Inspection Type: ☒ Routine ☐ Reinspection	**Reinspection required:** ☐ Yes ☒ No	
Inspection Element: BUS PLAN LARGE LOW RISK 1 UNIT		

File/CERS Review Violations

V	Viol #	Summary	Code
	H335	Failure to adequately complete and submit a HMBP into the California Environmental Reporting System (CERS)	HSC 6.95 25505, 25508(a)(1), 25508(d)
	H344	Failure to complete and submit the Business Activities Page and/or Business Owner Operator Identification Page in CERS	HSC 6.95 25508(a)(1); 19 CCR 4 2729.2(a)(1);
	H342	Failure to complete and submit hazardous material inventory information for all reportable hazardous materials on site in CERS	HSC 6.95 25505(a)(1), 25506, 25508(a)(1)
	H341	Failure to annually review and electronically certify that the business plan is complete, accurate, and up-to-date in CERS	HSC 6.95 25508(c), 25508.2
	H346	Failure to complete and submit a site map with all required content in CERS	HSC 6.95 25505(a)(2), 25508(a)(1)
	H347	Failure to submit an adequate emergency response plan and procedures in CERS	HSC 6.95 25505(a)(3), 25508(a)(1)
	H353	Failure to submit an adequate training program in CERS	HSC 6.95 25505(a)(4), 25508(a)(1)
	H340	Failure to notify property owner in writing that a HMBP is required	HSC 6.95 25505.1
	H336	Failure to provide property owner a copy of the HMBP upon request	HSC 6.95 25505.1

Onsite Inspection Violations

V	Viol #	Summary	Code
	H334	Failure to adequately establish and implement a HMBP	HSC 6.95 25507
	H343	Failure to revise HMBP in CERS within 30 days upon a substantial change in the handler's operation	HSC 6.95 25508.1(f)
	H345	Failure to update Facility Information and/or Hazardous Materials Inventory in CERS within 30 days upon a significant change	HSC 6.95 25508.1(a)-(e)
	H348	Failure to provide initial and annual safety training to all employees and/or failure to document and maintain training records for 3 years	HSC 6.95 25505(a)(4)
	H338	Failure to report a release or threatened release of a hazardous material to the CUPA and to California Office of Emergency Services	HSC 6.95 25510(a)

Inspector: WAQAR RUSTAM **Inspection Date:** 02/18/2016

CONDITIONAL EXEMPTIONS FROM REPORTING REQUIREMENTS

Agricultural handlers are conditionally exempt from electronically submitting Emergency Response and Employee Training Plans in CERS if the following requirements are met:

- Owner/Operator annually submits the Facility Information and Hazardous Materials Inventory electronically into CERS
- Each location/building, where hazardous materials (i.e. pesticides, petroleum products, fertilizers, etc.) are stored, is posted with warning signs that meet the following requirements:
  - Shall be conspicuous and visible from any direction of probable approach
  - Shall be of such size that it is readable from 25 feet and shall be labeled as follows:

> DANGER HAZARDOUS MATERIAL STORAGE AREA
> (the hazardous materials stored within shall be noted by category
> [i.e. pesticides, petroleum products, fertilizers, etc.])
> ALL UNAUTHORIZED PERSONS-KEEP OUT - IN AN EMERGENCY, CONTACT:
> (list the name and phone number of an emergency contact person(s))

  - Shall be repeated in an appropriate language other than English when persons who do not understand the English language may enter the posted location/building
- Owner/Operator provides training for all new employees and annual training, including refresher courses, for all employees in safety procedures in the event of a release or threatened release of a hazardous material, including, but not limited to, familiarity with the emergency plans and procedures

Exempt Facility Violations

V	Viol #	Summary	Code
	H760	Failure to submit Emergency Response/Contingency Plan in CERS when not meeting agricultural handler exemption requirements	HSC 6.95 25507.1, 25508(a)(1); 19 CCR 4 2733, 2734
	H758	Failure to submit Employee Training Plan in CERS when not meeting agricultural handler exemption requirements	HSC 6.95 25507.1, 25508(a)(1); 19 CCR 4 2733, 2734
	H759	Failure to establish and submit a HMBP in CERS when not meeting remote unstaffed facility exemption requirements	HSC 6.95 25505, 25506, 25507, 25507.2, 25508(a)(1)

SUMMARY OF OBSERVATIONS/VIOLATIONS

☒ **No violations of hazardous materials business plan laws/regulations were discovered. KERN CUPA greatly appreciates your efforts to comply with all the laws and regulations applicable to your facility.**

☐ **Violations were observed/discovered as listed below. ALL VIOLATIONS MUST BE CORRECTED WITHIN 30 DAYS OR AS SPECIFIED. CUPA must be informed in writing with a certification that compliance has been achieved. A false statement that compliance has been achieved is a violation of the law and punishable by a fine of not less than $2,000 or more than $25,000 for each violation. Your facility may be reinspected any time during normal business hours. If a second reinspection becomes necessary due to non compliance, a reinspection charge of $100.00 per hour may be charged to the facility.**

You may request a meeting with the Program Manager to discuss the inspection findings and/or the proposed corrective actions. The issuance of this Summary of Violations does not preclude the CUPA from taking administrative, civil, or criminal action.

INSPECTION COMMENTS:

COMMENTS: **Go to http://www.co.kern.ca.us/eh/ (Hazardous Materials) for forms and information.**



Inspector: WAQAR RUSTAM **Signature of Facility Representative:**

Inspection Date: 02/18/2016

ENVIRONMENTAL HEALTH SERVICES DEPARTMENT

MATTHEW CONSTANTINE, R.E.H.S., Director

2700 "M" STREET, SUITE 300
BAKERSFIELD, CA 93301-2370
Voice: (661) 862-8700
Fax: (661) 862-8701
TTY Relay: (800) 735-2929
Web: www.co.kern.ca.us/eh
E-mail: *eh@co.kern.ca.us*

RESOURCE MANAGEMENT AGENCY

DAVID PRICE III, RMA DIRECTOR

Animal Control Department
Community and Economic Development Department
Engineering and Survey Services Department
Environmental Health Services Department
Planning Department
Roads Department

July 01, 2009

CERTIFIED UNIFIED PROGRAM AGENCY (CUPA)
HAZARDOUS MATERIAL INSPECTION FORM

Date: 07/01/2009 Facility ID: FA0000222 File #: 000222

Facility Name: EXXONMOBIL OIL CORP - BELRIDGE			**Inspection Type**		
Site Address: 19662 HIGHWAY 33 RD MCKITTRICK, CA 93251			☒ **Routine**		
			☐ **Reinspection**		
Phone: (661)762-7371			☐ **Complaint**		
PROGRAMS INSPECTED:	☒ Business Plan	☐ HW Generator	☐ UST	☐ AGT	☐ CalARP
REINSPECTION REQUIRED:	☐ Business Plan	☐ HW Generator	☐ UST	☐ AGT	☐ CalARP

VIOLATION

YES	NO/NA	VIOL. #	BUSINESS PLAN REQUIREMENTS
☐	☒	BP01	**Inventory of hazardous materials is accurate, up to date, and complete [HSC 6.95, 25504, Title 19 CCR 2729].**
☐	☒	BP02	**Site layout/facility maps are accurate [HSC 6.95,25504; Title 19 CCR 2729].**
☐	☒	BP03	**Hazardous materials are stored in properly labeled and non-deteriorated containers [HSC 25124(b)(3)(A & B)].**
☐	☒	BP04	**The hazardous materials inventory shall be submitted annually on or before March 1 [Title 19 CCR 2729.4(b)].**
☐	☒	ER01	**Contingency Plan is complete, updated, and maintained on site [HSC 6.95, 25504;Title 19 CCR 2731 Title 22 CCR 66265.53-54].**
☐	☒	ER02	**Facility is operated and maintained to prevent/mitigate fire, explosion, or release of hazardous material or waste which could threaten human health or the environment [Title 22 CCR 66265.31; Title 19 CCR 2731].**
☐	☒	ER03	**Business has equipment required to, or appropriate for, safe handling of hazardous materials [Title 22 CCR 66265.32 & .34].**
☐	☒	TR01	**Facility has a training program appropriate for the size and complexity of business and nature of hazardous materials handled [Title 19 CCR 2732; Title 22 CCR 66265.16].**
☐	☒	TR02	**Training documentation is maintained on site for current personnel. [Title 19 CCR 2732; Title 22 CCR 66265.16].**

COMMENTS: **Go to http://www.co.kern.ca.us/eh/cupaprogram.asp for forms and information.**

GPS Coordinates: Latitude: **Longtitude:**

INSPECTOR: BILAL KORIN **DATE:** 07/01/2009

SUMMARY OF OBSERVATIONS/VIOLATIONS

☒ **No violations of underground storage tank, hazardous materials, or hazardous waste laws/regulations were discovered. KERN CUPA greatly appreciates your efforts to comply with all the laws and regulations**

☐ **Violations were observed/discovered as listed below. All violations must be corrected by implementing the corrective action listed by each violation. If you disagree with any of the violations or corrective actions required, please inform the CUPA in writing.**

ALL VIOLATIONS MUST BE CORRECTED WITHIN 30 DAYS OR AS SPECIFIED. CUPA must be informed in writing with a certification that compliance has been achieved. A false statement that compliance has been achieved is a violation of the law and punishable by a fine of not less than $2,000 or more than $25,000 for each violation. Your facility may be reinspected any time during normal business hours. If a second reinspection becomes necessary due to non compliance, a reinspection charge of $100.00 per hour may be charged to the facility.

You may request a meeting with the Program Manager to discuss the inspection findings and/or the proposed corrective actions. The issuance of this Summary of Violations does not preclude the CUPA from taking administrative, civil, or criminal action.

FACILITY NAME: EXXONMOBIL OIL CORP - BELRIDGE | **ADDRESS:** 19662 HIGHWAY 33 RD MCKITTRICK, CA 93251 | **FA ID:** FA0000222 **FILE ID:** 000222

VIOLATIONS

VIOL. NO	VIOL. TYPE	CORRECTIVE ACTION REQUIRED

INSPECTION COMMENTS:

INSPECTOR: BILAL KORIN
DATE: 07/01/2009

SIGNATURE OF FACILITY REP:

Certification: I certify under penalty of perjury that this facility has complied with the corrective actions listed on this inspection form.
Signature of Owner/Operator: _____ **Title:** _____ **Date:**

ENVIRONMENTAL HEALTH
DIVISION
2700 M STREET, SUITE 300, BAKERSFIELD, CA 93301-2370
VOICE: (661) 862-8740 FAX: (661) 862-8701
Web: www.co.kern.ca.us/eh E-mail: eh@co.kern.ca.us
"ONE VOICE"

MATTHEW CONSTANTINE, DIRECTOR
PUBLIC HEALTH SERVICES

CLAUDIA JONAH, MD
PUBLIC HEALTH OFFICER

CERTIFIED UNIFIED PROGRAM AGENCY (CUPA)
HAZARDOUS MATERIAL INSPECTION FORM

Report Date: 02/13/2013 Facility ID: FA0000222 File #: 000222

Facility Name: EXXONMOBIL OIL CORP - BELRIDGE	**Inspection Type**
Site Address: 19662 HIGHWAY 33 RD MCKITTRICK, CA 93251	☒ **Routine**
Phone: (661)763-7641	☐ **Reinspection**
	☐ **Complaint**

PROGRAMS INSPECTED:	☒ Business Plan	☐ HW Generator	☐ UST	☐ APSA
REINSPECTION REQUIRED:	☐ Business Plan	☐ HW Generator	☐ UST	☐ APSA

VIOLATION	VIOLATION NUMBER	BUSINESS PLAN REQUIREMENTS
✓	**BP01**	Inventory of hazardous materials is accurate, up to date, and complete [HSC 6.95, 25504, Title 19 CCR 2729].
	BP02	Site layout/facility maps are accurate [HSC 6.95,25504; Title 19 CCR 2729].
	BP03	Hazardous materials are stored in properly labeled and non-deteriorated containers [HSC 25124(b)(3)(A & B)].
	BP04	The hazardous materials inventory shall be submitted annually on or before March 1 [Title 19 CCR 2729.4(b)].
	ER01	Contingency Plan is complete, updated, and maintained on site [HSC 6.95, 25504;Title 19 CCR 2731 Title 22 CCR 66265.53-54].
	ER02	Facility is operated and maintained to prevent/mitigate fire, explosion, or release of hazardous material or waste which could threaten human health or the environment [Title 22 CCR 66265.31; Title 19 CCR 2731].
	ER03	Business has equipment required to, or appropriate for, safe handling of hazardous materials [Title 22 CCR 66265.32 & .34].
	TR01	Facility has a training program appropriate for the size and complexity of business and nature of hazardous materials handled [Title 19 CCR 2732; Title 22 CCR 66265.16].
	TR02	Training documentation is maintained on site for current personnel [Title 19 CCR 2732; Title 22 CCR 66265.16].

INSPECTOR: WAQAR RUSTAM **INSPECTION DATE:** 02/11/2013

FACILITY NAME: EXXONMOBIL OIL CORP - BELRIDGE

ADDRESS: 19662 HIGHWAY 33 RD MCKITTRICK, CA 93251

FA ID: FA0000222
FILE ID: 000222

SUMMARY OF OBSERVATIONS/VIOLATIONS

☐ **No violations of underground storage tank, hazardous materials, or hazardous waste laws/regulations were discovered. KERN CUPA greatly appreciates your efforts to comply with all the laws and regulations applicable to your facility.**

☒ **Violations were observed/discovered as listed below. All violations must be corrected by implementing the corrective action listed by each violation. If you disagree with any of the violations or corrective actions required, please inform the CUPA in writing.**

ALL VIOLATIONS MUST BE CORRECTED WITHIN 30 DAYS OR AS SPECIFIED. CUPA must be informed in writing with a certification that compliance has been achieved. A false statement that compliance has been achieved is a violation of the law and punishable by a fine of not less than $2,000 or more than $25,000 for each violation. Your facility may be reinspected any time during normal business hours. If a second reinspection becomes necessary due to non compliance, a reinspection charge of $100.00 per hour may be charged to the facility.

You may request a meeting with the Program Manager to discuss the inspection findings and/or the proposed corrective actions. The issuance of this Summary of Violations does not preclude the CUPA from taking administrative, civil, or criminal action.

VIOLATIONS

VIOLATION #	DEGREE OF VIOLATION	CORRECTIVE ACTION REQUIRED
BP01	CLASS II VIOLATION	Update inventory of hazardous materials. Inventory may be updated online at: http://cers.calepa.ca.gov/ **PLEASE UPDATE YOUR HAZARDOUS MATERIALS INVENTORY.**

INSPECTION COMMENTS:

ALL VIOLATIONS SHALL BE ABATED WITH IN 30 DAYS. ONCE THE VIOLATIONS ARE ABATED, PLEASE SIGN, DATE AND SUBMIT THE COMPLIANCE CERTIFICATE AT THE END OF THE INSPECTION REPORT.THIS SIGNED DOCCUMENT AND ANY OTHER REQUESTED DOCUMENT MAY BE SUBMITTED BY FAX @661-862-8701(ATTN:WAQAR) OR BY E-MAIL@ RUSTAMW@CO.KERN.CA.US. IF REINSPECTION BECOMES NECESSARY DUE TO NON COMPLIANCE WITH IN 30 DAYS,A REINSPECTION CHARGE OF $100 PER HOUR MAY BE CHARGED TO THE FACILITY.

COMMENTS: **Go to http://www.co.kern.ca.us/eh/cupaprogram.asp for forms and information.**

INSPECTOR: WAQAR RUSTAM
INSPECTION DATE: 02/11/2013

SIGNATURE OF FACILITY REP:

Certification: I certify under penalty of perjury that this facility has complied with the corrective actions listed on this inspection form.

Printed Name of Owner/Operator	**Title**
Signature of Owner/Operator	**Date**

KERN COUNTY
Public Health Services
DEPARTMENT

ENVIRONMENTAL HEALTH DIVISION
CERTIFIED UNIFIED PROGRAM AGENCY (CUPA)

MATTHEW CONSTANTINE
DIRECTOR

2700 M STREET, SUITE 300 BAKERSFIELD, CALIFORNIA 93301-2370 VOICE: 661-862-8740 FAX: 661-862-8701 WWW.CO.KERN.CA.US/EH

HAZARDOUS WASTE GENERATOR INSPECTION REPORT

Facility Name: EXXONMOBIL OIL CORP - BELRIDGE		**Facility ID:** FA0000222
Site Address: 19662 HIGHWAY 33 RD MCKITTRICK, CA 93251		**CERS ID:** 10230871 **EPA ID #:**
Phone: (661) 763-7641	**Consent Granted By:** Scott Hedlund	**Inspection Date:** 02/18/2016
Inspection Type: ☒ Routine ☐ Reinspection	**Reinspection required:** ☐ Yes ☒ No	

Conditionally Exempt Small Quantity Generator (CESQG)	Small Quantity Generator (SQG)	Large Quantity Generator (LQG)
40 CFR §261.5(a) & (e)	22 CCR § 66262.34(d), 66262.34(d)(3); HSC § 25123.3(h)(1)	22 CCR § 66262.34; HSC § 25123.3
. 100 kg or . 220 lbs or . 27 gal per month	. 100 kg but . 1,000 kg or . 220 lbs but . 2,240 lbs or . 27 gal but . 270 gal per month	. 1000 kg or . 2,240 lbs or . 270 gal per month
. 1 kg or . 2.2 lbs or . 0.3 gals per month acute or extremely hazardous waste	. 1 kg or . 2.2 lbs or . 0.3 gals per month acute or extremely hazardous waste	. 1 kg or . 2.2 lbs or .0.3 gals per month acute or extremely hazardous waste
. 100 kg or . 220 lbs or . 27 gal per month acute spill residue or soil		. 100 kg or . 220 lbs or .27 gals per month acute spill residue or soil
Accumulation Time Limits		
22 CCR § 66262.34(b)	22 CCR § 66262.34(d)(2), 66262.34(d)(3)	22 CCR 66262.34(a)
90 days from date 100 kg limit is reached	≤180 days or ≤270 days (if greater than 200 miles)	≤90 days

General Violations - All Generators

V	VIOL #	Summary	Code
	H235	OPERATING WITHOUT A PERMIT	HSC 6.11 25404.1
	H236	EPA ID NUMBER INCORRECT OR INACTIVE	22 CCR 12 66262.12
	H248	MANIFEST/CONSOLIDATED MANIFEST NOT MAINTAINED FOR 3 YEARS	22 CCR 12 66262.40(a); HSC 6.5 25160.2
	H246	FAILURE OF OWNER/OPERATOR TO SEND GENERATOR MANIFEST COPIES TO DTSC WITHIN 30 DAYS	22 CCR 12 66262.23(a)(4)
	H251	IMPROPER HAZARDOUS WASTE DETERMINATION	22 CCR 12 66262.11, 66262.40(c)
	H260	HAZARDOUS WASTE LABELING STANDARDS NOT MET	22 CCR 12 66262.34(f)
	H277	OPERATING RECKLESSLY UNDER PERMIT	HSC 6.5 25186, 25186.2
	H296	USED OIL & FUEL FILTER HANDLING REQUIREMENTS NOT FOLLOWED	22 CCR 16 66266.130
	H297	HAZARDOUS WASTE NOT TRANSPORTED BY REGISTERED HAULER	22 CCR 13 66263.41; HSC 6.5 25163(a)
	H298	IMPROPER DISPOSAL OF HAZARDOUS WASTE	HSC 6.5 25189.5(a)
	H302	FAILURE TO MEET EXCLUDED RECYCLABLE MATERIALS REQUIREMENTS	HSC 6.5 25143.2, 25143.9
	E001	IMPROPER EMPTY CONTAINER MANAGEMENT	22 CCR 66261.7(e),(f),(i)

Inspector: WAQAR RUSTAM **Inspection Date:** 02/18/2016

Conditionally Exempt Small Quantity Generator - Violations

V	VIOL #	Summary	Code
	C001	IMPROPER TRANSPORTATION OF WASTE TO FACILITY	HSC 25163(c)
	C242	FAILURE TO CONDUCT EMPLOYEE TRAINING	22 CCR 12 66262.34(d)(2); 40 CFR 262.34(d)(5)(iii)
	C267	TANK/CONTAINER IN POOR CONDITION OR DAMAGED	22 CCR 12 66262.34(d)(2); 40 CFR 265.171
	C269	HAZARDOUS WASTE CONTAINER INCOMPATIBLE WITH MATERIAL STORED	22 CCR 12 66262.34(d)(2); 40 CFR 265.172
	C271	OPEN HAZARDOUS WASTE TANK/CONTAINER	22 CCR 12 66262.34(d)(2); 40 CFR 265.173
	C273	FAILURE TO CONDUCT WEEKLY HAZARDOUS WASTE STORAGE AREA INSPECTION	22 CCR 12 66262.34(d)(2); 40 CFR 265.174
	C299	FAILURE TO IMPLEMENT EMERGENCY PLAN	22 CCR 12 66262.34(d)(2); 40 CFR 262.34(d)(5)(ii)
	C303	FACILITY NOT MAINTAINED TO PREVENT FIRE/EXPLOSION/RELEASE	22 CCR 12 66262.34(d)(2); 40 CFR 265.31
	C305	FAILURE TO MAINTAIN FACILITY EMERGENCY EQUIPMENT	22 CCR 12 66262.34(d)(2); 40 CFR 265.33
	C306	FAILURE TO HAVE EMERGENCY EQUIPMENT	22 CCR 12 66262.34(d)(2); 40 CFR 265.32
	C308	INADEQUATE AISLE SPACE	22 CCR 12 66262.34(d)(2); 40 CFR 265.35
	H259	HAZARDOUS WASTE ACCUMULATION TIME LIMIT EXCEEDED	22 CCR 12 66262.34(b)(1)

Small Quantity Generator - Violations

V	VIOL #	Summary	Code
	H242	FAILURE TO CONDUCT EMPLOYEE TRAINING	22 CCR 12 66262.34(d)(2); 40 CFR 262.34(d)(5)(iii)
	H256	HAZARDOUS WASTE ACCUMULATION TIME LIMIT EXCEEDED	22 CCR 66262.34(d)
	H267	TANK/CONTAINER IN POOR CONDITION OR DAMAGED	22 CCR 12 66262.34(d)(2); 40 CFR 265.171
	H269	HAZARDOUS WASTE CONTAINER INCOMPATIBLE WITH MATERIAL STORED	22 CCR 12 66262.34(d)(2); 40 CFR 265.172
	H271	OPEN HAZARDOUS WASTE TANK/CONTAINER	22 CCR 12 66262.34(d)(2); 40 CFR 265.173
	H273	FAILURE TO CONDUCT WEEKLY HAZARDOUS WASTE STORAGE AREA INSPECTION	22 CCR 12 66262.34(d)(2); 40 CFR 265.174
	H276	INCOMPATIBLE WASTE STORAGE	22 CCR 12 66262.34(d)(2); 40 CFR 265.17(b), 265.177
	H281	FAILURE TO COMPLETE DAILY TANK, MONITORING, AND DISCHARGE INSPECTIONS	22 CCR 66262.34(d)(2); 40 CFR 265.201(c)(1), 265.201(c)(2), 265.201(c)(3)
	H299	FAILURE TO IMPLEMENT EMERGENCY PLAN	22 CCR 12 66262.34(d)(2); 40 CFR 262.34(d)(5)(ii)
	H303	FACILITY NOT MAINTAINED TO PREVENT FIRE/EXPLOSION/RELEASE	22 CCR 12 66262.34(d)(2); 40 CFR 265.31
	H305	FAILURE TO MAINTAIN FACILITY EMERGENCY EQUIPMENT	22 CCR 12 66262.34(d)(2); 40 CFR 265.33
	H306	FAILURE TO HAVE EMERGENCY EQUIPMENT	22 CCR 12 66262.34(d)(2); 40 CFR 265.32
	H308	INADEQUATE AISLE SPACE	22 CCR 12 66262.34(d)(2); 40 CFR 265.35

Large Quantity Generator - Violations

V	VIOL #	Summary	Code
	H237	FAILURE TO HAVE A CONTINGENCY PLAN	22 CCR 15 66265.51
	H240	CONTINGENCY PLAN INCORRECT OR NOT IMPLEMENTED	22 CCR 15 66265.52
	H245	FAILURE TO CONDUCT EMPLOYEE TRAINING	22 CCR 15 66265.16

Large Quantity Generator - Violations (continued)

V	VIOL #	Summary	Code
	H258	HAZARDOUS WASTE ACCUMULATION TIME LIMIT EXCEEDED	22 CCR 12 66262.34(a)
	H268	TANK/CONTAINER IN POOR CONDITION OR DAMAGED	22 CCR 15 66265.171
	H270	HAZARDOUS WASTE CONTAINER INCOMPATIBLE WITH MATERIAL STORED	22 CCR 15 66265.172
	H272	OPEN HAZARDOUS WASTE TANK/CONTAINER	22 CCR 15 66265.173
	H274	FAILURE TO CONDUCT WEEKLY HAZARDOUS WASTE STORAGE AREAS INSPECTIONS	22 CCR 15 66265.174
	H275	REACTIVE AND IGNITABLE WASTE NOT 50 FT FROM PROPERTY LINE	22 CCR 15 66265.176
	H279	INCOMPATIBLE WASTE STORAGE	22 CCR 15 66265.17(b), 66265.177
	H289	FAILURE TO CONDUCT DAILY HAZARDOUS WASTE TANK INSPECTIONS	22 CCR 15 66265.195
	H286	FAILURE TO OBTAIN AND/OR MAINTAIN HAZARDOUS WASTE TANK ASSESSMENT	22 CCR 15 66265.192(a), 66265.192(h)
	H291	FAILURE TO MEET SECONDARY CONTAINMENT REQUIREMENTS	22 CCR 15 66265.193
	H292	FAILURE TO MEET TANK CLOSURE REQUIREMENTS AND DOCUMENTATION	22 CCR 15 66265.111, 66265.114, 66265.197
	H294	FAILURE TO MEET HAZARDOUS WASTE TANK RELEASE REQUIREMENTS	22 CCR 15 66265.196
	H301	FAILURE TO MAINTAIN FACILITY EMERGENCY EQUIPMENT	22 CCR 15 66265.33
	H304	FACILITY NOT MAINTAINED TO PREVENT FIRE/EXPLOSION/RELEASE	22 CCR 15 66265.31
	H307	FAILURE TO HAVE EMERGENCY EQUIPMENT	22 CCR 15 66265.32
	H309	INADEQUATE AISLE SPACE	22 CCR 15 66265.35
	H310	FAILURE TO MEET PRECAUTION REQUIREMENTS FOR REACTIVE AND IGNITABLE WASTE	22 CCR 15 66265.17(a)
	H312	FAILURE TO CONDUCT HAZARDOUS WASTE TANK CATHODIC INSPECTION	22 CCR 15 66265.195(b)
	H313	FAILURE TO MAINTAIN SECURITY OF HAZARDOUS WASTE AREA	22 CCR 15 66265.14
	A268	FAILURE TO STORE HAZARDOUS WASTE IN CONTAINERS/TANKS THAT MEET THE AIR EMISSIONS REQUIREMENTS	22 CCR 15 66265.178

Universal Waste Generator - Violations

V	VIOL #	Summary	Code
	H317	FAILURE TO MANAGE BATTERIES AS UNIVERSAL WASTE	22 CCR 23 66273.2(a)
	H318	FAILURE TO CONDUCT EMPLOYEE TRAINING	22 CCR 23 66273.36
	H319	FAILURE TO DISPOSE OF ELECTRONICS PROPERLY	22 CCR 23 66273.3
	H320	FAILURE TO MEET OFFSITE SHIPMENT REQUIREMENTS	22 CCR 23 66273.38; 49 CFR 1 172.201(e)
	H321	FAILURE TO MEET PROPER LABELING REQUIREMENTS	22 CCR 23 66273.34
	H322	IMPROPER MANAGEMENT OF MERCURY CONTAINING PRODUCTS	22 CCR 23 66273.4
	H323	FAILURE TO PROPERLY MANAGE MERCURY CONTAINING LAMP BULBS	22 CCR 23 66273.5
	H324	FAILURE TO PROPERLY MANAGE CRT TUBES AND GLASS	22 CCR 23 66273.6, 66273.7
	H325	IMPROPER HANDLING OF AEROSOL CANS	HSC 6.5 25201.16(e)
	H326	FAILURE TO MANAGE UNIVERSAL WASTE TO PREVENT RELEASE TO THE ENVIRONMENT	22 CCR 23 66273.33.5
	H328	FAILURE TO MEET ACCUMULATION STANDARDS FOR AEROSOL CANS	HSC 6.5 25201.16(f)
	H329	ILLEGAL DISPOSAL OF UNIVERSAL WASTE	22 CCR 23 66273.31(a)
	H330	UNIVERSAL WASTE ACCUMULATION TIME LIMIT EXCEEDED	22 CCR 23 66273.35

Inspector: WAQAR RUSTAM **Inspection Date:** 02/18/2016

Waste Lead Acid Battery Generator - Violations

V	VIOL #	Summary	Code
	H250	FAILURE TO MAINTAIN LEAD BATTERY DISPOSAL DOCUMENTATION	22 CCR 16 66266.81(a)(4)(B)
	H261	IMPROPER MANAGEMENT OF 11 OR MORE SPENT VEHICLE LEAD-ACID BATTERIES	22 CCR 16 66266.81(a)(3)
	H290	IMPROPER MANAGEMENT OF 10 OR LESS SPENT VEHICLE LEAD-ACID BATTERIES	22 CCR 16 66266.81(a)(1)
	H293	IMPROPER HANDLING OF DAMAGED LEAD BATTERY	22 CCR 16 66266.81(b)
	H316	FAILURE TO PROPERLY MANAGE NON-AUTOMOTIVE LEAD BATTERIES	22 CCR 23 66273.2(b)(1)

SUMMARY OF OBSERVATIONS/VIOLATIONS

☒ **No violations of hazardous waste laws/regulations were discovered. KERN CUPA greatly appreciates your efforts to comply with all the laws and regulations applicable to your facility.**

☐ **Violations were observed/discovered as listed below. All violations must be corrected by implementing the corrective action listed by each violation. If you disagree with any of the violations or corrective actions required, please inform the CUPA in writing.**

ALL VIOLATIONS MUST BE CORRECTED WITHIN 30 DAYS OR AS SPECIFIED. CUPA must be informed in writing with a certification that compliance has been achieved. A false statement that compliance has been achieved is a violation of the law and punishable by a fine of not less than $2,000 or more than $25,000 for each violation. Your facility may be reinspected any time during normal business hours. If a second reinspection becomes necessary due to non compliance, a reinspection charge of $100.00 per hour may be charged to the facility.

You may request a meeting with the Program Manager to discuss the inspection findings and/or the proposed corrective actions. The issuance of this Summary of Violations does not preclude the CUPA from taking administrative, civil, or criminal action.

INSPECTION COMMENTS:

COMMENTS: **Go to http://www.co.kern.ca.us/eh/ (Hazardous Materials) for forms and information.**



Inspector: WAQAR RUSTAM
Inspection Date: 02/18/2016

Signature of Facility Representative:

CERTIFIED UNIFIED PROGRAM AGENCY PERMIT

KERN COUNTY PUBLIC HEALTH SERVICES DEPARTMENT

ENVIRONMENTAL HEALTH SERVICE DIVISION

2700 M ST, SUITE 300, BAKERSFIELD, CA 93301

(661) 862-8740 www.co.kern.ca.us/eh e-mail: hazmatprogram@co.kern.ca.us

REGULATED FACILITY:

EXXONMOBIL OIL CORP - BELRIDGE
19662 HIGHWAY 33 RD
MCKITTRICK CA 93251

IDENTIFICATION NUMBERS:

FACILITY ID: FA0000222
CERS ID: 10230871

OWNER(S) OF RECORD:

ExxonMobil Oil Corporation

General Health Program	Permit #	Additional Information	PIP*	Effective Thru
BUS PLAN LARGE LOW RISK 1 UNIT	0001713			06/30/2017
SMALL QUANTITY HAZARDOUS WASTE GENERATOR	0030118			06/30/2017

Permit Issued: 1/22/2016

Matthew Constantine
Public Health Services Director

This ENVIRONMENTAL HEALTH PERMIT is issued to the owner(s) and establishment shown above subject to compliance with all applicable laws and regulations. Permit is valid unless revoked or suspended for violation of applicable laws and regulations.

PERMIT IS NON-TRANSFERABLE AND MUST BE PROMINENTLY DISPLAYED IN THE PLACE OF BUSINESS

* **PIP - P**erformance **I**ncentive **P**rogram is a voluntary program for facilities that handle extremely hazardous material(s).

DENNIS SLAUSON
ExxonMobil Oil Corporation
1001 W Ash Street
Taft, CA 93268

ENVIRONMENTAL HEALTH
DIVISION
2700 M STREET, SUITE 300, BAKERSFIELD, CA 93301-2370
VOICE: (661) 862-8740 FAX: (661) 862-8701
Web: www.co.kern.ca.us/eh E-mail: eh@co.kern.ca.us
"ONE VOICE"

MATTHEW CONSTANTINE, DIRECTOR
PUBLIC HEALTH SERVICES

CLAUDIA JONAH, MD
PUBLIC HEALTH OFFICER

CERTIFIED UNIFIED PROGRAM AGENCY (CUPA)
HAZARDOUS MATERIAL INSPECTION FORM

Report Date: 02/13/2013 Facility ID: FA0000222 File #: 000222

Facility Name: EXXONMOBIL OIL CORP - BELRIDGE	**Inspection Type**
Site Address: 19662 HIGHWAY 33 RD MCKITTRICK, CA 93251	☒ **Routine**
Phone: (661)763-7641	☐ **Reinspection**
	☐ **Complaint**

PROGRAMS INSPECTED:	☒ Business Plan	☐ HW Generator	☐ UST	☐ APSA
REINSPECTION REQUIRED:	☐ Business Plan	☐ HW Generator	☐ UST	☐ APSA

VIOLATION	VIOLATION NUMBER	BUSINESS PLAN REQUIREMENTS
✓	**BP01**	Inventory of hazardous materials is accurate, up to date, and complete [HSC 6.95, 25504, Title 19 CCR 2729].
	BP02	Site layout/facility maps are accurate [HSC 6.95,25504; Title 19 CCR 2729].
	BP03	Hazardous materials are stored in properly labeled and non-deteriorated containers [HSC 25124(b)(3)(A & B)].
	BP04	The hazardous materials inventory shall be submitted annually on or before March 1 [Title 19 CCR 2729.4(b)].
	ER01	Contingency Plan is complete, updated, and maintained on site [HSC 6.95, 25504;Title 19 CCR 2731 Title 22 CCR 66265.53-54].
	ER02	Facility is operated and maintained to prevent/mitigate fire, explosion, or release of hazardous material or waste which could threaten human health or the environment [Title 22 CCR 66265.31; Title 19 CCR 2731].
	ER03	Business has equipment required to, or appropriate for, safe handling of hazardous materials [Title 22 CCR 66265.32 & .34].
	TR01	Facility has a training program appropriate for the size and complexity of business and nature of hazardous materials handled [Title 19 CCR 2732; Title 22 CCR 66265.16].
	TR02	Training documentation is maintained on site for current personnel [Title 19 CCR 2732; Title 22 CCR 66265.16].

INSPECTOR: WAQAR RUSTAM **INSPECTION DATE:** 02/11/2013

FACILITY NAME: EXXONMOBIL OIL CORP - BELRIDGE

ADDRESS: 19662 HIGHWAY 33 RD MCKITTRICK, CA 93251

FA ID: FA0000222
FILE ID: 000222

SUMMARY OF OBSERVATIONS/VIOLATIONS

☐ **No violations of underground storage tank, hazardous materials, or hazardous waste laws/regulations were discovered. KERN CUPA greatly appreciates your efforts to comply with all the laws and regulations applicable to your facility.**

☒ **Violations were observed/discovered as listed below. All violations must be corrected by implementing the corrective action listed by each violation. If you disagree with any of the violations or corrective actions required, please inform the CUPA in writing.**

ALL VIOLATIONS MUST BE CORRECTED WITHIN 30 DAYS OR AS SPECIFIED. CUPA must be informed in writing with a certification that compliance has been achieved. A false statement that compliance has been achieved is a violation of the law and punishable by a fine of not less than $2,000 or more than $25,000 for each violation. Your facility may be reinspected any time during normal business hours. If a second reinspection becomes necessary due to non compliance, a reinspection charge of $100.00 per hour may be charged to the facility.

You may request a meeting with the Program Manager to discuss the inspection findings and/or the proposed corrective actions. The issuance of this Summary of Violations does not preclude the CUPA from taking administrative, civil, or criminal action.

VIOLATIONS

VIOLATION #	DEGREE OF VIOLATION	CORRECTIVE ACTION REQUIRED
BP01	CLASS II VIOLATION	Update inventory of hazardous materials. Inventory may be updated online at: http://cers.calepa.ca.gov/ **PLEASE UPDATE YOUR HAZARDOUS MATERIALS INVENTORY.**

INSPECTION COMMENTS:

ALL VIOLATIONS SHALL BE ABATED WITH IN 30 DAYS. ONCE THE VIOLATIONS ARE ABATED, PLEASE SIGN, DATE AND SUBMIT THE COMPLIANCE CERTIFICATE AT THE END OF THE INSPECTION REPORT.THIS SIGNED DOCCUMENT AND ANY OTHER REQUESTED DOCUMENT MAY BE SUBMITTED BY FAX @661-862-8701(ATTN:WAQAR) OR BY E-MAIL@ RUSTAMW@CO.KERN.CA.US. IF REINSPECTION BECOMES NECESSARY DUE TO NON COMPLIANCE WITH IN 30 DAYS,A REINSPECTION CHARGE OF $100 PER HOUR MAY BE CHARGED TO THE FACILITY.

COMMENTS: **Go to http://www.co.kern.ca.us/eh/cupaprogram.asp for forms and information.**

INSPECTOR: WAQAR RUSTAM
INSPECTION DATE: 02/11/2013

SIGNATURE OF FACILITY REP:

Certification: I certify under penalty of perjury that this facility has complied with the corrective actions listed on this inspection form.

Printed Name of Owner/Operator	**Title**
Signature of Owner/Operator	**Date**

CERTIFIED UNIFIED PROGRAM AGENCY PERMIT

KERN COUNTY PUBLIC HEALTH SERVICES DEPARTMENT

ENVIRONMENTAL HEALTH SERVICE DIVISION

2700 M ST, SUITE 300, BAKERSFIELD, CA 93301

(661) 862-8740 www.co.kern.ca.us/eh e-mail: hazmatprogram@co.kern.ca.us

REGULATED FACILITY:

Torrance Valley Pipeline Company LLC-BELRIDGE
19662 HIGHWAY 33 RD
MCKITTRICK CA 93251

IDENTIFICATION NUMBERS:

FACILITY ID: FA0000222

CERS ID: 10230871

OWNER(S) OF RECORD:

Torrance Valley Pipeline Company LLC

General Health Program	Permit #	Additional Information	PIP*	Effective Thru
BUS PLAN LARGE LOW RISK 1 UNIT	0001713			06/30/2017
SMALL QUANTITY HAZARDOUS WASTE GENERATOR	0030118			06/30/2017

Permit Issued: 9/21/2016

Matthew Constantine
Public Health Services Director

This ENVIRONMENTAL HEALTH PERMIT is issued to the owner(s) and establishment shown above subject to compliance with all applicable laws and regulations. Permit is valid unless revoked or suspended for violation of applicable laws and regulations.

PERMIT IS NON-TRANSFERABLE AND MUST BE PROMINENTLY DISPLAYED IN THE PLACE OF BUSINESS

* **PIP - P**erformance **I**ncentive **P**rogram is a voluntary program for facilities that handle extremely hazardous material(s).

Torrance Valley Pipeline Company LLC
111 W Ocean Blvd., Suite 1500
Long Beach, CA 90802

KERN COUNTY
Public Health Services
DEPARTMENT

ENVIRONMENTAL HEALTH DIVISION
CERTIFIED UNIFIED PROGRAM AGENCY (CUPA)

MATTHEW CONSTANTINE
DIRECTOR

2700 M STREET, SUITE 300 BAKERSFIELD, CALIFORNIA 93301-2370 VOICE: 661-862-8740 FAX: 661-862-8701 KERNPUBLICHEALTH.COM

HAZARDOUS MATERIALS BUSINESS PLAN (HMBP) INSPECTION REPORT

Facility Name: Advanced Industrial Services-Belridge Yard		**Facility ID:** FA0048567
Site Address: 20322 7th Standard Road Lost Hills, CA 93251		**CERS ID:** 10767367
Phone: (562) 940-8305	**Consent Granted By:** Ty Johnston	**Inspection Date:** 11/13/2020
Inspection Type: ☒ Routine ☐ Reinspection		**Reinspection required:** ☒ Yes ☐ No
Inspection Element: BUS PLAN SMALL LOW RISK 1 UNIT		

File/CERS Review Violations

V	Viol #	Summary	Code
	H335	Failure to adequately submit a complete HMBP into the California Environmental Reporting System (CERS)	HSC 6.95 25505, 25508(a)(1)
	F001	Failure to pay the Hazardous Materials Management Program permit fees.	KCOC 8.04.030
✓	H344	Failure to complete and submit the Business Activities page and/or Business Owner/Operator Identification page in CERS	HSC 6.95 25508(a)(1); 19 CCR 4 2729.2(a)(1);
✓	H342	Failure to complete and submit Hazardous Materials Inventory information for all hazardous materials at or above reportable quantities in CERS	HSC 6.95 25505(a)(1), 25506, 25508(a)(1)
	H341	Failure to annually review and electronically certify that the HMBP is complete and accurate on or before the annual due date	HSC 6.95 25508(c), 25508.2
	H346	Failure to complete and submit Site Map with all required content in CERS	HSC 6.95 25505(a)(2), 25508(a)(1)
✓	H347	Failure to submit an adequate Emergency Response/Contingency plan in CERS	HSC 6.95 25505(a)(3), 25508(a)(1)
	H353	Failure to submit an adequate Employee Training Plan in CERS	HSC 6.95 25505(a)(4), 25508(a)(1)
	H340	Failure to notify property owner in writing that a HMBP is required	HSC 6.95 25505.1
	H336	Failure to provide property owner a copy of the HMBP upon request	HSC 6.95 25505.1

Onsite Inspection Violations

V	Viol #	Summary	Code
	H334	Failure to adequately establish and implement a HMBP	HSC 6.95 25507
	H345	Failure to revise HMBP in CERS within 30 days upon a change of information, inventory, address, ownership, or operation.	HSC 6.95 25508.1(a)-(f)
	H348	Failure to provide initial and annual safety training to all employees and/or failure to document and maintain training records for 3 years	HSC 6.95 25505(a)(4)
	H338	Failure to report a release or threatened release of a hazardous material to the CUPA and to California Office of Emergency Services	HSC 6.95 25510(a)
	H761	Failure to have the HMBP readily available to personnel of the business/facility	HSC 6.95 25505(c)

Inspector: MARTY A BROWNFIELD **Inspection Date:** 11/13/2020

CONDITIONAL EXEMPTIONS FROM REPORTING REQUIREMENTS

Agricultural handlers are conditionally exempt from electronically submitting Emergency Response and Employee Training Plans in CERS if the following requirements are met:

- Owner/Operator annually submits the Facility Information and Hazardous Materials Inventory electronically into CERS
- Each location/building, where hazardous materials (i.e. pesticides, petroleum products, fertilizers, etc.) are stored, is posted with warning signs that meet the following requirements:
  - Shall be conspicuous and visible from any direction of probable approach
  - Shall be of such size that it is readable from 25 feet and shall be labeled as follows:

DANGER HAZARDOUS MATERIAL STORAGE AREA
(the hazardous materials stored within shall be noted by category
[i.e. pesticides, petroleum products, fertilizers, etc.])
ALL UNAUTHORIZED PERSONS-KEEP OUT - IN AN EMERGENCY, CONTACT:
(list the name and phone number of an emergency contact person(s))

  - Shall be repeated in an appropriate language other than English when persons who do not understand the English language may enter the posted location/building
- Owner/Operator provides training for all new employees and annual training, including refresher courses, for all employees in safety procedures in the event of a release or threatened release of a hazardous material, including, but not limited to, familiarity with the emergency plans and procedures

Exempt Facility Violations

V	Viol #	Summary	Code
	H760	Failure to submit Emergency Response/Contingency Plan in CERS when not meeting agricultural handler exemption requirements	HSC 6.95 25507.1, 25508(a)(1); 19 CCR 4 2733, 2734
	H758	Failure to submit Employee Training Plan in CERS when not meeting agricultural handler exemption requirements	HSC 6.95 25507.1, 25508(a)(1); 19 CCR 4 2733, 2734
	H857	Failure of agricultural handler to post warning signs on buildings where pesticides, petroleum, or fertilizers are stored as required in the exemption.	HSC 6.95 25507.1(a)(2); 19 CCR 4 2670, 2671
	H759	Failure to establish and submit a HMBP in CERS when not meeting remote unstaffed facility exemption requirements	HSC 6.95 25505, 25506, 25507, 25507.2, 25508(a)(1)

SUMMARY OF OBSERVATIONS/VIOLATIONS

☐ **No violations of hazardous materials business plan laws/regulations were discovered. KERN CUPA greatly appreciates your efforts to comply with all the laws and regulations applicable to your facility.**

☒ **Violations were observed/discovered as listed below. ALL VIOLATIONS MUST BE CORRECTED WITHIN 30 DAYS OR AS SPECIFIED. CUPA must be informed in writing with a certification that compliance has been achieved. A false statement that compliance has been achieved is a violation of the law and punishable by a fine of not less than $2,000 or more than $25,000 for each violation. Your facility may be reinspected any time during normal business hours. If a second reinspection becomes necessary due to non compliance, a reinspection charge of $115.00 per hour may be charged to the facility.**

You may request a meeting with the Program Manager to discuss the inspection findings and/or the proposed corrective actions. The issuance of this Summary of Violations does not preclude the CUPA from taking administrative, civil, or criminal action.

VIOLATIONS

Violation Number	Violation Text	Violation Degree	Comply by
H342	**Failure to complete and electronically submit Hazardous Materials Inventory information for all hazardous materials on site at or above reportable quantities. HSC 6.95 25506, 25505(a)(1), 25508(a)(1)**	**CLASS II VIOLATION**	**12/13/2020**

Inspector: **MARTY A BROWNFIELD** **Inspection Date:** **11/13/2020**

Violation Details & Corrective Action Required:

The facility Owner/Operator needs to make the following revisions to the hazardous materials inventory they have submitted in the California Environmental Reporting System (CERS):

1.) The facility is reporting the "Storage Temperature" and "Storage Pressure" wrong.
a.) All non aerosol containers (cans, buckets, drums, etc) should be reported as being stored "AT" ambient temperature and pressure.
b.) All aerosol spray cans should be reported as being stored "AT" ambient temperature and "ABOVE" ambient pressure.

The facility Owner/Operator has been directed twice before to correct these issues, (1) August 2, 2018, (2) June 23, 2020. These corrections should have been made within 30 days of being told to complete them. (See Attached CERS Pages)

Please complete the required submittal No Later Than December 13, 2020. Please email your Inspector, Marty Brownfield - martyb@kerncounty.com when you have completed the required submittal so the violation can be cleared.

H344 **Failure to complete and electronically submit the Business Activities page and/or Business Owner/Operator Identification page. HSC 6.95 25508(a)(1), 19 CCR 4 2652(a)(1)** **CLASS II VIOLATION** **12/13/2020**

Violation Details & Corrective Action Required:

Facility needs to update the following information in the California Environmental Reporting System (CERS) "Business activities Page"
1.) Change physical address to "actual" location. ie: "AERA Energy Belridge property - Hill Road - Contractor Lot XXX" Currently you are using the AERA street address.
2.) Change the answer to the "Do you generate hazardous waste" from no to YES.

Please complete the required submittal No Later Than December 13, 2020. Please email your Inspector, Marty Brownfield - martyb@kerncounty.com when you have completed the required submittal so the violation can be cleared.

H347 **Failure to establish and electronically submit an adequate Emergency Response/Contingency Plan and procedures for use in the event of a release or threatened release of a hazardous material, including, but not limited to, all of the following:**
(A) Immediate notification contacts to the appropriate local emergency response personnel and to the unified program agency.
(B) Procedures for the mitigation of a release or threatened release to minimize any potential harm or damage to persons, property, or the environment.
(C) Evacuation plans and procedures, including immediate notice, for the business site. HSC 6.95 25505(a)(3), 25508(a)(1) **CLASS II VIOLATION** **12/13/2020**

Violation Details & Corrective Action Required:

The facility's contingency plan currently uploaded in CERS does not contain all required information. (Please refer to attached CERS pages)

The facility Owner/Operator is directed to complete and upload the "Template Format" Consolidated Contingency Plan that is available as a download fillable PDF. Please ensure you also include Kern County Environmental Health office number 661-862-8740 and Kern County Environmental Health 24 Hr. Emergency Response and Spill Reporting Number 661-549-9927 in the areas provided on the template.

Please complete the required submittal No Later Than December 13, 2020. Please email your Inspector, Marty Brownfield - martyb@kerncounty.com when you have completed the required submittal so the violation can be cleared.

INSPECTION COMMENTS:

COMMENTS: **Go to http://www.kernpublichealth.com/hazardous-materials for forms and information.**

Inspector: **MARTY A BROWNFIELD** **Inspection Date:** **11/13/2020**

Inspector: MARTY A BROWNFIELD **Signature of Facility Representative:**

Inspection Date: 11/13/2020

Certification: I certify under penalty of perjury that this facility has complied with the corrective actions listed on this inspection form.

Printed Name of Owner/Operator	**Title**
Signature of Owner/Operator	**Date**

KERN COUNTY
Public Health Services
DEPARTMENT

ENVIRONMENTAL HEALTH DIVISION
UNIFIED PROGRAM AGENCY (UPA)

MATTHEW CONSTANTINE
DIRECTOR

2700 M STREET, SUITE 300 BAKERSFIELD, CALIFORNIA 93301-2370 VOICE: 661-862-8740 FAX: 661-862-8701 KERNPUBLICHEALTH.COM

HAZARDOUS WASTE GENERATOR INSPECTION REPORT

Facility Name: Advanced Industrial Services-Belridge Yard		**Facility ID:** FA0048567
Site Address: 20322 7th Standard Road Lost Hills, CA 93251		**CERS ID:** 10767367 **EPA ID #:**
Phone: (562) 940-8305	**Consent Granted By:** Ty Johnston	**Inspection Date:** 11/13/2020
Inspection Type: ☒ Routine ☐ Reinspection		**Reinspection required:** ☒ Yes ☐ No

Small Quantity Generator (SQG)	Large Quantity Generator (LQG)
22 CCR § 66262.34(d), 66262.34(d)(3); HSC § 25123.3(h)(1)	22 CCR § 66262.34; HSC § 25123.3
≤1,000 kg or ≤2,240 lbs or ≤270 gal per month	≥1000 kg or ≥2,240 lbs or ≥270 gal per month
Acute or Extremely Hazardous Waste	
≤1 kg or ≤2.2 lbs or ≤0.3 gals per month	≥1 kg or ≥2.2 lbs or ≥0.3 gals per month
Acute Spill Residue or Soil	
	≥100 kg or ≥220 lbs or ≥27 gals per month
Accumulation Time Limits	
22 CCR § 66262.34(b)*, 66262.34(d)(2), 66262.34(d)(3)	22 CCR 66262.34(a)
≤180 days or ≤270 days (if greater than 200 miles) *90 days from date 100 kg limit is reached	≤90 days

General Violations - All Generators

V	VIOL #	Summary	Code
	H804	Failure to report data electronically when required	HSC 6.11 25404(e)(4)
	F004	Failure to pay Hazardous Waste Generator permit fees	KCOC 8.04.030
✓	H236	Failure to obtain/maintain an active/correct EPA ID number	22 CCR 12 66262.12
	H251	Improper hazardous waste determination	22 CCR 12 66262.11
	H248	Failure to comply with all consolidated manifest procedures	22 CCR 12 66262.40(a); HSC 6.5 25160.2
	H239	Failure to properly complete the Uniform Hazardous Waste Manifest	22 CCR 12 66262.23(a)
	H243	Failure to properly prepare manifests for transportation	22 CCR 12 66262.20
	H246	Failure of owner/operator to send generator manifest copies to DTSC within 30 days	22 CCR 12 66262.23(a)(4)
	H241	Failure to maintain signed copies of manifests for 3 years	22 CCR 12 66262.40(a)
	H297	Hazardous waste not transported by registered hauler	22 CCR 13 66263.41; HSC 6.5 25163(a)
	H260	Improper labeling of hazardous waste containers/portable tanks	22 CCR 12 66262.34(f)
	H810	Failure mark stationary tanks with "Hazardous Waste" and/or accumulation start date	22 CCR 12 66262.34(f)

Inspector: MARTY A BROWNFIELD **Inspection Date:** 11/13/2020

General Violations - All Generators (continued)

V	VIOL #	Summary	Code
	H298	Disposal of hazardous waste at an unauthorized location	HSC 6.5 25189.5(a), 25201(a)
	H302	Failure to manage recyclable materials according to requirements	HSC 6.5 25143.2, 25143.9
	H296	Failure to properly manage used oil and fuel filters	22 CCR 16 66266.130; HSC 6.5 25250.22
	H812	Failure to properly manage empty containers > 5 gallons	22 CCR 11 66261.7
	H811	Failure to follow all requirements for hazardous waste satellite accumulation	22 CCR 12 66262.34(e)
	H808	Failure to properly manage soiled/contaminated rages before being sent for laundering	HSC 6.5 25144.6(b)

Small Quantity Generator - Violations

V	VIOL #	Summary	Code
	H242	Failure to conduct employee training on waste handling and emergency procedures	22 CCR 12 66262.34(d)(2); 40 CFR 262.34(d)(5)(iii)
	H256	Hazardous waste accumulation time limit exceeded	HSC 6.5 25123.3(h)(1); 22 CCR 12 66262.34(d)
	H259	Acutely/extremely hazardous waste accumulation time limit exceeded	HSC 6.5 25123.3(c), 25123.3(h)(1)(C); 22 CCR 12 66262.34(b)(1)
	H267	Failure to accumulate hazardous waste in containers that are in good condition	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(1), 262.34(d)(2), 265.171
	H269	Failure to store hazardous waste in containers made of or lined with a material compatible with the hazardous waste to be stored	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(2), 265.172
	H271	Failure to keep hazardous waste tank/container closed	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(2), 265.173
	H276	Failure to separate incompatible waste during storage	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(2), 265.17(b), 265.177
	H273	Failure to conduct weekly hazardous waste storage area inspections	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(2), 265.174
	H281	Failure to conduct daily inspections of hazardous waste tank systems	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(3), 265.201(c)(1), 265.201(c)(2), 265.201(c)(3)
	H299	Failure to post emergency information	22 CCR 12 66262.34(d)(2); 40 CFR 262.34(d)(5)(ii)
	H303	Failure to maintain facility to prevent fire, explosion, and/or release	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(4), 265.31
	H306	Failure to have all required emergency equipment	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(4), 265.32
	H305	Failure to maintain all required emergency equipment	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(4), 265.33
	H308	Failure to maintain adequate aisle space	22 CCR 12 66262.34(d)(2); 40 CFR 1 262.34(d)(4), 265.35
	H798	Failure to complete Uniform Hazardous Waste Manifest exception report when required	HSC 6.5 25123.3(h); 22 CCR 12 66262.42 (a),(c),(d)

Large Quantity Generator - Violations

V	VIOL #	Summary	Code
	H245	Failure to conduct annual employee training and maintain documentation until facility closure	22 CCR 12 66262.34(a)(4); 22 CCR 15 66265.16
	H237	Failure to prepare and implement a contingency plan	22 CCR 12 66262.34(a)(4); 22 CCR 15 66265.51
	H240	Failure to include all required information in the contingency plan	22 CCR 12 66262.34(a)(4); 22 CCR 15 66265.52

Large Quantity Generator - Violations (continued)

V	VIOL #	Summary	Code
	H238	Failure to maintain a copy of the contingency plan on site and/or submit a copy to all responding agencies	22 CCR 12, 66262.34(a)(4); 22 CCR 15 66265.53
	H258	Failure to dispose of hazardous waste within 90 days of accumulation start	HSC 6.5 25123.3(b)(1), 25201; 22 CCR 12 66262.34(a)
	H268	Failure to accumulate hazardous waste in containers that are in good condition	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.171
	H270	Failure to store hazardous waste in containers made of or lined with a material compatible with the hazardous waste to be stored	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.172
	H272	Failure to keep hazardous waste tank/container closed	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.173
	H274	Failure to conduct weekly hazardous waste storage area inspections	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.174
	H289	Failure to conduct daily inspections of hazardous waste tank systems	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.195(a), 66265.195(c)
	H309	Failure to maintain adequate aisle space	22 CCR 12 66262.34(a)(4); 22 CCR 15 66265.35
	H275	Failure to locate reactive and ignitable waste at least 15 meters (50 feet) from the facility's property line	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.176
	H279	Failure to separate incompatible waste during storage	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.17(b), 66265.177
	H304	Failure to maintain facility to prevent fire, explosion, and/or release	22 CCR 12 66262.34(a)(4); 22 CCR 15 66265.31
	H291	Failure to meet secondary containment requirements for hazardous waste tank systems or components	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.193
	H294	Failure to immediately remove from service a tank system which is unfit for use and/or comply with applicable requirements	22 CCR 15 66265.196
	H292	Failure to meet tank system closure requirements	22 CCR 15 66265.111, 66265.114, 66265.197
	H286	Failure to obtain and/or maintain a new hazardous waste tank assessment by a professional engineer	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.192(a)
	H800	Failure to complete an assessment or reassessment of a hazardous waste tank as required	22 CCR 15 66265.192(h)
	H312	Failure to conduct hazardous waste tank system cathodic protection system inspections as required	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.195(b), 66265.195(c)
	H815	Failure to comply with air emmisions requirements for hazardous waste in containers	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.178
	H816	Failure to comply with air emmisions requirements for hazardous waste in tanks	22 CCR 12 66262.34(a)(1); 22 CCR 15 66265.202
	H307	Failure to have all required emergency equipment	22 CCR 12 66262.34(a)(4); 22 CCR 15 66265.32
	H301	Failure to inspect and/or maintain all safety/emergency equipment as required	22 CCR 12 66262.34(a)(4); 22 CCR 15 66265.33
	H244	Failure to complete Uniform Hazardous Waste Manifest exception report when required	22 CCR 12 66262.42(a),(b),(d)
	H799	Failure to complete certification of waste minimization on all manifests	22 CCR 12 66262.27(a)
	H257	Failure to adequately complete, and maintain for review, all requirements of the source reduction evaluation review and plan (SB-14)	HSC 6.5 25244.19, 25244.21; 22 CCR 31 67100.5
	H254	Failure to properly prepare a source reduction evaluation review and plan every four years	HSC 6.5 25244.19; 22 CCR 31 67100.7, 67100.8
	H255	Failure to prepare a summary progress report and submitted it to DTSC every four years	22 CCR 31 67100.9

Universal Waste Generator - Violations

V	VIOL #	Summary	Code
	H318	Failure to comply with all universal waste training requirements	22 CCR 23 66273.36
	H321	Faillure to meet universal waste labeling requirements	22 CCR 23 66273.34
	H330	Universal waste accumulation exceeded the 1 year limit	22 CCR 23 66273.35
	H329	Failure to disposal of universal waste at an appropriate destination facility	22 CCR 23 66273.31(a)
	H320	Failure to properly prepare and/or retain shipping papers for all universal waste shipped	22 CCR 23 66273.38; 49 CFR 1 172.201(e)
	H325	Failure to handle waste aerosol cans to prevent fire, explosion, and/or release	HSC 6.5 25201.16(e)
	H328	Failure to meet accumulation standards for aerosol cans	HSC 6.5 25201.16(f)
	H326	Failure to properly clean up and/or contain spills of electronic devices, CRTs and/or CRT glass	22 CCR 23 66273.33.5

Waste Lead Acid Battery Generator - Violations

V	VIOL #	Summary	Code
	H290	Failure to meet requirements for handling, storing, and/or transporting lead acid batteries	22 CCR 16 66266.81(a)(1)
	H293	Failure to properly manage, store, and/or label damaged lead acid batteries	22 CCR 16 66266.81(b)
	H250	Failure to maintain documentation for disposal of lead acid batteries for 3 years	22 CCR 16 66266.81(a)(4)(B)
	H261	Failure to meet all requirements when accepting spent lead acid batteries	22 CCR 16 66266.81(a)(3)

SUMMARY OF OBSERVATIONS/VIOLATIONS

☐ **No violations of hazardous waste laws/regulations were discovered. KERN CUPA greatly appreciates your efforts to comply with all the laws and regulations applicable to your facility.**

☒ **Violations were observed/discovered as listed below. All violations must be corrected by implementing the corrective action listed by each violation. If you disagree with any of the violations or corrective actions required, please inform the CUPA in writing.**

ALL VIOLATIONS MUST BE CORRECTED WITHIN 30 DAYS OR AS SPECIFIED. CUPA must be informed in writing with a certification that compliance has been achieved. A false statement that compliance has been achieved is a violation of the law and punishable by a fine of not less than $2,000 or more than $25,000 for each violation. Your facility may be reinspected any time during normal business hours. If a second reinspection becomes necessary due to non compliance, a reinspection charge of $115.00 per hour may be charged to the facility.

You may request a meeting with the Program Manager to discuss the inspection findings and/or the proposed corrective actions. The issuance of this Summary of Violations does not preclude the CUPA from taking administrative, civil, or criminal action.

VIOLATIONS

Violation Number	Violation Text	Violation Degree	Comply by
H236	**Failure to obtain an Identification Number prior to treating, storing, disposing of, transporting or offering for transportation any hazardous waste. 22 CCR 12 66262.12**	**CLASS II VIOLATION**	**12/13/2020**

Violation Details & Corrective Action Required:

The facility is a generator of hazardous wastes (paints, coatings & paint related wastes). Facility has an agreement with AERA Energy to take their waste generated on AERA property to AERA's waste consolidation area for disposal.

The facility's "Temporary" EPA ID Number has been inactive since September 24, 2018. Facility Owner/Operator is directed to obtain a Permanent EPA Hazardous Waste Generator Identification Number from the California Department of Toxic Substances Control.

Please complete the required application to DTSC and submit proff of compliance No Later Than December 13, 2020. Please email your Inspector, Marty Brownfield - martyb@kerncounty.com when you have completed the required submittal so the violation can be cleared.

INSPECTION COMMENTS:

COMMENTS: **Go to http://www.kernpublichealth.com/hazardous-materials for forms and information.**

Inspector: MARTY A BROWNFIELD
Inspection Date: 11/13/2020

Signature of Facility Representative:

Certification: I certify under penalty of perjury that this facility has complied with the corrective actions listed on this inspection form.

Printed Name of Owner/Operator **Title**

Signature of Owner/Operator **Date**

Advanced Industrial Services-Belridge Yard (CERSID: 10767367)

Facility Information Accepted Feb 9, 2021

Submitted on 12/3/2020 11:26:52 AM by *Eduardo Ortega* of ADVANCED INDUSTRIAL SERVICES INC (PARAMOUNT, CA)
Submittal was ***Accepted*** on 2/9/2021 11:15:26 AM by BROWNFIELD, MARTY A

- Business Activities
- Business Owner/Operator Identification

Guidance Messages

- **Warning:**
  1. Business Activities - The Address for CERSID: 10767367 has changed from: '20322 7th Standard Rd, Mc Kittrick, CA 93251' to '20322 7th Standard Rd, Mc Kittrick, CA 93251'.

Hazardous Materials Inventory Accepted Feb 9, 2021

Submitted on 12/3/2020 11:26:52 AM by *Eduardo Ortega* of ADVANCED INDUSTRIAL SERVICES INC (PARAMOUNT, CA)
Submittal was ***Accepted*** on 2/9/2021 11:15:33 AM by BROWNFIELD, MARTY A

- Hazardous Material Inventory (20)
- Site Map (Official Use Only)
  - *Annotated Site Map (Official Use Only)* (Adobe PDF, 527KB)

Guidance Messages

- **Warning:**
  1. Hazardous Material Inventory - This inventory contains 4 trade secret material(s). Trade secret information must meet the criteria specified in California Civil Code 3426.1(d) and Government Code 6254.7

Emergency Response and Training Plans Accepted Feb 9, 2021

Submitted on 12/3/2020 11:26:52 AM by *Eduardo Ortega* of ADVANCED INDUSTRIAL SERVICES INC (PARAMOUNT, CA)
Submittal was ***Accepted*** on 2/9/2021 11:15:30 AM by BROWNFIELD, MARTY A

- Emergency Response/Contingency Plan
  - *Emergency Response/Contingency Plan* (Adobe PDF, 516KB)
- Employee Training Plan
  - *Employee Training Plan* (Adobe PDF, 336KB)

Site Identification

Advanced Industrial Services-Belridge Yard
20322 7th Standard Rd Lot 102 Hill Road
Mc Kittrick, CA 93251
County
Kern

CERS ID
10767367
EPA ID Number
CAC002967936

Submittal Status

Submitted on 12/3/2020 by *Eduardo Ortega* of ADVANCED INDUSTRIAL SERVICES INC (PARAMOUNT, CA)
Submittal was ***Accepted***; Processed on 2/9/2021 by *BROWNFIELD, MARTY A* for Kern County Environmental Health Services Department

Hazardous Materials

Does your facility have on site (for any purpose) at any one time, hazardous materials at or above 55 gallons for liquids, 500 pounds for solids, or 200 cubic feet for compressed gases (include liquids in ASTs and USTs); or is regulated under more restrictive inventory local reporting requirements (shown below if present); or the applicable Federal threshold quantity for an extremely hazardous substance specified in 40 CFR Part 355, Appendix A or B; or handle radiological materials in quantities for which an emergency plan is required pursuant to 10 CFR Parts 30, 40 or 70?	**Yes**

Underground Storage Tank(s) (UST)

Does your facility own or operate underground storage tanks?	**No**

Hazardous Waste

Is your facility a Hazardous Waste Generator?	**Yes**
Does your facility treat hazardous waste on-site?	**No**
Is your facility's treatment subject to financial assurance requirements (for Permit by Rule and Conditional Authorization)?	**No**
Does your facility consolidate hazardous waste generated at a remote site?	**No**
Does your facility need to report the closure/removal of a tank that was classified as hazardous waste and cleaned on-site?	**No**
Does your facility generate in any single calendar month 1,000 kilograms (kg) (2,200 pounds) or more of federal RCRA hazardous waste, or generate in any single calendar month greater than 1 kg (2.2 pounds) of RCRA acute hazardous waste; or generate more than 100 kg (220 pounds) of spill cleanup materials contaminated with RCRA acute hazardous waste.	**No**
Is your facility a Household Hazardous Waste (HHW) Collection site?	**No**

Excluded and/or Exempted Materials

Does your facility recycle more than 100 kg/month of excluded or exempted recyclable materials (per HSC 25143.2)?	**No**
Does your facility own or operate ASTs above these thresholds? Store greater than 1,320 gallons of petroleum products (new or used) in aboveground tanks or containers.	**No**
Does your facility have Regulated Substances stored onsite in quantities greater than the threshold quantities established by the California Accidental Release prevention Program (CalARP)?	**No**

Additional Information

No additional comments provided.

California Environmental Reporting System (CERS) — Business Owner Operator

Facility/Site

Advanced Industrial Services-Belridge Yard
20322 7th Standard Rd Lot 102 Hill Road
Mc Kittrick, CA 93251

CERS ID
10767367

Submittal Status

Submitted on 12/3/2020 by *Eduardo Ortega* of ADVANCED INDUSTRIAL SERVICES INC (PARAMOUNT, CA)
Submittal was ***Accepted***; Processed on 2/9/2021 by *BROWNFIELD, MARTY A* for Kern County Environmental Health Services Department

Identification

Ty Johnston

Operator Phone	Business Phone	Business Fax
(562) 243-4787	(562) 940-8305	(562) 940-8306

Beginning Date	Ending Date	
Dun & Bradstreet	**SIC Code**	**Primary NAICS**

Facility/Site Mailing Address

11712 Cherry St
Los Alamitos, CA 90720

Primary Emergency Contact

Ty Johnston
Title
Project Manager

Business Phone	24-Hour Phone	Pager Number
(562) 243-4787	(562) 243-4787	

Owner

Rex Johnston Jr.
(562) 243-4767
7831 Alondra Blvd.
Paramount, CA 90723

Secondary Emergency Contact

Jaime Cuevas
Title
Superintendent

Business Phone	24-Hour Phone	Pager Number
(562) 243-9717	(562) 824-6172	

Billing Contact

Johanna Felix
(562) 940-8305 johanna@adinservices.com
7831 Alondra Blvd
Paramount, CA 90723

Environmental Contact

Eduardo Ortega
(562) 458-6949 eortega@adinservices.com
7831 Alondra Blvd
Paramount, CA 90723

Name of Signer	Signer Title	Document Preparer
Eduardo Ortega	Safety Manager	Eduardo Ortega

Additional Information

Locally-collected Fields

Some or all of the following fields may be required by your local regulator(s).

Property Owner

Phone

Mailing Address

,

Assessor Parcel Number (APN)

Number of Employees

Facility ID
FA0048567

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **ADVANCED INDUSTRIAL SERVICES INC**
Facility Name **Advanced Industrial Services-Belridge Yard**
20322 7th Standard Rd, Mc Kittrick 93251

Chemical Location **Storage Container**

CERS ID **10767367**
Facility ID **FA0048567**
Status **Submitted** on 12/3/2020 11:26 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
DOT: 3 - Flammable and Combustible Liquids Flammable Liquid, Class I-C	**Enviroline 376F-60 Part A** CAS No Proprietary	**Gallons** State Liquid Type Mixture	**10** Storage Container Steel Drum, Can Days on Site: 90	**5**	5 Pressue Ambient Temperature Ambient	5 Waste Code	- Health Carcinogenicity - Health Acute Toxicity - Health Reproductive Toxicity - Health Skin Corrosion Irritation - Health Serious Eye Damage Eye Irritation - Health Specific Target Organ Toxicity				

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **ADVANCED INDUSTRIAL SERVICES INC**
Facility Name **Advanced Industrial Services-Belridge Yard**
20322 7th Standard Rd, Mc Kittrick 93251

Chemical Location **storage Container**

CERS ID **10767367**
Facility ID **FA0048567**
Status **Submitted** on 12/3/2020 11:26 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
DOT: 8 - Corrosives (Liquids and Solids)	**Enviroline 2405 Part B** CAS No 37244-96-5	**Gallons** State Liquid Type Mixture	**10** Storage Container Steel Drum, Can Days on Site: 90	**5**	5 Pressue Ambient Temperature Ambient	0 Waste Code 461	- Health Skin Corrosion Irritation - Health Respiratory Skin Sensitization - Health Serious Eye Damage Eye Irritation	Nepheline syenite Cyclohexanamine, 4,4'-methylenebis- FORMALDEHYDE, POLYMER WITH BENZENAMINE, HYDROGENAT	50% 25% 25%		37244-96-5 1761-71-3 135108-88-2

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **ADVANCED INDUSTRIAL SERVICES INC**
Facility Name **Advanced Industrial Services-Belridge Yard**
20322 7th Standard Rd, Mc Kittrick 93251

Chemical Location **Storage Container**

CERS ID **10767367**
Facility ID **FA0048567**
Status **Submitted** on 12/3/2020 11:26 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
DOT: 3 - Flammable and Combustible Liquids Combustible Liquid, Class III-B	**Carboline Thinner 254** CAS No 34590-94-8	**Gallons** State Liquid Type Pure	**10** Storage Container Can, Other	**5**	5 Pressue Ambient Temperature Ambient	10 Waste Code	- Physical Flammable - Health Reproductive Toxicity	DIPROPYLENE GLYCOL METHYL ETHER	100%	✓	34590-94-8
	Enviroline 376F-60 Part B CAS No 1761-71-3	**Gallons** State Liquid Type Mixture	**10** Storage Container Steel Drum, Can Days on Site: 90	**5**	5 Pressue Ambient Temperature Ambient	0 Waste Code	- Physical Flammable - Health Carcinogenicity - Health Acute Toxicity - Health Reproductive Toxicity - Health Skin Corrosion Irritation - Health Respiratory Skin Sensitization - Health Serious Eye Damage Eye Irritation - Health Specific Target Organ Toxicity	Cyclohexanamine, 4,4'-methylenebis FORMALDEHYDE, POLYMER WITH BENZENAMINE, HYDROGENAT Benzyl alcohol Diethylene triamine Xylenes	25% 25% 10% 10% 10%		1761-71-3 135108-88-2 100-51-6 111-40-0 1330-20-7
DOT: 3 - Flammable and Combustible Liquids	**Enviroline 405HTR Part A** CAS No 28064-14-4	**Gallons** State Liquid Type Mixture	**10** Storage Container Steel Drum, Can Days on Site: 90	**5**	5 Pressue Ambient Temperature Ambient	0 Waste Code 461	- Health Skin Corrosion Irritation - Health Respiratory Skin Sensitization - Health Serious Eye Damage Eye Irritation	PHENOL, POLYMER WITH FORMALDEHYDE, GLYCIDYL ETHER Xylenes	50% 10%		28064-14-4 1330-20-7
DOT: 3 - Flammable and Combustible Liquids	**Enviroline 2405 Part A** CAS No 28064-14-4	**Gallons** State Liquid Type Mixture	**10** Storage Container Steel Drum, Can Days on Site: 90	**5**	5 Pressue Ambient Temperature Ambient	0 Waste Code	- Health Acute Toxicity - Health Skin Corrosion Irritation - Health Respiratory Skin Sensitization - Health Serious Eye Damage Eye Irritation	PHENOL, POLYMER WITH FORMALDEHYDE, GLYCIDYL ETHER Glycidoxypropyltrimethoxysilane Nepheline syenite	50% 25% 50%		28064-14-4 2530-83-8 37244-96-5

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **ADVANCED INDUSTRIAL SERVICES INC**
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20322 7th Standard Rd, Mc Kittrick 93251

Chemical Location **Storage Container**

CERS ID **10767367**
Facility ID **FA0048567**
Status **Submitted** on 12/3/2020 11:26 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
DOT: 3 - Flammable and Combustible Liquids	**Carbozinc 859 Part A** CAS No: Multi State: Liquid Type: Mixture Storage Container: Can Days on Site: 90 Pressue: Ambient Temperature: Ambient Waste Code:	**Gallons**	5	1	1	0	- Physical Flammable - Health Carcinogenicity - Health Acute Toxicity - Health Skin Corrosion Irritation - Health Respiratory Skin Sensitization - Health Serious Eye Damage Eye Irritation	EPOXY RESIN Toluene TITANIUM DIOXIDE EPOXY RESIN METHYL ETHYL KETONE	25% 25% 25% 10% 10%		25036-25-3 108-88-3 13463-67-7 25068-38-6 78-93-3
DOT: 3 - Flammable and Combustible Liquids	**Carbozinc 859 Part B** CAS No: Multi State: Liquid Type: Mixture Storage Container: Can Days on Site: 90 Pressue: < Ambient Temperature: < Ambient Waste Code:	**Gallons**	5	1	1	0	- Physical Flammable - Health Carcinogenicity - Health Acute Toxicity - Health Skin Corrosion Irritation - Health Respiratory Skin Sensitization - Health Serious Eye Damage Eye Irritation - Health Specific Target Organ Toxicity	Toluene Isopropanol 1,2-BENZENEDICARBOXIOLIC ACID, DI-C9-11-BRANCHED AND LINEAR ALKYL ESTERS TRIS-2,4,6-(DIMETHYLAMINOMETHYL) PHENOL Benzyl alcohol	50% 25% 10% 10% 10%		108-88-3 67-63-0 68515-43-5 90-72-2 100-51-6
DOT: 3 - Flammable and Combustible Liquids	**Carboline 225E Thinner** CAS No: 67-64-1 State: Liquid Type: Pure Storage Container: Can Pressue: Ambient Temperature: Ambient Waste Code:	**Gallons**	5	5	1	2	- Physical Flammable - Health Respiratory Skin Sensitization - Health Serious Eye Damage Eye Irritation	Acetone	100%		67-64-1

Hazardous Materials And Wastes Inventory Matrix Report

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Chemical Location **Storage Container**

CERS ID **10767367**
Facility ID **FA0048567**
Status **Submitted** on 12/3/2020 11:26 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
DOT: 3 - Flammable and Combustible Liquids	**Carboline Thinner #10** CAS No: Multi State: Liquid Type: Mixture Storage Container: Can Days on Site: 90 Pressue: Ambient Temperature: Ambient Waste Code	**Gallons**	**10**	**5**	5	1	- Physical Flammable - Health Skin Corrosion Irritation - Health Respiratory Skin Sensitization - Health Serious Eye Damage Eye Irritation	META-XYLENE PARA-XYLENE ETHYL BENZENE ORTHO-XYLENE TOLUENE	50% 25% 25% 25% 10%		108-38-3 106-42-3 100-41-4 95-47-6 108-88-3
DOT: 3 - Flammable and Combustible Liquids	**MACROPOXY® 646 Fast Cure Epoxy Part A** CAS No: 68457-74-9 State: Liquid Type: Mixture Storage Container: Can Days on Site: 90 Pressue: Ambient Temperature: Ambient Waste Code	**Gallons**	**5**	**5**	1	0	- Physical Flammable - Health Acute Toxicity - Health Skin Corrosion Irritation - Health Respiratory Skin Sensitization - Health Serious Eye Damage Eye Irritation - Health Specific Target Organ Toxicity	Phenol, isobutylenated methylstyrenated Xylene Polyamide Ethylbenzene Triethylene Tetramine	25% 25% 25% 3% 1%		68457-74-9 1330-20-7 68410-23-1 100-41-4 112-24-3
DOT: 3 - Flammable and Combustible Liquids	**Sherwin Williams Reducer RK111** CAS No: Multi State: Liquid Type: Mixture Storage Container: Can Days on Site: 90 Pressue: Ambient Temperature: Ambient Waste Code	**Gallons**	**15**		5		- Physical Flammable - Health Respiratory Skin Sensitization - Health Serious Eye Damage Eye Irritation - Health Specific Target Organ Toxicity	p-Chlorobenzotrifluoride Acetone	60% 40%		98-56-6 67-64-1
DOT: 3 - Flammable and Combustible Liquids	**ZERO VOC EXEMPT SOLVEN 80/20** CAS No: Multi State: Liquid Type: Mixture Storage Container: Can Pressue: Ambient Temperature: Ambient Waste Code	**Gallons**	**10**	**5**	5	5	- Physical Flammable - Health Respiratory Skin Sensitization - Health Serious Eye Damage Eye Irritation	Acetone Methyl Acetate	80% 20%		67-64-1 79-20-9

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **ADVANCED INDUSTRIAL SERVICES INC**
Facility Name **Advanced Industrial Services-Belridge Yard**
20322 7th Standard Rd, Mc Kittrick 93251

Chemical Location **Storage Container**

CERS ID **10767367**
Facility ID **FA0048567**
Status **Submitted** on 12/3/2020 11:26 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
DOT: 8 - Corrosives (Liquids and Solids)	**Jasco Premium Paint and Epoxy Remove** CAS No: Multi	**Gallons** State: Liquid Type: Mixture	**5** Storage Container: Can Days on Site: 90	**1**	2 Pressue: Ambient Temperature: Ambient	1 Waste Code	- Health Reproductive Toxicity - Health Skin Corrosion Irritation - Health Respiratory Skin Sensitization - Health Serious Eye Damage Eye Irritation - Health Specific Target Organ Toxicity	Dichloromethane {Methylene chloride; R-30; Freon 30} Methanol {Methyl alcohol; Carbinol; Wood alcohol} Hydrotreated light distillate (petroleum)	60% 20% 5%		75-09-2 67-56-1 64742-47-8
DOT: 3 - Flammable and Combustible Liquids	**MACROPOXY® 646 Fast Cure Epoxy Part B** CAS No: 25068-38-6	**Gallons** State: Liquid Type: Mixture	**5** Storage Container: Can Days on Site: 90	**5**	1 Pressue: Ambient Temperature: Ambient	0 Waste Code	- Physical Flammable - Health Carcinogenicity - Health Reproductive Toxicity - Health Skin Corrosion Irritation - Health Respiratory Skin Sensitization - Health Serious Eye Damage Eye Irritation - Health Specific Target Organ Toxicity	Crystalline Silica, respirable powder Epoxy Polymer Methyl Isobutyl Ketone Xylene	75% 25% 10% 3%		14808-60-7 25068-38-6 108-10-1 1330-20-7

Hazardous Materials And Wastes Inventory Matrix Report

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20322 7th Standard Rd, Mc Kittrick 93251

Chemical Location **Storage Container**

CERS ID **10767367**
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DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
DOT: 8 - Corrosives (Liquids and Solids) Flammable Liquid, Class I-B	**Epo Phen FF Part A** CAS No 1309-37-1	**Gallons** State Liquid Type Mixture	**10** Storage Container Steel Drum, Can Days on Site: 90	**5**	5 Pressue Ambient Temperature Ambient	0 Waste Code 461	- Physical Flammable - Health Reproductive Toxicity - Health Skin Corrosion Irritation - Health Respiratory Skin Sensitization - Health Serious Eye Damage Eye Irritation	Iron Oxide Phenol, polymer with formaldehyde, glycidylether Xylene Methyl Ethyl Ketone	54% 26% 6% 5%		1309-37-1 28064-14-4 1330-20-7 78-93-3
DOT: 8 - Corrosives (Liquids and Solids)	**ENVIROLINE B-FLEX 9400TR Part A** CAS No 28064-14-4	**Gallons** State Liquid Type Mixture	**10** Storage Container Can Days on Site: 90	**5**	5 Pressue Ambient Temperature Ambient	0 Waste Code	- Physical Flammable - Health Skin Corrosion Irritation - Health Respiratory Skin Sensitization - Health Serious Eye Damage Eye Irritation - Health Specific Target Organ Toxicity	Propylene Glycol Monomethyl Ether Quartz Wollastonite (Ca(SiO3)) Mica Titanium dioxide	50% 50% 25% 10% 10%		28064-14-4 14808-60-7 13983-17-0 12001-26-2 13463-67-7
DOT: 8 - Corrosives (Liquids and Solids) Combustible Liquid, Class II	**Enviroline 405HTR Part B** CAS No 37244-96-5	**Gallons** State Liquid Type Mixture	**10** Storage Container Steel Drum, Can Days on Site: 90	**5**	5 Pressue Ambient Temperature Ambient	0 Waste Code 461	- Health Skin Corrosion Irritation - Health Respiratory Skin Sensitization - Health Serious Eye Damage Eye Irritation	Nepheline syenite Cyclohexanamine, 4,4'-methylenebis- FORMALDEHYDE, POLYMER WITH BENZENAMINE, HYDROGENAT Titanium Dioxide Aluminum oxide	50% 25% 10% 10% 10%		37244-96-5 1761-71-3 135108-88-2 13463-67-7 1344-28-1
DOT: 3 - Flammable and Combustible Liquids	**Devoe T-17 Thinner** CAS No 763-69-9	**Gallons** State Liquid Type Pure	**10** Storage Container Can	**5**	1 Pressue Ambient Temperature Ambient	1 Waste Code	- Physical Flammable - Health Respiratory Skin Sensitization - Health Serious Eye Damage Eye Irritation	Ethyl 3-ethoxypropionate	100%		763-69-9

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **ADVANCED INDUSTRIAL SERVICES INC**
Facility Name **Advanced Industrial Services-Belridge Yard**
20322 7th Standard Rd, Mc Kittrick 93251

Chemical Location **Storage Container**

CERS ID **10767367**
Facility ID **FA0048567**
Status **Submitted** on 12/3/2020 11:26 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
DOT: 3 - Flammable and Combustible Liquids	**Sherwin Williams High Solids Poly Activator Part T** CAS No 28182-81-2	**Gallons** State Liquid Type Mixture	**10** Storage Container Can Days on Site: 90	**1**	5 Pressue Ambient Temperature Ambient	2 Waste Code 461	- Physical Flammable - Health Carcinogenicity - Health Acute Toxicity - Health Skin Corrosion Irritation - Health Respiratory Skin Sensitization - Health Serious Eye Damage Eye Irritation - Health Specific Target Organ Toxicity	Hexamethylene Diisocyanate Polymer Methyl n-Amyl Ketone Hexamethylene Diisocyanate (max.)	75% 50% 1%		28182-81-2 110-43-0 822-06-0

CALIFORNIA ENVIRONMENTAL REPORTING SYSTEM (CERS)

CONSOLIDATED EMERGENCY RESPONSE / CONTINGENCY PLAN

Prior to completing this Plan, please refer to the INSTRUCTIONS FOR COMPLETING A CONSOLIDATED CONTINGENCY PLAN

FACILITY ID #	CERS ID #	DATE OF PLAN PREPARATION/REVISION (MM/DD/YYYY)
FA 0 0 0 0 4 8 5 6 7 (A1.)	10767367 (A2.)	12/03/2020 (A3.)

BUSINESS NAME *(Same as Facility Name or DBA - Doing Business As)* (A4.)
Advanced Industrial Services, Inc.

BUSINESS SITE ADDRESS (A5.)
20322 7th Standard Road Lot 102 Hill Road

BUSINESS SITE CITY (A6.)		ZIP CODE (A7.)
Lost Hills	CA	93251

TYPE OF BUSINESS (e.g., Painting Contractor) (A8.)	INCIDENTAL OPERATIONS (e.g., Fleet Maintenance) (A9.)
Industrial Painting Contractor	Equipment Storage Facility

THIS PLAN COVERS CHEMICAL SPILLS, FIRES, AND EARTHQUAKES INVOLVING (Check all that apply): (A10.)

☒ 1. HAZARDOUS MATERIALS; ☒ 2. HAZARDOUS WASTES

INTERNAL FACILITY EMERGENCY RESPONSE WILL OCCUR BY (Check all that apply): (B1.)

☒ 1. CALLING PUBLIC EMERGENCY RESPONDERS (e.g., 9-1-1)
☒ 2. CALLING HAZARDOUS WASTE CONTRACTOR
☐ 3. ACTIVATING IN-HOUSE EMERGENCY RESPONSE TEAM

In the event of an emergency involving hazardous materials and/or hazardous waste, all facilities must IMMEDIATELY:
1. Notify facility personnel and evacuate if necessary in accordance with the Emergency Action Plan (Title 8 California Code of Regulations §3220);
2. Notify local emergency responders by calling 9-1-1;
3. Notify the local Unified Program Agency (UPA) at the phone number below; and
4. Notify the State Warning Center at (800) 852-7550.

Facilities that generate, treat, store or dispose of hazardous waste have additional responsibilities to notify and coordinate with other response agencies. Whenever there is an imminent or actual emergency situation such as an explosion, fire, or release, the Emergency Coordinator must follow the appropriate requirements for the category of facility and type of release involved:
1. Title 22 California Code of Regulations §66265.56. Emergency Procedures for generators of 1,000 kilograms or more of hazardous waste in any calendar month.
2. Title 22 California Code of Regulations §66265.196. Response to Leaks or Spills and Disposition of Leaking or Unfit-for-Use Tank Systems.
3. Title 40 Code of Federal Regulations §302.6. Notification requirements for a release of a hazardous substance equal to or greater than the reportable quantity.
4. Title 22 California Code of Regulations §66262.34(d)(2) and Title 40 Code of Federal Regulations §262.34(d)(5)(ii) for generators of less than 1000 kilograms of hazardous waste in any calendar month.

Following notification and before facility operations are resumed in areas of the facility affected by the incident, the Emergency Coordinator shall notify the local UPA and the local fire department's hazardous materials program, if necessary, that the facility is in compliance with requirements to:
1. Provide for proper storage and disposal of recovered waste, contaminated soil or surface water, or any other material that results from an explosion, fire, or release at the facility; and
2. Ensure that no material that is incompatible with the released material is transferred, stored, or disposed of in areas of the facility affected by the incident until cleanup procedures are completed.

EMERGENCY RESPONSE PHONE NUMBERS:		
	AMBULANCE, FIRE, POLICE AND CHP	9-1-1
	CALIFORNIA STATE WARNING CENTER (CSWC)/CAL OES.	(800) 852-7550
	NATIONAL RESPONSE CENTER (NRC)	(800) 424-8802
	POISON CONTROL CENTER	(800) 222-1222
	LOCAL UNIFIED PROGRAM AGENCY (UPA)	(661) 862-8740 (C1.)
	OTHER (Specify): (C2.)	(C3.)
NEAREST MEDICAL FACILITY / HOSPITAL NAME: Mercy Hospital Southwest Bakersfield (C4.)		(661) 663-6000 (C5.)

AGENCY NOTIFICATION PHONE NUMBERS:		
	CALIFORNIA DEPT. OF TOXIC SUBSTANCES CONTROL (DTSC)	(916) 255-3545
	REGIONAL WATER QUALITY CONTROL BOARD (RWQCB).	(C6.)
	U.S. ENVIRONMENTAL PROTECTION AGENCY (US EPA)	(800) 300-2193
	CALIFORNIA DEPT. OF FISH AND WILDLIFE (CDFW)	(916) 358-2900
	U.S. COAST GUARD (USCG)	(202) 267-2180
	CAL OSHA	(916) 263-2800
	CAL FIRE OFFICE OF THE STATE FIRE MARSHAL (OSFM)	(916) 323-7390
	OTHER (Specify): (C7.)	(C8.)
	OTHER (Specify): (C9.)	(C10.)

INTERNAL FACILITY EMERGENCY COMMUNICATIONS OR ALARM NOTIFICATION WILL OCCUR BY (Check all that apply): C11.

- [x] 1. VERBAL WARNINGS;
- [ ] 2. PUBLIC ADDRESS OR INTERCOM SYSTEM;
- [x] 3. TELEPHONE;
- [ ] 4. PAGERS;
- [ ] 5. ALARM SYSTEM;
- [ ] 6. PORTABLE RADIO

NOTIFICATIONS TO NEIGHBORING FACILITIES THAT MAY BE AFFECTED BY AN OFF-SITE RELEASE WILL OCCUR BY (Check all that apply): C12.

- [x] 1. VERBAL WARNINGS;
- [ ] 2. PUBLIC ADDRESS OR INTERCOM SYSTEM;
- [x] 3. TELEPHONE;
- [ ] 4. PAGERS;
- [ ] 5. ALARM SYSTEM;
- [ ] 6. PORTABLE RADIO

EMERGENCY COORDINATOR CONTACT INFORMATION: Ty Johnston C13.

PRIMARY EMERGENCY COORDINATOR NAME: Ty Johnston PHONE NO.: (562) 243-4787 PHONE NO.:

ALTERNATE EMERGENCY COORDINATOR NAME: Jaime Cuevas PHONE NO.: (562) 824-6172 PHONE NO.:

- [ ] Check if additional Emergency Coordinator contact and address information is available onsite or by calling PHONE NO.: -

Note: If more than one alternate emergency coordinator is designated, attach a list in order of responsibility.

D. EMERGENCY CONTAINMENT AND CLEANUP PROCEDURES

Check the applicable boxes to indicate your facility's procedures for containing spills and preventing and mitigating releases, fires and/or explosions.

D1.

- [x] 1. MONITOR FOR LEAKS, RUPTURES, PRESSURE BUILD-UP, ETC.;
- [ ] 2. PROVIDE STRUCTURAL PHYSICAL BARRIERS (e.g., Portable spill containment walls, built-in berms);
- [x] 3. PROVIDE ABSORBENT PHYSICAL BARRIERS (e.g., Pads, spill pigs, spill pillows);
- [ ] 4. COVER OR BLOCK FLOOR AND/OR STORM DRAINS;
- [ ] 5. LINED TRENCH DRAINS AND/OR SUMPS;
- [ ] 6. AUTOMATIC FIRE SUPPRESSION SYSTEM;
- [ ] 7. ELIMINATE SOURCES OF IGNITION FOR FLAMMABLE HAZARDS;
- [x] 8. STOP PROCESSES AND/OR OPERATIONS;
- [ ] 9. AUTOMATIC / ELECTRONIC EQUIPMENT SHUT-OFF SYSTEM;
- [ ] 10. SHUT OFF WATER, GAS, ELECTRICAL UTILITIES;
- [x] 11. CALL 9-1-1 FOR PUBLIC EMERGENCY RESPONDER ASSISTANCE AND/OR MEDICAL AID;
- [x] 12. NOTIFY AND EVACUATE PERSONS IN ALL THREATENED AND/OR IMPACTED AREAS;
- [x] 13. ACCOUNT FOR EVACUATED PERSONS IMMEDIATELY AFTER EVACUATION;
- [ ] 14. PROVIDE PROTECTIVE EQUIPMENT FOR ON-SITE EMERGENCY RESPONSE TEAM;
- [ ] 15. REMOVE CONTAINERS AND/OR ISOLATE AREAS;
- [x] 16. HIRE LICENSED HAZARDOUS WASTE CONTRACTOR;
- [x] 17. USE ABSORBENT MATERIAL FOR SPILL CONTAINMENT;
- [ ] 18. VACUUM SUCTION USING APPROPRIATE VACUUM (e.g., Intrinsically safe) FOR SPILL CONTROL AND/OR CLEANUP;
- [ ] 19. DECONTAMINATE PERSONNEL AND EQUIPMENT WITHIN DESIGNATED AREA AND DISPOSE OF WASTEWATER AS HAZARDOUS WASTE;
- [ ] 20. PROVIDE SAFE TEMPORARY STORAGE OF HAZARDOUS WASTE GENERATED DURING EMERGENCY ACTIONS;
- [ ] 21. OTHER (Specify):

D2.

E. FACILITY EVACUATION

THE FOLLOWING ALARM SIGNAL(S) WILL BE USED TO BEGIN EVACUATION OF THE FACILITY (Check all that apply): E1.

E2.

- [ ] 1. BELLS;
- [ ] 2. HORNS/SIRENS;
- [x] 3. VERBAL (i.e., Shouting);
- [x] 4. OTHER (Specify): Portable Air Horn

THE FOLLOWING LOCATION(S) WILL BE USED FOR AN EMERGENCY ASSEMBLY AREA(S) (e.g., Parking lot, street corner): E3.

Outside the gate on the south side

Note: The Emergency Coordinator must account for all onsite employees and visitors after evacuation.

EVACUATION ROUTE S AND ALTERNATE EVACUATION ROUTES ARE DESCRIBED AS FOLLOWS: E4.

- [ ] 1. WRITTEN PROCEDURES DESCRIBING ROUTES, EXITS, AND ASSEMBLY AREAS;
- [ ] 2. EVACUATION MAP(S) DEPICTING ROUTES, EXITS, AND ASSEMBLY AREAS;
- [x] 3. OTHER (Specify): Exiting any of the two main gate located on the south of the facility

E5.

Note: Evacuation procedures and/or maps should be posted in visible facility locations and must be included in the Contingency Plan.

F. ARRANGEMENTS FOR EMERGENCY SERVICES

ADVANCE ARRANGEMENTS FOR LOCAL EMERGENCY SERVICES (Check one of the following): F1.

- [ ] 1. HAVE BEEN DETERMINED NOT NECESSARY;
- [ ] 2. THE FOLLOWING ARRANGEMENTS HAVE BEEN MADE (Specify):

F2.

Note: Advance arrangements with local fire and police departments, hospitals, state and local emergency response teams, and/or emergency services contractors should be made for your facility, if necessary. Large Quantity Generators must describe arrangements in the Contingency Plan.

G. EMERGENCY EQUIPMENT

Check the applicable boxes to list emergency response equipment available at the facility, identify the location(s) where the equipment is kept, and indicate the equipment's capability, if applicable.

TYPE	EQUIPMENT AVAILABLE G1.	LOCATION G2.	CAPABILITY G3.
EXAMPLE	☒ *CHEMICAL PROTECTIVE GLOVES*	*SPILL RESPONSE KIT*	*SINGLE USE, OIL RESISTANT ONLY*
Safety and First Aid	1. ☐ CHEMICAL PROTECTIVE SUITS, APRONS, AND/OR VESTS		
	2. ☒ CHEMICAL PROTECTIVE GLOVES	Inside equipment storage container	single use nitryl gloves
	3. ☐ CHEMICAL PROTECTIVE BOOTS		
	4. ☒ SAFETY GLASSES, GOGGLES, AND FACE SHIELDS	Inside equipment storage container	ANZI approved
	5. ☒ HARD HATS	Inside equipment storage container	ANZI approved
	6. ☒ AIR-PURIFYING RESPIRATORS	Inside equipment storage container	ANZI approved
	7. ☐ SELF-CONTAINED BREATHING APPARATUS (SCBA)		
	8. ☒ FIRST AID KITS	Inside equipment storage container	OSHA first aid kit requirements
	9. ☐ PLUMBED EYEWASH FOUNTAIN AND/OR SHOWER		
	10. ☒ PORTABLE EYEWASH KITS AND/OR STATION	Inside Office	OSHA requirements
	11. ☐ OTHER		
Fire Fighting	12. ☒ PORTABLE FIRE EXTINGUISHERS	See annotated site map for locations	10 lbs, 20 lbs, Class ABC
	13. ☐ FIXED FIRE SUPPRESSION SYSTEMS AND/ OR SPRINKLERS		
	14. ☐ FIRE ALARM BOXES		
	15. ☐ OTHER		
Spill Control and Clean-Up	16. ☐ ALL-IN-ONE SPILL KIT		
	17. ☒ ABSORBENT MATERIAL	Inside material storage container	Pads
	18. ☐ CONTAINER FOR USED ABSORBENT		
	19. ☐ BERM AND/OR DIKING EQUIPMENT		
	20. ■ BROOM	Next to storage container	Push brooms
	21. ■ SHOVEL	Next to storage container	Square shovels
	22. ☐ VACUUM		
	23. ☐ EXHAUST HOOD		
	24. ☐ SUMP AND/OR HOLDING TANK		
	25. ☐ CHEMICAL NEUTRALIZERS		
	26. ☐ GAS CYLINDER LEAK REPAIR KIT		
	27. ☐ SPILL OVERPACK DRUMS		
	28. ☐ OTHER		
Communi-cations and Alarm Systems	29. ☒ TELEPHONES (e.g., Cellular)	Cell phone or office phone	
	30. ☐ INTERCOM AND/OR PA SYSTEM		
	31. ☐ PORTABLE RADIOS		
	32. ☐ AUTOMATIC ALARM CHEMICAL MONITORING EQUIPMENT		
Other	33. ☐ OTHER		
	34. ☐ OTHER		

H. EARTHQUAKE VULNERABILITY

Identify areas of the facility that are vulnerable to hazardous materials releases due to seismic motion. These areas require immediate isolation and inspection.

VULNERABLE AREAS (Check all that apply): H1.

- [x] 1. HAZARDOUS MATERIALS AND/OR WASTE STORAGE AREAS
- [ ] 2. PROCESS LINES AND PIPING
- [ ] 3. LABORATORY
- [ ] 4. WASTE TREATMENT AREA

LOCATIONS (e.g., Shop, outdoor shed, lab): H2.

In the center of the facility in the open area and inside material storage containers.

Identify mechanical systems vulnerable to releases / spills due to earthquake-related motion. These systems require immediate isolation and inspection.

VULNERABLE SYSTEMS AND/OR EQUIPMENT (Check all that apply): H3.

- [x] 1. SHELVES, CABINETS AND/OR RACKS
- [ ] 2. TANKS AND SHUT-OFF VALVES
- [ ] 3. PORTABLE GAS CYLINDERS
- [ ] 4. EMERGENCY SHUT-OFF AND/OR UTILITY VALVES
- [ ] 5. SPRINKLER SYSTEMS
- [ ] 6. STATIONARY PRESSURIZED CONTAINERS (e.g., Propane tank)

LOCATIONS: H4.

Inside materials storage containers

I. EMPLOYEE TRAINING

Employee training is required for all employees and/or contractors handling hazardous materials and/or hazardous wastes during normal and/or emergency operations. Most facilities will need to submit a separate Training Plan. However, your CUPA may accept this section as the Training Plan for some small facilities.
Employee training plans may include the following content:

- Applicable laws and regulations;
- Emergency response plans and procedures;
- Safety Data Sheets;
- Hazard communication related to health and safety;
- Methods for safe handling of hazardous substances;
- Hazards of materials and processes (e.g., fire, explosion, asphyxiation);
- Hazard mitigation, prevention and abatement procedures;
- Coordination of emergency response actions;
- Notification procedures for local emergency responders, CUPA, Cal OES, and onsite personnel;
- Communication and alarm systems;
- Personal protective equipment;
- Use and maintenance of emergency response equipment and supplies (e.g. Fire extinguishers, respirators, spill control materials);
- Decontamination procedures;
- Evacuation procedures and evacuation staging locations;
- Identification of facility areas, equipment, and systems vulnerable to earthquakes and other natural disasters.
- OTHER (Specify):

Check the applicable boxes below to indicate how the employee training program is administered.

- [x] 1. FORMAL CLASSROOM
- [x] 2. VIDEOS
- [x] 3. SAFETY MEETINGS
- [ ] 4. STUDY GUIDES / MANUALS — I1.
- [ ] 5. OTHER (Specify): _____ I2.
- [ ] 6. NOT APPLICABLE SINCE FACILITY HAS NO EMPLOYEES
- [x] 7. CHECK IF A SEPARATE EMPLOYEE TRAINING PLAN IS USED AND UPLOADED TO CERS AS A PDF DOCUMENT I3.
- [ ] 8. CHECK IF EMPLOYEE TRAINING IS COVERED BY THE ABOVE REFERENCED CONTENT AND OTHER DOCUMENTS ONSITE I4.

EMPLOYEE TRAINING FREQUENCY AND RECORDKEEPING TRAINING MUST BE:

- Provided initially for new employees as soon as possible following the date of hire. New employees should not work in an unsupervised position that involves hazardous materials handling and/or hazardous waste management without proper training;
- Provided within six months from the date of hire for new employees at a large quantity generator;
- Ongoing and provided at least annually;
- Amended prior to a change in process or work assignment;
- Given upon modification to the Emergency Response/Contingency Plan.

Large Quantity Generator Training: Large quantity generators (1,000 kg or more) must retain written plan and documentation of employee training which includes:

- A written description of the type and amount of both initial and ongoing training that will be given to persons filling each job position having responsibility for hazardous waste management and/or emergency response.
- The name, job title and job description for each position at the facility related to hazardous waste management.
- Current employee training records must be retained until closure of the facility and former employee training records must be retained for at least three years after termination of employment.

Small Quantity Generator Training: Small quantity generators (less than 1,000 kg) must include basic hazardous waste management and emergency response procedures but a written employee training plan and training records are not required. In order to show that the facility has met the small quantity generator employee training requirement, an employee training plan and training records may be made available.

Hazardous Materials Business Plan Training: Businesses must provide initial and annual employee training that includes the content referenced above. The training may be based on the job position and training records must be made available for a period of at least three years.

J. LIST OF ATTACHMENTS

Check one of the following: J1.

- [x] 1. NO ATTACHMENTS ARE REQUIRED; or
- [ ] 2. THE FOLLOWING DOCUMENTS ARE ATTACHED: J2.

ADVANCED INDUSTRIAL SERVICES, INC.

Painting • Special Coatings • Lead Abatement
Sandblasting • Fireproofing • Waterproofing• Wallcovering

Hazard Communication Program and Training

The purpose of this program is to inform interested persons, including employees, that Advanced Industrial Services, In., is complying with the OSHA Hazard Communication Standard, Title 29 Code of Federal Regulations 1910.1200, by compiling a hazardous chemicals list, using safety data sheets (SDSs), ensuring that containers are labeled or provided other forms of warning, and training our employees.

This program applies to all work operations in our company where employees may be exposed to hazardous chemicals under normal working conditions or during an emergency situation. Under this program, our employees will be informed of the contents of the Hazard Communication Standard, the hazards of chemicals with which they work, safe handling procedures, and measures to take to protect themselves from these chemicals, among other training elements.

Eduardo Ortega/Safety Manager who is the Hazard Communication Program Coordinator, has overall responsibility for the program, including to review and update the program, as necessary. Copies of this written program may be obtained from Eduardo Ortega/Safety Manager who keeps the program located in at the Paramount office. Moreover, all employees, or their designated representatives, may obtain further information about this written program, the Hazard Communication Standard, applicable SDSs, and our chemical list from Eduardo Ortega/Safety Manager.

Finally, if after reading this program, you find that improvements can be made, please contact Eduardo Ortega/Safety Manager. We encourage all suggestions because we are committed to the success of our written Hazard Communication Program. We strive for clear understanding, safe behavior, and involvement in the program from every level of the company.

List of Hazardous Chemicals

Our “chemical inventory” is a list of product identifiers of hazardous chemicals known to be present at our workplace. Anyone who comes in contact with the hazardous chemicals on the list needs to know what those chemicals are and how to protect themselves. That is why it is so important that hazardous chemicals are identified, whether they are found in a container or generated in work operations (for example, welding fumes, dusts and exhaust fumes). The hazardous chemicals on the chemical inventory can cover a variety of physical forms including liquids, solids, gases, vapors, fumes, and mists. Sometimes hazardous chemicals can be identified using purchase orders. Identification of other chemicals may require an actual survey of the workplace.

The chemical inventory is attached to this written Hazard Communication Program. However, the Program Coordinator also keeps a copy of the chemical inventory list located 20322 7th Standard Road, Contractors Row Lot 102, Lost Hills , CA 93251 where it is accessible during work hours. The chemical inventory serves as a list of every hazardous chemical for which an SDS must be maintained.

Safety Data Sheets (SDSs)

SDSs are basically fact sheets for chemicals that pose a physical or health hazard in the workplace. These sheets provide our employees with specific information on the chemicals in their work areas.

Ty Johnston/Supervisor is responsible for obtaining and maintaining the SDSs at our workplace and will contact the chemical manufacturer or vendor if additional research is necessary. All new procurements for the company must be cleared by Ty Johnston/Supervisor.

SDSs are kept readily accessible to all employees during each work shift at the following location(s): Belridge AERA yard office building. Employees may obtain the SDSs sheets during any time of the day during working hours.

Labels and Other Forms of Warning

In most cases, hazardous chemical containers at the workplace must be clearly labeled, tagged, or marked in accordance with the Hazard Communication Standard, either with:

The product identifier, signal word, hazard statement(s), pictogram(s), and precautionary statement(s); or

The product identifier and words, pictures, symbols, or combination thereof, which provide at least “general” information regarding the hazards of the chemicals, and which, in conjunction with the other information immediately available to employees under the Hazard Communication Program, will provide employees with the “specific” information regarding the physical and health hazards of the hazardous chemical.

While not required for in-house labeling, the name and address of the manufacturer, importer, or other responsible party may also be found on the label, tag, or marking. Hazards not otherwise classified do not have to be addressed on a container.

Because the product identifier is found on the label, the SDS, and our chemical inventory, the product identifier links these three sources of information, permitting cross-referencing. The product identifer used by the supplier may be a common or trade name, a chemical name, or a number. Employees should be aware that label information can be verified by referring to the corresponding SDS.

Jaime Cuevas/Shop Foreman is responsible for ensuring that all hazardous chemicals in containers at the workplace have proper labels or other forms of warning that are legible, in English (although other languages may also be included), and displayed clearly on the container or readily available in the work area throughout each work shift, as required. This person will update labels, as necessary. Jaime Cuevas/Shop Foreman also ensures that newly purchased chemicals are checked for labels when containers are received.

Jaime Cuevas/Shop Foreman is responsible for ensuring the proper labeling, tagging, or marking of any shipped containers leaving the workplace. These labels, tags, or marks must provide not only the product identifier, signal word, hazard statement(s), pictogram(s), and precautionary statement(s) but also the name, address, and telephone number of the chemical manufacturer, importer, or other responsible party.

A poster is displayed to inform employees about the Hazard Communication Standard. It is located at the Belridge AERA yard inside the storage container.

If employees transfer chemicals from a labeled container to a portable, secondary container that is intended only for their IMMEDIATE use, no labels, tags, or markings are required on the portable container. Otherwise portable containers must be labeled, tagged, or marked in accordance with our in-house labeling system for workplace containers.

Finally, the following procedures are used to review and update label information when necessary, to ensure that labels that fall off or become unreadable are immediately replaced: by notifying the manufacturer and replacing with the proper label.

Training

Everyone who works with or is potentially "exposed" to hazardous chemicals on the job will receive initial training on the Hazard Communication Standard and the safe use of those hazardous chemicals before starting work. "Exposure" means that "an employee is subjected in the course of employment to a chemical that is a physical or health hazard, and includes potential (e.g., accidental or possible) exposure." Whenever a new chemical hazard is introduced or an old hazard changes, additional training is provided. All training is conducted by Eduardo Ortega/Safety Manager.

Effective information and training is a critical part of the Hazard Communication Program. We train our employees to read and understand the information on labels and SDSs, determine how the information can be obtained and used in their own work areas, and understand the risks of exposure to the chemicals in their work areas, as well as ways to protect themselves. Our goal is to ensure employees know that they are exposed to hazardous chemicals, have the skills to read and use labels and SDSs, and understand how to appropriately follow the protective measures we have established. We urge our employees to ask Eduardo Ortega/Safety Manager questions for greater comprehension.

As part of the assessment of the training program, Eduardo Ortega/Safety Manager asks for input from employees regarding the training they have received and their suggestions for improving it. In this way, we hope to reduce any incidence of chemical-related illness or injury.

Training Content

Any employee who will be handling hazardous chemicals must be trained prior to working with the chemical. Training is conducted yearly. A schedule of training can be obtained by contacting Eduardo Ortega/Safety Manager. Employees are trained by hazard categories (i.e., flammability, carcinogenicity, etc.). The format of the training program consists of Power Point presentations, Handouts, Video and Quiz.

The training program emphasizes these elements:

- Summary of the Hazard Communication Standard.
- What hazardous chemicals are present in operations in employee work areas.
- Chemical and physical properties of hazardous chemicals (e.g., flash point, reactivity, etc.) and how to detect the presence or release of these chemicals (including chemicals in unlabeled pipes).
- Physical hazards of chemicals (e.g., potential for fire, explosion, etc.)
- Health hazards, including signs and symptoms of overexposure, associated with exposure to chemicals and any medical condition known to be aggravated by exposure to them.
- Any simple asphyxiation, combustible dust, and pyrophoric hazards, as well as hazards not otherwise classified, of chemicals in work areas.
- Any steps the company has taken to reduce or prevent exposure to hazardous chemicals, such as engineering controls.
- Procedures to protect against hazards and exposure (e.g., work practices or methods to assure proper use and handling of chemicals and any required personal protective equipment and its proper use and maintenance).
- Procedures for reporting and responding to chemical emergencies.
- How to read and use both the workplace labeling system and labels received on shipped containers.
- The order of information found on SDSs and how to read the information and what it means.
- How to access SDSs and the written Hazard Communication Program, including the chemical inventory.

The procedure to train new employees at the time of their initial assignment is on date of hired they must watch the HazCom *What You Need to Know* video and pass a written quiz by 80% or better. If the employee does not pass the quiz, he must watch the video again and retake the quiz until he gets a passing grade.

Training logs are signed by employees upon completion of their training and are kept by Eduardo Ortega/Safety Manager.

Hazards of Non-routine Tasks

Periodically, employees are required to perform non-routine tasks that involve hazardous chemicals. When employees will be required to perform hazardous non-routine tasks, such as confined space that have the potential to expose employees to hazardous chemicals, we inform them of these hazards by: communication and training in confined space by a competent person.

Hazards of Unlabeled Pipes

Work activities are sometimes performed by employees in areas where hazardous chemicals are transferred through unlabeled pipes. We inform employees of the hazards of chemicals contained in unlabeled pipes in their work areas by: providing training in recognizing potential hazards, pre-job walks and job hazard analysis before work can be performed near pipes.

Multi-Employer Site

When contractors or any other employers' workers will be working at this workplace, the Hazard Communication Program Coordinator, Eduardo Ortega/Safety Manager, will:

- Provide the other employer(s) as follows with SDSs for any of our hazardous chemicals to which their employees may be exposed: by submitting all SDSs to the other employer(s) safety personnel and inform them in writing.
- Relay to other employer(s) all necessary in-house labeling system and precautionary information for normal operations and foreseeable emergencies: by communication and verifying training of all employees.

Moreover, it is the responsibility of Eduardo Ortega/Safety Manager to obtain from each contractor or other employer the appropriate hazard information on chemicals they bring onsite, including SDSs, the labeling system used, and the precautionary measures to be taken in working with or near these chemicals.

Additional Information

As stated earlier, all employees, or their designated representatives, may obtain further information on this written program, the Hazard Communication Standard, applicable SDSs, and the chemical inventory from Eduardo Ortega/Safety Manager.

CENTURYLINK - LOST HILLS - LSHLCABK (CERSID: 10237522)

Facility Information **Accepted Jul 8, 2022**

Submitted on 1/27/2022 12:48:15 PM by *Colin Snowberg* of CenturyLink (Broomfield, Colorado)
Submittal was ***Accepted*** on 7/8/2022 3:30:58 PM by Cruz-Oropeza, Anthony

- Business Activities
- Business Owner/Operator Identification

Hazardous Materials Inventory **Accepted Jul 8, 2022**

Submitted on 1/27/2022 12:48:15 PM by *Colin Snowberg* of CenturyLink (Broomfield, Colorado)
Submittal was ***Accepted*** on 7/8/2022 3:31:03 PM by Cruz-Oropeza, Anthony

- Hazardous Material Inventory (1)
- Site Map (Official Use Only)
  - *Annotated Site Map (Official Use Only)* (Adobe PDF, 714KB)

Emergency Response and Training Plans **Accepted Jul 8, 2022**

Submitted on 1/27/2022 12:48:15 PM by *Colin Snowberg* of CenturyLink (Broomfield, Colorado)
Submittal was ***Accepted*** on 7/8/2022 3:31:01 PM by Cruz-Oropeza, Anthony

- Emergency Response/Contingency Plan
  - *Emergency Response/Contingency Plan* (Adobe PDF, 375KB)
- Employee Training Plan
  - *Employee Training Plan* (Adobe PDF, 150KB)

Site Identification

CENTURYLINK - LOST HILLS - LSHLCABK
16631 HIGHWAY 33
LOST HILLS, CA 93249

County
Kern

CERS ID
10237522

EPA ID Number

Submittal Status

Submitted on 1/27/2022 by *Colin Snowberg* of CenturyLink (Broomfield, Colorado)
Submittal was ***Accepted***; Processed on 7/8/2022 by *Cruz-Oropeza, Anthony* for Kern County Environmental Health Services Department

Hazardous Materials

Does your facility have on site (for any purpose) at any one time, hazardous materials at or above 55 gallons for liquids, 500 pounds for solids, or 200 cubic feet for compressed gases (include liquids in ASTs and USTs); or is regulated under more restrictive inventory local reporting requirements (shown below if present); or the applicable Federal threshold quantity for an extremely hazardous substance specified in 40 CFR Part 355, Appendix A or B; or handle radiological materials in quantities for which an emergency plan is required pursuant to 10 CFR Parts 30, 40 or 70?	**Yes**

Underground Storage Tank(s) (UST)

Does your facility own or operate underground storage tanks?	**No**

Hazardous Waste

Is your facility a Hazardous Waste Generator?	**No**
Does your facility treat hazardous waste on-site?	**No**
Is your facility's treatment subject to financial assurance requirements (for Permit by Rule and Conditional Authorization)?	**No**
Does your facility consolidate hazardous waste generated at a remote site?	**No**
Does your facility need to report the closure/removal of a tank that was classified as hazardous waste and cleaned on-site?	**No**
Does your facility generate in any single calendar month 1,000 kilograms (kg) (2,200 pounds) or more of federal RCRA hazardous waste, or generate in any single calendar month greater than 1 kg (2.2 pounds) of RCRA acute hazardous waste; or generate more than 100 kg (220 pounds) of spill cleanup materials contaminated with RCRA acute hazardous waste.	**No**
Is your facility a Household Hazardous Waste (HHW) Collection site?	**No**

Excluded and/or Exempted Materials

Does your facility recycle more than 100 kg/month of excluded or exempted recyclable materials (per HSC 25143.2)?	**No**
Does your facility own or operate ASTs above these thresholds? Store greater than 1,320 gallons of petroleum products (new or used) in aboveground tanks or containers.	**No**
Does your facility have Regulated Substances stored onsite in quantities greater than the threshold quantities established by the California Accidental Release prevention Program (CalARP)?	**No**

Additional Information

No additional comments provided.

Facility/Site

CENTURYLINK - LOST HILLS - LSHLCABK
16631 HIGHWAY 33
LOST HILLS, CA 93249

CERS ID
10237522

Submittal Status

Submitted on 1/27/2022 by *Colin Snowberg* of CenturyLink (Broomfield, Colorado)
Submittal was ***Accepted***; Processed on 7/8/2022 by *Cruz-Oropeza, Anthony* for Kern County Environmental Health Services Department

Identification

CenturyLink Communications

Operator Phone	Business Phone	Business Fax
(720) 888-0676	(720) 888-1000	

Beginning Date	Ending Date	
Dun & Bradstreet	**SIC Code**	**Primary NAICS**
073090917	4813	517311

Facility/Site Mailing Address

700 W Mineral Avenue, UT D25.09
Littleton, CO 80120

Primary Emergency Contact

Rafael Hernandez
Title
Technician, Field Operations

Business Phone	24-Hour Phone	Pager Number
(805) 223-1189	(866) 864-2255	

Owner

CenturyLink Communications
(720) 888-1000
700 W Mineral Avenue, UT D25.09
Littleton, CO 80120

Secondary Emergency Contact

Danny Ng
Title
Manager, Field Operations

Business Phone	24-Hour Phone	Pager Number
(415) 309-0303	(866) 864-2255	

Billing Contact

Robert Gurdikian
(720) 888-0676 bob.gurdikian@lumen.com
700 W Mineral Avenue, UT D25.09
Littleton, CO 80120

Environmental Contact

Robert Gurdikian
(720) 888-0676 bob.gurdikian@lumen.com
700 W Mineral Avenue, UT D25.09
Littleton, CO 80120

Name of Signer	Signer Title	Document Preparer
Robert Gurdikian	Regional EHS Manager III	Robert Gurdikian

Additional Information

Locally-collected Fields

Some or all of the following fields may be required by your local regulator(s).

Property Owner

Phone

Mailing Address

,

Assessor Parcel Number (APN)
06822055

Number of Employees
0

Facility ID

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **CenturyLink**
Facility Name **CENTURYLINK - LOST HILLS - LSHLCABK**
16631 HIGHWAY 33, LOST HILLS 93249

Chemical Location **Under Gen 1 (Belly Tank)**

CERS ID **10237522**
Facility ID
Status **Submitted** on 1/27/2022 12:48 PM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
DOT: 3 - Flammable and Combustible Liquids Combustible Liquid, Class II	**Diesel Fuel No. 2** CAS No 68476-34-6	**Gallons** State Liquid Type Pure	**384** Storage Container Aboveground Tank	**384**	384 Pressue Ambient Temperature Ambient	Waste Code	- Physical Flammable - Physical Explosive - Health Carcinogenicity - Health Acute Toxicity - Health Skin Corrosion Irritation - Health Specific Target Organ Toxicity - Health Aspiration Hazard				



APPROXIMATE SCALE: 1 inch = 2,300 feet

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Facility Boundary

Access Point



APPROXIMATE SCALE: 1 inch = 50 feet

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- AST — Aboveground Storage Tank (beneath generator)
- B — Battery (equipped with alarm)
- E — Electric Shutoff
- EXIT — Emergency Exit
- Staging Area
- Evacuation Route
- Fence
- Gate

CALIFORNIA ENVIRONMENTAL REPORTING SYSTEM (CERS)

CONSOLIDATED EMERGENCY RESPONSE / CONTINGENCY PLAN

Prior to completing this Plan, please refer to the INSTRUCTIONS FOR COMPLETING A CONSOLIDATED CONTINGENCY PLAN

A. FACILITY IDENTIFICATION AND OPERATIONS OVERVIEW

FACILITY ID # A1.	CERS ID # A2.	DATE OF PLAN PREPARATION/REVISION (MM/DD/YYYY) A3.
	10230871	01/14/2022

BUSINESS NAME *(Same as Facility Name or DBA - Doing Business As)* A4.
Torrance Valley Pipeline Company LLC

BUSINESS SITE ADDRESS A5.
19662 Highway 33 Rd.

BUSINESS SITE CITY A6.		ZIP CODE A7.
Mckittrick	CA	93251

TYPE OF BUSINESS (e.g., Painting Contractor) A8.	INCIDENTAL OPERATIONS (e.g., Fleet Maintenance) A9.
Pipeline Operator	Pipeline Maintenance

THIS PLAN COVERS CHEMICAL SPILLS, FIRES, AND EARTHQUAKES INVOLVING (Check all that apply): A10.

☒ 1. HAZARDOUS MATERIALS; ☒ 2. HAZARDOUS WASTES

B. INTERNAL RESPONSE

INTERNAL FACILITY EMERGENCY RESPONSE WILL OCCUR BY (Check all that apply): B1.

☒ 1. CALLING PUBLIC EMERGENCY RESPONDERS (e.g., 9-1-1)
☒ 2. CALLING HAZARDOUS WASTE CONTRACTOR
☒ 3. ACTIVATING IN-HOUSE EMERGENCY RESPONSE TEAM

C. EMERGENCY COMMUNICATIONS, PHONE NUMBERS AND NOTIFICATIONS

In the event of an emergency involving hazardous materials and/or hazardous waste, all facilities must IMMEDIATELY:
1. Notify facility personnel and evacuate if necessary in accordance with the Emergency Action Plan (Title 8 California Code of Regulations §3220);
2. Notify local emergency responders by calling 9-1-1;
3. Notify the local Unified Program Agency (UPA) at the phone number below; and
4. Notify the State Warning Center at (800) 852-7550.

Facilities that generate, treat, store or dispose of hazardous waste have additional responsibilities to notify and coordinate with other response agencies. Whenever there is an imminent or actual emergency situation such as an explosion, fire, or release, the Emergency Coordinator must follow the appropriate requirements for the category of facility and type of release involved:
1. Title 22 California Code of Regulations §66265.56. Emergency Procedures for generators of 1,000 kilograms or more of hazardous waste in any calendar month.
2. Title 22 California Code of Regulations §66265.196. Response to Leaks or Spills and Disposition of Leaking or Unfit-for-Use Tank Systems.
3. Title 40 Code of Federal Regulations §302.6. Notification requirements for a release of a hazardous substance equal to or greater than the reportable quantity.
4. Title 22 California Code of Regulations §66262.34(d)(2) and Title 40 Code of Federal Regulations §262.34(d)(5)(ii) for generators of less than 1000 kilograms of hazardous waste in any calendar month.

Following notification and before facility operations are resumed in areas of the facility affected by the incident, the Emergency Coordinator shall notify the local UPA and the local fire department's hazardous materials program, if necessary, that the facility is in compliance with requirements to:
1. Provide for proper storage and disposal of recovered waste, contaminated soil or surface water, or any other material that results from an explosion, fire, or release at the facility; and
2. Ensure that no material that is incompatible with the released material is transferred, stored, or disposed of in areas of the facility affected by the incident until cleanup procedures are completed.

EMERGENCY RESPONSE PHONE NUMBERS:		
	AMBULANCE, FIRE, POLICE AND CHP	9-1-1
	CALIFORNIA STATE WARNING CENTER (CSWC)/CAL OES.	(800) 852-7550
	NATIONAL RESPONSE CENTER (NRC)	(800) 424-8802
	POISON CONTROL CENTER	(800) 222-1222
	LOCAL UNIFIED PROGRAM AGENCY (UPA)	(661) 549-9927 C1.
	OTHER (Specify): Patriot Environmental Serviec C2.	(800) 624-9136 C3.
NEAREST MEDICAL FACILITY / HOSPITAL NAME:	Mercy Southwest Hospital C4.	(661) 663-6000 C5.

AGENCY NOTIFICATION PHONE NUMBERS:		
	CALIFORNIA DEPT. OF TOXIC SUBSTANCES CONTROL (DTSC)	(916) 255-3545
	REGIONAL WATER QUALITY CONTROL BOARD (RWQCB).	(559) 445-5116 C6.
	U.S. ENVIRONMENTAL PROTECTION AGENCY (US EPA)	(800) 300-2193
	CALIFORNIA DEPT. OF FISH AND WILDLIFE (CDFW)	(916) 358-2900
	U.S. COAST GUARD (USCG)	(202) 267-2180
	CAL OSHA	(916) 263-2800
	CAL FIRE OFFICE OF THE STATE FIRE MARSHAL (OSFM)	(916) 323-7390
	OTHER (Specify): National Response Center C7.	(800) 424-8802 C8.
	OTHER (Specify): C9.	C10.

INTERNAL FACILITY EMERGENCY COMMUNICATIONS OR ALARM NOTIFICATION WILL OCCUR BY (Check all that apply): C11.

- [x] 1. VERBAL WARNINGS;
- [ ] 2. PUBLIC ADDRESS OR INTERCOM SYSTEM;
- [x] 3. TELEPHONE;
- [ ] 4. PAGERS;
- [ ] 5. ALARM SYSTEM;
- [ ] 6. PORTABLE RADIO

NOTIFICATIONS TO NEIGHBORING FACILITIES THAT MAY BE AFFECTED BY AN OFF-SITE RELEASE WILL OCCUR BY (Check all that apply): C12.

- [x] 1. VERBAL WARNINGS;
- [ ] 2. PUBLIC ADDRESS OR INTERCOM SYSTEM;
- [x] 3. TELEPHONE;
- [ ] 4. PAGERS;
- [ ] 5. ALARM SYSTEM;
- [ ] 6. PORTABLE RADIO

EMERGENCY COORDINATOR CONTACT INFORMATION: This site does not generate hazardous waste. C13.
Scott Hedlund (661) 381-8038

PRIMARY EMERGENCY COORDINATOR NAME: Anthony Mooney PHONE NO.: (661) 763-7641 PHONE NO.: (661) 345-7643

ALTERNATE EMERGENCY COORDINATOR NAME: Cory Engle PHONE NO.: (805) 503-0787 PHONE NO.: (805) 503-0787

- [ ] Check if additional Emergency Coordinator contact and address information is available onsite or by calling PHONE NO.:

Note: If more than one alternate emergency coordinator is designated, attach a list in order of responsibility.

D. EMERGENCY CONTAINMENT AND CLEANUP PROCEDURES

Check the applicable boxes to indicate your facility's procedures for containing spills and preventing and mitigating releases, fires and/or explosions.

D1.

- [x] 1. MONITOR FOR LEAKS, RUPTURES, PRESSURE BUILD-UP, ETC.;
- [ ] 2. PROVIDE STRUCTURAL PHYSICAL BARRIERS (e.g., Portable spill containment walls, built-in berms);
- [x] 3. PROVIDE ABSORBENT PHYSICAL BARRIERS (e.g., Pads, spill pigs, spill pillows);
- [x] 4. COVER OR BLOCK FLOOR AND/OR STORM DRAINS;
- [x] 5. LINED TRENCH DRAINS AND/OR SUMPS;
- [ ] 6. AUTOMATIC FIRE SUPPRESSION SYSTEM;
- [x] 7. ELIMINATE SOURCES OF IGNITION FOR FLAMMABLE HAZARDS;
- [x] 8. STOP PROCESSES AND/OR OPERATIONS;
- [x] 9. AUTOMATIC / ELECTRONIC EQUIPMENT SHUT-OFF SYSTEM;
- [x] 10. SHUT OFF WATER, GAS, ELECTRICAL UTILITIES;
- [x] 11. CALL 9-1-1 FOR PUBLIC EMERGENCY RESPONDER ASSISTANCE AND/OR MEDICAL AID;
- [x] 12. NOTIFY AND EVACUATE PERSONS IN ALL THREATENED AND/OR IMPACTED AREAS;
- [x] 13. ACCOUNT FOR EVACUATED PERSONS IMMEDIATELY AFTER EVACUATION;
- [x] 14. PROVIDE PROTECTIVE EQUIPMENT FOR ON-SITE EMERGENCY RESPONSE TEAM;
- [x] 15. REMOVE CONTAINERS AND/OR ISOLATE AREAS;
- [x] 16. HIRE LICENSED HAZARDOUS WASTE CONTRACTOR;
- [x] 17. USE ABSORBENT MATERIAL FOR SPILL CONTAINMENT;
- [x] 18. VACUUM SUCTION USING APPROPRIATE VACUUM (e.g., Intrinsically safe) FOR SPILL CONTROL AND/OR CLEANUP;
- [x] 19. DECONTAMINATE PERSONNEL AND EQUIPMENT WITHIN DESIGNATED AREA AND DISPOSE OF WASTEWATER AS HAZARDOUS WASTE;
- [x] 20. PROVIDE SAFE TEMPORARY STORAGE OF HAZARDOUS WASTE GENERATED DURING EMERGENCY ACTIONS;
- [ ] 21. OTHER (Specify): D2.

E. FACILITY EVACUATION

THE FOLLOWING ALARM SIGNAL(S) WILL BE USED TO BEGIN EVACUATION OF THE FACILITY (Check all that apply): E1.

E2.

- [ ] 1. BELLS;
- [ ] 2. HORNS/SIRENS;
- [x] 3. VERBAL (i.e., Shouting);
- [ ] 4. OTHER (Specify):

THE FOLLOWING LOCATION(S) WILL BE USED FOR AN EMERGENCY ASSEMBLY AREA(S) (e.g., Parking lot, street corner): E3.

Main entrance gate south of the facility by Highway 166.

Note: The Emergency Coordinator must account for all onsite employees and visitors after evacuation.

EVACUATION ROUTE S AND ALTERNATE EVACUATION ROUTES ARE DESCRIBED AS FOLLOWS: E4.

- [x] 1. WRITTEN PROCEDURES DESCRIBING ROUTES, EXITS, AND ASSEMBLY AREAS;
- [x] 2. EVACUATION MAP(S) DEPICTING ROUTES, EXITS, AND ASSEMBLY AREAS;
- [ ] 3. OTHER (Specify): E5.

Note: Evacuation procedures and/or maps should be posted in visible facility locations and must be included in the Contingency Plan.

F. ARRANGEMENTS FOR EMERGENCY SERVICES

ADVANCE ARRANGEMENTS FOR LOCAL EMERGENCY SERVICES (Check one of the following): F1.

- [ ] 1. HAVE BEEN DETERMINED NOT NECESSARY;
- [x] 2. THE FOLLOWING ARRANGEMENTS HAVE BEEN MADE (Specify): OSRO contracts our in place with Clean Harbors and Patriot Environmental as listed in our Integrated Contingency Plan. F2.

Note: Advance arrangements with local fire and police departments, hospitals, state and local emergency response teams, and/or emergency services contractors should be made for your facility, if necessary. Large Quantity Generators must describe arrangements in the Contingency Plan.

G. EMERGENCY EQUIPMENT

Check the applicable boxes to list emergency response equipment available at the facility, identify the location(s) where the equipment is kept, and indicate the equipment's capability, if applicable.

TYPE	EQUIPMENT AVAILABLE G1.	LOCATION G2.	CAPABILITY G3.
EXAMPLE	☒ *CHEMICAL PROTECTIVE GLOVES*	*SPILL RESPONSE KIT*	*SINGLE USE, OIL RESISTANT ONLY*
Safety and First Aid	1. ☒ CHEMICAL PROTECTIVE SUITS, APRONS, AND/OR VESTS	Located at Continental Station	Single Use
	2. ☒ CHEMICAL PROTECTIVE GLOVES	Located at Continental Station	Single Use
	3. ☒ CHEMICAL PROTECTIVE BOOTS	Located at Continental Station	Single Use
	4. ☒ SAFETY GLASSES, GOGGLES, AND FACE SHIELDS	In all company vehicles	
	5. ☒ HARD HATS	In all company vehicles	
	6. ☒ AIR-PURIFYING RESPIRATORS		Single Use
	7. ☐ SELF-CONTAINED BREATHING APPARATUS (SCBA)		
	8. ☒ FIRST AID KITS	In company vehicles and control room	Single Use, < 25 employees
	9. ☐ PLUMBED EYEWASH FOUNTAIN AND/OR SHOWER		
	10. ☒ PORTABLE EYEWASH KITS AND/OR STATION	Outside control room exit	Single Use
	11. ☐ OTHER		
Fire Fighting	12. ☒ PORTABLE FIRE EXTINGUISHERS	In company vehicles/see facility maps	Single Use, 25 lb extinguisher
	13. ☐ FIXED FIRE SUPPRESSION SYSTEMS AND/ OR SPRINKLERS		
	14. ☐ FIRE ALARM BOXES		
	15. ☐ OTHER		
Spill Control and Clean-Up	16. ☒ ALL-IN-ONE SPILL KIT	At control room spill kit	Single Use, 95 gallon capacity
	17. ☒ ABSORBENT MATERIAL	At control room spill kit	Single Use, 95 gallon capacity
	18. ☒ CONTAINER FOR USED ABSORBENT	At control room spill kit	
	19. ☐ BERM AND/OR DIKING EQUIPMENT		
	20. ☐ BROOM		
	21. ☒ SHOVEL	At Continental Station	
	22. ☒ VACUUM	Patriot/Clean Harbors	130 BBL per truck
	23. ☐ EXHAUST HOOD		
	24. ☐ SUMP AND/OR HOLDING TANK		
	25. ☐ CHEMICAL NEUTRALIZERS		
	26. ☐ GAS CYLINDER LEAK REPAIR KIT		
	27. ☒ SPILL OVERPACK DRUMS		1-95 gallon overpack at each facility
	28. ☐ OTHER		
Communi-cations and Alarm Systems	29. ☒ TELEPHONES (e.g., Cellular)		
	30. ☐ INTERCOM AND/OR PA SYSTEM		
	31. ☐ PORTABLE RADIOS		
	32. ☐ AUTOMATIC ALARM CHEMICAL MONITORING EQUIPMENT		
Other	33. ☐ OTHER		
	34. ☐ OTHER		

H. EARTHQUAKE VULNERABILITY

Identify areas of the facility that are vulnerable to hazardous materials releases due to seismic motion. These areas require immediate isolation and inspection.

VULNERABLE AREAS (Check all that apply): H1.

- ☐ 1. HAZARDOUS MATERIALS AND/OR WASTE STORAGE AREAS
- ☒ 2. PROCESS LINES AND PIPING
- ☐ 3. LABORATORY
- ☐ 4. WASTE TREATMENT AREA

LOCATIONS (e.g., Shop, outdoor shed, lab): H2.

Throughout facility, below and above ground.

Identify mechanical systems vulnerable to releases / spills due to earthquake-related motion. These systems require immediate isolation and inspection.

VULNERABLE SYSTEMS AND/OR EQUIPMENT (Check all that apply): H3.

- ☐ 1. SHELVES, CABINETS AND/OR RACKS
- ☐ 2. TANKS AND SHUT-OFF VALVES
- ☐ 3. PORTABLE GAS CYLINDERS
- ☒ 4. EMERGENCY SHUT-OFF AND/OR UTILITY VALVES
- ☐ 5. SPRINKLER SYSTEMS
- ☐ 6. STATIONARY PRESSURIZED CONTAINERS (e.g., Propane tank)

LOCATIONS: H4.

Facility is equipped with seismic detection equipment which shuts facility down at 6.0 or above earthquake

I. EMPLOYEE TRAINING

Employee training is required for all employees and/or contractors handling hazardous materials and/or hazardous wastes during normal and/or emergency operations. Most facilities will need to submit a separate Training Plan. However, your CUPA may accept this section as the Training Plan for some small facilities.
Employee training plans may include the following content:

- Applicable laws and regulations;
- Emergency response plans and procedures;
- Safety Data Sheets;
- Hazard communication related to health and safety;
- Methods for safe handling of hazardous substances;
- Hazards of materials and processes (e.g., fire, explosion, asphyxiation);
- Hazard mitigation, prevention and abatement procedures;
- Coordination of emergency response actions;
- Notification procedures for local emergency responders, CUPA, Cal OES, and onsite personnel;
- Communication and alarm systems;
- Personal protective equipment;
- Use and maintenance of emergency response equipment and supplies (e.g. Fire extinguishers, respirators, spill control materials);
- Decontamination procedures;
- Evacuation procedures and evacuation staging locations;
- Identification of facility areas, equipment, and systems vulnerable to earthquakes and other natural disasters.
- OTHER (Specify): Training is web based

Check the applicable boxes below to indicate how the employee training program is administered.

☐ 1. FORMAL CLASSROOM ☐ 2. VIDEOS ☐ 3. SAFETY MEETINGS ☐ 4. STUDY GUIDES / MANUALS I1.

☒ 5. OTHER (Specify): I2.

☒ 6. NOT APPLICABLE SINCE FACILITY HAS NO EMPLOYEES

☐ 7. CHECK IF A SEPARATE EMPLOYEE TRAINING PLAN IS USED AND UPLOADED TO CERS AS A PDF DOCUMENT I3.

☐ 8. CHECK IF EMPLOYEE TRAINING IS COVERED BY THE ABOVE REFERENCED CONTENT AND OTHER DOCUMENTS ONSITE I4.

EMPLOYEE TRAINING FREQUENCY AND RECORDKEEPING TRAINING MUST BE:

- Provided initially for new employees as soon as possible following the date of hire. New employees should not work in an unsupervised position that involves hazardous materials handling and/or hazardous waste management without proper training;
- Provided within six months from the date of hire for new employees at a large quantity generator;
- Ongoing and provided at least annually;
- Amended prior to a change in process or work assignment;
- Given upon modification to the Emergency Response/Contingency Plan.

Large Quantity Generator Training: Large quantity generators (1,000 kg or more) must retain written plan and documentation of employee training which includes:

- A written description of the type and amount of both initial and ongoing training that will be given to persons filling each job position having responsibility for hazardous waste management and/or emergency response.
- The name, job title and job description for each position at the facility related to hazardous waste management.
- Current employee training records must be retained until closure of the facility and former employee training records must be retained for at least three years after termination of employment.

Small Quantity Generator Training: Small quantity generators (less than 1,000 kg) must include basic hazardous waste management and emergency response procedures but a written employee training plan and training records are not required. In order to show that the facility has met the small quantity generator employee training requirement, an employee training plan and training records may be made available.

Hazardous Materials Business Plan Training: Businesses must provide initial and annual employee training that includes the content referenced above. The training may be based on the job position and training records must be made available for a period of at least three years.

J. LIST OF ATTACHMENTS

Check one of the following: J1.

☒ 1. NO ATTACHMENTS ARE REQUIRED; or

☐ 2. THE FOLLOWING DOCUMENTS ARE ATTACHED: J2.

EMPLOYEE TRAINING PLAN REQUIREMENTS AND TEMPLATE

All facilities are required to create and implement an employee training plan. Below is a template of requirements for the Hazardous Materials Business Plan and Hazardous Waste Generator program elements. This template will help facilities ensure that all requirements for each program are covered and will help draft a site-specific plan for your facility. Training requirements for the Hazardous Materials Business Plan and Hazardous Waste Generator programs can be found in Health and Safety Code Chapter 6.95 Article 1, Chapter 6.5, Title 19 § 2732, and Chapter 22 of California Code of Regulations § 66265.16. This template may be uploaded onto CERS and will satisfy the above mentioned regulations.

1. Programs
   a. Facility maintains hazardous materials at or above the reporting quantities of 55 gallons of a liquid, 500 pounds of a solid, and/or 200 cubic feet of a compressed gas

      ☑ YES Complete section 1b

   b. Hazardous Materials Business Plan Requirements (HSC § 25504(c))
      i. Methods of safe handling of hazardous materials

a. Follow all established procedures and perform job duties as trained
b. Be cautious and pay close attention to what you are doing
c. Always use required PPE
d. Make sure all containers are properly labeled and appropriate for material
e. Read SDSs (SDS Online system)
f. Use materials solely for intended purpose
g. Store materials properly
h. Understand emergency procedures

      ii. Safety procedures in the event of a release or threatened release of a hazardous material as described in Emergency Action/Contingency Plan

a. Follow Universal Spill Response Procedures (USRP)
b. Identify potential hazards and determine whether a release has occurred.
c. Activate local emergency systems and take appropriate immediate actions based on level of training and the ability to act safely.
d. Make required notifications and request assistance as needed.
e. Assist responding agencies by providing access to the facility and information about the facility.

      iii. Procedures for coordination with local emergency organizations

a. The Environmental Project Manager will work with the field technicians to determine if the release is subject to California or Federal spill reporting requirements.
b. The Environmental Project Manager will contact the appropriate regulatory agencies and initiate reporting as necessary.
c. Call HazMat One for emergency chemical spill/release services. HazMat One is required by contract to have qualified spill response personnel on-site within 2 hours of being notified of a spill.

iv. Communication and alarm systems

a. An alarm system would notify any maintenance personnel of a potential hazard. Those alarms will vary from High/Low Fuel level, interstitial alarming, and low voltage/high heat readings on batteries.
b. Personnel will use cell phones for contacting appropriate emergency services immediately.
c. Designated personnel (Environmental Project Manager and emergency contacts) will be contacted immediately as a representative is on call 24-7.
d. In the event of a spill or incident, appropriate agencies will be contacted for cleanup and notification.

v. Use of emergency response equipment and supplies employees may use

Facility emergency equipment includes the following:
-Portable fire extinguishers maintained in accordance with NFPA 10
-Portable first aid kits
-Smoke and Heat detection alarms (fire alarms)
-Spill control equipment including pads, absorbent material, shovels, and brooms
- Personal Protective Equipment including gloves, goggles, and face shields
Employees may place absorbent materials in such a manner as to prevent a spill from flowing into a sensitive area. Control and clean-up of spills shall not be performed by staff if the scope of the incident is beyond their capability.

vi. Procedures for using, inspection of, repairing, and/or replacing facility emergency and monitoring equipment

a. All facilities are inspected based on a Preventative Maintenance (PM) schedule not to exceed 90 days.
b. Inspections involve all critical infrastructure at the site, including tanks, generators, batteries, and cooling/heating sytems.
c. Monitoring equipment is regularly checked to ensure it is available and maintained according to manufacturer's specifications.

vii. Evacuation/re-entry procedures and assembly point locations

a. Most site locations are unmanned, and if manned only during regular work hours.
b. If an emergency should occur when employees/visitors are present, proceed to the nearest exit and assemble at a safe distance away from the facility.
c. All emergency exit routes are clearly marked allowing personnel an easy exit in the event of an emergency.
d. If the site is manned, the senior employee on-site is responsible to account for the whereabouts of personnel.

c. Facility stores/generates hazardous waste

- [ ] YES — Complete section 1d
- [x] NO — Do not complete section 1d

d. Hazardous Waste Generator Requirements (HSC Chapter 6.5, 22 CCR § 66265.16)

i. Proper packaging and labeling of all waste

ii. On-site management and storage requirements

iii. Proper use of safety equipment and hazardous waste management supplies

iv. Off-site transportation requirements

v. Interaction with waste haulers and disposal sites including manifesting

vi. Conducting and documentation off periodic inspections

Frequency of inspections: _____

2. Required Training Topics – By Job Title

While all topics in section 1 must be covered, not every individual must be trained in each topic for respective program(s). Training given to each individual will commensurate with the tasks assigned to that employee.

Example: An employee who physically handles hazardous wastes but does not fill out or manage manifests needs training in handling not manifesting, while the clerical person responsible for the manifests needs training in manifesting but not handling the wastes.

Training on SDSs (Safety Data Sheets) including specific hazard(s) of each chemical to which employees may be exposed, including routes of exposure (i.e. inhalation, ingestion, absorption, etc.) is required.

Procedures for specific job titles (optional):

Personnel are required to perform awareness training on a yearly basis, educating employees on hazardous materials. Initial and annual training is	
provided through pre-configured online training environment audio and video presentations. For SPCC sites, there is also an online training for	
SPCC Plans which is required initially and then on a minimum 3 year cycle. In general, the overall training includes:	
a. SDSs	b. SPCC plans
c. HAZMAT business plan materials	d. Emergency Evacuation
e. Safe handling procedures for hazardous materials	f. Procedures for coordination with emergency response agencies
g. Proper use of safety equipment	h. Universal spill response procedures
i. Notification to Environmental Project Managers	

3. Personal Responsibilities

   Responsibility for ensuring the training plan is compliant to all requirements and implementation is assigned to: Environmental Project Manager, Facility Coordinator, Field Managers

   Special Responsibilities are as follows:

TRAINING TASK	ASSIGNED TO

4. Training Frequency

   New employees will successfully complete training within 6 months after date of employment or assignment to a new position at facility. All employees are to receive at least annual training, including refresher courses. In the event of new assignments or changes in operation, training will be provided before the new assignment or change in operation takes place. Employees will not handle hazardous materials and/or hazardous waste without supervision until trained.

   Date of last training: _____

   Date of next training: _____

   Additional dates for refresher courses (optional):

COURSE	DATE

5. Training Documentation

   All training must be documented. Training records on current personnel shall be kept until closure of the facility. Training records on former employees shall be kept for at least three years from the date the employee last worked at the facility. Records that document that the requirements, trainings, and job experience have met must be kept and maintained.

Career Compass Web site, Environmental PM and Field Managers have access.

Training records are kept: _____

Berry Petroleum Co - HILL PROPERTY (CERSID: 10231549)

Facility Information Accepted Aug 24, 2022

Submitted on 2/24/2022 11:50:19 AM by *Jason Green* of Berry Petroleum Company, LLC (BAKERSFIELD, CA)
Submittal was ***Accepted*** on 8/24/2022 3:29:20 PM by FUNK, LAUREL D

- Business Activities
- Business Owner/Operator Identification

Guidance Messages

- **Warning:**
  1. Business Activities - The Facility Name for CERSID: 10231549 has changed from: 'LINN Operating, Inc. - HILL PROPERTY' to 'Berry Petroleum Co - HILL PROPERTY'.

Hazardous Materials Inventory Accepted Aug 24, 2022

Submitted on 2/24/2022 11:50:19 AM by *Jason Green* of Berry Petroleum Company, LLC (BAKERSFIELD, CA)
Submittal was ***Accepted*** on 8/24/2022 3:29:29 PM by FUNK, LAUREL D

- Hazardous Material Inventory (39)
- Site Map (Official Use Only)
  - *Light Oil Facility* (Adobe PDF, 212KB)
  - *Wells with chemical* (Adobe PDF, 309KB)
  - *Warehouse* (Adobe PDF, 217KB)
  - *Heavy Oil Facility* (Adobe PDF, 316KB)
  - *Tulare Water Plant* (Adobe PDF, 371KB)
  - *Annotated Site Map (Official Use Only)* (Adobe PDF, 217KB)

Emergency Response and Training Plans Accepted Aug 24, 2022

Submitted on 2/24/2022 11:50:19 AM by *Jason Green* of Berry Petroleum Company, LLC (BAKERSFIELD, CA)
Submittal was ***Accepted*** on 8/24/2022 3:29:23 PM by FUNK, LAUREL D

- Emergency Response/Contingency Plan
  - *Emergency Response/Contingency Plan* (Adobe PDF, 338KB)
- Employee Training Plan
  - Provided In Submital Element: Emergency Response and Training Plans

Aboveground Petroleum Storage Act Accepted Aug 24, 2022

Submitted on 2/24/2022 11:50:19 AM by *Jason Green* of Berry Petroleum Company, LLC (BAKERSFIELD, CA)
Submittal was ***Accepted*** on 8/24/2022 3:29:32 PM by FUNK, LAUREL D

- Aboveground Petroleum Storage Act Documentation
  - Provided In Submital Element: Hazardous Materials Inventory
- APSA Facility Information

California Environmental Reporting System (CERS) — Business Activities

Site Identification

Berry Petroleum Co - HILL PROPERTY
18271 HIGHWAY 33
MCKITTRICK, CA 93251-9737
County
Kern

CERS ID
10231549
EPA ID Number
CAL000408589

Submittal Status

Submitted on 2/24/2022 by *Jason Green* of Berry Petroleum Company, LLC (BAKERSFIELD, CA)
Submittal was ***Accepted***; Processed on 8/24/2022 by *FUNK, LAUREL D* for Kern County Environmental Health Services Department

Hazardous Materials

Does your facility have on site (for any purpose) at any one time, hazardous materials at or above 55 gallons for liquids, 500 pounds for solids, or 200 cubic feet for compressed gases (include liquids in ASTs and USTs); or is regulated under more restrictive inventory local reporting requirements (shown below if present); or the applicable Federal threshold quantity for an extremely hazardous substance specified in 40 CFR Part 355, Appendix A or B; or handle radiological materials in quantities for which an emergency plan is required pursuant to 10 CFR Parts 30, 40 or 70?	**Yes**

Underground Storage Tank(s) (UST)

Does your facility own or operate underground storage tanks?	**No**

Hazardous Waste

Is your facility a Hazardous Waste Generator?	**Yes**
Does your facility treat hazardous waste on-site?	**No**
Is your facility's treatment subject to financial assurance requirements (for Permit by Rule and Conditional Authorization)?	**No**
Does your facility consolidate hazardous waste generated at a remote site?	**No**
Does your facility need to report the closure/removal of a tank that was classified as hazardous waste and cleaned on-site?	**No**
Does your facility generate in any single calendar month 1,000 kilograms (kg) (2,200 pounds) or more of federal RCRA hazardous waste, or generate in any single calendar month greater than 1 kg (2.2 pounds) of RCRA acute hazardous waste; or generate more than 100 kg (220 pounds) of spill cleanup materials contaminated with RCRA acute hazardous waste.	**No**
Is your facility a Household Hazardous Waste (HHW) Collection site?	**No**

Excluded and/or Exempted Materials

Does your facility recycle more than 100 kg/month of excluded or exempted recyclable materials (per HSC 25143.2)?	**No**
Does your facility own or operate ASTs above these thresholds? Store greater than 1,320 gallons of petroleum products (new or used) in aboveground tanks or containers.	**Yes**
Does your facility have Regulated Substances stored onsite in quantities greater than the threshold quantities established by the California Accidental Release prevention Program (CalARP)?	**No**

Additional Information

No additional comments provided.

Facility/Site

Berry Petroleum Co - HILL PROPERTY
18271 HIGHWAY 33
MCKITTRICK, CA 93251-9737

CERS ID
10231549

Submittal Status

Submitted on 2/24/2022 by *Jason Green* of Berry Petroleum Company, LLC (BAKERSFIELD, CA)
Submittal was ***Accepted***; Processed on 8/24/2022 by *FUNK, LAUREL D* for Kern County Environmental Health Services Department

Identification

Berry Petroleum Company

Operator Phone	Business Phone	Business Fax
(661) 616-3900	(661) 616-3900	

Beginning Date	Ending Date	
Dun & Bradstreet	**SIC Code**	**Primary NAICS**
	1311	211111

Facility/Site Mailing Address

11117 River Run Boulevard
Bakersfield, CA 93311

Primary Emergency Contact

Davey Cooper
Title
Foreman 1 Production

Business Phone	24-Hour Phone	Pager Number
(661) 762-7383	(661) 623-0432	

Owner

Berry Petroleum
(661) 616-3900
11117 River Run Boulevard
Bakersfield, CA 93311

Secondary Emergency Contact

Greg Juengst
Title
District Production Superintendent

Business Phone	24-Hour Phone	Pager Number
(661) 293-8184	(661) 340-6928	

Billing Contact

Cory Eagar
(661) 616-3856 ceagar@bry.com
11117 River Run
Bakersfield, CA 93311

Environmental Contact

Cory Eagar
(661) 616-3856 ceagar@bry.com
11117 River Run Boulevard
Bakersfield, CA 93311

Name of Signer	Signer Title	Document Preparer
Jason Green	Health & Safety Representative	Jason Green

Additional Information

Locally-collected Fields

Some or all of the following fields may be required by your local regulator(s).

Property Owner

Berry Petroleum
Phone
(661) 616-3900
Mailing Address
11117 River Run Boulevard
Bakersfield, CA 93311

Assessor Parcel Number (APN)

Number of Employees
0

Facility ID

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **Berry Petroleum Company, LLC**
Facility Name **Berry Petroleum Co - HILL PROPERTY**
18271 HIGHWAY 33, MCKITTRICK 93251-9737

Chemical Location **Colm-Tank 2**

CERS ID **10231549**
Facility ID
Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
DOT: 3 - Flammable and Combustible Liquids Flammable Liquid, Class I-C	**CRUDE OIL** CAS No 68410-00-4	**Gallons** State Liquid Type Pure	**21000** Storage Container Aboveground Tank Days on Site: 365	**21000**	1000 Pressue Ambient Temperature Ambient	Waste Code	- Physical Flammable - Health Skin Corrosion Irritation - Health Serious Eye Damage Eye Irritation				

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **Berry Petroleum Company, LLC**
Facility Name **Berry Petroleum Co - HILL PROPERTY**
18271 HIGHWAY 33, MCKITTRICK 93251-9737

Chemical Location **Colm-Tank 4**

CERS ID **10231549**
Facility ID
Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
Flammable Liquid, Class I-A	**Wash Tank Crude Oil/Water** CAS No 68410-00-4	**Gallons** State Liquid Type Pure	**42000** Storage Container Aboveground Tank Days on Site: 365	**42000**	1000 Pressue Ambient Temperature Ambient	Waste Code	- Physical Flammable - Health Skin Corrosion Irritation - Health Serious Eye Damage Eye Irritation	Produced Water Crude Oil	90% 10%		

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **Berry Petroleum Company, LLC**
Facility Name **Berry Petroleum Co - HILL PROPERTY**
18271 HIGHWAY 33, MCKITTRICK 93251-9737

Chemical Location **Colm-Tank 5**

CERS ID **10231549**
Facility ID
Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
DOT: 3 - Flammable and Combustible Liquids Flammable Liquid, Class I-C	**Produced Water** CAS No 68410-00-4	**Gallons** State Liquid Type Mixture	**42000** Storage Container Aboveground Tank Days on Site: 365	**42000**	1000 Pressue Ambient Temperature Ambient	Waste Code	- Physical Flammable - Health Skin Corrosion Irritation - Health Serious Eye Damage Eye Irritation	Produced Water Crude Oil	90% 10%		

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **Berry Petroleum Company, LLC**
Facility Name **Berry Petroleum Co - HILL PROPERTY**
18271 HIGHWAY 33, MCKITTRICK 93251-9737

Chemical Location **Diatomite Main Corridor**

CERS ID **10231549**
Facility ID
Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
DOT: 3 - Flammable and Combustible Liquids	**PAO3857D Paraffin Dispersant** CAS No	**Gallons** State: Liquid Type: Mixture	**125** Storage Container: Plastic/Non-metalic Drum Days on Site: 365	**125**	100 Pressue Temperature	Waste Code	- Health Carcinogenicity - Health Skin Corrosion Irritation - Health Respiratory Skin Sensitization - Health Serious Eye Damage Eye Irritation - Health Specific Target Organ Toxicity - Health Hazard Not Otherwise Classified	LIGHT AROMATIC NAPHTHA 1,2,4-TRIMETHYLBENZENE 1,3,5 Trimethylbenzene Ammonium alkylaryl sulfonates Fatty acid/alkanolamine reaction product	30% 20% 5% 5% 5%		64742-95-6 95-63-6 108-67-8 TRADE SECRET TRADE SECRET

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **Berry Petroleum Company, LLC**
Facility Name **Berry Petroleum Co - HILL PROPERTY**
18271 HIGHWAY 33, MCKITTRICK 93251-9737

Chemical Location **Diatomite Water Plant (DWP) & Tulare Water Plant**

CERS ID **10231549**
Facility ID
Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
	PARFIN DISPERSANT PAO103	**Gallons**	**200**	**200**	100		- Physical Flammable	ALIPHATIC PETROLEUM DISTILLATE	60%		64742-89-8
Combustible Liquid, Class II, Highly Toxic	CAS No 64742-95-6	State Liquid Type Mixture	Storage Container Aboveground Tank Days on Site: 365		Pressue Ambient Temperature Ambient	Waste Code	- Physical SelfHeating - Physical Hazard Not Otherwise Classified - Health Acute Toxicity - Health Reproductive Toxicity - Health Skin Corrosion Irritation - Health Respiratory Skin Sensitization - Health Serious Eye Damage Eye Irritation - Health Specific Target Organ Toxicity - Health Aspiration Hazard	TOLUENE ALKYLARYL SULFONATES 2-ETHYLHEXANOL LIGHT AROMATIC NAPHTHA	60% 10% 5% 5%		108-88-3 TRADE SECRET 104-76-7 64742-95-6

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **Berry Petroleum Company, LLC**
Facility Name **Berry Petroleum Co - HILL PROPERTY**
18271 HIGHWAY 33, MCKITTRICK 93251-9737

Chemical Location **Diatomite Water Plant Walnut Shell Filters**

CERS ID **10231549**
Facility ID
Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities Max. Daily	Largest Cont.	Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only) Component Name	% Wt	EHS	CAS No.
	PFR3573 Citric Acid	**Gallons**	**250**	**250**	100			Citric Acid	50%		77-42-9
	CAS No	State: Liquid	Storage Container: Plastic/Non-metalic Drum		Pressue: Ambient	Waste Code					
		Type: Mixture	Days on Site: 365		Temperature: Ambient						

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **Berry Petroleum Company, LLC**
Facility Name **Berry Petroleum Co - HILL PROPERTY**
18271 HIGHWAY 33, MCKITTRICK 93251-9737

Chemical Location **Heavy Oil Facility (HOF); East of LACT UNIT**

CERS ID **10231549**
Facility ID
Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
	XYLENE	**Gallons**	**75**	**75**	5			XYLENE	60%		1330-20-7
	CAS No	State	Storage Container		Pressue	Waste Code		ETHYLBENZENE	10%		100-41-4
Flammable Liquid, Class I-B		Liquid	Steel Drum		Ambient				0%		
		Type			Temperature				0%		
		Mixture	Days on Site: 365		Ambient				0%		

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **Berry Petroleum Company, LLC**
Facility Name **Berry Petroleum Co - HILL PROPERTY**
18271 HIGHWAY 33, MCKITTRICK 93251-9737

Chemical Location **Heavy Oil Facility (HOF); TANK Skim Tank T-202**

CERS ID **10231549**
Facility ID
Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
Flammable Liquid, Class I-A	**Skim-CRUDE OIL** CAS No 68410-00-4	**Gallons** State Liquid Type Pure	**42000** Storage Container Belowground Tank Days on Site: 365	**42000**	2100 Pressue Ambient Temperature Ambient	Waste Code	- Physical Flammable - Health Skin Corrosion Irritation - Health Serious Eye Damage Eye Irritation	Produced Water Crude Oil	90% 10% 0% 0% 0%		

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **Berry Petroleum Company, LLC**
Facility Name **Berry Petroleum Co - HILL PROPERTY**
18271 HIGHWAY 33, MCKITTRICK 93251-9737

Chemical Location **Heavy Oil Facility (HOF); TANK T-205**

CERS ID **10231549**
Facility ID
Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
Flammable Liquid, Class I-A	**CRUDE OIL** CAS No 68410-00-4	**Gallons** State Liquid Type Pure	**84000** Storage Container Aboveground Tank Days on Site: 365	**84000**	42000 Pressue Ambient Temperature Ambient	Waste Code	- Physical Flammable - Health Skin Corrosion Irritation - Health Serious Eye Damage Eye Irritation		100%		

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **Berry Petroleum Company, LLC**
Facility Name **Berry Petroleum Co - HILL PROPERTY**
18271 HIGHWAY 33, MCKITTRICK 93251-9737

Chemical Location **Heavy Oil Facility (HOF); TANK T-206**

CERS ID **10231549**
Facility ID
Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Largest Cont.	Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
Flammable Liquid, Class I-A	**CRUDE OIL** CAS No 68410-00-4	**Gallons** State Liquid Type Pure	**210000** Storage Container Aboveground Tank Days on Site: 365	**210000**	105000 Pressue Ambient Temperature Ambient	Waste Code	- Physical Flammable - Health Skin Corrosion Irritation - Health Serious Eye Damage Eye Irritation		100% 0% 0% 0% 0%		

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org.	**Berry Petroleum Company, LLC**	Chemical Location	CERS ID **10231549**
Facility Name	**Berry Petroleum Co - HILL PROPERTY**	**Heavy Oil Facility (HOF);TANK T-202**	Facility ID
	18271 HIGHWAY 33, MCKITTRICK 93251-9737		Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
	CRUDE OIL	**Gallons**	**42000**	**42000**	21000		- Physical Flammable - Health Skin Corrosion Irritation - Health Serious Eye Damage Eye Irritation	Produced Water Crude Oil	90%		
Flammable Liquid, Class I-A	CAS No 68410-00-4	State Liquid Type Pure	Storage Container Aboveground Tank Days on Site: 365		Pressue Ambient Temperature Ambient	Waste Code					

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **Berry Petroleum Company, LLC**
Facility Name **Berry Petroleum Co - HILL PROPERTY**
18271 HIGHWAY 33, MCKITTRICK 93251-9737

Chemical Location **Heavy Oil Facility near V-222 & Light Oil Facility-Chemical Alley, Diatomite Main Corridor, Well 70**

CERS ID **10231549**
Facility ID
Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities Max. Daily	Largest Cont.	Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only) Component Name	% Wt	EHS	CAS No.
DOT: 3 - Flammable and Combustible Liquids	**CRW6255b CORROSION INHIBITOR**	**Gallons**	**125**	**125**	100		- Health Acute Toxicity	Methanol	30%		67-56-1
	CAS No	State: Liquid	Storage Container: Plastic/Non-metalic Drum		Pressue: Ambient	Waste Code	- Health Skin Corrosion Irritation	Amine derivatives	5%		TRADE SECRET
		Type: Mixture			Temperature: Ambient		- Health Serious Eye Damage Eye Irritation	Sulfur Compound	5%		TRADE SECRET
							- Health Specific Target Organ Toxicity	Quaternary ammonium compound	5%		TRADE SECRET
								Acid phosphate ester	5%		TRADE SECRET

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **Berry Petroleum Company, LLC**
Facility Name **Berry Petroleum Co - HILL PROPERTY**
18271 HIGHWAY 33, MCKITTRICK 93251-9737

Chemical Location **Heavy Oil Facility, Light Oil Facility, Tulare Water Plant south of steam generatros**

CERS ID **10231549**
Facility ID
Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities Max. Daily	Largest Cont.	Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only) Component Name	% Wt	EHS	CAS No.
	Finrock Rock Drill 100 Lube Oil	**Gallons**	**250**	**125**	200			Distillates, petroleum, hydrotreated heavy paraffinic	90%		64742-54-7
	CAS No	State: Liquid	Storage Container: Steel Drum		Pressue: Ambient	Waste Code		Non-Hazardous Materials	10%		
		Type: Pure			Temperature: Ambient						

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org.	**Berry Petroleum Company, LLC**	Chemical Location	CERS ID **10231549**
Facility Name	**Berry Petroleum Co - HILL PROPERTY**	**Light Oil facility (LOF) at Chemical Alley-West of Tank 2,**	Facility ID
	18271 HIGHWAY 33, MCKITTRICK 93251-9737	**Well #s 70, 673C, 252H**	Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
	SCW4003 SCALE INHIBITOR	**Gallons**	**800**	**200**	400		- Health Serious Eye Damage Eye Irritation				
	CAS No	State: Liquid	Storage Container: Plastic/Non-metalic Drum		Pressue: Ambient	Waste Code					
		Type: Mixture	Days on Site: 365		Temperature: Ambient						

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **Berry Petroleum Company, LLC**
Facility Name **Berry Petroleum Co - HILL PROPERTY**
18271 HIGHWAY 33, MCKITTRICK 93251-9737

Chemical Location **Light Oil Facility (LOF); TANK T-101**

CERS ID **10231549**
Facility ID
Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
Flammable Liquid, Class I-A	**Wash Tank Crude Oil/Water** CAS No 68410-00-4	**Gallons** State Liquid Type Mixture	**210000** Storage Container Aboveground Tank Days on Site: 365	**210000**	105000 Pressue Ambient Temperature Ambient	Waste Code	- Physical Flammable - Health Skin Corrosion Irritation - Health Serious Eye Damage Eye Irritation				

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **Berry Petroleum Company, LLC**
Facility Name **Berry Petroleum Co - HILL PROPERTY**
18271 HIGHWAY 33, MCKITTRICK 93251-9737

Chemical Location **Light Oil Facility (LOF); TANK T-102**

CERS ID **10231549**
Facility ID
Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
Flammable Liquid, Class I-A	**Wash Tank Crude Oil/Water** CAS No 68410-00-4	**Gallons** State Liquid Type Mixture	**210000** Storage Container Aboveground Tank Days on Site: 365	**210000**	105000 Pressue Ambient Temperature Ambient	Waste Code	- Physical Flammable - Health Skin Corrosion Irritation - Health Serious Eye Damage Eye Irritation				

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **Berry Petroleum Company, LLC**
Facility Name **Berry Petroleum Co - HILL PROPERTY**
18271 HIGHWAY 33, MCKITTRICK 93251-9737

Chemical Location **Light Oil Facility (LOF); TANK T-103**

CERS ID **10231549**
Facility ID
Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Largest Cont.	Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
Flammable Liquid, Class I-A	**CRUDE OIL** CAS No 68410-00-4	**Gallons** State Liquid Type Pure	**210000** Storage Container Aboveground Tank Days on Site: 365	**210000**	105000 Pressue Ambient Temperature Ambient	Waste Code	- Physical Flammable - Health Skin Corrosion Irritation - Health Serious Eye Damage Eye Irritation		100% 0% 0% 0% 0%		

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **Berry Petroleum Company, LLC**
Facility Name **Berry Petroleum Co - HILL PROPERTY**
18271 HIGHWAY 33, MCKITTRICK 93251-9737

Chemical Location **Light Oil Facility (LOF); TANK T-104**

CERS ID **10231549**
Facility ID
Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Largest Cont.	Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
Flammable Liquid, Class I-A	**CRUDE OIL** CAS No 68410-00-4	**Gallons** State Liquid Type Pure	**210000** Storage Container Aboveground Tank Days on Site: 365	**210000**	105000 Pressue Ambient Temperature Ambient	Waste Code	- Physical Flammable - Health Skin Corrosion Irritation - Health Serious Eye Damage Eye Irritation	100% 0% 0% 0% 0%		

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **Berry Petroleum Company, LLC**
Facility Name **Berry Petroleum Co - HILL PROPERTY**
18271 HIGHWAY 33, MCKITTRICK 93251-9737

Chemical Location
Light Oil Facility (LOF); TANK T-106

CERS ID **10231549**
Facility ID
Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
	CRUDE OIL	**Gallons**	**21000**	**21000**	5000		- Physical		100%		
Flammable Liquid, Class I-A	CAS No 68410-00-4	State: Liquid Type: Pure	Storage Container: Aboveground Tank Days on Site: 365		Pressue: Ambient Temperature: Ambient	Waste Code	Flammable - Health Skin Corrosion Irritation - Health Serious Eye Damage Eye Irritation		0% 0% 0% 0%		

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **Berry Petroleum Company, LLC**
Facility Name **Berry Petroleum Co - HILL PROPERTY**
18271 HIGHWAY 33, MCKITTRICK 93251-9737

Chemical Location **Produced Water Tank T-401**

CERS ID **10231549**
Facility ID
Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
	XC402-Industrial Bactericide	**Gallons**	**400**	**200**	300		- Physical Flammable	Alkyl*-1,3-propylene-diamine acetate (*Coco)	25%		61791-64-8
	CAS No	State: Liquid	Storage Container: Plastic/Non-metalic Drum		Pressue: Ambient	Waste Code	- Health Acute Toxicity	Oxydiethylene bis(alkyl* dimethyl ammonium chloride)	20%		68607-28-3
Flammable Liquid, Class I-C		Type: Mixture	Days on Site: 365		Temperature: Ambient		- Health Skin Corrosion Irritation	Methanol	20%		67-56-1
							- Health Serious Eye Damage Eye Irritation	Isoprppanol	20%		67-63-0
							- Health Specific Target Organ Toxicity				

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **Berry Petroleum Company, LLC**
Facility Name **Berry Petroleum Co - HILL PROPERTY**
18271 HIGHWAY 33, MCKITTRICK 93251-9737

Chemical Location **Tulare Water Plant**

CERS ID **10231549**
Facility ID
Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
Flammable Liquid, Class I-C, Highly Toxic	**WETTING AGENT WAW3003** CAS No 67-56-1	**Gallons** State Liquid Type Storage Container Plastic/Non-metalic Drum Days on Site: 365	**200**	**200**	100 Pressue Ambient Temperature Ambient	Waste Code	- Physical Flammable - Health Acute Toxicity - Health Serious Eye Damage Eye Irritation - Health Specific Target Organ Toxicity	Methanol Oxyalkylated alkyphenol	40% 20%		67-56-1 Trade secret
DOT: 8 - Corrosives (Liquids and Solids) Corrosive, Toxic	**Hydrochloric Acid 24.8%** CAS No	**Gallons** State Liquid Type Mixture Storage Container Aboveground Tank Days on Site: 365	**6000**	**6000**	3000 Pressue Temperature	Waste Code	- Health Skin Corrosion Irritation - Health Respiratory Skin Sensitization - Health Serious Eye Damage Eye Irritation - Health Specific Target Organ Toxicity	Hydrochloric Acid	25%		7647-01-0
	SRW156 SCALE INHIBITOR CAS No	**Gallons** State Liquid Type Mixture Storage Container Plastic/Non-metalic Drum Days on Site: 365	**125**	**125**	60 Pressue Ambient Temperature Ambient	Waste Code	- Physical Corrosive To Metal - Health Carcinogenicity - Health Skin Corrosion Irritation - Health Respiratory Skin Sensitization - Health Serious Eye Damage Eye Irritation - Health Aspiration Hazard	Sodium edetate Sodium hydroxide Trisodium nitrilotriacetic acid	40% 5% 1%		Trade Secret 1310-73-2 5064-31-3

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **Berry Petroleum Company, LLC**
Facility Name **Berry Petroleum Co - HILL PROPERTY**
18271 HIGHWAY 33, MCKITTRICK 93251-9737

Chemical Location **Tulare Water Plant, next to weak acid tank**

CERS ID **10231549**
Facility ID
Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
DOT: 8 - Corrosives (Liquids and Solids) Corrosive, Toxic, Water Reactive, Class 1	**Caustic Soda** CAS No 1310-73-2	**Gallons** State Solid Type Mixture	**6000** Storage Container Aboveground Tank Days on Site: 365	**6000**	3000 Pressue Ambient Temperature Ambient	Waste Code 214	- Physical Corrosive To Metal - Health Skin Corrosion Irritation - Health Serious Eye Damage Eye Irritation - Health Aspiration Hazard - Health Hazard Not Otherwise Classified	Sodium Hydroxide	25%		001310-73-2

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **Berry Petroleum Company, LLC**
Facility Name **Berry Petroleum Co - HILL PROPERTY**
18271 HIGHWAY 33, MCKITTRICK 93251-9737

Chemical Location **Tulare Water Plant, North of Steam Generators at Cut Shack**

CERS ID **10231549**
Facility ID
Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Largest Cont.	Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
DOT: 3 - Flammable and Combustible Liquids	**Solvent** CAS No 64742-88-7	**Gallons** State Liquid Type Pure	**250** Storage Container Aboveground Tank	**250**	200 Pressue Temperature	Waste Code	- Physical Flammable - Health Specific Target Organ Toxicity - Health Aspiration Hazard	Solvent naphtha (petroleum), medium aliph.	100%		

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **Berry Petroleum Company, LLC**
Facility Name **Berry Petroleum Co - HILL PROPERTY**
18271 HIGHWAY 33, MCKITTRICK 93251-9737

Chemical Location **Tulare Water Plant-South of Steam Generators**

CERS ID **10231549**
Facility ID
Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
	Gear Oil	**Gallons**	**125**	**125**	100			Oil, mineral	98%		8012-95-1
	CAS No	State: Liquid	Storage Container: Steel Drum		Pressue: Ambient	Waste Code		Long chain alkyl amine	0%		
		Type: Pure			Temperature: Ambient			2,6- di-tert-butylphenol	0%		

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **Berry Petroleum Company, LLC**
Facility Name **Berry Petroleum Co - HILL PROPERTY**
18271 HIGHWAY 33, MCKITTRICK 93251-9737

Chemical Location **Tulare Water Plant-Steam Generators**

CERS ID **10231549**
Facility ID
Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Largest Cont.	Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
DOT: 2.2 - Nonflammable Gases	**Helium Gas**	**Cu. Feet**	**2000**	**10000**	2000		- Physical Gas Under Pressure - Health Simple Asphyxiant				
	CAS No: 7440-59-7	State: Gas	Storage Container: Cylinder		Pressue	Waste Code					
		Type: Pure	Days on Site: 365		Temperature						

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **Berry Petroleum Company, LLC**
Facility Name **Berry Petroleum Co - HILL PROPERTY**
18271 HIGHWAY 33, MCKITTRICK 93251-9737

Chemical Location **Warehouse**

CERS ID **10231549**
Facility ID
Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Largest Cont.	Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
	Hydraulic Oil	**Gallons**	**55**	**55**	55		- Physical Flammable - Health Aspiration Hazard				
	CAS No	State: Liquid	Storage Container: Steel Drum		Pressue	Waste Code					
		Type: Pure	Days on Site: 365		Temperature						
	Hydraulic Oil	**Gallons**	**55**	**55**	50						
	CAS No	State: Liquid	Storage Container: Steel Drum		Pressue: Ambient	Waste Code					
		Type: Pure	Days on Site: 365		Temperature: Ambient						

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **Berry Petroleum Company, LLC**
Facility Name **Berry Petroleum Co - HILL PROPERTY**
18271 HIGHWAY 33, MCKITTRICK 93251-9737

Chemical Location **Well 673C**

CERS ID **10231549**
Facility ID
Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Largest Cont.	Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
	FORSA™ SCW4002 SCALE INHIBITOR	**Gallons**	**125**	**125**	100						
	CAS No	State: Liquid	Storage Container: Plastic/Non-metalic Drum		Pressue: Ambient	Waste Code					
		Type: Mixture	Days on Site: 365		Temperature: Ambient						

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **Berry Petroleum Company, LLC**
Facility Name **Berry Petroleum Co - HILL PROPERTY**
18271 HIGHWAY 33, MCKITTRICK 93251-9737

Chemical Location **Well 743D**

CERS ID **10231549**
Facility ID
Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
DOT: 3 - Flammable and Combustible Liquids	**CROPCI4U** CAS No	**Gallons** State: Liquid Type	**125** Storage Container: Plastic/Non-metalic Drum Days on Site: 365	**125**	100 Pressue: Ambient Temperature: Ambient	Waste Code	- Physical Flammable - Health Carcinogenicity - Health Skin Corrosion Irritation - Health Serious Eye Damage Eye Irritation - Health Specific Target Organ Toxicity	LIGHT AROMATIC NAPHTHA 1,2,4-TRIMETHYLBENZENE Amine derivatives 1,3,5-TROMETHYLBENZENE XYLENE	40% 30% 20% 10% 5%		64742-95-6 95-63-6 TRADE SECRET 108-67-8 1330-20-7

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **Berry Petroleum Company, LLC**
Facility Name **Berry Petroleum Co - HILL PROPERTY**
18271 HIGHWAY 33, MCKITTRICK 93251-9737

Chemical Location **WELL CORRIDORS; DIATOMITE MAIN**

CERS ID **10231549**
Facility ID
Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
Toxic	**RBW517 WATER CLARIFIER** CAS No	**Gallons** State: Liquid Type: Mixture	**120** Storage Container: Aboveground Tank Days on Site: 365	**120**	100 Pressue: Ambient Temperature: Ambient	Waste Code	- Health Serious Eye Damage Eye Irritation	Ammonium chloride	5%		7783-20-2
	DMO8000U DEMULSIFIER CAS No	**Gallons** State: Liquid Type: Mixture	**180** Storage Container: Aboveground Tank Days on Site: 365	**180**	150 Pressue: Ambient Temperature: Ambient	Waste Code					

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **Berry Petroleum Company, LLC**
Facility Name **Berry Petroleum Co - HILL PROPERTY**
18271 HIGHWAY 33, MCKITTRICK 93251-9737

Chemical Location **West of Heavy Oil Facility**

CERS ID **10231549**
Facility ID
Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
DOT: 3 - Flammable and Combustible Liquids Flammable Liquid, Class I-B	**Paraffin Dispersant** CAS No	**Gallons** State: Liquid Type: Mixture	**250** Storage Container: Plastic/Non-metalic Drum Days on Site: 365	**125**	125 Pressue Temperature	Waste Code	- Physical Flammable - Health Carcinogenicity - Health Skin Corrosion Irritation - Health Serious Eye Damage Eye Irritation - Health Specific Target Organ Toxicity	Light aromatic naphtha 1,2,4-Trimethylbenzene 1,3,5 Trimethylbenzene Ammonium alkylaryl sulfonates Fatty acid/alkanolamine reaction product	30% 20% 5% 5% 5%		64742-95-6 95-63-6 108-67-8 TRADE SECRET TRADE SECRET
DOT: 3 - Flammable and Combustible Liquids	**DMO8298X DEMULSIFIER** CAS No	**Gallons** State: Liquid Type: Mixture	**125** Storage Container: Plastic/Non-metalic Drum	**125**	100 Pressue: Ambient Temperature: Ambient	Waste Code	- Physical Flammable - Health Carcinogenicity - Health Skin Corrosion Irritation - Health Serious Eye Damage Eye Irritation - Health Specific Target Organ Toxicity	LIGHT AROMATIC NAPHTHA 1,2,4-TRIMETHYLBENZENE 1,3,5 Trimethylbenzene Xylene 1,2,3-Trimethylbenzene	40% 30% 10% 10% 5%		64742-65-6 95-63-6 108-67-8 1330-20-7 526-73-8
	FLW163 FLOTATION AID CAS No	**Gallons** State: Liquid Type: Mixture	**375** Storage Container: Plastic/Non-metalic Drum Days on Site: 365	**250**	200 Pressue: Ambient Temperature: Ambient	Waste Code	- Health Hazard Not Otherwise Classified	Petroleum distillates Oxyalkylated alkylphenol	30% 5%		64742-47-8 TRADE SECRET
	RBO6671 WATER CLARIFIER CAS No	**Gallons** State: Liquid Type: Mixture	**125** Storage Container: Plastic/Non-metalic Drum	**125**	100 Pressue: Ambient Temperature: Ambient	Waste Code	- Health Acute Toxicity - Health Skin Corrosion Irritation - Health Serious Eye Damage Eye Irritation	Acrylic polyamide	40%		58627-30-8

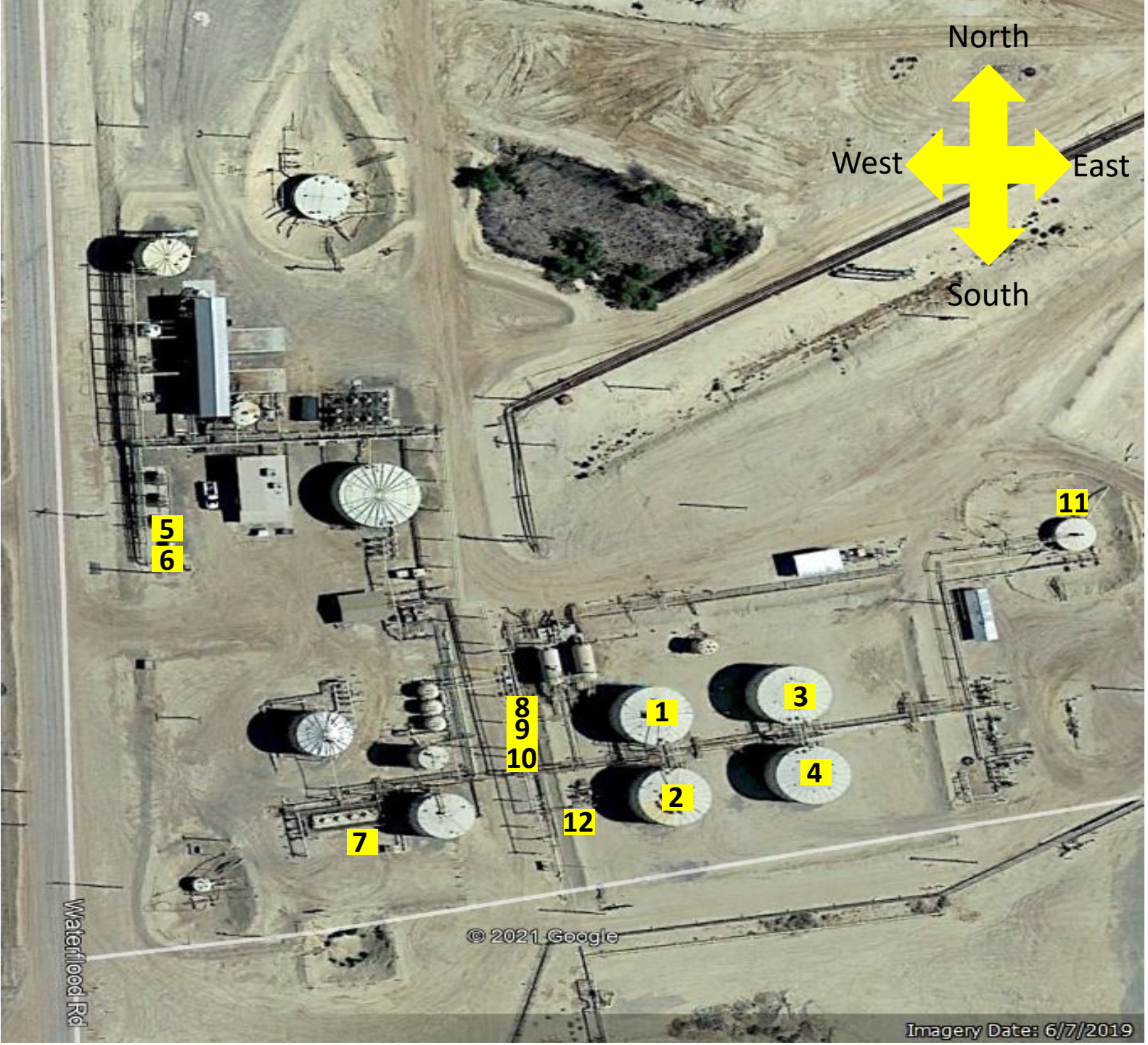
Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **Berry Petroleum Company, LLC**
Facility Name **Berry Petroleum Co - HILL PROPERTY**
18271 HIGHWAY 33, MCKITTRICK 93251-9737

Chemical Location **West of Light Oil Facility in Chemical Alley**

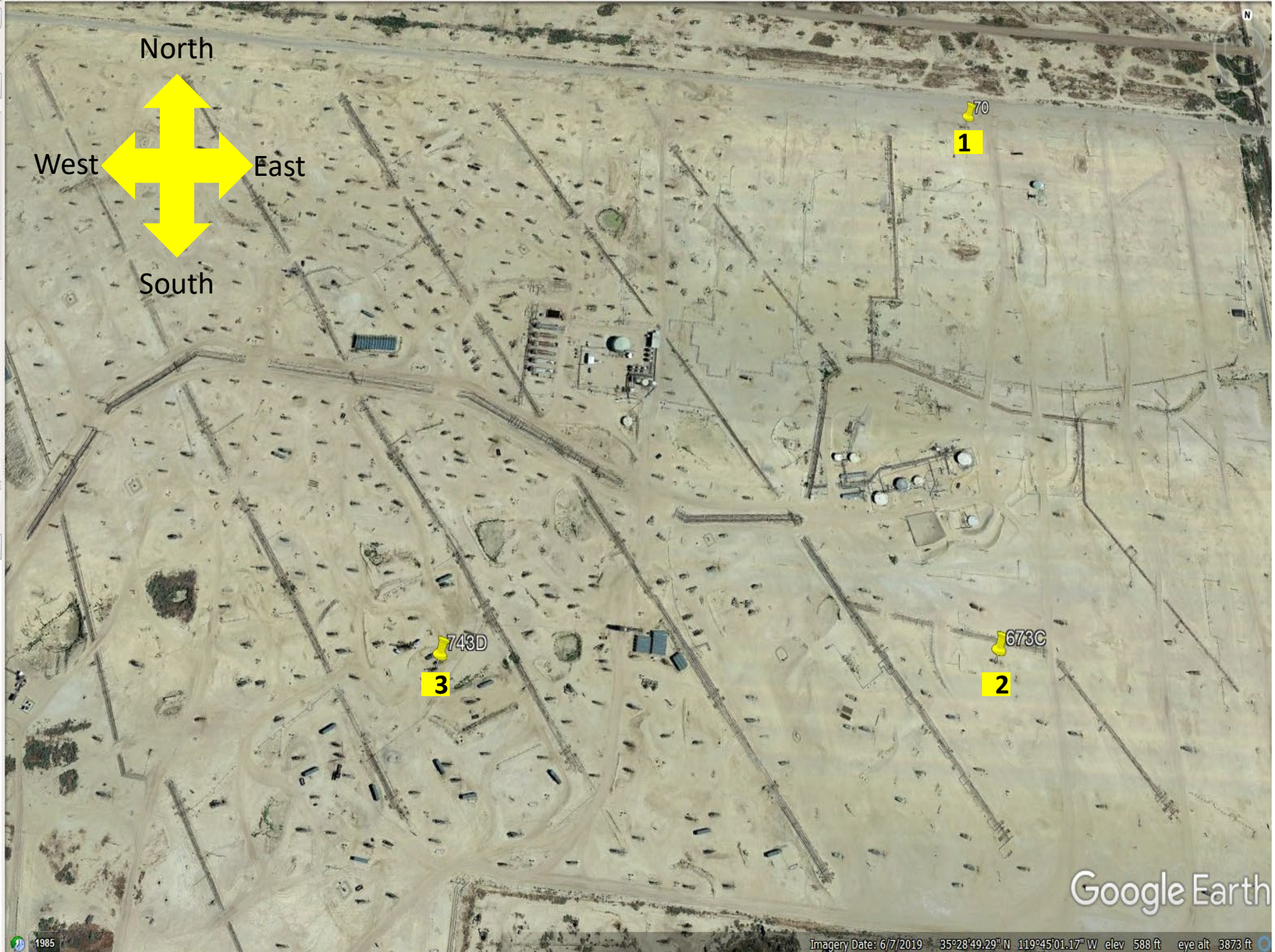
CERS ID **10231549**
Facility ID
Status **Submitted** on 2/24/2022 11:50 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Largest Cont.	Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
DOT: 3 - Flammable and Combustible Liquids Flammable Liquid, Class I-A	**CRW9070** CAS No	**Gallons** State: Liquid Type: Mixture	**200** Storage Container: Plastic/Non-metalic Drum Days on Site: 365	**200**	100 Pressue: Ambient Temperature: Ambient	Waste Code	- Physical Flammable - Health Acute Toxicity - Health Skin Corrosion Irritation - Health Serious Eye Damage Eye Irritation - Health Specific Target Organ Toxicity	METHANOL Amine Derivative Quaternary Ammonium Compound Isopropanol Oxyalkylated Alkyphenil	30% 20% 20% 10% 5%		67-56-1 TRADE SECRET TRADE SECRET 67-63-0 TRADE SECRET
Oxidizing, Class 2	**PFR4923 Bioperoxide** CAS No	**Gallons** State: Liquid Type: Mixture	**200** Storage Container: Plastic/Non-metalic Drum Days on Site: 365	**200**	150 Pressue: Temperature:	Waste Code	- Health Acute Toxicity - Health Skin Corrosion Irritation - Health Respiratory Skin Sensitization - Health Serious Eye Damage Eye Irritation	Hydrogen peroxide Proprietary	20% 5%		7722-84-1 TRADE SECRET



Light Oil Facility Chemicals:

1. Wash Tank-Oil/Water-Tank 101
2. Wash Tank-Oil/Water-Tank 102
3. Crude Oil-Tank 103
4. Crude Oil-Tank 104
5. PFR3573 50% Citric Acid
6. PAO103-Paraffin Dispersant
7. OSW3019-Oxygen Scavenger
8. SCW4003-Forsa Scale Inhibitor
9. CRW6225-Corrosion Inhibitor
10. CRW9070-Corrosion Inhibitor
11. Skim Oil-Tank 106
12. Finrock Rock Drill 100-Lube Oil



Wells with chemical:

1. Well 70-CRW6255 Corrosion Inhibitor
2. Well 673C-FORSA SCW4002 Scale Inhibitor
3. Well743D-CROPCI4U Corrosion Inhibitor



Warehouse Chemicals:

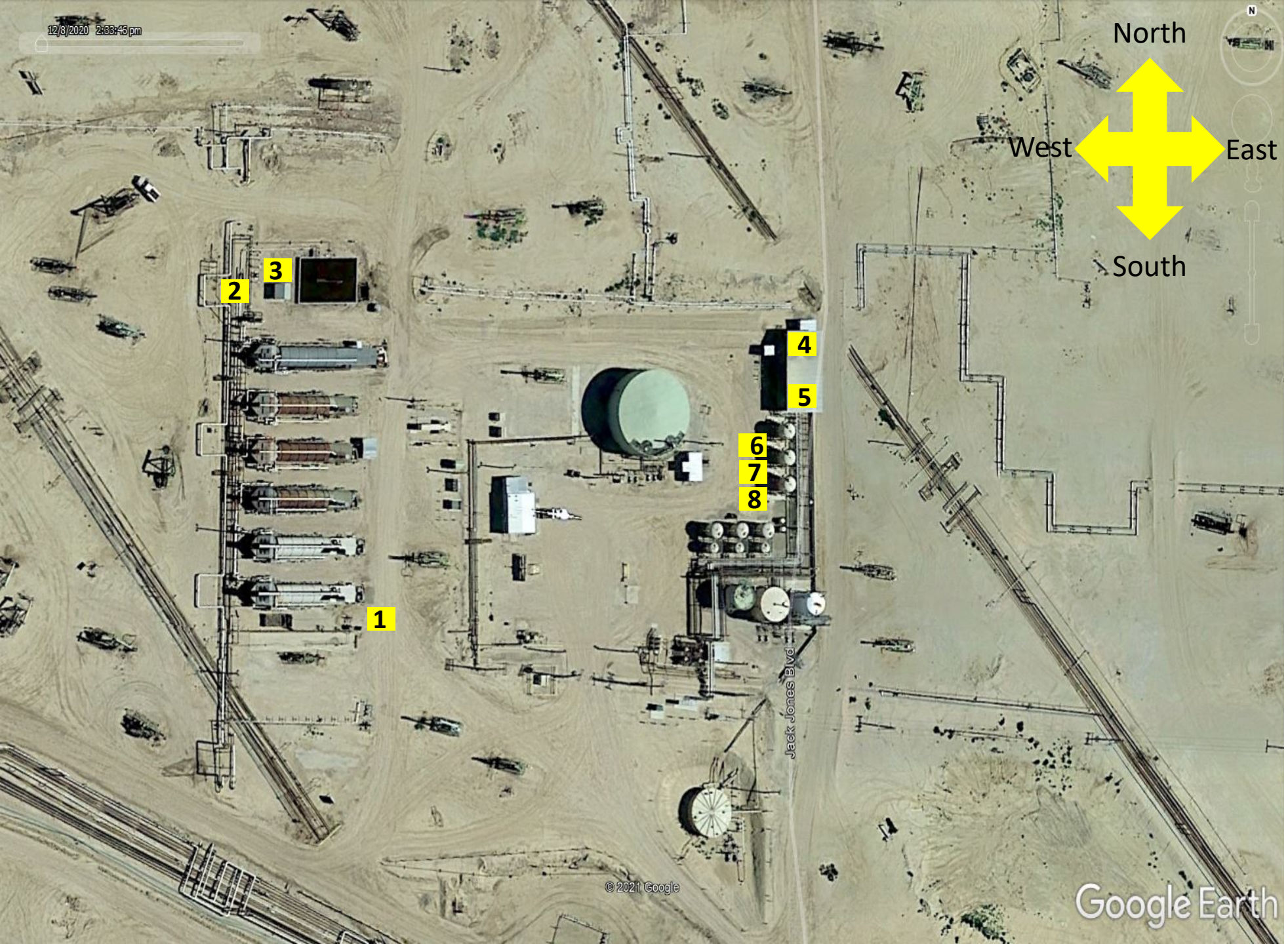
1. Azolla ZS100-Hydraulic Oil
2. Finaroc 100-Rock Drill Oil
3. Carter EP320 Industrial EP Gear Oil
4. Shell S2 M68 Industrial Hydraulic Fluid



Heavy Oil Facility

Chemicals:

1. RBO6671-Water Clarifier
2. FLW163-Flotation Aid
3. DMO7045-Demulisfier
4. DMO8298X-Demulisifer
5. PAO3857D-Paraffin Dispersant
6. CRW6225-Corrosion Inhibitor
7. PFR83-Xylene
8. Tretolite DMO8298X-Demulisifer
9. Forsa PAO3857D-Paraffin Dispersant
10. Crude Oil-Tank 205
11. Crude Oil-Tank 206
12. Crude Oil (Skim)-Tank 202
13. Finrock 100-Rock Drill Oil



Tulare Water Plant Chemicals:

1. Carter EP320-
   Industrial EP Gear Oil
2. Helium Calibration Gas
3. Solvent-SOL142HT
4. Hydrochloric Acid 24.8%
5. Sodium Hydroxide (Na(OH))
   Caustic Soda
6. SRW156-Scale Inhibitor
7. PAO103-Paraffin Dispersant
8. WAW3003-Wetting Agent



Colm Lease

Tank #5-1,000bbl
Produced Water Tank

Tank #4-1,000bbl
Wash Tank

Tank #2-500bbl
Oil Stock Tank

CALIFORNIA ENVIRONMENTAL REPORTING SYSTEM (CERS)

CONSOLIDATED EMERGENCY RESPONSE / CONTINGENCY PLAN

Prior to completing this Plan, please refer to the INSTRUCTIONS FOR COMPLETING A CONSOLIDATED CONTINGENCY PLAN

A. FACILITY IDENTIFICATION AND OPERATIONS OVERVIEW

FACILITY ID # — — 1.

CERS ID A1.: 10231549

DATE OF PLAN PREPARATION/REVISION A2.: 2/7/2022

BUSINESS NAME *(Same as Facility Name or DBA - Doing Business As)* 3.: Berry Corporation-Hill Property

BUSINESS SITE ADDRESS 103.: 18271 Hwy 33

BUSINESS SITE CITY 104.: McKittrick | CA | ZIP CODE 105.: 93251

TYPE OF BUSINESS (e.g., Painting Contractor) A3.: Oil & Gas Exploitation and Production

INCIDENTAL OPERATIONS (e.g., Fleet Maintenance) A4.:

THIS PLAN COVERS CHEMICAL SPILLS, FIRES, AND EARTHQUAKES INVOLVING: (Check all that apply) A5.

☒ 1. HAZARDOUS MATERIALS; ☐ 2. HAZARDOUS WASTES

B. INTERNAL RESPONSE

INTERNAL FACILITY EMERGENCY RESPONSE WILL OCCUR VIA: (Check all that apply) B1.

☒ 1. CALLING PUBLIC EMERGENCY RESPONDERS (i.e., 9-1-1)
☒ 2. CALLING HAZARDOUS WASTE CONTRACTOR
☒ 3. ACTIVATING IN-HOUSE EMERGENCY RESPONSE TEAM

C. EMERGENCY COMMUNICATIONS, PHONE NUMBERS AND NOTIFICATIONS

Whenever there is an imminent or actual emergency situation such as an explosion, fire, or release, the Emergency Coordinator (or his/her designee when the Emergency Coordinator is on call) shall:

1. Activate internal facility alarms or communications systems, where applicable, to notify all facility personnel.
2. Notify appropriate local authorities (i.e., call 9-1-1).
3. Notify the California Emergency Management Agency at (800) 852-7550.

Before facility operations are resumed in areas of the facility affected by the incident, the emergency coordinator shall notify the California Department of Toxic Substances Control (DTSC), the local Unified Program Agency (UPA), and the local fire department's hazardous materials program that the facility is in compliance with requirements to:

1. Provide for proper storage and disposal of recovered waste, contaminated soil or surface water, or any other material that results from an explosion, fire, or release at the facility; and
2. Ensure that no material that is incompatible with the released material is transferred, stored, or disposed of in areas of the facility affected by the incident until cleanup procedures are completed.

INTERNAL FACILITY EMERGENCY COMMUNICATIONS OR ALARM NOTIFICATION WILL OCCUR VIA: (Check all that apply) C1.

☒ 1. VERBAL WARNINGS; ☐ 2. PUBLIC ADDRESS OR INTERCOM SYSTEM; ☒ 3. TELEPHONE;
☐ 4. PAGERS; ☒ 5. ALARM SYSTEM; ☒ 6. PORTABLE RADIO

NOTIFICATIONS TO NEIGHBORING FACILITIES THAT MAY BE AFFECTED BY AN OFF-SITE RELEASE WILL OCCUR BY: (Check all that apply) C2.

☒ 1. VERBAL WARNINGS; ☐ 2. PUBLIC ADDRESS OR INTERCOM SYSTEM; ☒ 3. TELEPHONE;
☐ 4. PAGERS; ☒ 5. ALARM SYSTEM; ☐ 6. PORTABLE RADIO

EMERGENCY RESPONSE PHONE NUMBERS:

AMBULANCE, FIRE, POLICE AND CHP	9-1-1
CALIFORNIA EMERGENCY MANAGEMENT AGENCY (CAL/EMA)	(800) 852-7550
NATIONAL RESPONSE CENTER (NRC)	(800) 424-8802
POISON CONTROL CENTER	(800) 222-1222
LOCAL UNIFIED PROGRAM AGENCY (UPA/CUPA) Kern County Environmental Health	(661) 862-8740 C3.
OTHER (Specify): CUPA- (661)549-9885 or C4.	(661) 549-9927 C5.
NEAREST MEDICAL FACILITY / HOSPITAL NAME: Mercy Southwest Hospital C6.	(661) 663-6000 C7.

AGENCY NOTIFICATION PHONE NUMBERS:

CALIFORNIA DEPT. OF TOXIC SUBSTANCES CONTROL (DTSC)	(916) 255-3545
REGIONAL WATER QUALITY CONTROL BOARD	(559) 445-5116 C8.
U.S. ENVIRONMENTAL PROTECTION AGENCY (US EPA)	(800) 300-2193
CALIFORNIA DEPT OF FISH AND GAME (DFG)	(916) 358-2900
U.S. COAST GUARD	(202) 267-2180
CAL/OSHA	(916) 263-2800
STATE FIRE MARSHAL	(916) 445-8200
OTHER (Specify): CALGEM C9.	(661) 322-4031 C10.
OTHER (Specify): C11.	C12.

D. EMERGENCY CONTAINMENT AND CLEANUP PROCEDURES

SPILL PREVENTION, CONTAINMENT, AND CLEANUP PROCEDURES: (Check all boxes that apply to indicate your procedures for containing spills, releases, fires or explosions; and. preventing and mitigating associated harm to persons, property, and the environment.)

D1.

- [x] 1. MONITOR FOR LEAKS, RUPTURES, PRESSURE BUILD-UP, ETC.;
- [ ] 2. PROVIDE STRUCTURAL PHYSICAL BARRIERS (e.g., Portable spill containment walls);
- [ ] 3. PROVIDE ABSORBENT PHYSICAL BARRIERS (e.g., Pads, pigs, pillows);
- [ ] 4. COVER OR BLOCK FLOOR AND/ OR STORM DRAINS;
- [x] 5. BUILT-IN BERM IN WORK / STORAGE AREA;
- [ ] 6. AUTOMATIC FIRE SUPPRESSION SYSTEM;
- [ ] 7. ELIMINATE SOURCES OF IGNITION FOR FLAMMABLE HAZARDS (e.g. Flammable liquids, Propane);
- [x] 8. STOP PROCESSES AND/OR OPERATIONS;
- [x] 9. AUTOMATIC / ELECTRONIC EQUIPMENT SHUT-OFF SYSTEM;
- [x] 10. SHUT-OFF WATER, GAS, ELECTRICAL UTILITIES AS APPROPRIATE;
- [x] 11. CALL 9-1-1 FOR PUBLIC EMERGENCY RESPONDER ASSISTANCE / MEDICAL AID;
- [x] 12. NOTIFY AND EVACUATE PERSONS IN ALL THREATENED AREAS;
- [x] 13. ACCOUNT FOR EVACUATED PERSONS IMMEDIATELY AFTER EVACUATION CALL;
- [x] 14. PROVIDE PROTECTIVE EQUIPMENT FOR ON-SITE RESPONSE TEAM;
- [x] 15. REMOVE OR ISOLATE CONTAINERS / AREA AS APPROPRIATE;
- [x] 16. HIRE LICENSED HAZARDOUS WASTE CONTRACTOR;
- [x] 17. USE ABSORBENT MATERIAL FOR SPILLS WITH SUBSEQUENT PROPER LABELING, STORAGE, AND HAZARDOUS WASTE DISPOSAL AS APPROPRIATE;
- [ ] 18. SUCTION USING SHOP VACUUM WITH SUBSEQUENT PROPER LABELING, STORAGE, AND HAZARDOUS WASTE DISPOSAL AS APPROPRIATE;
- [ ] 19. WASH / DECONTAMINATE EQUIPMENT W/ CONTAINMENT and DISPOSAL OF EFFLUENT / RINSATE AS HAZARDOUS WASTE;
- [x] 20. PROVIDE SAFE TEMPORARY STORAGE OF EMERGENCY-GENERATED WASTES;
- [ ] 21. OTHER (Specify):

D2.

E. FACILITY EVACUATION

THE FOLLOWING ALARM SIGNAL(S) WILL BE USED TO BEGIN EVACUATION OF THE FACILITY (CHECK ALL THAT APPLY): E1.

- [ ] 1. BELLS;
- [x] 2. HORNS/SIRENS;
- [x] 3. VERBAL (I.E., SHOUTING);
- [x] 4. OTHER (Specify): Cell phones, radios

E2.

THE FOLLOWING LOCATION(S) IS/ARE EVACUEE EMERGENCY ASSEMBLY AREA(S) (i.e., Front parking lot, specific street corner, etc.) E3.

1/2 mile East on contractors road off of HWY33. 35°29'3", 119°44'42"

Note: The Emergency Coordinator must account for all on site employees and/or site visitors after evacuation.

- [x] EVACUATION ROUTE MAP(S) POSTED AS REQUIRED E4.

Note: The map(s) must show primary and alternate evacuation routes, emergency exits, and primary and alternate staging areas, and must be prominently posted throughout the facility in locations where it will be visible to employees and visitors.

F. ARRANGEMENTS FOR EMERGENCY SERVICES

Explanation of Requirement: Advance arrangements with local fire and police departments, hospitals, and/or emergency services contractors should be made as appropriate for your facility. You may determine that such arrangements are not necessary.

ADVANCE ARRANGEMENTS FOR LOCAL EMERGENCY SERVICES (Check one of the following) F1.

- [ ] 1. HAVE BEEN DETERMINED NOT NECESSARY; *or*
- [x] 2. THE FOLLOWING ARRANGEMENTS HAVE BEEN MADE (Specify):

F2.

The following contractor resources are approved vendors for Berry Corporation that could be called when necessary:
> Initial Response - Truitt Oilfield Maintenance, Steve Upton, 661-399-5021
> Initial Response - Accelerated Environmental, Bill Cox, 661-337-0562
> Clean Up & Waste Handling - Patriot Environmental, Dave Larson 661-477-4250

G. EMERGENCY EQUIPMENT

Check all boxes that apply to list emergency response equipment available at the facility and identify the location(s) where the equipment is kept and the equipment's capability, if applicable. [e.g., ☒CHEMICAL PROTECTIVE GLOVES | Spill response kit | One time use, Oil & solvent resistant only.]

TYPE	EQUIPMENT AVAILABLE G1.	LOCATION	CAPABILITY *(If applicable)*
Safety and First Aid	1. ☐ CHEMICAL PROTECTIVE SUITS, APRONS, OR VESTS	G2.	G3.
	2. ☒ CHEMICAL PROTECTIVE GLOVES	G4. Carried by operators	G5. Rubber gloves
	3. ☐ CHEMICAL PROTECTIVE BOOTS	G6.	G7.
	4. ☒ SAFETY GLASSES / GOGGLES / SHIELDS	G8. Carried by operators	G9.
	5. ☒ HARD HATS	G10. Carried by operators	G11.
	6. ☐ CARTRIDGE RESPIRATORS	G12.	G13.
	7. ☐ SELF-CONTAINED BREATHING APPARATUS (SCBA)	G14.	G15.
	8. ☒ FIRST AID KITS / STATIONS	G16. Company Vehicles, field office	G17.
	9. ☐ PLUMBED EYEWASH FOUNTAIN / SHOWER	G18.	G19.
	10. ☒ PORTABLE EYEWASH KITS	G20. Company vehicles	G21. Eye Wash Bottle
	11. ☐ OTHER	G22.	G23.
	12. ☐ OTHER	G24.	G25.
Fire Fighting	13. ☒ PORTABLE FIRE EXTINGUISHERS	G26. Various locations throughout facility, company vehicles	G27.
	14. ☐ FIXED FIRE SYSTEMS / SPRINKLERS / FIRE HOSES	G28.	G29.
	15. ☐ FIRE ALARM BOXES OR STATIONS	G30.	G31.
	16. ☐ OTHER	G32.	G33.
Spill Control and Clean-Up	17. ☐ ALL-IN-ONE SPILL KIT	G34.	G35.
	18. ☐ ABSORBENT MATERIAL	G36.	G37.
	19. ☐ CONTAINER FOR USED ABSORBENT	G38.	G39.
	20. ☒ BERMING / DIKING EQUIPMENT	G40. Tanks, vessels, etc.	G41. AB1960, SPCC
	21. ☒ BROOM	G42. Available at facility	G43.
	22. ☒ SHOVEL	G44. Available at facility	G45.
	23. ☐ SHOP VAC	G46.	G47.
	24. ☐ EXHAUST HOOD	G48.	G49.
	25. ☒ EMERGENCY SUMP / HOLDING TANK	G50. Emergency overflow pits	G51.
	26. ☐ CHEMICAL NEUTRALIZERS	G52.	G53.
	27. ☐ GAS CYLINDER LEAK REPAIR KIT	G54.	G55.
	28. ☐ SPILL OVERPACK DRUMS	G56.	G57.
	29. ☐ OTHER	G58.	G59.
Communi-cations and Alarm Systems	30. ☒ TELEPHONES (Includes cellular)	G60. Carried by Company personnel	G61.
	31. ☐ INTERCOM / PA SYSTEM	G62.	G63.
	32. ☒ PORTABLE RADIOS	G64.	G65.
	33. ☒ AUTOMATIC ALARM CHEMICAL MONITORING EQUIPMENT	G66. Gas Plant, HOF, and Steam Generator site	G67.
Other	34. ☐ OTHER	G68.	G69.
	35. ☐ OTHER	G70.	G71.

H. EARTHQUAKE VULNERABILITY

Identify areas of the facility that are vulnerable to hazardous materials releases / spills due to earthquake-related motion. These areas require immediate isolation and inspection.

VULNERABLE AREAS: (Check all that apply)	H1.	LOCATIONS (e.g., shop, outdoor shed, forensic lab)	
☒ 1. HAZARDOUS MATERIALS / WASTE STORAGE AREA		Chemical containers located throughout facility (see site maps)	H2.
☒ 2. PROCESS LINES / PIPING		Located throughout facility	H3.
☐ 3. LABORATORY			H4.
☐ 4. WASTE TREATMENT AREA			H5.

Identify mechanical systems vulnerable to releases / spills due to earthquake-related motion. These systems require immediate isolation and inspection.

VULNERABLE SYSTEMS: (Check all that apply)	H6.	LOCATIONS	
☐ 1. SHELVES, CABINETS AND RACKS			H7.
☒ 2. TANKS (EMERGENCY SHUTOFF)		Various locations in field	H8.
☒ 3. PORTABLE GAS CYLINDERS			H9.
☒ 4. EMERGENCY SHUTOFF AND/OR UTILITY VALVES			H10.
☐ 5. SPRINKLER SYSTEMS			H11.
☒ 6. STATIONARY PRESSURIZED CONTAINERS (e.g., Propane dispensing tank)			H12.

I. EMPLOYEE TRAINING

Explanation of Requirement: Employee training is required for all employees handling hazardous materials and hazardous wastes in day-to-day or clean-up operations including volunteers and/or contractors. Training must be:

- Provided within 6 months for new hires;
- Amended as necessary prior to change in process or work assignment;
- Given upon modification to the Emergency Response / Contingency Plan, and updated/refreshed annually for all employees.

Required content includes all of the following:

- Material Safety Data Sheets;
- Hazard communication related to health and safety;
- Methods for safe handling of hazardous substances;
- Fire hazards of materials / processes;
- Conditions likely to worsen emergencies;
- Coordination of emergency response;
- Notification procedures;
- Applicable laws and regulations;
- Communication and alarm systems;
- Personal protective equipment;
- Use of emergency response equipment (e.g. Fire extinguishers, respirators, etc.);
- Decontamination procedures;
- Evacuation procedures;
- Control and containment procedures;
- UST monitoring system equipment and procedures (if applicable).

INDICATE HOW EMPLOYEE TRAINING PROGRAM IS ADMINISTERED (Check all that apply) I1.

☒ 1. FORMAL CLASSROOM; ☒ 2. VIDEOS; ☒ 3. SAFETY / TAILGATE MEETINGS;

☒ 4. STUDY GUIDES / MANUALS (Specify): Field Operating Guidelines, Emergency Response Manual/Annual HAZWOPER I2.

☒ 5. OTHER (Specify): Computer-based training I3.

☐ 6. NOT APPLICABLE BECAUSE FACILITY HAS NO EMPLOYEES

Large Quantity Generator (LQG) Training Records: Large quantity hazardous waste generators (i.e., who generate more than 270 gallons/1,000 kilograms of hazardous waste per month) must retain written documentation of employee hazardous waste management training sessions which includes:

- A written outline/agenda of the type and amount of both introductory and continuing training that will be given to persons filling each job position having responsibility for the management of hazardous waste (e.g., labeling, manifesting, compliance with accumulation time limits, etc.).
- The name, job title, and date of training for each hazardous waste management training session given to an employee filling such a job position; and
- A written job description for each of the above job positions that describes job duties and the skills, education, or other qualifications required of personnel assigned to the position.
- Current employee training records must be retained until closure of the facility.
- Former employee training records must be retained at least three years after termination of employment.

J. LIST OF ATTACHMENTS

(Check one of the following) J1.

☐ 1. NO ATTACHMENTS ARE REQUIRED; *or*

☐ 2. THE FOLLOWING DOCUMENTS ARE ATTACHED: J2.

K. SIGNATURE / CERTIFICATION

Certification: Based on my inquiry of those individuals responsible for obtaining the information, I certify under penalty of law that I have personally examined and am familiar with the information submitted and believe the information is true, accurate, and complete, and that a copy is available on site.

SIGNATURE OF OWNER/OPERATOR	DATE SIGNED K1.
Jason Green	2/7/2022
NAME OF SIGNER (print) K2.	TITLE OF SIGNER K3.
Jason Green	Health and Safety Representative

California Environmental Reporting System (CERS)

Aboveground Petroleum Storage Act - Facility Information Report

Facility/Site

Berry Petroleum Co - HILL PROPERTY
18271 HIGHWAY 33
MCKITTRICK, CA 93251-9737

CERS ID
10231549

CAL000408589

Submittal Status

Submitted on 2/24/2022 by *Jason Green* of Berry Petroleum Company, LLC (BAKERSFIELD, CA)
Submittal was ***Accepted***; Processed on 8/24/2022 by *FUNK, LAUREL D* for Kern County Environmental Health Services Department

APSA Facility Information

Conditionally Exempt APSA Tank Facility
N

Date Of SPCC Plan Certification or Date of 5-Year Review
1/31/2019

Total Aboveground Storage Capacity of Petroleum	Number of Tanks in Underground Area(s)
12075000	11

PLAINS PIPELINE LP - BELRIDGE (CERSID: 10234243)

Facility Information **Submitted Feb 23, 2022**

Submitted on 2/23/2022 10:35:36 AM by *Amanda Herd* of PLAINS PIPELINE LP (BAKERSFIELD, CA)

- Business Activities
- Business Owner/Operator Identification

Hazardous Materials Inventory **Submitted Feb 23, 2022**

Submitted on 2/23/2022 10:35:36 AM by *Amanda Herd* of PLAINS PIPELINE LP (BAKERSFIELD, CA)

- Hazardous Material Inventory (4)
- Site Map (Official Use Only)
  - *Annotated Site Map (Official Use Only)* (Adobe PDF, 1288KB)

Emergency Response and Training Plans **Submitted Feb 23, 2022**

Submitted on 2/23/2022 10:35:36 AM by *Amanda Herd* of PLAINS PIPELINE LP (BAKERSFIELD, CA)

- Emergency Response/Contingency Plan
  - *Emergency Response/Contingency Plan* (Adobe PDF, 540KB)
- Employee Training Plan
  - *Employee Training Plan* (Adobe PDF, 60KB)

Site Identification

PLAINS PIPELINE LP - BELRIDGE
18667 WATERFLOOD RD
MCKITTRICK, CA 93251
County
Kern

CERS ID
10234243
EPA ID Number

Submittal Status

Submitted on 2/23/2022 by *Amanda Herd* of PLAINS PIPELINE LP (BAKERSFIELD, CA)

Hazardous Materials

Does your facility have on site (for any purpose) at any one time, hazardous materials at or above 55 gallons for liquids, 500 pounds for solids, or 200 cubic feet for compressed gases (include liquids in ASTs and USTs); or is regulated under more restrictive inventory local reporting requirements (shown below if present); or the applicable Federal threshold quantity for an extremely hazardous substance specified in 40 CFR Part 355, Appendix A or B; or handle radiological materials in quantities for which an emergency plan is required pursuant to 10 CFR Parts 30, 40 or 70?	**Yes**

Underground Storage Tank(s) (UST)

Does your facility own or operate underground storage tanks?	**No**

Hazardous Waste

Is your facility a Hazardous Waste Generator?	**No**
Does your facility treat hazardous waste on-site?	**No**
Is your facility's treatment subject to financial assurance requirements (for Permit by Rule and Conditional Authorization)?	**No**
Does your facility consolidate hazardous waste generated at a remote site?	**No**
Does your facility need to report the closure/removal of a tank that was classified as hazardous waste and cleaned on-site?	**No**
Does your facility generate in any single calendar month 1,000 kilograms (kg) (2,200 pounds) or more of federal RCRA hazardous waste, or generate in any single calendar month greater than 1 kg (2.2 pounds) of RCRA acute hazardous waste; or generate more than 100 kg (220 pounds) of spill cleanup materials contaminated with RCRA acute hazardous waste.	**No**
Is your facility a Household Hazardous Waste (HHW) Collection site?	**No**

Excluded and/or Exempted Materials

Does your facility recycle more than 100 kg/month of excluded or exempted recyclable materials (per HSC 25143.2)?	**No**
Does your facility own or operate ASTs above these thresholds? Store greater than 1,320 gallons of petroleum products (new or used) in aboveground tanks or containers.	**No**
Does your facility have Regulated Substances stored onsite in quantities greater than the threshold quantities established by the California Accidental Release prevention Program (CalARP)?	**No**

Additional Information

No additional comments provided.

Facility/Site

PLAINS PIPELINE LP - BELRIDGE
18667 WATERFLOOD RD
MCKITTRICK, CA 93251

CERS ID
10234243

Submittal Status

Submitted on 2/23/2022 by *Amanda Herd* of PLAINS PIPELINE LP (BAKERSFIELD, CA)

Identification

Plains Pipeline

Operator Phone	Business Phone	Business Fax
(713) 646-4186	(661) 336-7900	(661) 336-7920

Beginning Date	Ending Date	
Dun & Bradstreet	**SIC Code**	**Primary NAICS**
	4612	

Facility/Site Mailing Address

3600 BOWMAN CT.
BAKERSFIELD, CA 93308

Primary Emergency Contact

Operations Control Center
Title
Pipeline System Control Center

Business Phone	24-Hour Phone	Pager Number
(661) 336-7908	(800) 322-7473	

Owner

PLAINS PIPELINE LP
(661) 336-7903
3600 BOWMAN CT
BAKERSFIELD, CA 93308

Secondary Emergency Contact

DARREN PALMER
Title
DISTRICT MANAGER

Business Phone	24-Hour Phone	Pager Number
(661) 336-7908	(661) 978-4915	

Billing Contact

PLAINS MARKETING, LP
(661) 336-7903
3600 BOWMAN COURT
BAKERSFIELD, CA 93308

Environmental Contact

Amanda Herd
(661) 477-2090 ARHERD@PAALP.COM
3600 BOWMAN CT
BAKERSFIELD, CA 93308

Name of Signer	Signer Title	Document Preparer
AMANDA HERD	Health, Safety & Environmental Specialist	AMANDA HERD

Additional Information

Locally-collected Fields

Some or all of the following fields may be required by your local regulator(s).

Property Owner

PLAINS PIPELINE LP
Phone
(661) 336-7903
Mailing Address
3600 BOWMAN COURT
BAKERSFIELD, CA 93308

Assessor Parcel Number (APN)
085-210-21
Number of Employees
0
Facility ID

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **PLAINS PIPELINE LP**
Facility Name **PLAINS PIPELINE LP - BELRIDGE**
18667 WATERFLOOD RD, MCKITTRICK 93251

Chemical Location **Cylinders at ends of station piping**

CERS ID **10234243**
Facility ID
Status **Submitted** on 2/23/2022 10:35 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Quantities: Largest Cont.	Quantities: Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
DOT: 2.2 - Nonflammable Gases Cryogen	**COMPRESSED NITROGEN** CAS No 7727-37-9	**Cu. Feet** State Gas Type Pure	**750** Storage Container Cylinder Days on Site: 365	**250**	500 Pressue > Ambient Temperature Ambient	Waste Code	- Physical Gas Under Pressure - Health Respiratory Skin Sensitization - Health Serious Eye Damage Eye Irritation - Health Aspiration Hazard	COMPRESSED NITROGEN	100%		7727-37-9

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **PLAINS PIPELINE LP**
Facility Name **PLAINS PIPELINE LP - BELRIDGE**
18667 WATERFLOOD RD, MCKITTRICK 93251

Chemical Location **Emergency Generator**

CERS ID **10234243**
Facility ID
Status **Submitted** on 2/23/2022 10:35 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities: Max. Daily	Largest Cont.	Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only): Component Name	% Wt	EHS	CAS No.
DOT: 3 - Flammable and Combustible Liquids Combustible Liquid, Class II	**Diesel Fuel No. 2** CAS No 68476-34-6	**Gallons** State Liquid Type Pure	**80** Storage Container Other Days on Site: 365	**80**	60 Pressue Ambient Temperature Ambient	0 Waste Code	- Physical Flammable - Health Carcinogenicity - Health Acute Toxicity - Health Skin Corrosion Irritation - Health Respiratory Skin Sensitization - Health Specific Target Organ Toxicity - Health Aspiration Hazard				

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **PLAINS PIPELINE LP**
Facility Name **PLAINS PIPELINE LP - BELRIDGE**
18667 WATERFLOOD RD, MCKITTRICK 93251

Chemical Location **Located near station piping**

CERS ID **10234243**
Facility ID
Status **Submitted** on 2/23/2022 10:35 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities Max. Daily	Largest Cont.	Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only) Component Name	% Wt	EHS	CAS No.
	SHELL CORENA S4 R32	**Gallons**	**20**	**5**	10		- Health Acute Toxicity - Health Skin Corrosion Irritation - Health Serious Eye Damage Eye Irritation				
	CAS No	State: Liquid Type: Pure	Storage Container: Plastic/Non-metalic Drum Days on Site: 365		Pressue: Ambient Temperature: Ambient	Waste Code					

Hazardous Materials And Wastes Inventory Matrix Report

CERS Business/Org. **PLAINS PIPELINE LP**
Facility Name **PLAINS PIPELINE LP - BELRIDGE**
18667 WATERFLOOD RD, MCKITTRICK 93251

Chemical Location **Two 50,000 BBL ASTs**

CERS ID **10234243**
Facility ID
Status **Submitted** on 2/23/2022 10:35 AM

DOT Code/Fire Haz. Class	Common Name	Unit	Quantities Max. Daily	Largest Cont.	Avg. Daily	Annual Waste Amount	Federal Hazard Categories	Hazardous Components (For mixture only) Component Name	% Wt	EHS	CAS No.
	CRUDE OIL CAS No 68410-00-4	**Gallons** State Liquid Type Pure	**4200000** Storage Container Aboveground Tank Days on Site: 365	**2100000**	3360000 Pressue Ambient Temperature Ambient	Waste Code	- Physical Flammable - Health Carcinogenicity - Health Skin Corrosion Irritation - Health Serious Eye Damage Eye Irritation - Health Specific Target Organ Toxicity - Health Aspiration Hazard - Health Germ Cell Mutagenicity	Crude Oil	100%		68410-00-4



This user generated map has been prepared from sources considered to be reliable. However, Plains Pipeline L.P. hasfurnished this copy for information only and assumes no responsibility for the accuracy or completeness of data shown.

PLAINS ALL AMERICAN PIPELINE, L.P.

Belridge Facility

Site Map	Scale: 1:1,515
Figure 1	Sheet No.: 1/1

Date: 6/27/2014 Created By: Author: James C Buchanan

CALIFORNIA ENVIRONMENTAL REPORTING SYSTEM (CERS)

CONSOLIDATED EMERGENCY RESPONSE / CONTINGENCY PLAN

Prior to completing this Plan, please refer to the INSTRUCTIONS FOR COMPLETING A CONSOLIDATED CONTINGENCY PLAN

A. FACILITY IDENTIFICATION AND OPERATIONS OVERVIEW

FACILITY ID # 0 0 0 3 0 7 7 — 1.

CERS ID A1. 10234243

DATE OF PLAN PREPARATION/REVISION A2. 2/21/2022

BUSINESS NAME *(Same as Facility Name or DBA - Doing Business As)* 3.
Plains Pipeline LP- Belridge

BUSINESS SITE ADDRESS 103.
18667 Waterflood Road

BUSINESS SITE CITY 104. McKittrick

CA

ZIP CODE 105. 93251

TYPE OF BUSINESS (e.g., Painting Contractor) A3.
Pipeline- Crude Oil

INCIDENTAL OPERATIONS (e.g., Fleet Maintenance) A4.
Pumping/Storage

THIS PLAN COVERS CHEMICAL SPILLS, FIRES, AND EARTHQUAKES INVOLVING: (Check all that apply) A5.

☒ 1. HAZARDOUS MATERIALS; ☐ 2. HAZARDOUS WASTES

B. INTERNAL RESPONSE

INTERNAL FACILITY EMERGENCY RESPONSE WILL OCCUR VIA: (Check all that apply) B1.

☒ 1. CALLING PUBLIC EMERGENCY RESPONDERS (i.e., 9-1-1)
☒ 2. CALLING HAZARDOUS WASTE CONTRACTOR
☒ 3. ACTIVATING IN-HOUSE EMERGENCY RESPONSE TEAM

C. EMERGENCY COMMUNICATIONS, PHONE NUMBERS AND NOTIFICATIONS

Whenever there is an imminent or actual emergency situation such as an explosion, fire, or release, the Emergency Coordinator (or his/her designee when the Emergency Coordinator is on call) shall:

1. Activate internal facility alarms or communications systems, where applicable, to notify all facility personnel.
2. Notify appropriate local authorities (i.e., call 9-1-1).
3. Notify the California Emergency Management Agency at (800) 852-7550.

Before facility operations are resumed in areas of the facility affected by the incident, the emergency coordinator shall notify the California Department of Toxic Substances Control (DTSC), the local Unified Program Agency (UPA), and the local fire department's hazardous materials program that the facility is in compliance with requirements to:

1. Provide for proper storage and disposal of recovered waste, contaminated soil or surface water, or any other material that results from an explosion, fire, or release at the facility; and
2. Ensure that no material that is incompatible with the released material is transferred, stored, or disposed of in areas of the facility affected by the incident until cleanup procedures are completed.

INTERNAL FACILITY EMERGENCY COMMUNICATIONS OR ALARM NOTIFICATION WILL OCCUR VIA: (Check all that apply) C1.

☒ 1. VERBAL WARNINGS; ☐ 2. PUBLIC ADDRESS OR INTERCOM SYSTEM; ☒ 3. TELEPHONE;
☐ 4. PAGERS; ☐ 5. ALARM SYSTEM; ☐ 6. PORTABLE RADIO

NOTIFICATIONS TO NEIGHBORING FACILITIES THAT MAY BE AFFECTED BY AN OFF-SITE RELEASE WILL OCCUR BY: (Check all that apply) C2.

☒ 1. VERBAL WARNINGS; ☐ 2. PUBLIC ADDRESS OR INTERCOM SYSTEM; ☒ 3. TELEPHONE;
☐ 4. PAGERS; ☐ 5. ALARM SYSTEM; ☐ 6. PORTABLE RADIO

EMERGENCY RESPONSE PHONE NUMBERS:

AMBULANCE, FIRE, POLICE AND CHP	9-1-1
CALIFORNIA EMERGENCY MANAGEMENT AGENCY (CAL/EMA)	(800) 852-7550
NATIONAL RESPONSE CENTER (NRC)	(800) 424-8802
POISON CONTROL CENTER	(800) 222-1222
LOCAL UNIFIED PROGRAM AGENCY (UPA/CUPA) Kern County Environmental Health	(661) 862-8740 C3.
OTHER (Specify): 24 hour number CUPA 661-549-9927/661-549-9885 C4.	C5.
NEAREST MEDICAL FACILITY / HOSPITAL NAME: Mercy Southwest Hospital C6.	(661) 633-6000 C7.

AGENCY NOTIFICATION PHONE NUMBERS:

CALIFORNIA DEPT. OF TOXIC SUBSTANCES CONTROL (DTSC)	(916) 255-3545
REGIONAL WATER QUALITY CONTROL BOARD	(559) 445-5116 C8.
U.S. ENVIRONMENTAL PROTECTION AGENCY (US EPA)	(800) 300-2193
CALIFORNIA DEPT OF FISH AND GAME (DFG)	(916) 358-2900
U.S. COAST GUARD	(202) 267-2180
CAL/OSHA	(916) 263-2800
STATE FIRE MARSHAL	(916) 445-8200
OTHER (Specify): C9.	C10.
OTHER (Specify): C11.	C12.

D. EMERGENCY CONTAINMENT AND CLEANUP PROCEDURES

SPILL PREVENTION, CONTAINMENT, AND CLEANUP PROCEDURES: (Check all boxes that apply to indicate your procedures for containing spills, releases, fires or explosions; and. preventing and mitigating associated harm to persons, property, and the environment.)

D1.

- [x] 1. MONITOR FOR LEAKS, RUPTURES, PRESSURE BUILD-UP, ETC.;
- [x] 2. PROVIDE STRUCTURAL PHYSICAL BARRIERS (e.g., Portable spill containment walls);
- [x] 3. PROVIDE ABSORBENT PHYSICAL BARRIERS (e.g., Pads, pigs, pillows);
- [x] 4. COVER OR BLOCK FLOOR AND/ OR STORM DRAINS;
- [x] 5. BUILT-IN BERM IN WORK / STORAGE AREA;
- [ ] 6. AUTOMATIC FIRE SUPPRESSION SYSTEM;
- [x] 7. ELIMINATE SOURCES OF IGNITION FOR FLAMMABLE HAZARDS (e.g. Flammable liquids, Propane);
- [x] 8. STOP PROCESSES AND/OR OPERATIONS;
- [x] 9. AUTOMATIC / ELECTRONIC EQUIPMENT SHUT-OFF SYSTEM;
- [x] 10. SHUT-OFF WATER, GAS, ELECTRICAL UTILITIES AS APPROPRIATE;
- [x] 11. CALL 9-1-1 FOR PUBLIC EMERGENCY RESPONDER ASSISTANCE / MEDICAL AID;
- [x] 12. NOTIFY AND EVACUATE PERSONS IN ALL THREATENED AREAS;
- [x] 13. ACCOUNT FOR EVACUATED PERSONS IMMEDIATELY AFTER EVACUATION CALL;
- [x] 14. PROVIDE PROTECTIVE EQUIPMENT FOR ON-SITE RESPONSE TEAM;
- [x] 15. REMOVE OR ISOLATE CONTAINERS / AREA AS APPROPRIATE;
- [x] 16. HIRE LICENSED HAZARDOUS WASTE CONTRACTOR;
- [x] 17. USE ABSORBENT MATERIAL FOR SPILLS WITH SUBSEQUENT PROPER LABELING, STORAGE, AND HAZARDOUS WASTE DISPOSAL AS APPROPRIATE;
- [x] 18. SUCTION USING SHOP VACUUM WITH SUBSEQUENT PROPER LABELING, STORAGE, AND HAZARDOUS WASTE DISPOSAL AS APPROPRIATE;
- [x] 19. WASH / DECONTAMINATE EQUIPMENT W/ CONTAINMENT and DISPOSAL OF EFFLUENT / RINSATE AS HAZARDOUS WASTE;
- [x] 20. PROVIDE SAFE TEMPORARY STORAGE OF EMERGENCY-GENERATED WASTES;
- [ ] 21. OTHER (Specify):

D2.

E. FACILITY EVACUATION

THE FOLLOWING ALARM SIGNAL(S) WILL BE USED TO BEGIN EVACUATION OF THE FACILITY (CHECK ALL THAT APPLY): E1.

- [ ] 1. BELLS;
- [ ] 2. HORNS/SIRENS;
- [x] 3. VERBAL (I.E., SHOUTING);
- [ ] 4. OTHER (Specify):

E2.

THE FOLLOWING LOCATION(S) IS/ARE EVACUEE EMERGENCY ASSEMBLY AREA(S) (i.e., Front parking lot, specific street corner, etc.) E3.

Facility entrance/open space east of facility

Note: The Emergency Coordinator must account for all on site employees and/or site visitors after evacuation.

- [x] EVACUATION ROUTE MAP(S) POSTED AS REQUIRED

E4.

Note: The map(s) must show primary and alternate evacuation routes, emergency exits, and primary and alternate staging areas, and must be prominently posted throughout the facility in locations where it will be visible to employees and visitors.

F. ARRANGEMENTS FOR EMERGENCY SERVICES

Explanation of Requirement: Advance arrangements with local fire and police departments, hospitals, and/or emergency services contractors should be made as appropriate for your facility. You may determine that such arrangements are not necessary.

ADVANCE ARRANGEMENTS FOR LOCAL EMERGENCY SERVICES (Check one of the following) F1.

- [x] 1. HAVE BEEN DETERMINED NOT NECESSARY; *or*
- [ ] 2. THE FOLLOWING ARRANGEMENTS HAVE BEEN MADE (Specify):

F2.

G. EMERGENCY EQUIPMENT

Check all boxes that apply to list emergency response equipment available at the facility and identify the location(s) where the equipment is kept and the equipment's capability, if applicable. [e.g., ☒ CHEMICAL PROTECTIVE GLOVES | Spill response kit | One time use, Oil & solvent resistant only.]

TYPE	EQUIPMENT AVAILABLE G1.	LOCATION	CAPABILITY *(If applicable)*
Safety and First Aid	1. ☐ CHEMICAL PROTECTIVE SUITS, APRONS, OR VESTS	G2.	G3.
	2. ☒ CHEMICAL PROTECTIVE GLOVES	G4. Personal	G5.
	3. ☒ CHEMICAL PROTECTIVE BOOTS	G6. Personal	G7.
	4. ☒ SAFETY GLASSES / GOGGLES / SHIELDS	G8. Personal	G9.
	5. ☒ HARD HATS	G10. Personal	G11.
	6. ☒ CARTRIDGE RESPIRATORS	G12. Personal	G13.
	7. ☐ SELF-CONTAINED BREATHING APPARATUS (SCBA)	G14.	G15.
	8. ☒ FIRST AID KITS / STATIONS	G16. Office	G17.
	9. ☐ PLUMBED EYEWASH FOUNTAIN / SHOWER	G18.	G19.
	10. ☐ PORTABLE EYEWASH KITS	G20.	G21.
	11. ☐ OTHER	G22.	G23.
	12. ☐ OTHER	G24.	G25.
Fire Fighting	13. ☒ PORTABLE FIRE EXTINGUISHERS	G26. Facility, Lab and Personal	G27.
	14. ☐ FIXED FIRE SYSTEMS / SPRINKLERS / FIRE HOSES	G28.	G29.
	15. ☐ FIRE ALARM BOXES OR STATIONS	G30.	G31.
	16. ☐ OTHER	G32.	G33.
Spill Control and Clean-Up	17. ☒ ALL-IN-ONE SPILL KIT	G34. Personal	G35.
	18. ☒ ABSORBENT MATERIAL	G36. Personal	G37.
	19. ☐ CONTAINER FOR USED ABSORBENT	G38.	G39.
	20. ☒ BERMING / DIKING EQUIPMENT	G40. Around all tanks	G41.
	21. ☒ BROOM	G42. Personal; located in office	G43.
	22. ☒ SHOVEL	G44. Personal; located in office	G45.
	23. ☐ SHOP VAC	G46.	G47.
	24. ☐ EXHAUST HOOD	G48.	G49.
	25. ☐ EMERGENCY SUMP / HOLDING TANK	G50.	G51.
	26. ☐ CHEMICAL NEUTRALIZERS	G52.	G53.
	27. ☐ GAS CYLINDER LEAK REPAIR KIT	G54.	G55.
	28. ☐ SPILL OVERPACK DRUMS	G56.	G57.
	29. ☐ OTHER	G58.	G59.
Communi-cations and Alarm Systems	30. ☒ TELEPHONES (Includes cellular)	G60. Personal/Lab	G61.
	31. ☐ INTERCOM / PA SYSTEM	G62.	G63.
	32. ☐ PORTABLE RADIOS	G64.	G65.
	33. ☐ AUTOMATIC ALARM CHEMICAL MONITORING EQUIPMENT	G66.	G67.
Other	34. ☐ OTHER	G68.	G69.
	35. ☐ OTHER	G70.	G71.

H. EARTHQUAKE VULNERABILITY

Identify areas of the facility that are vulnerable to hazardous materials releases / spills due to earthquake-related motion. These areas require immediate isolation and inspection.

VULNERABLE AREAS: (Check all that apply)	H1.	LOCATIONS (e.g., shop, outdoor shed, forensic lab)	
☐ 1. HAZARDOUS MATERIALS / WASTE STORAGE AREA			H2.
☒ 2. PROCESS LINES / PIPING		Tank area and east of tanks.	H3.
☐ 3. LABORATORY			H4.
☐ 4. WASTE TREATMENT AREA			H5.

Identify mechanical systems vulnerable to releases / spills due to earthquake-related motion. These systems require immediate isolation and inspection.

VULNERABLE SYSTEMS: (Check all that apply)	H6.	LOCATIONS	
☐ 1. SHELVES, CABINETS AND RACKS			H7.
☒ 2. TANKS (EMERGENCY SHUTOFF)		Tank Area	H8.
☐ 3. PORTABLE GAS CYLINDERS			H9.
☒ 4. EMERGENCY SHUTOFF AND/OR UTILITY VALVES		Tank Area	H10.
☐ 5. SPRINKLER SYSTEMS			H11.
☐ 6. STATIONARY PRESSURIZED CONTAINERS (e.g., Propane dispensing tank)			H12.

I. EMPLOYEE TRAINING

Explanation of Requirement: Employee training is required for all employees handling hazardous materials and hazardous wastes in day-to-day or clean-up operations including volunteers and/or contractors. Training must be:

- Provided within 6 months for new hires;
- Amended as necessary prior to change in process or work assignment;
- Given upon modification to the Emergency Response / Contingency Plan, and updated/refreshed annually for all employees.

Required content includes all of the following:

- Material Safety Data Sheets;
- Hazard communication related to health and safety;
- Methods for safe handling of hazardous substances;
- Fire hazards of materials / processes;
- Conditions likely to worsen emergencies;
- Coordination of emergency response;
- Notification procedures;
- Applicable laws and regulations;
- Communication and alarm systems;
- Personal protective equipment;
- Use of emergency response equipment (e.g. Fire extinguishers, respirators, etc.);
- Decontamination procedures;
- Evacuation procedures;
- Control and containment procedures;
- UST monitoring system equipment and procedures (if applicable).

INDICATE HOW EMPLOYEE TRAINING PROGRAM IS ADMINISTERED (Check all that apply) I1.

☒ 1. FORMAL CLASSROOM; ☒ 2. VIDEOS; ☒ 3. SAFETY / TAILGATE MEETINGS;

☒ 4. STUDY GUIDES / MANUALS (Specify): Operations & Maintenance Manual; Emergency Response Plan; Safety Manual I2.

☐ 5. OTHER (Specify): _____ I3.

☐ 6. NOT APPLICABLE BECAUSE FACILITY HAS NO EMPLOYEES

Large Quantity Generator (LQG) Training Records: Large quantity hazardous waste generators (i.e., who generate more than 270 gallons/1,000 kilograms of hazardous waste per month) must retain written documentation of employee hazardous waste management training sessions which includes:

- A written outline/agenda of the type and amount of both introductory and continuing training that will be given to persons filling each job position having responsibility for the management of hazardous waste (e.g., labeling, manifesting, compliance with accumulation time limits, etc.).
- The name, job title, and date of training for each hazardous waste management training session given to an employee filling such a job position; and
- A written job description for each of the above job positions that describes job duties and the skills, education, or other qualifications required of personnel assigned to the position.
- Current employee training records must be retained until closure of the facility.
- Former employee training records must be retained at least three years after termination of employment.

J. LIST OF ATTACHMENTS

(Check one of the following) J1.

☒ 1. NO ATTACHMENTS ARE REQUIRED; *or*

☐ 2. THE FOLLOWING DOCUMENTS ARE ATTACHED: J2.

K. SIGNATURE / CERTIFICATION

Certification: Based on my inquiry of those individuals responsible for obtaining the information, I certify under penalty of law that I have personally examined and am familiar with the information submitted and believe the information is true, accurate, and complete, and that a copy is available on site.

SIGNATURE OF OWNER/OPERATOR	DATE SIGNED K1.
Amanda R Herd	2/21/2022
NAME OF SIGNER (print) K2.	TITLE OF SIGNER K3.
Amanda Herd	HSE Specialist I

2022 SAFETY TRAINING MATRIX

Course	Reoccurrence
Access to Employee Exposure & Medical Records	Annually
Accident and Injury Reporting	2 years
Active Shooter - Run Hide Fight	Once
Asbestos Awareness Training	Annually
Atmospheric Monitoring - Equipment/Testing	Annually
Back Safety	2 years
Benzene Awareness Training	Annually
Bloodborne Pathogens	2 years
Code of Business Conduct	Annually
Confined Space Training	3 years
Control of Hazardous Energy (LOTO)	Annually
DOT Federal Motor Carrier Safety Regulations FMSCA	Annually
Drug & Alcohol Awareness	Once
Electrical (Safe Work Practices) Training	3 years
Excavation, Trenching, and Shoring (General Awareness)	3 years
Fall Protection Training	2 years
Fire Extinguisher Training	2 years
First Aid/CPR/AED/Bloodborne Pathogens	2 years
First Responder Media Training	Annually
H2S	Annually
Hand and Power Tool Safety Training	Once
Harassment Training - Employee	Annually
Hazard Communication for the Employee	Annually
Hazardous Material Transportation Introduction	3 years
Hearing Conservation Training	Annually
Heat Illness Prevention	Annually
Ladder Safety	3 years
Lead Awareness	Annually
NORM (Radiation)	Once
Office Hazard Recognition and Response	3 years
Permits (including JSA, Confined Space, Hot Work, Excavation and LOTO)	Annually
Personal Electronic Devices	Annually
Personal Protective Equipment - Basics (Introductory) Training	3 years
Pipeline/Facility Security	Annually
Respiratory Protection Training	Annually
Response Plan (Emergency Action Plan)	Annually
Safe Driving Skills	Annually
Safe Writing	2 years
Smith System Driving	5 years
Scaffold Safety Training	Once
SPCC Plan Awareness	Annually
Storage of Flammable & Combustible Liquids Storing & Handling LPG	3 years
TTX - Table Top Exercise	Annually
Walking Working Surfaces	2 years

APPENDIX G
INTERVIEW FORMS

ASTM 1527-13 or 1527-21 Phase I ESA
USER QUESTIONAIRE

Subject Property Address/Location: North and South Belridge Oil Fields, Centered on 35.501525°, -119.751895° (World Geodetic System of 1984 [WGS 84]).

Type of Property: Developed Oil and Gas Field

Type of Transaction (property acquisition, refinance, lease, etc.): N/A

Why is a Phase I ESA required: The Phase I ESA is prepared in support of a Carbon Capture and Storage Project

Identification of all reliant parties: _____

The User must provide the following information (if available) to the *environmental professional*. Failure to provide this information could result in a determination that *"all appropriate inquiry"* is not complete.

1) Environmental liens that are filed or recorded against the Subject Property (40 C.F.R. § 312.25).
Did a search of land title records (or judicial records where appropriate) identify any environmental liens filed or recorded against the Subject Property under federal, tribal, state, or local law?

A search of land title records did not identify any environmental liens filed or recorded against the property under federal, tribal, state, or local law.

2) Activity and use limitations that are in place on the Subject Property or that have been filed or recorded against the Subject Property. Did a search of land title records (or judicial records where appropriate, see Note 1 above) identify any AULs, such as engineering controls, land use restrictions or institutional controls that are in place at the Subject Property and/or have been filed or recorded against the Subject Property under federal, tribal, state or local law?

A search of land title records did not identify any Activity and Use Limitations (AULs) that have been filed/recorded against the Property or that are in place on the Property, under federal, tribal, state or local law.

3) Specialized knowledge or experience of the person seeking to qualify for the LLP (40 C.F.R. § 312.28).
Do you have any specialized knowledge or experience related to the Subject Property or nearby properties? For example, are you involved in the same line of business as the current or former occupants of the Subject Property or an adjoining property so that you would have specialized knowledge of the chemicals and processes used by this type of business?

No.

4) Relationship of the purchase price to the fair market value of the Subject Property if it were not contaminated (40 C.F.R. § 312.29). Does the purchase price being paid for this Subject Property reasonably reflect the fair market value of the property? If you conclude that there is a difference, have you considered whether the lower purchase price is because contamination is known or believed to be present at the Subject Property?

N/A.

5) Commonly known or reasonably ascertainable information about the Subject Property (40 C.F.R. § 312.30).
Are you aware of commonly known or reasonably ascertainable information about the Subject Property that would help the environmental professional to identify conditions indicative of releases or threatened releases? For example,

- Do you know the past uses of the Subject Property?

  This has been an active oilfield for over 100 years.

- Do you know of specific chemicals that are present or once were present at the Subject Property?

  We do have knowledge of the specific chemicals that have been and are currently present at the subject property. Mostly associated with extraction of Oil and Gas

- Do you know of spills or other chemical releases that have taken place at the Subject Property?

  All spill information is available at CalOES website.

- Do you know of any environmental cleanups that have taken place at the Subject Property?

  If any cleanups have taken place, they will be linked to the associated OES report.

6) The degree of obviousness of the presence or likely presence of contamination at the Subject Property, and the ability to detect the contamination by appropriate investigation (40 C.F.R. § 312.31).
Based on your knowledge and experience related to the Subject Property, are there any obvious indicators that point to the presence or likely presence of releases at the Subject Property?

We are not aware of any areas that have not already been identified by the Phase I ESA report.

Signature

Environmental Manager
Title

Keri D. Cimarolli
Name of User Completing Form (print)

3/22/2023
Date

F.2 Quantitative Risk Assessment (including CO2 Dispersion Modeling)

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CarbonFrontier
Carbon Capture and
Sequestration Project
Aera Energy LLC

Public Impact
Quantitative Risk Assessment

August 2023

PREPARED FOR:

Aera Energy LLC

Bakersfield, California

PREPARED BY:

Dixon Risk Consulting

Solvang, California

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EXECUTIVE SUMMARY

Aera Energy LLC (Aera) is proposing to develop a Carbon Capture and Sequestration (CCS) Project at their Belridge facility in western Kern County, California. The CarbonFrontier CCS Project will capture carbon dioxide (CO_2) from existing sources in the South Belridge oil field and transport the CO_2 by pipeline to the North Belridge oil field for geologic sequestration.

A Quantitative Risk Assessment (QRA) has been conducted to assess the potential for acute hazards to the public and the environment associated with the above ground Project facilities. The following activities have been assessed:

- CO_2 capture and compression from existing produced gas streams and flue gas emissions from existing stationary sources.
- Transport of dense phase CO_2 through an in-field pipeline to the North Belridge oil field for sequestration. The main pipeline will be approximately 10-miles in length, with branches to the injection wells.
- Injection of dense phase CO_2 into a depleted oil reservoir at over 8,000 feet deep for permanent geologic sequestration, utilizing 9 injection wells.
- Delivery of hazardous materials.

Loss of containment events from these activities may result in acute public or environmental hazards. A release of CO_2 from underground geologic storage may occur due to migration to the surface via an abandoned well, fault or fracture. The potential for migration to the surface has also been assessed in this analysis, although this will generally result in a slow dissipated release and is unlikely to be acutely hazardous. Extensive monitoring of the injection wells, dedicated monitoring wells, air, soil and vegetation sampling is proposed to identify any potential failures.

Potential hazardous material impacts to the public have been quantified. For any given release, the number of people potentially exposed will depend on the size of the release, time of day, weather conditions, and the likelihood that the public are in the area. The risks have been calculated by estimating the likelihood and consequences of potential release scenarios. Total risks to the public have been summated to calculate the likelihood of exposure to a level of concern.

The overall hazards to the public from all proposed operations have been calculated for potential exposure to toxic levels of concern, potential injury and potential for serious harm or fatality as follows:

Release Source	Population Groups Exposed	Level of Concern	Potential for Significant Injury	Potential for Serious Harm or Fatality
		Likelihood	Likelihood	Likelihood
Produced Gas Transfer - Pipeline Rupture	Vehicles on Hwy-33	1 in 56,000 years	-	-
Carbon Capture and Compression	None	-	-	-
CO_2 Pipeline Transfer – Pipeline Rupture	Vehicles on Hwy-33 Agricultural workers Solar panel workers Berry and Team oil field workers	1 in 2,900 years	1 in 27,000 years	1 in 300,000 years
CO_2 Injection Wells	Team Operating oil field workers	1 in 69 million years	-	-
Leakage of CO_2 from Sequestration Reservoir	None	-	-	-
Amine Truck Transportation	50-mile road traffic from Bakersfield	1 in 92,000 years	-	-
Sulfuric Acid Truck Transportation	50-mile road traffic from Bakersfield	1 in 59,000 years	1 in 250,000 years	1 in 4.6 million years
Total Risk of Public Exposure		**1 in 2,700 years**	**1 in 24,000 years**	**1 in 190,000 years**

The primary source of risk is the CO_2 transfer pipeline from South Belridge carbon capture facilities to North Belridge geologic sequestration. This contributes to 88% of the aggregate risk of exposure to a level of concern for all public populations in the vicinity.

The combined likelihood of public exposure to a concentration that may cause public concern is 1 in 2,700 years.

Potential risks to the public have also been calculated in terms of individual risk and the risk to society as a whole. The levels of risk have been compared to international criteria for tolerability of hazardous material risks from industrial activities. Risks to the public associated with the CarbonFrontier project are within all established criteria.

1. INTRODUCTION

1.1 Background

Aera Energy LLC (Aera) is proposing to develop a Carbon Capture and Sequestration (CCS) Project (Project) at their Belridge facility in western Kern County, California. The CarbonFrontier CCS Project will capture carbon dioxide (CO_2) from existing sources in the South Belridge oil field and transport the CO_2 by pipeline to the North Belridge oil field for geologic sequestration. The Project is located within Aera's oil field boundary.

The Project is subject to operating permits and environmental review, which includes, but is not limited to, the submittal of applications to Kern County Planning and Natural Resources Department and the US Environmental Protection Agency (EPA). These applications require the assessment of risks associated with the Project, including potentially adverse impacts on the environment, health, and safety.

Aera has requested that Dixon Risk Consulting (DRC) conduct a Quantitative Risk Assessment (QRA) to assess the potential for acute hazards to the public and the environment associated with the proposed Project. The QRA will address the likelihood of release and potential impacts associated with safety and environment, in order to assess the risk acceptability.

1.2 Scope of Work

This QRA assesses the acutely hazardous material risks to the public and environment associated with a potential loss of containment event for the proposed CarbonFrontier CCS Project. Carbon dioxide is the primary hazardous material of concern. CO_2 is a naturally occurring atmospheric gas, normally present in air at about 400 parts per million (ppm). In order to sequester CO_2 and store permanently underground in a depleted oil reservoir, CO_2 must be concentrated, treated, compressed, transported and injected deep underground. CO_2 will be compressed into a high-pressure dense phase fluid that exhibits properties between that of a liquid and a gas. On release, multiple phase changes occur causing rapid cooling of the gas and possible solid dry ice formation. The cold heavier than air gas may cause hazards to personnel or the environment as it spreads and dissipates.

This QRA is primarily concerned with acute hazards to the public on neighboring agricultural facilities, travelling on major roads, and neighboring non-Aera oil production workers. An acute risk is an immediate hazard resulting from a short-term event, such as an exposure to a toxic substance. Potential release events may occur due to equipment or operational failures that do not include planned releases such as blowdown events for maintenance.

The following activities have been assessed:

- CO_2 capture and compression from existing Tulare and Diatomite reservoir produced gas streams (Pre-Combustion), at a future site near Gas Plant 32.

- Pipeline transfer of Tulare produced gas from South of Seventh Standard Road to the gas treatment facility at Sulferox Plant 32 (SOX 32), then to the CO_2 Pre-Combustion capture facility.
- CO_2 capture and compression from flue gas emissions from existing stationary sources (Post-Combustion) within the South Belridge oil field. The capture sources are currently proposed to be at the Co-Generation Facility (Cogen) 32 and Steam Generator sites 2868 and 2972.
- Transport of the dense phase CO_2 through pipelines to the North Belridge oil field for injection into dedicated injection wells. The main pipeline will be approximately 10-miles in length, with branches to the injection wells.
- Injection of dense phase CO_2 into Underground Injection Control (UIC) EPA Class VI geologic sequestration wells.
- Bulk delivery of amine solvent and storage.
- Bulk delivery of sulfuric acid and storage.

Loss of containment events from these activities may result in acute public or environmental hazards. A release of CO_2 from underground geologic storage may occur due to migration to the surface via an abandoned well, fault or fracture. The potential for migration to the surface has also been assessed in this analysis, although this will generally result in a slow dissipated release and is unlikely to be acutely hazardous. Extensive monitoring of the injection wells, dedicated monitoring wells, air, soil and vegetation sampling is proposed to identify any potential failures.

Potential hazards to the public associated with acute exposure to hazardous materials have been assessed by calculating both the risk to individuals, and the risk to society as a whole. The risks have been determined by combining the potential severity and likelihood for three selected levels of concern. The levels range from minor injury, to potential fatality.

This QRA has been developed from information provided by Aera for the preliminary design as of October 2022. It has been assumed that the proposed carbon capture facilities are operating at full capacity of 2 million metric tons (MM mt) of CO_2 per year for approximately 20 years.

This scope of work is limited to the CarbonFrontier CCS facilities in the operational phase of the Project. The QRA does not include risks associated with construction or post injection phases of the project. Potential risks to Aera and Aera contract personnel have also not been included in this analysis.

Personnel and environmental hazards associated with long-term fugitive emissions have not been addressed in this analysis. Occupational accidents and other external events are also excluded.

1.3 Quantitative Risk Assessment Methodology

Quantitative Risk Assessment is an established methodology to quantify the risk of potential events, by estimating the likelihood and consequence of these events. Failures can include catastrophic rupture events which may result in a rapid release lasting minutes, or longer duration leak event lasting an hour or more. The dispersion of a hazardous release in the air was estimated through modeling, as described below in Section 5.

The risk to public personnel and the environment has been assessed using the following steps:

- Identify potential release scenarios.
- Assess the causes and frequency of historical incidents.
- Quantify the likelihood of these scenarios using published failure rate data.
- Determine the consequences and potential impact to public personnel and the environment.
- Combine the likelihood and consequences to calculate the risk to individuals and society.
- Assess the significance of the risk of injury, fatality or environmental harm against published risk tolerability criteria.

QRA provides an estimate of the risks, which tends to err on the side of conservatism. The approach was to make reasonable assumptions on the hazards, likelihood of failure and potential impacts of a release. In the process of QRA, numerous assumptions must be made, based on best available information. Where appropriate, sources of these assumptions, estimates and reasoning have been described.

2. PROJECT DESCRIPTION

2.1 Carbon Sequestration Project Overview

The proposed CarbonFrontier CCS Project will capture CO_2 in the South Belridge oil field from existing sources within the oil production operation. Captured CO_2 will be compressed, dehydrated, pumped then transported by an in-field pipeline to the sequestration site in North Belridge. The compressed CO_2 will be injected into a depleted oil reservoir at over 8,000 feet deep for permanent geologic sequestration. Locations of the proposed Project facilities are shown in Figure 2.1, and a preliminary block flow diagram in Figure 2.2.

It is anticipated that the proposed Project will sequester roughly 2 million metric tons (MM mt) of CO_2 per year beginning in 2027, for a period of approximately 20 years.

The South Belridge and North Belridge oil fields are contiguous, and cover an area approximately 13 miles long and three miles wide. Aera is the primary operator within both oil fields.

2.1.1 Source Streams

It is proposed to capture CO_2 from two types of existing sources; from produced natural gas pre-combustion, and from flue gas emissions post-combustion.

Pre-Combustion

This involves separation of CO_2 from existing produced natural gas streams, prior to combustion for steam generation. This source will extract approximately 0.2 MM mt per year of CO_2.

The Belridge Field has two natural gas streams associated with oil production which are proposed for CO_2 capture:

- Diatomite produced gas is associated with the production of light oil from the Diatomite formation. The gas has an average CO_2 content of approximately 36%. The gas is gathered at area compressor stations and routed by pipeline to Section 32, where it is treated to remove hydrogen sulfide (H_2S) in SOX 32.
- Tulare produced gas is associated with the production of heavy oil from the Tulare Sands. The CO_2 content is approximately 75%, and the H_2S content approximately 3,000 ppm. The gas is currently gathered, treated via sulferox to remove H_2S, and co-fired in steam generators for disposal. It is proposed to transfer the Tulare gas to Section 32 for treatment at Sulferox Plant 32. Tulare gas will be combined with the Diatomite gas gathered south of Seventh Standard Road (SOSS), compressed at the Del Sur compressor station, and transferred via pipeline to SOX 32. The pipeline is assumed to be an existing 16-inch diameter line, currently used for Diatomite gas, which is primarily located aboveground. Alternatively, a new 12 to 16-inch diameter pipeline will constructed primarily aboveground for transfer to the SOX 3-2 facility. Pipeline conditions are shown below, and the combined flow composition shown in Table 2.1.

Del Sur Produced Gas Transfer Line	Line Conditions		Line Length	
	Pressure	Temp	ft	miles
16-inch line from Del Sur Compressor Station to SOX 32	170 psig	100°F	18,800	3.6

psig = pounds per square inch gauge

Post-Combustion

CO_2 will be extracted from flue gas emissions at three existing stationary sources:

- The Co-Generation facility next to Gas Plant 32,
- Steam generator site 2868, and;
- Steam generator site 2972.

The generator sites each have ten 85 million British thermal unit (MMBtu) steam generators. These three sources will capture up to approximately 1.4 MM mt per year of CO_2

2.1.2 Carbon Capture Facilities

CO_2 capture and compression equipment will be constructed adjacent to four existing facilities within the developed South Belridge oil field.

It has been assumed that the carbon capture facilities will use solvent based amine absorption technology. This is established technology widely used in industry to remove CO_2 and H_2S from oil production natural gas, and refinery gas and liquid streams. The most commonly used amines are the alkanolamines; monoethanolamine (MEA), diethanolamine (DEA), and methyl diethanolamine (MDEA). Proprietary solvents have been developed with improved performance over traditional MEA, which may offer reduced regeneration energy, better performance for flue gas streams, and reduced solvent loss. The final choice of chemical for amine absorption has not been determined, although the general principles are the same for all absorption processes available.

The proposed design for the CO_2 capture facilities comprises a pre-scrubber, a CO_2 absorber column, a CO_2 stripper column, and associated pumps and heat exchangers. Process conditions and sizes of the vessels have been estimated to conduct the hazard analysis.

An example of an amine absorption carbon capture process flow diagram is shown in Figure 2.3. The gas stream for CO_2 capture enters the CO_2 absorber at the bottom of the column at about 100°F and 110 psig. Lean amine solution at about 30% MEA is pumped into the top of the tower. CO_2 is absorbed in the solvent, and the remaining gases leave from the top of the tower. The CO_2 rich solvent passes out of the bottom of the tower and then is transferred via a buffer vessel and heat exchanger to the amine regenerator tower. A reboiler at the bottom of the regenerator tower heats the solvent to reverse the absorption reaction. CO_2 is stripped from the solvent at about 225°F and 10 psig. The hot lean solvent is recycled back through heat exchangers and a cooler before being pumped back to the CO_2 absorber. The captured CO_2 stream passes to the compression and dehydration section.

2.1.3 CO_2 Compression and Dehydration

The captured CO_2 will be compressed and water removed. At the three post-combustion capture facilities, residual oxygen may also need to be removed.

It has been assumed that the initial compression stages use a centrifugal compressor, and free water is separated out through a series of compression and cooling stages. CO_2 will then be processed through a triethylene glycol (TEG) dehydration unit to reduce the water content to less than 258 ppm concentration. At the three post-combustion capture facilities, residual oxygen will be removed using an oxygen scavenger to less than 50 ppm concentration. The dried dense phase CO_2 will pass through a buffer drum, and then pumped to the CO_2 transfer pipeline at about 1,700 psig and 100°F.

At the North Belridge sequestration field, the CO_2 pressure may be increased as the reservoir pressure increases. A booster pump may be installed at Compressor Station 49 (CS 49) to increase the injection pressure.

2.1.4 CO_2 Pipeline Transport

The CO_2 transfer pipeline from the South Belridge capture facilities to North Belridge sequestration field will run primarily above ground across developed sections, utilizing existing infield pipeline routes. The main pipeline is assumed to be 12-inches in diameter, 10-miles in length, and operate at a pressure of 1,700 psig and temperature of 100°F. Distribution pipelines from CS 49 are assumed to be 12-inches, and lateral lines to the individual injection wells are assumed to be 6-inches in diameter. Lengths have been estimated as follows:

CO_2 Transfer Line	Line Conditions		Line Length	
	Pressure	Temp	ft	miles
4 x 8-inch lines from Pre-C and Post-C to transfer pipeline	1,700 psig	100°F	3,150	0.6
12-inch CO_2 transfer line to CS 49	1,700 psig	100°F	53,400	10.1
12-inch CO_2 distribution lines from CS 49 to sequestration field	1,700 psig	100°F	12,200	2.3
9 x 6-inch CO_2 lateral lines sequestration injection wells	1,700 psig	100°F	6,900	1.3
Total Length			**76,000**	**14.4**

The pipeline is assumed to be high strength carbon steel, designed to ANSI 1500 Class. A Supervisory Control and Data Acquisition (SCADA) pipeline monitoring system will be used for leak detection. The SCADA system shuts down the pipeline if conditions are detected outside pre-set pressure and flow conditions, and alarms will sound alerting to exceedance conditions.

Where the pipeline crosses a road, the pipeline will be within a secondary pipeline, protected from contact with soil. There are approximately 32 pipeline road crossings for a total length of about 800 ft.

As the reservoir pressure increases, it may be necessary to add a booster pump prior to injection, which would be located at CS 49, as shown on Figure 2.6.

2.1.5 CO_2 Sequestration

The proposed sequestration injection will be into the 64 Zone sandstones of the Lower Temblor Formation. These sands have produced oil and gas for almost 100 years and have a large, depleted storage capacity, numerous thick confining layers, high porosity and permeability. It is proposed to cease oil and gas production in the 64 Zone, and utilize the depleted reservoir for dedicated CO_2 sequestration. There are numerous wellbores available to repurpose for CO_2 injection. To repurpose the well, an entirely new CO_2 compatible casing string would be cemented to the surface within an existing wellbore. Wells not selected for injection or monitoring would be abandoned.

It is currently proposed to drill 4 new injection wells, and repurpose 5 existing wells, for a total of 9 injection wells. An additional 4 wells will be repurposed for monitoring. Up to four additional monitoring wells may also be constructed, either as repurposed oil wells and/or new wells, pending further evaluation.

Injection and monitoring wells will be equipped with downhole devices and equipment to evaluate external mechanical integrity of the wells and monitor growth of the CO_2 plume as it dissipates within the sequestration layer. Monitoring equipment will include pressure and temperature gauges and may also include acoustic sensors.

Four existing wells are proposed to monitor the CO_2 injection operations and ensure that the CO_2 injection remains within the 64 Zone reservoir. Monitoring wells neither produce nor inject fluids. Monitoring wells would be used to monitor temperature, pressure, fluid levels, acoustic signals, and for the collection of fluid and gas samples.

As part of the proposed Project, all wells that penetrate the confining zone into the proposed sequestration layer or deeper have been identified. The maximum extent of the plume, or pressure front, which may be created by the injected CO_2 as it dissipates within the sequestration layer has been defined by model simulations using Aera geological data sets and seismic surveys. The below ground area within which the plume may influence is called the Aera of Review (AoR). Within the AoR a total of 111 wells have been identified. Of these wells, 41 are operational, and 70 have been previously abandoned. The legacy abandoned wells have been assessed to verify all wells in the AoR are properly abandoned and ensure the integrity of abandoned wells for CO_2 sequestration. Up to 40 wells have been identified as requiring corrective action, and approximately 40 operational wells that are not to be reused for the proposed Project will be abandoned and plugged.

The EPA regulates the underground injection of fluids through the UIC Program, to ensure the safety of underground sources of drinking water. The EPA established a separate class of wells, UIC Class VI, for dedicated CO_2 geologic sequestration. The EPA tailored Class VI program rules to address the permanent storage of CO_2 and ensure that wells are appropriately sited, constructed, tested, monitored, funded, and closed once injection activities are completed.

The proposed CO_2 injection wells would be regulated by EPA's UIC Class VI well regulations (40 CFR 1467 et seq.).

2.1.6 Amine Solvent Truck Deliveries and Storage

Amine for pre and post combustion are likely to use different solvents, requiring four separate unloading and storage facilities, two near Gas Plant 32, and one at each steam generator sites 2868 and 2972.

It is proposed to import concentrated amine using bulk chemical cargo tanks of up to 6,000 gallons (143 barrels). The concentrated solvent will be stored in 21,000 gallon (500 barrel) tanks. In addition there will be 4 holding tanks of 168,000 gallons (4,000 barrel), one for each capture facility, to contain the working inventory of diluted solvent. After the capture facilities are in operation, it is assumed there will be 21 deliveries of 3,000 gallons per facility per year.

2.1.7 Sulfuric Acid Truck Deliveries and Storage

Sulfuric acid is proposed to be used for water treatment at each of the four carbon capture facilities. Sulfuric acid at 96% concentration will be imported using bulk chemical cargo tanks. It has been estimated there will be up to 6 deliveries of 3,000 gallons per facility per year. The sulfuric acid will be stored in one 8,400 gallon (200 barrel) tank at each facility, which may be constructed of either carbon steel or high-density polyethylene (HDPE).

2.2 Project Vicinity

The South Belridge and North Belridge oil fields are located within the Central Valley portion of Kern County. The two oil fields are contiguous and located approximately seven miles southwest of the community of Lost Hills and west of State Highway 33. Together, these cover an area of approximately 13 miles long and three miles wide.

The proposed CO_2 capture facilities are located within the developed portion of the South Belridge oil field. The CO_2 transfer pipeline to North Belridge will run primarily above ground across developed sections of the field, primarily within existing infield pipeline routes. The proposed CO_2 sequestration field is located in the North Belridge oil field, which is predominately developed with oil and gas production infrastructure. None of the proposed Project facilities are within areas designated as prime farmland or farmland of statewide importance.

Land adjacent to the Project sites is utilized for oil and gas exploration and production, grazing, agriculture and a solar field associated with agricultural development. Aera is the primary oil production operator within both oil fields, with two sections partially operated by third parties.

2.3 Populations

Personnel in the vicinity of a hazardous release could potentially be exposed to harmful concentrations of materials. Public populations include workers in non-Aera operated oil production areas, workers at the solar farm to the west of Highway 33, occupants of vehicles on Highway 33, agricultural workers within the orchards to the east of Highway 33, and a small housing tract on Lost Hills Road, north of Lerdo Hwy. For any given release, the number of

personnel potentially exposed will depend on the size of the release, time of day, weather conditions, and the likelihood that personnel are in the area.

Residential and Sensitive Receptors

A small housing tract of about 30 properties is located on Lost Hills Road, north of Lerdo Hwy, approximately three miles east of the Project site. The closest residential areas and sensitive receptors are located approximately six miles northeast of the Project site, within the community of Lost Hills. This includes the Lost Hills Elementary School and A.M. Thomas Middle School.

Non-Aera Operated Oil Production

There are 2 areas within the Belridge oil production field operated by other production companies; Berry Petroleum Operating LLC in South Belridge Section 19, and Team Operating LLC in North Belridge Section 36, as shown on Figure 2.1. These operators are considered public personnel. The number of non-Aera employees has been estimated based on the density of operating wells in each area. Where there is a high density of wells, it is assumed there will be a greater number of personnel in the area. Typical oil production population densities per square mile have been applied as follows:

Oil Production Population Density	Average Personnel per square mile (per acre)	
	Day	Out of Hours
High	80 (0.13)	10 (0.015)
Medium	30 (0.05)	3 (0.005)
Low	3 (0.005)	0.3 (0.0005)
Very Low	0.5 (0.0008)	0.05 (0.00008)

Operator	Production Field Area	Population Density
Berry Petroleum	South Belridge Section 19, north 50% of section	Medium
Berry Petroleum	South Belridge Section 19, southwest 25% of section	Low
Team Operating	North Belridge Section 36, southwest 30% of section	Medium / Low

For the calculation of potential hazardous material exposures, it has been assumed that oil field workers and contractors are not equally distributed within the oil production areas. The following daytime personnel distribution has been applied:

2 workers in close proximity 50% of the time
4 workers in close proximity 50% of the time

Solar Panel Field

Within Section 7 of South Belridge, there is an area of solar panels owned by Wonderful Nut Farms, which covers about 35 acres. Workers visiting this area are considered public personnel. It has been estimated that an average of two workers will be in the area for 20% of the time during the day.

Highway 33 Population

Highway 33 runs to the east of the Belridge oil field, parallel to the proposed pipeline route, as shown in Figure 2.1. The road is used for vehicles travelling north and south, to or from Highway 46, and for access to the Belridge oil field and agricultural areas.

Annual average daily traffic (AADT) is the primary measure used to evaluate traffic volumes for regional highways. Average daily traffic is measured by the California Department of Transportation (CalTrans) on a sampling basis. CalTrans traffic data was obtained for the years 2016 through 2020[42], and then used to calculate an average hourly volume of traffic on the Highway 33 segment parallel to the Project pipeline as follows:

Average number of vehicles =	8520 per day
Average number of day vehicles =	639 per hour
Average number of night vehicles =	71 per hour
Average vehicle speed =	50 mph

The probability that a vehicle will be within any 100 feet section of the highway has been calculated as:

Day time probability of a vehicle =	0.24 per 100 feet
Night time probability of a vehicle =	0.03 per 100 feet

According to the US Department of Transportation (DOT) Bureau of Transportation Statistics[49], the average vehicle occupancy for all roads and all purpose of travel is 1.6. For work travel only, the average vehicle occupancy is about 1.2. It has been assumed that there is an average of 1.4 personnel in each vehicle due to the high number of work vehicles on Highway 33.

Agricultural Populations

The vicinity surrounding the North and South Belridge oil fields is primarily utilized for agriculture, or is undeveloped land. The closest active orchards are to the east of Highway 33 with agricultural workers a minimum of about 2,000 feet from the proposed CO_2 pipeline route.

The density of agricultural workers has been estimated from county records of the crops grown and typical daytime worker densities for these crops:

Citrus orchards =	25 workers per square mile all year
Pistachio / Almond orchards =	25 workers per square mile, 25% of the year
Pistachio / Almond orchards =	2 workers per square mile, 75% of the year

2.4 Environmental Receptors

Land next to CCS Project sites and along the pipeline route is dominated by intensive oil and gas extraction infrastructure, including; wells, well pads, pipelines and access roads. There are also areas of barren land, annual grassland and low growing dessert scrub.

Wildlife

Habitat in the Project vicinity is generally disturbed by oil and gas exploration and production. Surrounding properties include areas used for agriculture, grazing, and undeveloped private

land. Wildlife that could be impacted by a potentially hazardous release include; insects, reptiles, and small mammals such as rodents, squirrels and foxes.

Surface Aquatic Resources

Stantec Consulting Services Inc. (Stantec) conducted a delineation of aquatic resources for the CarbonFrontier CCS Project[41]. The survey area consisted of the proposed CCS Project facilities, including approximately 13-miles of CO_2 transfer and distribution pipeline routes, and a 500-feet buffer around these facilities. No perennial surface water resources were identified in the survey area. Two seasonal drainage creeks were identified that run from west to east of the pipeline route. To the south of the capture facilities, the Chico Martinez Creek runs from west to east, with no connectivity to navigable water. The ephemeral Chico Martinez Creek is dry most of the year, though it can overflow the creek banks after a heavy rainfall.

No surface aquatic resources were identified that may be at risk due to a potentially hazardous release.

Subsurface Water Resources

A subsurface release of CO_2 may have the potential to impact underground water resources. A search has been conducted for the Project to identify potential water resources.

No water supply wells were identified within the AoR. Two potential underground sources of drinking water (USDWs) were identified, with most of the area either dry or the water contains solid concentrations exceeding acceptable USDW limits. The lowermost potential USDW, is separated from the proposed injection zone by more than 7,000 feet of strata, including many confining zones. Therefore, the injection of CO_2 associated with the development of the proposed storage complex is not expected to impact the groundwater quality of potential USDWs.

2.5 Topography

The land surrounding the proposed capture sites and along the pipeline route is relatively flat. The land slopes gradually from the northwest sequestration field at about 680 feet above sea level, to the southeast portion of the Project area at Steam Generator site 2868 at about 580 feet. For most of the area surrounding Project facilities and the pipeline route, there is a gentle gradient of about 1 percent sloping from west to east.

There is one section of the CO_2 pipeline route that crosses a highly disturbed production area to the north-east of Section 32 facilities, in Section 33 and Section 28. Here there are areas where the gradient is up to 6 percent, and the variable contours may create channels where dispersion of a dense low lying gas may be suppressed.

2.6 Weather Data

The Project vicinity is semi-arid, with an average annual rainfall of 5 to 6 inches. The summers are hot and dry, and the winters cool and damp with frequent ground fog. During calm atmospheric conditions, a thick ground fog may settle along the length of the Central Valley during the late fall and winter. A temperature inversion traps a layer of cool moist air near the surface causing the fog.

Weather conditions at the time of an accidental release will affect the speed of atmospheric dispersion, and the direction in which a hazardous cloud may drift. When wind speeds are low and the atmosphere stable, dispersion is reduced and can lead to increased localized exposure.

Weather data was obtained from the Missouri Triangle weather station #99006 for the years 2004 to 2008. The station is located immediately to the east of the Project area on Highway 33. The data was processed to assign weather stability categories for the various wind directions, wind speeds, solar radiation and time of day. The wind directions and speeds have been plotted as a wind rose as shown in Figure 2.7.

The predominant wind direction is from the west and southwest, which occurs about 47% of the time. Calm conditions, with drifting wind direction and less than 0.5 m/s wind speed occurs about 3% of the time. An additional 6% of the time, the wind speed is approximately 0.5 m/s, which may also be categorized as calm conditions and provides very little wind dispersion. Calm wind conditions occur primarily during the hours of 10 am and 3 pm, when atmospheric turbulence is high. Wind directions are indicated as blowing from, and the percent occurrences summarized as follows:

Wind Direction	Percent Occurrence
N	12
NE	18
E	5
SE	3
S	4
SW	14
W	33
NW	8
Calm	3

Meteorologists have defined six atmospheric stability classes, (A through F), each representing a different degree of turbulence in the atmosphere. During strong to moderate solar radiation, the air is heated near the ground causing it to rise. The atmosphere is considered unstable, and is classified as Pasquill Stability Class A through C, very unstable to slightly unstable. Higher wind speeds and moderate solar radiation are associated with moderate turbulence, classified as Pasquill Stability D. When solar radiation is weak or absent at night there is less turbulence, which is classified as slightly stable Pasquill Stability Class E, or stable Pasquill Stability Class F.

Weather measurements from the Missouri Triangle station were processed to categorize the data into the six atmospheric stability classes. Two meteorological conditions have been selected to represent worst-case and more typical conditions. A worst-case of “F” stability and 1.5 meters per second (m/s) wind speed represents low wind speed during the night when

hazardous vapors may accumulate. A more typical case of “D” stability and 4 meters per second wind speed, represents average weather conditions during the day and part of the night hours. These weather conditions have been applied to conduct atmospheric dispersion modeling of accidental releases as follows:

Day / Night	Stability Class	Wind Speed	Occurrence
Day	D	4 m/s (9 mph)	50 %
Night	F	1.5 m/s (3.5 mph)	34 %
Night	D	4 m/s (9 mph)	16 %

Figure 2.1 CarbonFrontier CCS Project Facility Layout

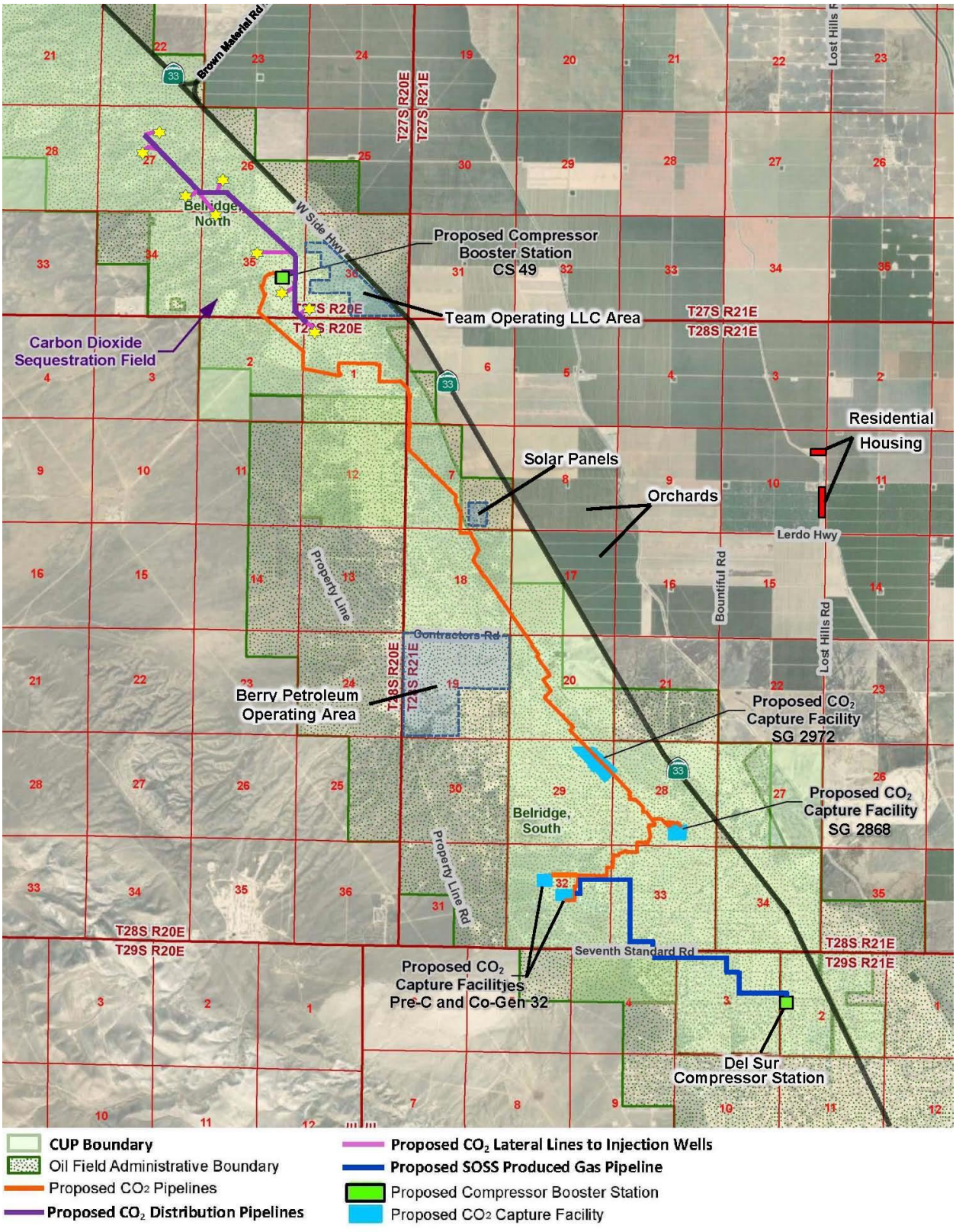


Table 2.1 Estimated Stream Compositions

Property	Produced Diatomite Gas	Del Sur Tulare and Diatomite Gas**	Carbon Dioxide to Sequestration
Composition % mol: (dry basis)			
H_2S	0.12 (1,200 ppm)	0.25 (2,500 ppm)	0.00003 – 0.0002 (0.3 – 2 ppm)
Sulfur	0.12 (1,200 ppm)	0.25 (2,500 ppm)	0.00005 – 0.0005 (0.5 – 5 ppm)
N_2	0.10	3.03	0 – 0.05
CO_2	36.38	65.62	97.5 – 99.9
C_1	40.97	24.45	0.01 – 0.3
C_2	5.37	1.53	0.003 – 0.2
C_3	7.72	2.08	0.005 – 0.2
C_4	6.09	1.85	0.003 – 0.2
C_5	2.34	0.88	0.002 – 0.08
C_6 +	0.91	0.31	-
Properties:			
Molecular Weight (MW)	33.7	37.1	44.0

** Combined flow from Del Sur compressor station of Tulare gas and Diatomite produced gas South of Seventh Standard

Figure 2.2 Block Flow Diagram of CarbonFrontier CCS Project

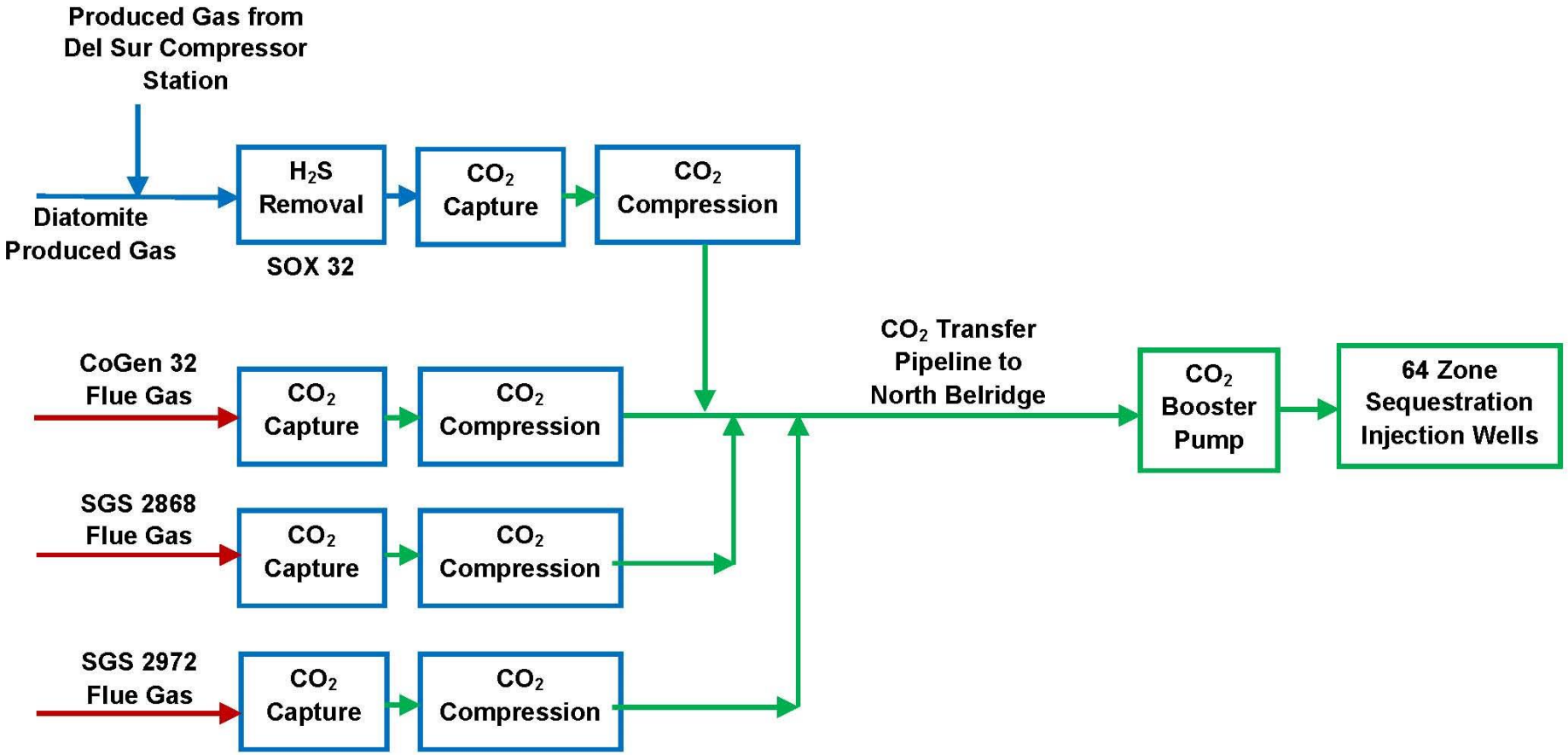


Figure 2.3 Example Carbon Capture Process Flow Diagram

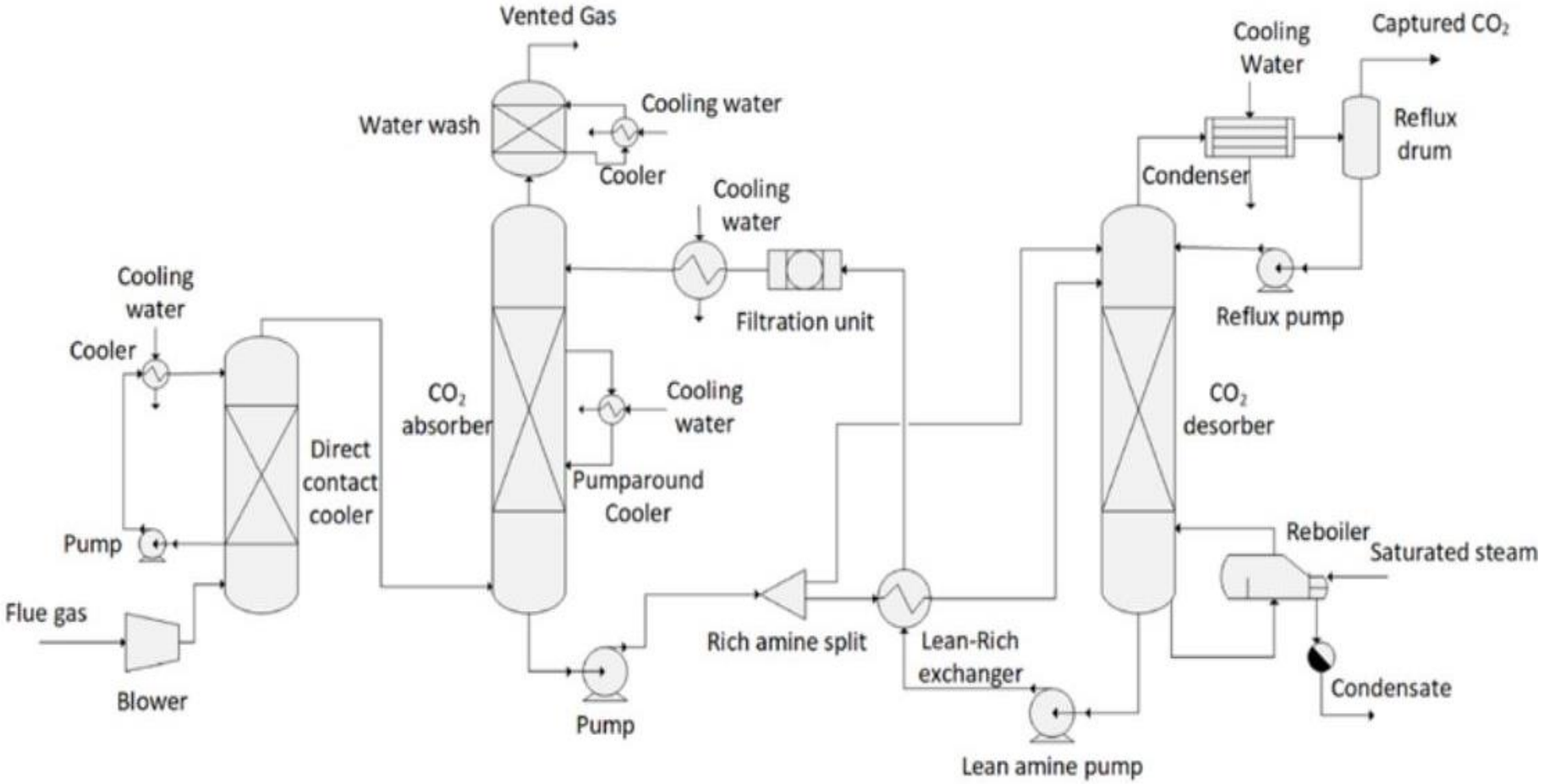


Figure 2.4 Section 32 Facilities Layout

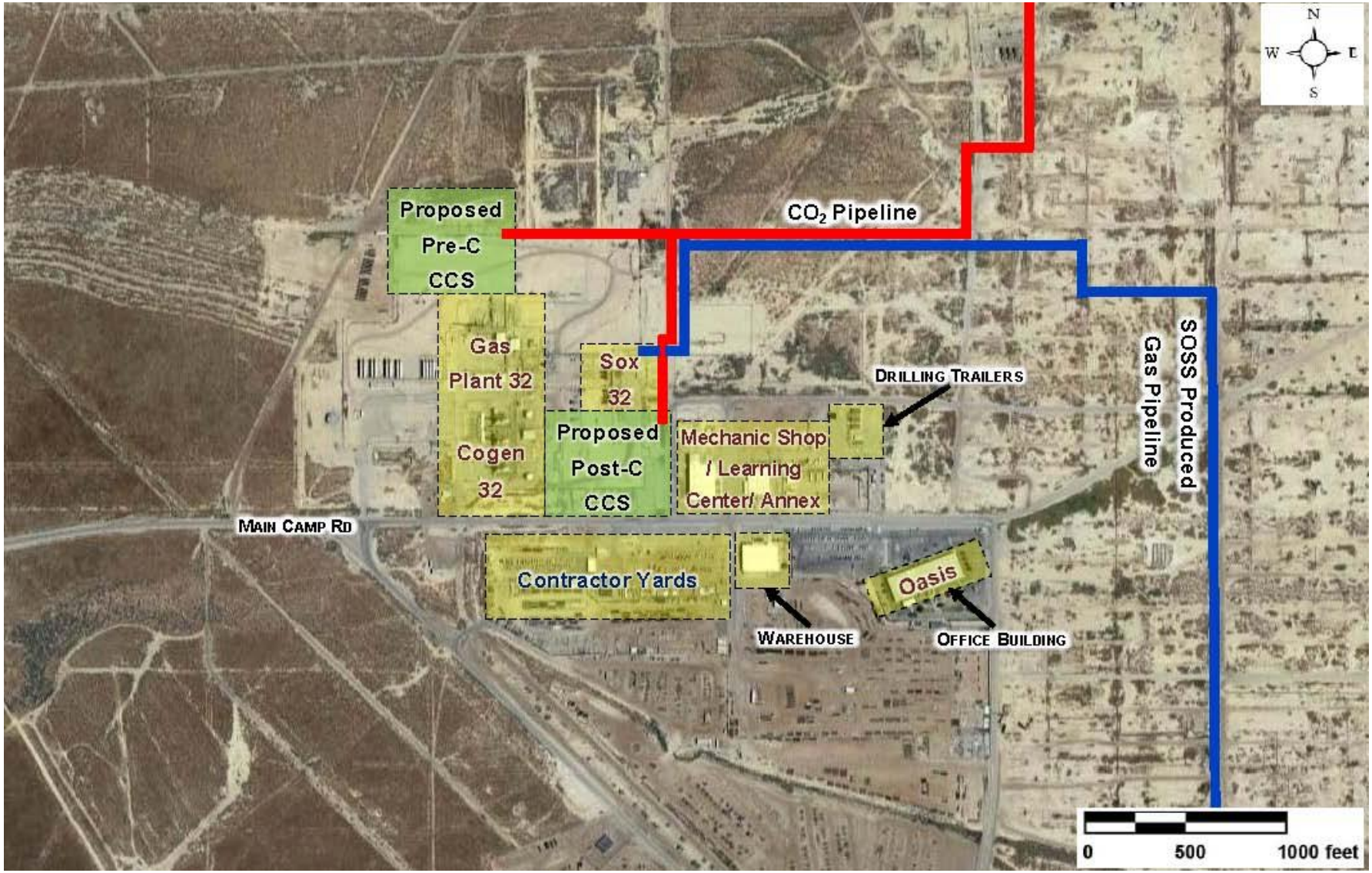


Figure 2.5 Section 20 and Contractors Road Layout

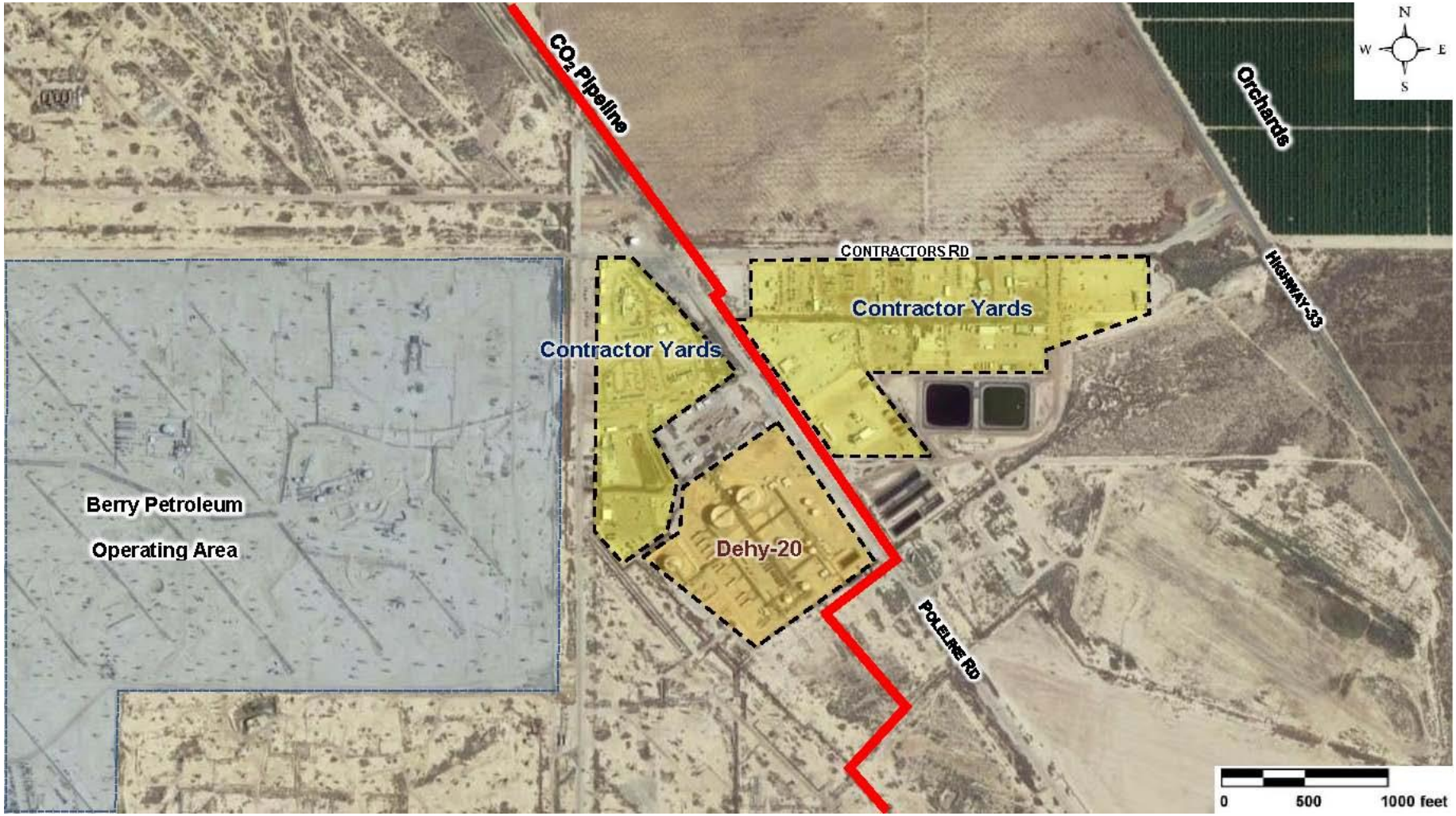


Figure 2.6 North Belridge Compressor Station 49 Layout

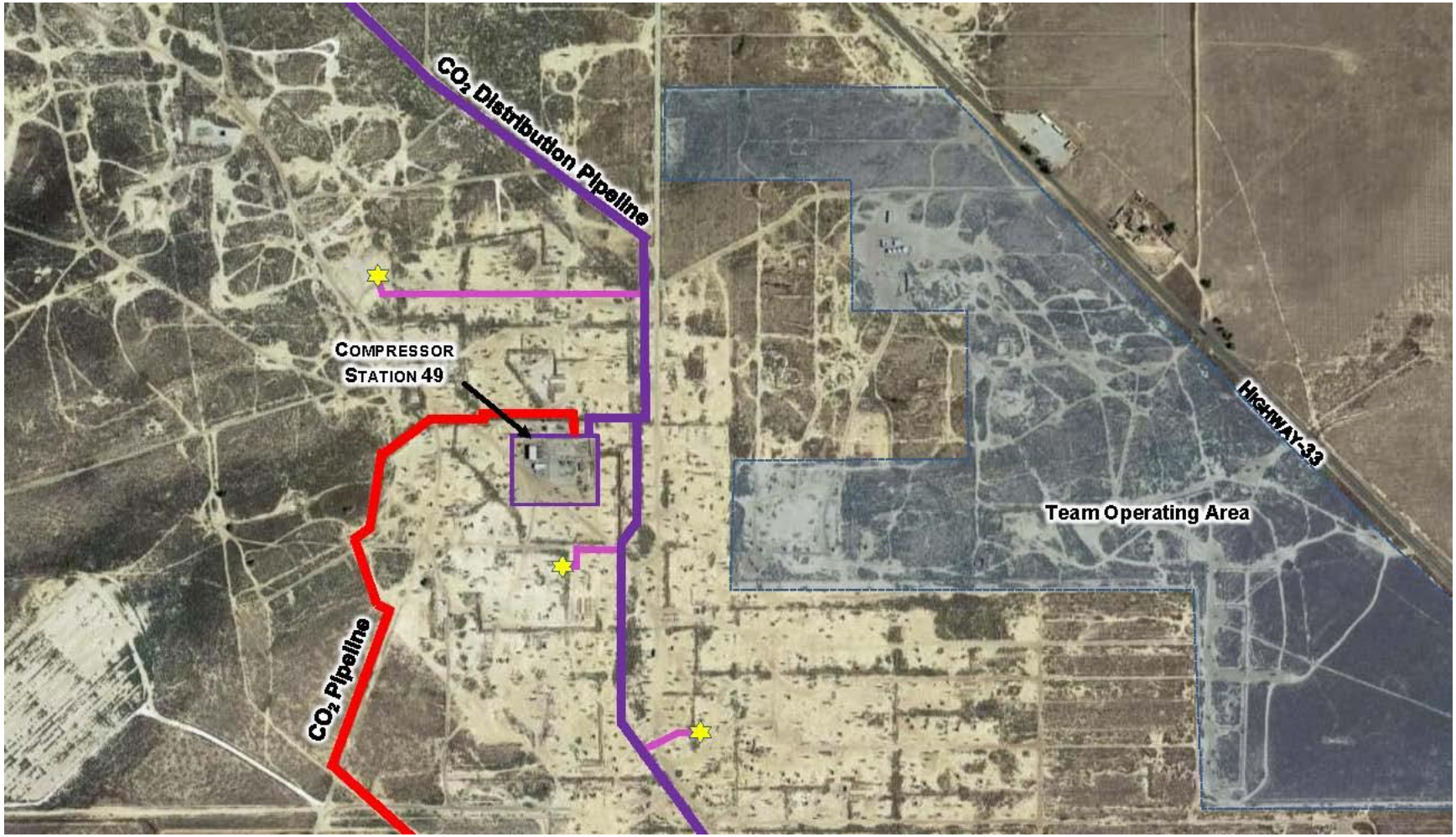
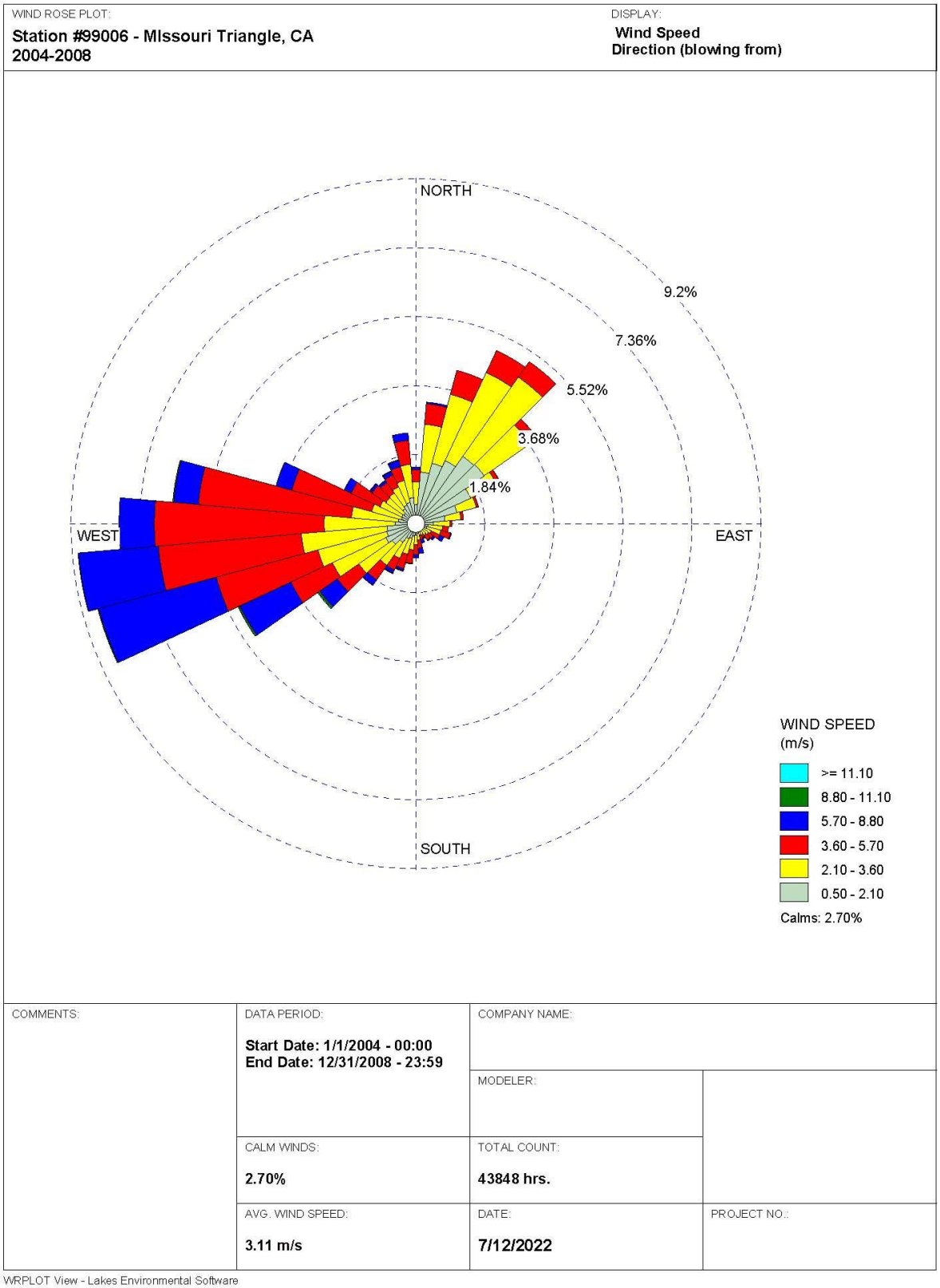


Figure 2.7 Wind Rose Plot - Missouri Triangle Meteorological Station



3. HAZARD IDENTIFICATION

A release of hazardous materials associated with the proposed CarbonFrontier CCS Project may result in acute short term exposure to the public. These may be due to a release of CO_2, natural gas, amine or sulfuric acid, and the impact will depend on the size, duration, material condition, and if personnel are in the vicinity at the time of release.

A review of previous incidents has been conducted to identify and quantify the likely hazards. The carbon sequestration industry is relatively new, and there is consequently limited historical information. Analogous industries were assessed to develop potential release scenarios and likelihoods of failure. A search was also made of CO_2 hazards associated with releases in other industries and from naturally occurring sources.

The hazards associated with each operational activity within the proposed CCS Project have been assessed from a review of incidents, these include;

- CO_2 capture and compression.
- Transport of the dense phase CO_2 through pipelines to the North Belridge oil field.
- Injection of dense phase CO_2 for geologic sequestration.
- Migration of CO_2 from geologic storage to the surface.

The preliminary design of the aboveground facilities for capture, compression, transport and injection of CO_2 at the sequestration site has been used to determine where releases could occur. A list of potential release scenarios has been developed in the following section, and the likelihoods of these releases quantified in Section 4.

3.1 Carbon Dioxide Sequestration Industry

Geological formations are currently being considered for numerous underground CO_2 sequestration projects for permanent storage into depleted oil and gas reservoirs and deep saline reservoirs. CO_2 in a supercritical state would be injected into a porous rock formation below ground. The process also requires that the geological formation has an overlying impermeable caprock, such as shale, so that injected CO_2 remains trapped underground. Depleted oil and gas reservoirs are proven geological formations that have trapped oil and gas below ground for millions of years, making these suitable to sequester CO_2.

These technologies have been demonstrated at multiple US and international sites. Worldwide, according to the Global CCS Institute[23], in 2022 there were 30 commercial facilities capturing CO_2, 13 of which are in the United States. These include facilities for both sequestration and enhanced oil recovery (EOR). In addition, there are approximately 34 pilot or demonstration-scale carbon capture facilities.

The transfer of CO_2 to sequestration sites will primarily be via dense phase CO_2 pipelines. The US has the most mileage of CO_2 transmission pipelines in the world, consisting of approximately 5,300 miles of pipelines. The majority of these pipelines supply dense phase CO_2 to the oil and

gas production industry for injection into reservoirs for EOR. Most of this CO_2 comes from high pressure high purity natural underground source domes. CO_2-EOR has been utilized in the US for several decades, primarily in western Texas and southeastern New Mexico. This provides some historical experience of dense phase CO_2 pipeline systems, and injection of CO_2 into depleted oil and gas reservoirs.

CO_2 injection for EOR was first implemented in 1972 in Scurry County, Texas, and was then used successfully throughout the Permian Basin in west Texas. There are nearly 13,000 CO_2-EOR injection wells in the US[1], and Meyer's report to the American Petroleum Institute (API) in 2007[34], provides valuable information and experience in the design and operation of CO_2 injection wells.

The EPA regulates the injection of fluids associated with oil and natural gas production via the UIC Class II program. This includes injection of CO_2 for EOR. The EPA established a separate class of wells, UIC Class VI, in December 2010, for projects where the purpose is dedicated geologic storage. To date, EPA has permitted two Class VI CO_2 injection wells, both at the Archer Daniels Midland (ADM) facility in Decatur, Illinois, and as of January 2023, have 33 injection well applications pending. North Dakota and Wyoming have been delegated primary enforcement authority to administer Class VI applications. To date, North Dakota has permitted two projects; the Red Trail Energy CCS project, and Minnkota's Project Tundra. Additional well permit applications are pending.

In the US, there are currently two facilities injecting the CO_2 solely for geologic sequestration. The first was the ADM facility in Illinois where CO_2 captured from ethanol production is injected into a saline reservoir. A total of more than 4 MM mt of CO_2 has been injected at the site. The second facility is the Red Trail Energy CCS project at its ethanol facility near Richardton, North Dakota. This facility started CCS operations in June 2022.

Since the reforms of Section 45Q carbon tax credit in 2018 and 2022, a total of 84 carbon capture projects have been announced in the US[23]. The tax credit incentivizes carbon capture and sequestration or utilization.

3.2 Analogous Fluid Injection Industries

There has been limited experience world-wide with large-scale CO_2 capture, transfer and sequestration. Analogous industries have therefore been assessed to develop potential release scenarios and likelihoods of failure. Underground natural gas storage, the use of CO_2 for EOR, steam injection for EOR, and acid gas injection into depleted wells for disposal provide some history of fluid injection into oil and gas reservoirs.

3.2.1 Underground Natural Gas Storage

Underground natural gas storage (UNGS) facilities have operated successfully in North America and Europe since the 1970s and provide historical experience relevant to CCS. These facilities are used to store large quantities of gas during off-peak months for withdrawal during peak usage months, balancing seasonal demand. The majority of gas storage projects utilize depleted oil and gas reservoirs, with some projects in saline formations and salt caverns.

Experience with natural gas storage in depleted oil and gas reservoirs is analogous to the proposed underground storage for CO_2.

The successful operation of UNGS projects has been the selection of a suitable reservoir; rock permeability, impermeability of the caprock, geological structure to maintain gas within the designated area and rock characteristics. The injection wells must be properly designed, installed, monitored and maintained, and abandoned wells in and near the project must be located and plugged. UNGS has been safe and effective, though where failures have occurred, it has been due to poor site selection, inadequate injection well monitoring and maintenance, leaking faults, or a failure of abandoned wells. Successful UNGS projects, and potential causes of failure, provide relevant experience to ensure CCS projects are designed for safe operation.

The recent failure of an injection and withdrawal well at Aliso Canyon, California, in 2015, initiated changes in regulatory requirements for UNGS injection and withdrawal wells. This incident is described below in Section 3.3. The Aliso Canyon well was operated with injection and withdrawal through both the well tubing and casing, creating a single point of failure for gas to escape the well bore. This configuration had been used in UNGS projects but is non-standard in the oil and gas industry. Injection wells for CO_2 storage are required to have separation between the inner injection tubing and the outer casing annulus, which provides a secondary barrier and ability to monitor for potential failures. California Division of Geologic Energy Management (CalGEM) revised the UNGS UIC regulations to require operators ensure that a single point of failure does not pose an immediate threat of loss of fluids. The revised regulations also require enhanced mechanical testing programs to identify well leaks or the potential for a leak to occur before it happens. Requirements for the design, operation and monitoring of CO_2 storage injection wells exceed those of the revised CalGEM UNGS UIC regulations. The potential for failure of CO_2 storage injection wells is therefore likely to be significantly lower than the historical performance of UNGS wells.

3.2.2 Carbon Dioxide Enhanced Oil Recovery

CO_2 has been used for EOR since 1972, primarily in western Texas and southeastern New Mexico. When an oil reservoir pressure is depleted through production, CO_2 flooding can be used in reservoirs deeper than 2,000 feet. The injected CO_2 dissolves in the oil and reduces the viscosity. Normally the CO_2 injection is alternated with water injection, where the water drives the oil towards the production zone. There are nearly 13,000 CO_2-EOR injection wells in the US, which provides valuable experience as an analogue for injection of CO_2 into depleted oil and gas reservoirs.

3.2.3 Thermally Enhanced Oil Recovery

Thermally enhanced oil recovery involves the injection of steam into the oil reservoir. By heating the oil with steam, the viscosity is reduced and permeability increased, allowing the oil to more readily flow into the production wells. This method of EOR has been used commercially since the 1960's.

The two primary methods are either cyclic steam injection or continuous injection via dedicated steam injectors. Both methods are utilized for oil reservoirs which are relatively shallow and contain viscous crude oils. Thermal EOR is widely used in the San Joaquin Valley California.

3.3 Carbon Dioxide and Analogous Industry Release Incidents

A review of incidents has been conducted to identify likely hazards associated with the proposed CarbonFrontier CCS Project. There have been a number of industrial and natural releases of CO_2 where injuries and fatalities due to CO_2 inhalation have occurred. Below are details of some CO_2 incidents that illustrate the characteristics of CO_2 releases, and potential impacts on human health and safety, and the environment.

Significant incidents associated with underground natural gas storage, and steam injection into oil and gas production wells for EOR have also been identified. These involve different hazardous materials, though both use similar technology for injection into oil and gas reservoirs.

2/22/2020 Satartia, Mississippi – 24-inch Pipeline Rupture

In 2007, a 31-mile CO_2 pipeline was built to connect the Tinsley oil field near Satartia in Mississippi, to a naturally occurring CO_2 gas supply under Jackson, Mississippi for EOR. In 2020, heavy rains caused a landslide which ruptured the 24-inch pipeline in a guillotine failure. The failure was detected by the SCADA system and quickly shutdown. The liquid CO_2 vaporized on release, creating a large dense cloud. Due to local topography, the plume migrated down the hill and valley towards the village of Satartia, approximately one mile from the pipeline. The plume travelled about twice the distance plume modeling had predicted.

A total of 200 residents were evacuated and 45 residents taken to the hospital, though none required inpatient hospitalization as a result of the release.

11/21/2018 CO_2 Unloading Incident

A CO_2 truck driver died when he failed to disconnect the unloading hose before driving away. The truck contents of about 2.5 mt (5,500 lb) refrigerated CO_2 were released in 15 minutes.

10/23/2015 Aliso Canyon, California, Natural Gas Storage Injection Well Failure

The Aliso Canyon facility in Los Angeles County is one of the largest underground natural gas storage facilities in the United States. Natural gas is stored in a depleted oil and gas sandstone formation at approximately 8,500 feet below ground, with gas being injected and withdrawn through 115 operational wells at the time of the incident. In 2015, there was a well failure, and gas was detected to be leaking from the ground on the hillsides below the wellhead. This incident resulted in a sustained and uncontrolled natural gas leak of approximately 100 thousand tons of methane. Over 5,000 families had to be evacuated, and the well took three and a half months to control.

The well was operated by injection and withdrawal through both the tubing and casing. A single point failure of the well casing allowed gas to escape the well and travel through the rock formation to the surface. The configuration in which both tubing and casing are used for injection and production is non-standard in the oil and gas industry, outside of the underground natural gas storage industry. Typically, oil and gas and production wells only produce fluid through the tubing, and maintain isolation between the tubing and casing. UIC injection wells also operate in a similar configuration, where the casing serves as a secondary barrier to monitor for failures.

6/13/2013 Louisiana, Abandoned Well Underground CO_2 Blowout

In 2013, an underground CO_2 blowout occurred at the CO_2-EOR Delhi field in Louisiana, when two or more plugged and abandoned wells failed underground. Methane, carbon dioxide, oil, water, brine and sands migrated to the surface in a sparsely populated, marshy area. The release lasted for more than six weeks and contaminated the air with CO_2 and methane.

8/9/2011 Mississippi, Abandoned Well CO_2 Blowout

In 2011, an improperly plugged and abandoned well failed at the CO_2-EOR Tinsley Field, Mississippi. There were incomplete records of abandoned wells at the site. A 2,000-feet deep well failed when the reservoir pressure increased on injection of CO_2. The blowout took 37 days to bring under control, sickened one worker, and suffocated deer and other animals[(2)].

6/21/2011 Midway-Sunset, Kern County, Steam Injection for EOR Incident

Steam injection into oil and gas reservoirs for EOR has been used in California for approximately 60 years. There have been a number of recently reported incidents where steam or well fluids have broken through natural geologic barriers and come to the surface.

In June 2011, an oil industry employee died in the Midway-Sunset oil field when the ground beneath him gave way and he fell into a pool of heated well fluid. The surface expression was believed to be due to nearby cyclic steam injection operations and the failure of an old abandoned well. The abandoned well pipe was reported to have been sheared as a result of ground movement. Revised CalGEM UIC regulations were implemented in April 2019[(7)] to prevent a recurrence of this incident.

2008 Mönchengladbach, Germany Incident

During an accident in Mönchengladbach, Germany, in August 2008, over 100 residents suffered from respiratory problems due to a CO_2 release, of which 19 were hospitalized. The incident involved the release of about 15 mt (90 barrels) of fire suppression CO_2 inside a factory, which leaked out of the building. At the time there was no wind, so the dense CO_2 cloud drifted down hill to the lowest lying region where there was a village about 1,500 feet away. The incident illustrated the hazards of CO_2 accumulation in calm or very low wind conditions, and flow of a dense cloud into lower lying areas.

2004 to 2011 In Salah CCS Project, Algeria

The In Salah CCS demonstration project in Algeria was the first commercial onshore facility to inject CO_2 into a depleted gas reservoir for permanent geological storage. Injection of CO_2 starting in 2004, into a 6,200 feet deep sandstone formation. During the project, 3.8 MM mt of CO_2 were injected. Extensive monitoring was conducted, including seismic analysis, sampling using gas tracers, downhole logging, surface gas monitoring and satellite data to monitor surface elevation changes. Monitoring results identified that CO_2 was potentially injected at a rate that caused well pressure to exceed the fracture pressure. Injection was suspended in 2011 after seven years of operations. To date, no leakage has been detected, though satellite monitoring detected deformation of land surfaces, and seismic monitoring indicated possible fracturing.

9/19/2002 CO_2 Storage Tank Explosion

A worker from Reliant Processing in Muleshoe, Texas, was killed when a CO_2 storage tank he was insulating exploded. The explosion was related to a build-up of excessive pressure and brittle fracture of two tanks due to extremely low temperatures. The US Occupational Safety

and Health Administration (OSHA) investigated this incident, and reported that the tanks were originally designed for liquefied petroleum gas (LPG) and not suitable for minimum CO_2 temperatures.

A similar incident occurred in Worms, Germany, in 1988. A catastrophic pressure failure occurred of a 30 mt capacity CO_2 storage tank due to the vessel relief valve icing up. Five weeks prior to the incident, the vessel had also been exposed to an extremely low temperature. The force of the explosion propelled the vessel nearly 1,000 feet, and resulted in 3 fatalities and 8 injuries.

2000 US EPA Fire Suppression System CO_2 Incident Assessment

Carbon dioxide has been used for many years in the special hazard fire protection industry worldwide. However, large quantities are needed to suppress a fire. The minimum CO_2 fire suppressant concentration is 34 percent, which is higher than the lethal concentration. In 2000, the EPA conducted an extensive research project to assess information on deaths, injuries and the risks associated with the use of carbon dioxide as a fire suppressant[50]. From 1975 to 1999, a total of 51 CO_2 incidents were identified that reported a total of 72 deaths and 145 injuries resulting from the discharge of CO_2 from fire extinguishing systems. The main cause was found to be accidental discharge during maintenance or testing. Since the report was published, additional fatal incidents have occurred. The incident in 2008 at Mönchengladbach, Germany, described above was another example of an accidental fire suppressant release.

1986 Lake Nyos, Cameroon

This is the most commonly cited incident involving CO_2 casualties. Lake Nyos is a volcanic lake which is naturally saturated with CO_2 leaking from the magma chamber below. In August 1986, an estimated 1.6 MM mt of CO_2 was suddenly released when the lake waters overturned. Over 1,700 people and 3,500 livestock were killed and thousands more were injured as the cloud travelled along the valley for more than 9 miles.

A similar incident occurred in 1984 at Lake Monoun when water overturned in the volcanic lake. The released CO_2 moved out of the crater and hung in a depression along a nearby river, where 37 people were asphyxiated.

The Lake Nyos incident illustrates the dangers of a large CO_2 release. However, the quantities of CO_2 released at Lake Nyos were several orders of magnitude larger than proposed for the CarbonFrontier CCS Project. The pipeline inventory is less than 1,000 mt, and each carbon capture facility contains a CO_2 inventory of less than 50 mt.

3/17/1982 Sheep Mountain, Loss of CO_2 Production Well Control

In March 1982, a blowout occurred in the Sheep Mountain, Colorado, during the drilling of a CO_2 production well into a natural reservoir at depths of 3,300 to 6,000 ft (1,000 to 1,800 m). The CO_2 release rate was estimated to be about 200 MM scf/day (120 kg/s). The high release rate made this a difficult well to kill, although industry now has a better understanding of managing the control of CO_2 wells[33].

1930's Crystal Geyser, Abandoned Well

Crystal Geyser in Utah is the largest cold geyser in the world. The geyser was unintentionally created in the 1930's after a prospective oil well was drilled about 2,600 ft (800 m) deep into a

fault zone above a natural CO_2 reservoir. Shortly after drilling, the well was abandoned and not properly capped, allowing CO_2 to be released through the well.

Crystal Geyser eruptions last from 7 to 98 minutes with a release rate between 330 and 790 lb/min (2.5 and 6 kg/s). Downwind CO_2 concentrations have been measured during eruptions, averaging about 4,000 ppm (0.4 %) at 160 feet, and 800 ppm at 330 feet[24]. This analysis suggests that even large and rapidly escaping CO_2 from the geyser results in concentrations that are below human health and safety concerns.

3.4 Hazardous Material Incident Databases

A hazardous material incident that meets an agency threshold must be reported by the owner or operator to regulatory authorities. Some authorities make incident reports available, which provides a basis for predicting what can go wrong, what the hazards may be, and how often these incidents occur.

US Department of Transportation (DOT)

Hazardous material transport between two facilities is regulated by the US DOT. This includes all modes of transport, (including; pipeline, railcar, and road) and in each phase of transport, (loading, unloading, and in transit). Significant incidents are required to be reported to the DOT, and records are maintained by Pipeline and Hazardous Materials Safety Administration (PHMSA) of the DOT. The reporting criteria vary depending on the chemical and mode of transport. These incident reports are recorded in the Hazardous Materials Incident Reporting System (HMIRS) database. The database is a useful source of information on hazardous material releases during transportation and casualties resulting from exposure to the hazardous material.

A reportable incident associated with a release from a hazardous liquid or carbon dioxide pipeline system is defined as an event that results in one or more of the following consequences:

- A death, or personal injury necessitating hospitalization, or;
- Explosion or fire, or;
- A release of 5 gallons or more of hazardous liquid or carbon dioxide, or;
- Estimated property damage, cost of clean-up and recovery, and value of lost product exceeding $50,000.

DOT natural gas pipeline reporting requirements are similar, except that the release reporting quantity is defined as; an unintentional estimated gas loss of 3 million cubic feet (MMCF) or more.

Non-pipeline DOT hazardous material transportation reporting requirements include:

- A death, or personal injury necessitating hospitalization, or;
- An unintentional release of a hazardous material, or;

- Public evacuation is required, or;
- A major transportation artery or facility is closed, or;
- A hazardous material cargo tank of 1,000 gallons or greater suffers structural damage.

Operation of CO_2 pipelines in the US are regulated under federal operations guidelines. However, in-field lines are generally exempt from federal pipeline regulations (49 CFR 195.1(b)(8)), and incidents associated with these lines are not included in the DOT PHMSA database.

National Response Center (NRC)

If there is an accidental release of a hazardous substance from a fixed facility or transportation system that meets the reporting threshold, the owner or operator is required to immediately notify the National Response Center (NRC). The NRC is a part of the federally established National Response System and staffed 24 hours a day by the US Coast Guard. The amount of chemical released before emergency notification depends on the particular chemical. For DEA and H_2S, the reportable quantity (RQ) is 100 pounds, whereas there is no RQ for CO_2, MEA or MDEA. For sulfuric acid, the emergency release RQ is 1,000 pounds (65 gallons). However, all releases of any quantity must be reported if there is a threat to human health, an offsite environmental impact, a threat to navigable waters including surface water and drainages, public evacuation, or closure of a transportation artery.

The NRC maintains a database with call logs on each incident. The call logs provide an initial incident description and information on casualties. Significant fixed facility incidents are reportable if the release is above the chemical RQ, or if there is offsite environmental impact. However, smaller releases at fixed facilities less than the RQ are typically not reportable. Most amine solvent and sulfuric acid releases at fixed facilities are less than the RQ, and are therefore not included in the call logs of the NRC.

The reporting thresholds for DOT regulated transportation incidents are lower than NRC thresholds, and therefore have primarily been used to assess the hazard potential for transportation incidents.

California Occupational Safety and Health Administration (Cal-OSHA)

All releases that result in reportable injuries or a discharge to the environment must also be reported to Cal-OSHA. Federal OSHA makes available report summaries on fatality and catastrophic incidents that OSHA investigates. This provides information on potentially significant hazards to personnel and the public associated with the proposed Project. Incidents reviewed involved the release of CO_2 within all industries, storage of amine solvents and sulfuric acid, amine gas treating, and hazardous material transportation.

3.4.1 Carbon Capture and Compression Incident Data

A search has been conducted of reported NRC and OSHA significant incidents to identify potentially hazardous releases of CO_2 and ethanol amines from fixed facilities. These reports were searched covering a 20-year period, 2002 to 2021, to identify potential hazards associated with amine carbon capture facilities and CO_2 compression.

A total of 37 NRC reported incidents were identified, associated with CO_2 fixed facility incidents, one of which was also investigated by OSHA. Releases were reported to dissipate quickly to below hazardous concentrations within process facilities, without causing a threat to the environment or personnel. Excluded from the incident list were over 200 incidents of process vapor combustion releases of CO_2 at a flare or elevated venting due to equipment startup or shutdown. Other excluded incidents were associated with releases from fire extinguishing systems, CO_2 cylinders, dry ice and accumulation of fumes in enclosed areas. Personnel casualties were reported in three food industry incidents due an accumulation of CO_2 within an enclosed, or partially enclosed area.

A search of ethanol amine fixed facility incidents identified a total of 172 relevant NRC reports, and no OSHA significant incident investigations for MEA, DEA or MDEA. 75% of these incidents were at gas treating processes for the removal of H_2S or CO_2, and there were no reports of significant casualties. Approximately 70% of the reports were associated with DEA even though MEA is more commonly used for gas treating. This is likely due to DEA having an RQ of 100 lb, whereas there is no RQ for MEA. This makes DEA releases more likely to be reportable than MEA releases.

A list of the fixed facility incidents for CO_2 and ethanol amines is shown in Table 3.1. The facilities include oil and gas production facilities, gas processing, chemical and industrial gas manufacturers, food industry and warehouse facilities.

3.4.2 CO_2 Pipeline Transportation Incident Data

Incidents meeting the reporting threshold for DOT regulated pipeline systems are reported to the PHMSA of the DOT. The PHMSA database has been searched for incidents involving pipeline transportation of dense phase CO_2 during the 20-year period, 2002 to 2021. A total of 100 records were identified, 25 associated with line pipe, and an additional 75 associated with auxiliary equipment such as valves, meter stations, and pressure relief. The releases were categorized by the size of release and mode of failure, in order to assess the likelihood of release.

Releases have been categorized by following sizes:

- Pinhole: Failure size smaller or equal to the area of a 0.5-inch diameter hole.
- Crack / Hole: Effective diameter of the failure greater than 0.5-inches and less than the pipeline diameter.
- Rupture: Effective failure size the diameter of the pipeline or greater.

To ensure consistency within the PHMSA database and for comparison with other data sources, releases reported to the PHMSA were re-categorized based on the size of the leak or hole as defined above. For example, some records indicated rupture events which were clearly not full bore ruptures from the reported hole dimensions and release quantities. Some PHMSA release cause categories were changed in 2010, so adjustments were made for consistency.

The total length of CO_2 pipelines in operation for each year from 2002 to 2021 has been summed from annual DOT reports submitted by pipeline operators. US operating experience

over the 20 years totals 91,000 mile-years. The likelihood of failure has been calculated by release size per 1,000 mile-years of pipeline operation as follows:

Pipe Release Size	US DOT CO_2 Pipeline Data for Years 2002 to 2021			
	Number of Pipe Release	%	Average Release Size (bbl)	Failure Rate per 1,000 mile-years
Pinhole	15	60	17	0.164
Crack / Hole	9	36	105	0.098
Rupture	1	4	9,532	0.011
Total	**25**			**0.273**

The number of incidents and pipeline operating miles is limited, and therefore the failure rates have a high degree of uncertainty. For example, an incident in 2018 involved the failure of a girth weld. The pipeline was out of service due to maintenance activities and being refilled at the time of failure. If operational, this would likely have resulted in a total rupture of the pipeline, doubling the calculated rupture failure rate above.

Dense phase CO_2 transmission pipelines typically operate at pressures between 1,200 and 2,200 psig, with an average maximum allowable operating pressure (MAOP) of about 2,000 psig. The CO_2 pipeline diameters range from 4 inch to 30 inch, with an average of 17 inches. The average pipeline age is currently 27 years.

Releases associated with pipeline auxiliary equipment have been categorized by the type and size of leak as follows:

Auxiliary Equipment Releases	US DOT CO_2 Pipeline System Data for Years 2002 to 2021		
	Number of Release	%	Average Release Size (bbl)
Auxiliary Equipment on Mainline Pipeline, in Right-Of-Way			
Mainline Valve /Flange Leaks	10	13	55
Mainline Relief Valve Failure / Leak	4	5	1,347
Mainline Connection Failure	4	5	2,450
Mainline Auxiliary Valve Frozen	1	1	41,177
Pump / Meter Station Equipment			
Valve / Flange / Weld Leaks	28	37	9
Connection Failure	3	4	8
Pig Launcher / Receiver Leak	7	9	63
Relief Valve Failure / Leak	18	24	261
Total	**75**		

Releases associated with auxiliary equipment were typically small flange or valve leaks. Medium sized releases occurred due to the failure of relief valves or connection failures. Approximately 75% of these occurred on operator-controlled sites.

The causes of pipeline and auxiliary equipment releases have been categorized as shown in Table 3.2. The predominant causes of failure associated with line pipe are external corrosion (40%) and material failure (48%). The predominant causes of failure associated with auxiliary equipment are gasket and seal leaks, malfunction of control or relief valves, and construction failure.

Over the last 20 years, there have been 2 major CO_2 pipeline releases in the US:

- *2/22/2020 Satartia, Mississippi* - Guillotine failure of 24-inch CO_2 transmission pipeline due to ground movement after heavy rains. This incident is described in Section 3.2.
- *10/7/2020 Yazoo County, Mississippi* – A large release to atmosphere occurred due to a blowdown valve freezing open. Work was being conducted to reconnect the pipeline that had ruptured near Satartia in February 2020. An 8-inch valve froze in the open position due to internal dry-ice formation as CO_2 flashed across the valve. A total of approximately 40,000 barrels (5,200 mt) of CO_2 were released over about 24 hours until the pipeline segment pressure had reduced enough to allow the valve to thaw and be closed. A large CO_2 cloud formed, and the nearby highway closed. Air monitoring was conducted in the surrounding area, and personnel kept at a safe distance.

DOT pipeline incident reports describe releases of CO_2 to have been identified by either flow monitoring equipment, or a visible cloud. Large pipeline failures were identified by SCADA monitoring systems, which initiated shutdown and isolation of mainline valves. A SCADA system will not be able to detect small leaks, but due to the very low temperature on release, these are likely to be detected by the public or employees. Small above ground releases have been identified as a result of ice forming on equipment, or the sound of vapor release due to the high pressure drop, or a low laying vapor cloud formed by moisture condensing. Below ground leaks have been reported as a result of vapors seen at ground level, or ice forming on the ground above a leak. One report described the ground heaving above a CO_2 pipeline due to a 4-foot ball of dry ice below the surface.

No significant injuries or fatalities have occurred due to CO_2 pipeline incidents. The Satartia pipeline rupture in February 2020 resulted in a total of 200 residents being evacuated and 45 residents taken to the hospital. No residents were admitted due to hazardous material exposure.

3.4.3 CO_2 Injection Well Incident Data

There is insufficient operating experience with EPA UIC Class VI injection wells to predict the likelihood of failure from historical events, and to date, no well blowouts have been reported at dedicated storage sites. However, CO_2 has been injected into active oil and gas production formations for EOR since 1972. A search of incident data has been conducted to identify significant releases that have occurred, and assess potential consequences associated with the failure of CO_2 injection wells.

Loss of well control events are not normally reported to the NRC or Federal agencies, unless there is an off-site impact. A search of Texas well reports identified four blowouts associated

with CO_2-EOR wells over a 10-year period, 2012 to 2021. These were due to wellhead equipment failure, three of which were during well workovers.

Releases may also occur due to a well bore leak and migration to the surface, either through the overlaying formation, or via a poorly abandoned well. These incidents result in a slower release which would be detected by monitoring and unlikely to cause an acute health hazard.

Incidents associated with CO_2-EOR and analogous UNGS facilities reported in the media include:

- 6/2/2016 – Cordona Lake, Texas. A faulty wellhead failed, releasing CO_2 about 20-feet into the air. H_2S, CO_2 and hydrocarbon monitoring was conducted, and no hazardous concentrations were detected.
- 12/7/2015 – Gaines, Texas. A CO_2-EOR injection well head failure occurred during well maintenance. The failure caused a blowout and 25 local homes had to be evacuated for nearly a week. There were no reports of injuries. Most concerns were associated with exposure to H_2S, which was present in the CO_2.
- 10/23/2015 – Aliso Canyon UNGS, California. Well casing failure allowed gas to escape the well and travel through the rock formation to the surface. Over 5,000 families had to be evacuated, and the well took three and a half months to control.
- 1/17/2001 – Yaggy UNGS Facility, Kansas. Natural gas was injected for storage into salt caverns at a depth of 600 to 900 feet. An injection / production well casing failed, leaking gas into the rock formation. The gas migrated approximately nine miles underground, and then traveled to the surface through several abandoned brine wellbores. The released gas caused two gas explosions in Hutchinson, Kansas, destroyed buildings and killed two persons in a mobile home park.

From historical records, there is clearly a potential hazard associated with injection well failure. Reports of CO_2 blowouts via the well bore indicate that these incidents may be a concern for acute risks in the local vicinity, although releases have mainly dissipated quickly. Well bore leaks may also occur, and migrate through the rock formation to the surface. Well casing leaks are likely to migrate slowly to the surface without causing acute health hazards, although these may cause serious hazards if migration to the surface is via an idle or improperly abandoned well. An analysis of CO_2-EOR and analogous injection well failure rates is discussed in Section 4.3.

3.4.4 Leakage of CO_2 From Geologic Storage to the Surface

A search of NRC data identified three well incidents associated with CO_2-EOR releases over the 20-year period 2002 to 2021. These incidents were caused in 2018 by CO_2 migration below ground being released to the surface via three improperly plugged and abandoned wells.

Incidents associated with fluid migration from underground storage reported in the media include:

- 8/9/2011 –Tinsley Production Field, Mississippi. A CO_2 blowout occurred at a CO_2-EOR operation via an inadequately abandoned well that took 37 days to control, sickened one worker, and killed deer, birds, fish and other animals.
- 2004 to 2005 – Salt Creek, Wyoming, CO_2-EOR Project. CO_2 was detected seeping to the surface via well bores of poor integrity. There was rapid dispersion of CO_2 at the surface, and well remediation work was performed to eliminate the seeps.
- 1953 – Herscher-Gainsville UNGS Facility, Illinois. Natural gas was injected for storage into a depleted oil reservoir, at a depth of about 1,500 feet. Several months after start of operation, gas started to migrate through the caprock. Leaks were controlled by reducing the injection pressure and pressurizing the formation above the reservoir with water.

The CarbonFrontier CCS reservoir has been carefully selected to ensure permanent storage of CO_2. This reservoir trapped oil and natural gas over geologic timescales and provides compelling empirical evidence of a robust geologic trap. Potential causes of fluid migration out of the reservoir have been identified from a review of incidents at analogous fluid storage facilities. Mitigation and monitoring measures have been proposed to minimize the risks of potential failure modes.

Wells that penetrate the confining zone into the proposed sequestration layer include injection wells, monitoring wells, and abandoned wells. Failure of well integrity creates the highest risk for leakage of fluids to the surface.

Potential failure modes for fluid leakage to the surface include:

- Leaks via well penetrations through the caprock
- Failure of containment due to faults or fractures in the caprock
- Failure of the caprock due to over-pressurization
- Induced fracturing and fault activation due to locally exceeded reservoir pressures
- Seismic activity

A release from the sequestration reservoir will most likely be a slow dissipation to the surface. Seepage of CO_2 is not uncommon in regions influenced by volcanism, and the concentrations measured indicate that it is highly unlikely that a slow leak from a CO_2 storage reservoir will pose a hazard to personnel or the environment.

3.4.5 Amine Unloading and Storage Incident Data

It is proposed to import concentrated amine using bulk chemical cargo tanks and unload into storage tanks. Hazardous materials transport of corrosive materials is regulated by the DOT, and significant incidents reported to the PHMSA of the DOT. Incidents may also be reported to the NRC if there is a threat to human health or the environment. DOT and NRC data were searched over a 20-year period, 2002 to 2021, to identify potential hazards associated with ethanol amine transport and unloading.

A total of 74 release incidents were identified, as summarized in Table 3.3. In transit releases were due to truck collision or equipment failure. Unloading incidents were due to; hose or hose

connection failure, other equipment failure, or operating error. Only 2 injury incidents were reported, both occurred during unloading due to equipment or hose failure.

3.4.6 Sulfuric Acid Unloading and Storage Incident Data

It is proposed to import sulfuric acid using bulk chemical cargo tanks and unload into storage tanks. Hazardous materials transport is regulated by the DOT, and significant incidents reported to the PHMSA of the DOT. Incidents may also be reported to the NRC if there is a threat to human health or the environment. DOT and NRC data were searched covering a 20-year period, 2002 to 2021, to identify potential hazards associated with bulk road transportation and unloading of concentrated sulfuric acid.

A total of 687 relevant release incidents were identified, about 34 per year, as summarized in Table 3.4. Sulfuric acid is widely used across a range of industries, and the higher number of incidents relative to amine solvent transportation is due to the higher number of shipments. Incidents were categorized to determine the mode of failure, size of release, and potential for casualties. Nearly 70% of the release incidents were associated with unloading. A total of 10 incidents were due to unloading sulfuric acid into a tank containing an incompatible chemical, or an incompatible chemical being unloaded into a sulfuric acid storage tank.

3.5 Hazardous Material Casualties

A number of natural and industrial releases of CO_2 have resulted in injuries or fatalities due to CO_2 inhalation. Examples of some major CO_2 release incidents were presented in Section 3.2 to illustrate the potential hazards of CO_2, which were mainly due to large CO_2 releases or where there was restricted dispersion due to confinement. Industrial incidents associated with CO_2 and amine exposure have been identified in Section 3.3 for incidents reported to the DOT, NRC, and State agencies for well regulation and oversight. Due to the limited data available, it is not possible to project the likelihood of casualties from previous incidents. However, these incidents provide a basis to predict the hazards of release.

Carbon Capture and Compression

Carbon capture will involve the use of amine absorption technology. Personnel hazards may occur due to a release of amine or concentrated CO_2 within the process area, where there may be partial confinement from equipment. Amine absorption is widely used in industry to remove CO_2 and H_2S from oil production and refining streams. A total of 172 amine facility incidents were identified over 20 years, with no serious injuries or fatalities reported, as listed in Table 3.1.

A total of 37 incidents were identified to be associated with fixed facilities with CO_2 process streams and compressed CO_2. There was 1 fatality and 2 injury incidents, all associated with releases into confined areas. No casualties were reported associated with amine treating facilities or CO_2 compression.

CO_2 Pipeline Transportation

PHMSA records of 25 CO_2 pipeline releases and 75 auxiliary equipment releases over 20 years, 2002 to 2021, show no fatalities or hospitalized injuries. However, one 24-inch pipeline rupture event in Satartia, Mississippi in 2002 resulted in 45 residents seeking medical attention.

Another incident required the evacuation of surrounding residents. There is clearly the potential for a large CO_2 release to be hazardous a significant distance from the release location.

CO_2 Injection Well Failure

CO_2 injection for EOR has been in operation in the US since the 1970's. There have been no fatality or serious injury incidents reported from approximately 13,000 injection wells in the US. Well control incidents are reported to state agencies, and 2 events were identified that required evacuation of nearby residents over a 20-year period. One of these evacuations was required due to the hazard of H_2S in the naturally occurring CO_2 used for EOR.

CO_2 Leakage from Geologic Storage to the Surface

A release of CO_2 may occur due to underground migration to the surface. These incidents have resulted in a slow dissipated release, and are unlikely to be acutely hazardous except if undetected vapors accumulate in low lying areas.

No incidents of fluid leakage from storage have been identified that have resulted in public casualties due to CO_2 exposure. Sudden large releases from volcanic sources have resulted in significant loss of life due to CO_2 exposure, although these are not comparable in scale to the slow seepage that is possible from CO_2 sequestration.

Amine Unloading and Storage

A total of 44 bulk transportation incidents and 30 bulk storage incidents were identified to be associated with ethanol amines, as listed in Table 3.3. These have resulted in 2 unloading injury incidents, both due to liquid spray on connection failure. On-site personnel are in close proximity to corrosive fluids and possible spray releases during unloading, and will wear personal protective equipment. Public personnel are highly unlikely to be in close proximity to amine unloading and storage facilities.

Sulfuric Acid Unloading and Storage

A total of 687 bulk road transportation and unloading incidents were identified to be associated with concentrated sulfuric acid, as listed in Table 3.4. There were two employee fatality incidents due to major releases; one occurred due to a truck rollover and cargo release, and the other due to an unloading hose connection failure. Approximately 75% of the sulfuric acid injury incidents were associated with on-site personnel exposure during unloading. Aera personnel and contractors will wear personal protective equipment to minimize the risk of potential exposure during unloading. Public personnel are highly unlikely to be in close proximity to sulfuric acid unloading and storage facilities.

During road transit, there have been 13 injury incidents over 20 years. Public personnel or emergency responders were exposed to sulfuric acid releases in 11 of the injury incidents. From data published by the DOT Bureau of Transportation[49], there are an estimated 400,000 sulfuric acid truck deliveries per year. Historically, the likelihood of public exposure to a sulfuric acid release whilst a truck is in transit is very low, approximately 1 in every 700,000 deliveries.

Sulfuric acid is highly reactive, and when mixed with incompatible chemicals in error can result in the release of toxic gas and heat. There have been a total of 10 incidents associated with sulfuric acid when a bulk cargo has unloaded into the wrong storage tank containing an incompatible chemical. One major incident resulted in a toxic gas cloud impacting the

neighboring community, although this was the result of unloading sulfuric acid into a tank containing sodium hypochlorite (bleach), which would not be stored in bulk at the proposed CarbonFrontier facilities.

3.6 Potential Hazardous Release Scenarios

Historical incidents of CO_2 releases and incidents from similar industries, were used to develop potential release scenarios for each CCS operation, as listed in Table 3.4. Estimates have been developed for the likelihood of release, as discussed in Section 4. Hazards associated with these release scenarios are then discussed in Section 5.6.

Table 3.1 NRC Reported CO_2 and Ethanol Amine Fixed Facility Incidents 2002-2021

Facility Type	NRC Reported Releases (2002 to 2021)		
	Number of Releases	Exposure Incidents	
		Fatality	Injury
Fixed Facility CO_2 Releases			
- Oil and Gas Production	5	-	-
- Oil and Gas Processing / Amine Treating	9	-	-
- Chemical / Industrial Gas / Fertilizer	11	-	-
- Food Industry / Warehouse	12	1	2
- **TOTAL**	**37**	**1**	**2**
Fixed Facility Ethanol Amine Releases			
- Amine Gas Treating Process	130	-	-
- Amine PSV / Vent / Flare liquid release	19	-	-
- Amine Transfer Lines / Pumps	14	-	-
- Chemical Manufacturers of Ethanol Amine	9	-	-
- **TOTAL**	**172**	**0**	**0**

Ethanol amine incident numbers include MEA, DEA and MDEA.
Incidents are categorized by the highest level of casualty.

Table 3.2 US DOT CO_2 Pipeline Causes of Release

Incident Cause	DOT CO_2 Pipeline System Releases (2002 to 2021)		
	Line Pipe Releases	Auxiliary Equipment	Total
External Corrosion	10	1	11
Internal Corrosion	0	-	-
Total Corrosion	**10**	**1**	**11**
Ground Movement	0	-	-
Heavy Rains / Floods	1	-	1
Total Natural Force	**1**	**0**	**1**
External Impact Failure	1	-	1
Other Outside Force	-	1	1
Total External Impact	**1**	**1**	**2**
Construction / Installation Failure	6	8	14
Manufacturing Related	5	-	5
Environmental Cracking	1	-	1
Total Material Failure	**12**	**8**	**20**
Valve / Gasket / Seal Leaks	-	32	32
Malfunction of Control / Relief	-	21	21
Incorrect Operation	1	3	4
Equipment not Installed Correctly	-	3	3
Wrong Equipment Specified or Installed	-	5	5
Total Equipment/Operations	**1**	**64**	**65**
Miscellaneous	-	1	1
Unknown	-	-	-
Total Other	**0**	**1**	**1**
Total Number of Releases	**25**	**75**	**100**

Table 3.3 DOT and NRC Reported Ethanol Amine Transportation and Storage Incidents 2002-2021

Facility Type	Number of Release Events	Amine Exposure Incidents	
		Fatality	Injury
Ethanol Amine Bulk Road Transport			
- In Transit, vehicle collision or rollover	8	-	-
- In Transit, equipment failure	12	-	-
- In Transit, operating error	2	-	-
- Loading/Unloading, hose / hose connection	8	-	1
- Loading/Unloading, other equipment failure	9	-	1
- Loading/Unloading, operating error	5	-	-
- **TOTAL Transport**	**44**	**0**	**2**
Ethanol Amine Unloading to Storage			
- Bulk storage tank overflow	8	-	-
- Bulk storage tank, line or connection failure	22	-	-
- **TOTAL**	**30**	**0**	**0**
TOTAL Amine Transportation and Storage Releases	**74**	**0**	**2**

Ethanol amine incident numbers include MEA, DEA and MDEA.

Table 3.4 DOT and NRC Reported Sulfuric Acid Transportation and Storage Incidents 2002-2021

Facility Type	Number of Release Events	H_2SO_4 Exposure Incidents		
		Fatality	Hospitalized Injury	Non-Hospitalized Injury
H_2SO_4 Bulk Road Transport				
- In Transit, vehicle collision or rollover	49	1	-	3
- In Transit, equipment failure	76	-	1	6
- In Transit, operating error	91	-	1	1
- Unloading, hose / hose connection	94	1	3	9
- Unloading, other equipment failure	140	-	3	4
- Unloading, operating error	89	-	7	13
- Unloading into incompatible chemical tank	10	-	4	3
- **TOTAL Transport**	**547**	**2**	**19**	**39**
H_2SO_4 Unloading to Storage				
- Storage tank overflow	94	-	-	1
- Storage tank, line or connection failure	46	-	-	2
- **TOTAL Storage**	**140**	**0**	**0**	**3**
TOTAL Transportation and Storage	**687**	**2**	**19**	**42**

H_2SO_4 = Sulfuric acid

Table 3.5 Summary of Potential Release Scenarios

Release Source	Scenarios
1. CO_2 Source Stream Pipeline Failure from Del Sur - Medium sized pipeline leak - 16-inch pipeline guillotine failure	Failure of 16-inch above ground pipeline transferring combined Tulare and Diatomite gas flow from Del Sur Compressor Station to SOX 32. Potential CO_2 and H_2S exposure.
2. Carbon Capture and Compression - Vessel or connecting line 2-inch failure - Vessel or connecting line failure - CO_2 compressor 10% pipe diameter failure - CO_2 compressor catastrophic failure - CO_2 buffer vessel failure	Large or medium sized release of amine solution. Potential hazard in close proximity. Large of medium low pressure CO_2 release upstream of compression at 20 psig. Large of medium CO_2 release of gaseous CO_2 within compression and treating section at 500 psig. Large or medium sized release of liquefied CO_2 at 1,300 psig.
3. CO_2 Transfer Line to Sequestration Field - 12-inch pipeline, 2-inch hole release - 12-inch pipeline guillotine rupture - CO_2 booster pump 1-inch hole release - CO_2 booster pump rupture - 12-inch distribution line, 2-inch hole release - 12-inch distribution line, guillotine rupture - 6-inch distribution line, 1-inch hole release - 6-inch distribution line, guillotine rupture	12-inch CO_2 transfer line failure at 1,700 psig and 100^{o}F. Above ground lines. Horizontal high momentum, or impinged low momentum release.
4. CO_2 Sequestration Well Injection - Well head equipment release, 1-inch hole - Loss of well control, 2-inch hole equivalent - Loss of well control, full bore vertical flow - Well casing failure and migration of CO_2 to the surface	Horizontal momentum jet release or impinged low momentum. Worst-case horizontal impinged low momentum release. Vertical full bore release at high flow rate, rapid reduction in flowrate as 4-inch well tubing depressurizes.
5. Leakage of CO_2 From Sequestration Reservoir - Leaks via well penetrations - Faults and fractures - Caprock failure due to over-pressurization - Induced faults or fractures - Seismic activity	Migration of CO_2 from geologic storage to the surface. Slow dissipated release.
6. Amine Unloading and Storage - Bulk truck delivery - Unloading hose or connection failure	Truck leak during transit. Unloading hose leak or failure. 0.5-inch connection failure. Potential hazard in close proximity.
7. Sulfuric Acid Unloading and Storage - Bulk truck delivery - Unloading hose or connection failure - Mix of incompatible chemicals in error	Truck leak during transit. Unloading hose leak or failure. 0.5-inch connection failure. Potential hazard in close proximity. Toxic gas and/or corrosive spray release on mix of incompatible chemicals.

4. RELEASE FREQUENCY ASSESSMENT

The likelihood that a hazardous release will occur, and the potential size of the release, has been estimated using published generic failure rate data. The data has been generated from incident records gathered over a variety of installations and therefore represents an industry average.

The failure rate of a piece of equipment is influenced by a large number of factors, including: design specification, manufacture, application, operating conditions and maintenance. The same piece of equipment may be used in a wide variety of operating conditions and environments, and some attempts have been made to allow for these factors. Published data has been selected for carbon dioxide separation, compression, pipeline transmission, well injection, truck unloading and high-pressure storage. Generic failure rate data have been modified for the CarbonFrontier CCS Project proposed by Aera, based on the proposed design described in Section 2, and historical incident data described in Section 3.

4.1 Process Equipment Failure Rate Data

It is proposed to operate four carbon capture facilities adjacent to existing facilities within the developed South Belridge oil field. The proposed design for the CO_2 capture and compression facilities comprises a pre-scrubber, a CO_2 absorber column, a CO_2 stripper column, and associated pumps and heat exchangers, and a compression and dehydration unit. An example carbon capture process flow diagram is shown in Figure 2.3. It has been assumed that MEA absorption technology will be used. Although the absorption chemicals selected in the final design may be different, the basic hazards and process design are likely to be similar.

Amines used for CO_2 absorption and capture are corrosive, which has been reported as an issue in facilities using MEA. Advanced proprietary amine solvents are likely to be selected for post-combustion absorption, which are reported be less corrosive than MEA. The vapor pressure of proprietary solvents may also be significantly lower, reducing solvent carryover in the overhead absorber gas stream.

Releases for process equipment have been characterized by three different hole sizes:

- Small one-half-inch (5 to 12 mm) diameter
- Medium one inch to two-inch (12 to 50 mm) diameter
- Large over two-inches or rupture (50 mm) diameter

Small leaks are representative of flange leaks, instrument tapping failures and leaks due to corrosion/erosion. These are unlikely to cause a significant hazard for CO_2 or amine releases, and have not been included in the risk analysis. Medium leaks are representative of small connection or line failures, and larger corrosion leaks. Large releases are representative of all large failures, including vessel failure, process line failure, mechanical damage and maloperation.

A summary of generic failure rates selected from literature are shown in Table 4.1 and described below.

4.1.1 Process Vessel Failure Rates

Historical failure rates for process pressure vessels are reported in several data sources, including Center for Chemical Process Safety of the American Institute of Chemical Engineers (CCPS)[10], Smith and Warwick[39], and Lees[31]. CCPS quote an average failure rate for "significant" failures as 1 every 10,000 years (1×10^{-4} per year). This has been taken as the frequency of a 1-inch vessel or connecting pipe failure for smaller vessels, and 2-inch hole for large vessels. From data reported by Smith and Warwick, Lees, and the UK Health and Safety Executive (UKHSE)[46], a large release or rupture occurs at about 1×10^{-5} per year. This has been distributed as 50% instantaneous rupture and 50% large failure resulting in the release of vessel contents over 10 minutes.

The sudden catastrophic rupture of a vessel containing dense phase CO_2 may cause a Boiling Liquid Expanding Vapor Explosion (BLEVE) and flying debris. This is described below in Sections 4.4 and 4.5. To date, there have been three reported CO_2 storage tank BLEVEs due to accidental over-pressurization[16], and one CO_2 cargo truck BLEVE have resulted in casualties. Process vessels are less likely to fail suddenly due to over-pressurization. It has been estimated that 10% of process vessel ruptures will result in a BLEVE.

4.1.2 Process Piping Failure Rates

A study performed by the US Atomic Energy Authority[47] (WASH-1400) has the largest population of piping failure rate data. These represent base failure rates for process piping in an environment where there is minimal vibration, corrosion and erosion. For piping where there is likelihood of corrosion, erosion, vibration or cyclic stresses, a correction factor of 3 to 10 is recommended. The failure rates reported in WASH-1400 with a correction factor applied are comparable with other data sources reviewed, including TNO[12] and UKHSE. The following failure rates have been selected assuming adequate corrosion control:

Full rupture of process piping 6 to 12-inches	$= 6 \times 10^{-8}$ per ft-year
Full rupture of process piping > 12 to 20-inches	$= 2 \times 10^{-8}$ per ft-year
Full rupture of process piping > 20-inches	$= 1 \times 10^{-8}$ per ft-year
1-inch hole in process piping 6 to 12-inches	$= 2 \times 10^{-7}$ per ft-year
2-inch hole in process piping > 12-inches	$= 1 \times 10^{-7}$ per ft-year

4.1.3 Pump Failure Rates

Most pump leaks are due to seal or gland failures. Larger releases are reported by the TNO and UKHSE to occur about 1 every 2,000 years (5×10^{-4} per year), with an effective diameter of 10% of the connecting piping. Lees[31] and TNO report that catastrophic failures occur about 1 every 10,000 years (1×10^{-4} per year). These may be caused by fracture, breakage or collapse of the pump that would typically result in larger releases.

4.1.4 Compressor Failure Rates

Failure rates for compressors have been developed from leak rates and leak size distributions published by the E&P Forum[19] and Lees[31]. Reciprocating compressors are reported to have

failure about 1 every 25 years. Most releases from compressors are small, with approximately 1 percent being large, and 6 percent being medium releases.

4.2 Pipeline Failure Rates

Pipeline failure rates have been calculated from US DOT PHMSA incident data, and compared to data published in Europe. The release sizes and causes of release have been assessed to select appropriate failure rates for CO_2 and produced gas transfer lines proposed for Aera's CarbonFrontier CCS Project.

4.2.1 Pipeline Incident Data

Pipeline failure rates have been calculated for CO_2 pipelines using 20 years of US DOT reported incident data, as discussed in Section 3.3.2. To date, there is limited operating experience with CO_2 pipelines, and therefore predicted failure rates for CO_2 pipelines may not be reliable. There is also insufficient CO_2 pipeline data for analysis on the influence of pipeline diameter and release cause to predict failure rates for the design of the Project pipelines.

It is likely that CO_2 pipelines will experience similar failure rates to natural gas transmission pipelines. These products are both transferred by high pressure pipelines with similar designs and causes of failure as discussed below in Section 4.2.4.

Natural gas transmission pipeline incidents have been reported in the US and Europe for many years, and represent an excellent source of information on pipeline failure rates within a large network of pipelines. Pipeline failure rates have been calculated for both US DOT PHMSA data[49], and for the European Gas Pipeline Incident Group (EGIG) data[17] for the most recent 20 years of data. These are compared below to the failure rate calculated for US DOT CO_2 pipelines:

Source	Failure rate per 1,000 mile-years	Reporting Criteria	Average Diameter (in)
US DOT - PHMSA[49] CO_2 Transmission 2002-2021	0.27	> 5 gallons or > $50,000	17
US DOT - PHMSA[49] Gas Transmission 2002-2021	0.15	> 3 MMSCF > $50,000	19
EGIG[17] Gas Transmission 2000-2019	0.24	All leaks	20

Each of the sources provides data on reportable incidents, which are different for each data source. The PHMSA data includes incidents that meet the DOT reporting thresholds, which are 5 gallons for a CO_2 release and 3 million standard cubic feet (MMSCF) for natural gas. The European reporting threshold for gas transmission pipelines is lower than US DOT reporting threshold, which may result in the higher apparent incident rate for European pipelines, due to the inclusion of smaller leaks in the data.

4.2.2 Distribution of Release Sizes

US DOT and European EGIG gas transmission line data have been analyzed to calculate the failure rate by release size as follows:

Release Size	US DOT Data for Years 2002 to 2021 [49]		
	Number of Pipe Releases	%	Failure Rate per 1,000 mile-years
Pinhole /Crack (<1/2-inch)	271	30%	0.046
Hole	321	36%	0.054
Rupture (=>pipe diameter)	304	34%	0.052
Total	**896**		**0.152**

Release Size	EGIG Data 2000 to 2019 [17]		
	Number of Pipe Releases	%	Failure Rate per 1,000 mile-years
Pinhole /Crack (<1/2-inch)	244	63%	0.149
Hole	94	24%	0.057
Rupture (=>pipe diameter)	50	13%	0.031
Total	**388**		**0.237**

The exclusion of smaller releases in the US DOT data results in an unrealistic release size distribution. The size distribution has been therefore been adjusted using the European EGIG data which includes all release sizes.

4.2.3 Pipeline Diameter and Wall Thickness

The US DOT collects data on pipeline infrastructure from operator annual reports[35]. This includes information on the total length, diameter, installation date, and commodities transported. This data has been used to calculate pipeline failure rates by mile and diameter of pipe.

Pipeline failure rates are reported to be dependent on the diameter of the line. This has been largely attributed in literature to the increase in pipe wall thickness with larger diameter lines, the ability of a pipeline to withstand external impact with increasing wall thickness, and the time interval where corrosion may be detected and addressed before causing a failure. US DOT pipeline rupture failure rates have been calculated for natural gas transmission data by pipeline diameter, as shown in Table 4.2. However, as only releases above the reporting threshold are included in the US DOT data, a correction factor has been applied based on an analysis of the European EGIG data as follows:

Pipeline Diameter	Diameter Factor
=< 4 inches	3.8
> 4 to 8 inches	2.6
> 8 to 12 inches	1.4
> 12 inches	1

The threat of failure related to pipeline diameter and wall thickness for natural gas and CO_2 pipelines is likely to be similar. The average MAOP of CO_2 pipelines has been calculated as approximately 2,000 psig, whereas the average MAOP of natural gas pipelines is approximately 770 psig. The increase in wall thickness and higher grade of steel for CO_2 pipelines compared to natural gas pipelines will likely result in a lower CO_2 pipeline failure rate for a similar diameter pipeline.

4.2.4 Cause of Release

Historically, natural gas and hazardous material liquid pipeline failures are caused by third-party interference, corrosion, construction or material defects (e.g. welds), ground movement or operator errors. US DOT natural gas pipeline ruptures have been categorized by cause of failure and pipeline diameter as shown in Table 4.2. The cause distributions are summarized as follows:

Corrosion	27%
Natural Force Damage	10%
External Impact	31%
Material Failure	27%
Equipment / Operations	2%
Other	3%

Internal Corrosion - Most CO_2 pipelines in the US transport naturally occurring CO_2 sources to oil production areas for EOR. There is little experience of CO_2 pipelines with impurities such as SO_x, NO_x, N_2, O_2, and CO due to combustion, although low concentrations are unlikely to significantly increase the internal corrosion rate with reliable monitoring. Reported experience to date with CO_2 pipelines indicates that the internal corrosion rate is comparable with natural gas pipelines, provided no free water is present. Moisture content of CO_2 entering the pipeline will need to be monitored.

External Corrosion – This has been a major cause of failure for below ground transmission pipelines. External corrosion is less likely for the CCS Project pipelines which are proposed to be predominantly above ground, on raised pipe supports to minimize external corrosion. An external corrosion modification factor of about 0.2 has been suggested in literature for above ground pipelines[(15)].

Natural Force Damage - Natural force damage includes events such as earth movement due to landslide, subsidence, seismic activity, flooding and erosion. The proposed Aera CCS pipelines are to be located across primarily gently sloping terrain, and above ground where there is less force on the pipeline if movement occurs. The probability of failure due to earth movement is likely to be significantly lower than average. An external impact modification factor of about 0.2 has been suggested for above ground pipelines.

External Impact - External impact is primarily due to damage caused by excavation impact on below ground pipelines. The proposed Aera CO_2 pipeline will be above ground and on Aera property where there is greater control over activities. The likelihood of external interference is therefore significantly lower, although there is still the possibility of vehicle impact.

Material Failure / Equipment / Operations - Maintaining dense phase CO_2 within design specifications will be more challenging than with natural gas. There may be additional stresses on the pipeline due to rapid changes in temperature due to a leak, equipment failure or operational error. There is the possibility of brittle failure due to rapid cooling, and ice formation during depressurization. Seals and valves will also need to be specifically selected for CO_2 service. This may increase the likelihood of failure due to equipment and operations.

Overall, the failure rate for an above ground CO_2 pipeline on non-public property is likely to be lower than an equivalent sized below ground gas transmission line. However, due to the uncertainty in potential material failures, equipment and operations, and limited historical data for CO_2 pipelines, it has been conservatively assumed that failure rates for the Project CO_2 pipelines are equivalent to natural gas pipelines. Modification factors have been applied for the above ground produced gas transfer line from Del Sur Compressor Station to SOX 32 for the likely reduction in external corrosion and reduction in the potential for external impact.

4.2.5 CO_2 and Gas Transfer Line Failure Rates

Published data for US DOT natural gas transmission failures have been adjusted to take account of the likely under reporting due to the reporting criteria and adjusted for pipe diameter. The following failure rates have been selected for the proposed above ground CO_2 transfer lines and produced gas transfer line from Del Sur Compressor Station to SOX 32.

Line Diameter	Line Content	Failure Rate (per mile-yr)	
		Medium Hole (2-inch)	Large / Rupture
> 4 to 8 inches	Dense phase CO_2	2.0×10^{-4}	1.1×10^{-4}
> 8 to 12 inches	Dense phase CO_2	1.6×10^{-4}	8.8×10^{-5}
> 12 to 20 inches	Dense phase CO_2	1.3×10^{-4}	7.3×10^{-5}
> 12 to 20 inches	Del Sur Production Gas Transfer	7.8×10^{-5}	4.4×10^{-5}

The overall pipeline release frequencies are shown in Table 4.3.

4.3 Injection Well Failure Rates

A well blowout may occur due to the loss of pressure control causing fluid to migrate up and out of a well. These may be caused by mechanical failure, flawed or damaged equipment, operational error or unpredictable circumstances such as well-head impact. Most well control problems are either quickly controlled by safety equipment, or result in a minor release and are not included in the category of “blowout” in published incident data.

There are few dedicated CO_2 storage injection wells to date, with limited operating experience. Industrial operations such as CO_2-EOR production, natural gas storage, and acid gas injection for permanent geological storage will have differences to dedicated CO_2 storage, but they provide analogues for the likelihood and severity of blowouts that could occur.

Failure rates associated with CO_2 injection wells may also have similarities with production wells. There is more historical experience with oil and gas production wells to allow calculation of failures rates during various well phases, and these have been compared to failure rates reported for other analogous injection wells.

Underground Natural Gas Storage

The storage of natural gas in geological formations has been used in North America and Europe since the 1970's. Depleted oil and gas reservoirs are utilized for 83.5% of this storage, natural aquifers for 12.6% and the remainder in salt caverns and converted coal mines.

The International Energy Agency (IEA) sponsored a study of the natural gas storage industry as an analogue for CO_2 storage in 2006[27]. The gas storage industry experience was assessed for applicability to CO_2 sequestration, and historical failure modes and frequencies were developed. The IEA provided the following estimated well failure rates for world-wide and European data:

Natural gas injection well	2.0×10^{-5} per well-year (world-wide incidents)
Natural gas injection well	5.1×10^{-5} per well-year (European incidents)

The European failure rate calculated was more than twice the likelihood of the world-wide data. This was due to the inclusion of smaller incidents in the European data compared to the world-wide data, which included mainly larger events captured from media reports that resulted in casualties, property damage, site evacuation or uncontrolled leak. Smaller events, such as leaks caused by casing failure that could be easily remedied, were not included in the world-wide incident rates.

The failure modes described for the world-wide significant incident data were as follows:

Well casing failure with gas migration to surface	44% (7 events)
Well control failure with release via well bore	25% (4 events)
Caprock failure or improperly selected reservoir	25% (4 events)
Release via improperly abandoned wells	6% (1 event)

Three of the caprock failure events listed above occurred at saline aquifer storage sites. These were shallower storage facilities without multiple confining layers, and without the proven ability to contain fluids for millions of years such as in depleted oil and gas reservoirs. The fourth event occurred in a relatively shallow depleted gas reservoir due to over-pressurization. None of these events are likely to be relevant for projecting the long-term storage ability of the CarbonFrontier project.

Natural gas storage in geological formations is likely to have greater similarities with CO_2 storage in depleted oil and gas reservoirs than storage in underground caverns. Releases from caverns were reported in 38% of the world-wide incidents, although these are used in only 4% of underground gas storage. The exclusion of cavern events reduces the reported world-wide failure rates by 35%. The failure rate for significant releases is then estimated as:

Natural gas injection well	1.3×10^{-5} per well-year

CO_2-EOR Operations

CO_2 has been injected into active oil and gas production formations for EOR since 1972. Loss of well control events are reported to state agencies, but many states have limited historical records. The Texas Railroad Commission (RRC) maintains the most comprehensive well control records, although incidents are not identified by the type of well, and details are limited for older records.

A study on well blowout rates was conducted by Porse et al in 2014[36] for 3 Texas districts over a 14 year period from 1998 to 2011. This study included the 2 districts where 99% of Texas CO_2-EOR wells are located. A total of 84 well blowouts were identified in these 2 districts, only 1 of which was a CO_2 injection well. The failure rates for production and injection wells were calculated as follows:

Oil well servicing and production	3.0×10^{-5} per production well-year
CO_2 injection well	1.1×10^{-5} per injection well-year

An analysis has been conducted for this QRA using Texas RRC records for the 10 year period, 2012 to 2021. A search was conducted for well control events within the same 2 districts as the Porse study. A total of 61 blowouts were identified, which were then cross checked against well information to identify the type of well. Four of the blowouts were associated with CO_2 injection wells, 2 of which occurred during well workovers. It has been reported in a survey by ARI in 2019[1] that Texas has 6,840 active CO_2-EOR wells, which provides the following injection wells failure rate:

CO_2 injection well	5.8×10^{-5} per injection well-year

Combining the results of both studies results for the 24-year period, an overall CO_2-EOR injection well blowout rate has been calculated as 3.1×10^{-5} per injection well-year.

California Thermally Enhanced Oil Recovery

A study was conducted by Jordon[28] on the frequency and consequences of loss of well control events in California Oil and Gas District 4, from 1991 to 2005. District 4 is located in the southern San Joaquin basin, which includes Kern County. The purpose of the analysis was to assess the risk of well failure associated with steam injection. In District 4, 59% of oil production is via thermally enhanced recovery. Thermal enhancement involves the injection of large quantities of steam into the formation, which has some similarities with CO_2 injection.

Well blowout data was obtained from California Division of Oil, Gas and Geothermal Resources, (DOGGR, now called CalGEM) and newspaper archives. A total of 102 individual blowouts were identified and the following failure rates calculated:

Drilling and completion	4.0×10^{-4} per well in thermally enhanced field
Steam flood injection well	1.4×10^{-4} per injection well-year
Steam flood production well	4.3×10^{-5} per well-year
Thermal well servicing	3.5×10^{-5} per well servicing
Thermal well P&A	1.0×10^{-5} per well (estimated)

Steam blowouts from injection wells migrated out of the well casing to the surface in 70% of incidents, and were released through the well bore in 30% of incidents. There was only one underground blowout identified during the study that occurred via an older abandoned well, despite over 100 years of oil production in the district. Since the study was conducted, a second underground blowout incident occurred at the Midway-Sunset oil field in 2011. An oil industry employee died when the ground beneath him gave way due to the release of reservoir fluids from a nearby steam injection operation. An abandoned well pipe was reported to have been sheared as a result of ground movement, creating a pathway for reservoir fluids to the surface.

The blowout rate was reported to decline significantly during the study period, most likely as a result of increasing experience, improved technology, and/or changes in safety culture.

Offshore Oil and Gas Production

Data on well blowouts is readily available for offshore incidents in the Gulf of Mexico and the North Sea. The US Bureau of Ocean Energy Management (BOEM), and the Norwegian Foundation for Scientific and Industrial Research (SINTEF) publish data on offshore incidents in the Gulf of Mexico, and internationally. This provides a comprehensive database for oil production wells, although the failure rates associated with drilling and completion in a depleted reservoir for CO_2 sequestration are likely to be significantly lower.

Offshore oil well failure rates reported by BOEM and SINTEF were compiled by Bercha under contract to the BOEM as follows[3]:

Drilling and completion	7.1×10^{-4} per well
Well Servicing	3.1×10^{-4} per well servicing
Production	1.1×10^{-4} per well-year

California Oil and Gas Production

Failure rates for oil and gas wells in California have been analyzed from a report on the History of Oil and Gas Well Blowouts in California, 1950 to 1990, published by the California Division of Oil, Gas and Geothermal Resources, 1993[5]. The data is based on a smaller population of wells than the offshore BOEM and SINTEF data, and the incident reporting for earlier years may not be as complete. The following failure rates have been calculated from this data for well servicing and production operations:

Well Servicing and Production	3.1×10^{-4} per well-year

The failure rates reported for California onshore production facilities are consistent with those published for offshore wells. The oil and gas production data includes incidents that occurred before improved well monitoring technology, equipment, and changes in safety culture were implemented. This has been reported to significantly reduce the incidents of well control failure.

Selected Well Failure Rates

Well failure rates for natural gas storage, CO_2-EOR, steam flood operations in Kern County, offshore and onshore oil production are all relatively similar. The reported blowout rates for

Kern County steam injection wells were higher than other sources, possibly due to operation at shallower depths.

The proposed CarbonFrontier CCS Project will utilize an 8,000 deep sandstone formation, which is at low pressure due to depletion from oil and gas production. The risks of an oil and gas blowout associated with well drilling and completion of injection wells is therefore very low. Only failure rates for well servicing and production have been considered in the risk calculations.

The failure rate for an injection well blowout has been selected as 5×10^{-5} per injection well-year, based on injection wells for natural gas storage in geological formations, and CO_2-EOR injection wells in Texas. Many wells control failures reported were not full well bore releases. It has been estimated that well head releases the equivalent to a 2-inch hole occur in 75% of the well control failure events, and full casing flow in 25% of events.

The overall failure rates for loss of well control have been selected as:

Operational Phase	Release Size	Failure Rate (per well-year)
Injection Well Blowout	Full casing diameter flow	1.3×10^{-5}
Injection Well Blowout	2-inch diameter release	3.8×10^{-5}
Wellhead Release	1-inch diameter release	2×10^{-4}
Monitoring Well Blowout	Full casing diameter flow	2.5×10^{-6}
Monitoring Well Blowout	1-inch diameter release	2.3×10^{-5}
Abandoned Well Release	Migration to surface	5.0×10^{-8}

The overall well release frequencies are shown in Table 4.4.

Blowout rates in oil and gas activities are reported by Jordan et al[28] have declined significantly in recent years due to improved technology, increased experience and changes in safety practices. These improvements are likely to be seen in the reliability of CO_2 injection wells.

4.4 Amine Transportation and Storage Failure Rate Data

It is proposed to import concentrated amine using bulk chemical cargo tanks of approximately 6,000 gallons (143 barrels). The concentrated solvent will be stored in 21,000 gallon (500 barrel) tanks. In addition there will be 4 holding tanks of 168,000 gallons (4,000 barrels), one for each capture facility, to contain the working inventory of diluted solvent. After the capture facilities are in operation, it is assumed there will be 21 deliveries of 3,000 gallons per facility per year, with the truck driving 50 miles from the Bakersfield area.

An assessment has been made of hazardous material incidents involving bulk ethanol amine truck transportation, unloading and storage. The likelihood of a hazardous release, and the potential size of the release, has been estimated using published generic failure rate data. The

data has been generated from incident records gathered over a variety of installations and therefore represents an industry average which is not specific to corrosion materials.

Truck Transportation

A chemical release and potential hazard may occur due to truck vehicle collision, roll-over that causes a tank release, or equipment failure on the vehicle.

Truck accident rates are reported in published data as vehicle miles traveled and are typically quoted per million vehicle miles traveled (MVMT). National vehicle and truck accident rates are published annually by the Federal Motor Carrier Safety Administration (FMCSA)[21]. For the year 2020, the average truck accident rate was 1.37 per MVMT. It was reported in a 2001 FMCSA study[20], that hazardous material cargo vehicles had an accident rate about 30% lower than average trucks. The release probability for tank trucks, given an accident, is reported by Harwood[25] to be between 5% and 9%. A release probability of 9% has been selected, which gives an estimate of a truck collision release as 0.09 per MVMT.

Additional incidents occur due to non-collision events, such as; truck non-collision rollover, equipment failures, and operating error. Equipment failures are typically smaller release events. From an assessment of in-transit truck incidents discussed in Section 3.3, these causes resulted in about 65% of releases, to give an overall release estimate of 0.26 per MVMT.

From an assessment of the transportation release sizes reported in the DOT PHMSA database, approximately 90% of the releases were categorized as small, which is less than 5 percent of the cargo.

Truck Unloading

A potential hazard may occur due to an unloading error, hose failure, or failure of connecting equipment. Failure rates have been selected from those reported by the UKHSE[46] for an average hazardous material facility. These were developed from work at chlorine facilities, which are likely applicable to safety precautions for amine unloading.

The following failure rates have been selected for the unloading hose and connections:

Failure equivalent to hose diameter = 4×10^{-6} per operation
Failure equivalent to 0.5-inch diameter = 4×10^{-5} per operation

An assessment has been conducted of unloading incidents reported to the DOT and NRC over a 20-year period, and the results shown in Table 3.3. Incidents not related to hose failures were reported to be due to a component failures and operating error, such as failure to open or close a valve. These releases were typically smaller than those associated with unloading hose failures. An estimate has been made of truck component and operating failure rates as follows:

Release equivalent to 1-inch diameter = 1×10^{-5} per operation

Amine Storage

A storage tank failure may be due to overfill, failure of a pipe connection, or failure of the tank shell. CCPS[10] and Federal Emergency Management Agency (FEMA)[22] quote an average failure rate for “significant” storage tank failures as 1 every 10,000 years per tank. It has been assumed these are equivalent to a medium sized 2-inch failure. The catastrophic failure rate for chemical storage tanks with double walls is reported by FEMA to occur 1 every million years. It

has been assumed that connection failures and holes occur at the same rate as single walled storage tanks.

The likelihood of a tank overfill is dependent on the type of instrumentation provided for level control and the frequency of filling. Failure rates are reported by Lees[31] to be in the order of 1 in 100 to 10,000 years per tank or less. For tanks equipped with high level alarms and independent high-high levels alarms with automatic shutdowns, the likelihood of overfill is reported to be approximately 1 in 10,000 years per tank. It has been estimated that the overfill rate for amine storage tanks will be approximately 1 in 10,000 years per tank, (1×10^{-4} per tank-year) based on 21 deliveries of amine per capture facility per year and typical hazardous material unloading facilities.

The following failure rates have been selected for amine storage tanks:

Storage tank rupture	$= 1 \times 10^{-6}$ per tank
Medium hole / connection 2-inch diam	$= 1 \times 10^{-4}$ per tank
Tank overfill	$= 1 \times 10^{-4}$ per tank

The summary of the overall amine unloading and storage release frequencies are shown in Table 4.5.

4.5 Sulfuric Acid Transportation and Storage Failure Rate Data

It is proposed to import sulfuric acid at 96% concentration using bulk chemical cargo tanks of approximately 3,000 gallons (71 barrels). The sulfuric acid will be stored in one 8,400 gallon (200 barrel) tank at each carbon capture facility. It has been estimated there will be up to 6 deliveries of 3,000 gallons per facility per year, with the truck driving 50 miles from the Bakersfield area.

An assessment has been made of hazardous material incidents involving bulk sulfuric acid truck transportation, unloading and storage. The likelihood of a hazardous release, and the potential size of the release, has been estimated using published generic failure rate data, and historical incident data.

Truck Transportation

A chemical release and potential hazard may occur due to truck vehicle collision, roll-over that causes a tank release, or equipment failure on the vehicle.

Hazardous material truck accident rates are described above for amine transportation as 0.09 collision releases per MVMT. Non-collision release events were the cause of about 75% of the reported releases, to give an overall release estimate of 0.36 per MVMT. More sulfuric acid releases were reported per MVMT than amine due to the greater hazards associated with concentrated sulfuric acid. The release sizes were estimated to be small 90% of the time.

Truck Unloading

A potential hazard may occur due to an unloading error, hose failure, or failure of connecting equipment. Failure rates have been selected from those reported by the UKHSE[46] for an average hazardous material facility, as described above for amine transportation.

The following failure rates have been selected for equipment failures and operating errors:

Failure equivalent to hose diameter	= 4 x 10^{-6} per operation
Failure equivalent to 0.5-inch diameter	= 4 x 10^{-5} per operation
Release equivalent to 1-inch diameter	= 1 x 10^{-5} per operation

Sulfuric Acid Storage

Failure rates for storage tanks, connection failure and tank overfill were developed based on data from CCPS[10], (FEMA)[22], and Lees[31]. These are described above in Section 4.4 for amine storage, and are applicable to sulfuric acid storage.

Storage tank rupture	= 1 x 10^{-6} per tank
Medium hole / connection 2-inch diam	= 1 x 10^{-4} per tank
Tank overfill	= 1 x 10^{-4} per tank

Unloading into Incompatible Chemical Tank

The accidental mixing of many acids and bases or other incompatible chemicals during unloading operations can lead to potentially dangerous reactions, release of heat, and the generation of toxic gas.

An estimate has been made of the number of sulfuric acid truck deliveries per year in the US from the DOT Commodity Flow Survey[49], as 400,000 per year. For the 20-year period of data searched, there have been 10 reported incidents of a bulk sulfuric acid truck being unloaded into a tank containing an incompatible chemical, or an incompatible chemical being unloaded into a sulfuric acid tank. These events resulted in seven injury incidents. This equates to approximately one incompatible chemical incident every million deliveries. Additional less hazardous unloading incidents may have also occurred that were not reportable to the DOT or NRC. A facility incident is reportable if the event results in injuries, or results in the release of a reportable quantity of hazardous material, or there is an off-site impact.

4.6 Earthquake Failure Rates

The Project site is located in California's seismically active San Joaquin Valley region where there are a number of active faults with the potential to produce strong ground motion. Strong ground shaking due to an earthquake may cause damage to line connections or vessels resulting in a release.

The hazards associated with an earthquake are due to ground shaking, ground liquefaction and seismic induced settling. Reports of earthquake damage indicate that differences in the ground types can result in large differences in the damage done. Lees[31] reports, "Bedrock is generally regarded as a sound foundation and alluvium less satisfactory. Alluvium tends to absorb the effects of small earthquakes but to amplify those of larger ones, giving rise to the effect of soil amplification." The Belridge facility is located on alluvium that may have an increased risk of liquefaction and settlement, increasing the potential for process equipment damage.

The likelihood of ground shaking is reported as hazard areas by the US Geological Survey (USGS)[53]. These hazards are expressed in terms of the probability of exceeding a calculated strength. For example, the Project area shows a 2% probability of exceedance of peak ground

accelerations (PGA) of 0.49 g in 50 years, which equates to an annual probability of 1 in 2,500 (4×10^{-4} /year) of the earthquake strength being exceeded each year. The likelihood of peak ground acceleration at the Project site is calculated as:

Probability of Exceedance	Frequency	PGA (g)
10% in 50 years	2×10^{-3} /year (1 in 500 years)	0.26 g
2% in 50 years	4×10^{-4} /year (1 in 2,500 years)	0.49 g

Where: PGA = Peak Ground Acceleration
g = acceleration due to gravity

An earthquake which produces a PGA of 0.6g or greater is estimated to occur at a frequency of less than 1 in 100,000 years (1×10^{-5} /year).

Large earthquakes have the potential to cause damage to below ground lines and storage tanks. Above ground lines and process equipment are designed with some flexibility and are less vulnerable to failure in an earthquake. The CCS Project pipelines are primarily located above ground, with only road crossings passing underground. A review was conducted of reported earthquake damage to process facilities in close proximity to earthquakes to estimate the likelihood of damage.

Kern County Earthquake, 1952 - This earthquake occurred on the White Wolf Fault, twenty-three miles south of Bakersfield, near an oil producing area. Facilities in the area were designed for earthquakes, and generally vessels were well anchored and above ground pipework provided with flexibility. This minimized the reported process damage. However, many storage tanks were damaged, underground linework failed, and two butane storage spheres collapsed due to the failure of supporting columns.

Hyogo-ken Nanbu (Kobe), Japan, 1995 - Two refineries were located about 20 miles from the epicenter of this earthquake. Ground acceleration at these facilities was estimated to be about 0.25g, and no major process damage was reported. Damage occurred to storage tanks and piping joints at a nearby terminal as a result of ground liquefaction.

Kocaeli, Turkey, 1999 - Tupras Refinery was located about 6 miles from the earthquake epicenter. The refinery suffered severe shaking, with a peak ground acceleration estimated at 0.32g. Facilities were built to US earthquake codes, and generally performed well in the earthquake. The refinery was built on solid ground, and did not suffer from serious liquefaction, except at in area on reclaimed land. The earthquake caused significant damage to the tank farm. The spherical pressurized LPG tanks showed no visible damage, and there was no reported damage to process vessels or pipe joints. At a nearby liquefied gas plant, concrete tank supports failed on 2 out of 3 pressurized tanks, although the vessels did not fail.

A report published by the California State Fire Marshal in 1993[8] examined the history of underground hazardous liquid pipeline failures due to earthquake damage, and provides a prediction of the number of incidents as:

0.2 to 0.3g PGA	0.0039 incidents per mile of pipe	3.9×10^{-3} /mile
0.3 to 0.65g PGA	0.035 incidents per mile of pipe	3.5×10^{-2} /mile

The CarbonFrontier CCS Project pipelines and processing equipment will be designed to seismic safety standards which allow some flexibility and movement, although a large earthquake still has the potential to exceed design limits. Above ground pipelines and linework will have a lower likelihood of failure in an earthquake as the lines are not constrained by soil and are designed with some flexibility.

The incident rates for above ground lines have been estimated to be an order of magnitude lower than below ground lines, as follows:

Release Size	**Above Ground Line Failure rate**
Medium	9.8×10^{-7} /mile-year
Large / Rupture	4.2×10^{-7} /mile-year

The risk of an earthquake causing a hazardous release has been included in the overall likelihood of release. An earthquake could result in the failure of the processing equipment, CO_2 pipeline, CO_2 injection equipment or storage tank. These have been added to the generic failure rates summarized in Tables 4.1 and 4.3 for the calculation of release frequencies.

Table 4.1 Predicted Release Frequencies for Carbon Capture and Compression

Equipment	Release Size	Failure Rate	Counts	Release Frequency (per year)
Process Pressure Vessel – feed gas	Large / Rupture	1×10^{-5} per vessel-yr	1 vessel	1×10^{-5}
	2-inch hole	1×10^{-4} per vessel-yr		1×10^{-4}
Pressure Vessel – amine and CO_2	Large / Rupture	1×10^{-5} per vessel-yr	3 vessels	3×10^{-5}
	2-inch hole	1×10^{-4} per vessel-yr		3×10^{-4}
Linework >20-inch feed gas	Large / Rupture	1×10^{-8} per ft-year	300 ft	3×10^{-6}
	2-inch hole	1×10^{-7} per ft-year		3×10^{-5}
Linework 12-inch amine flow	Large / Rupture	6×10^{-8} per ft-year	300 ft	1.8×10^{-5}
	1-inch hole	2×10^{-7} per ft-year		6×10^{-5}
Pumps - amine	Large / Rupture	1×10^{-4} per pump-yr	4 pumps	4×10^{-4}
	1-inch hole	5×10^{-4} per pump-yr		2×10^{-3}
Compressor	Large	4×10^{-4} per compressor-yr	4 compressors	1.6×10^{-3}
	1-inch hole	2.5×10^{-3} per compressor-yr	4 compressors	1×10^{-2}
Pressure Vessels - Compressor and TEG Dehy	Large / Rupture	1×10^{-5} per vessel-yr	7 vessels	7×10^{-5}
	1-inch hole	1×10^{-4} per vessel-yr		7×10^{-4}
Linework 12-inch CO_2 flow	Large / Rupture	6×10^{-8} per ft-year	400 ft	2.4×10^{-5}
	1-inch hole	2×10^{-7} per ft-year		8×10^{-5}
Buffer Drum – dense phase CO_2	Rupture / Instantaneous	1×10^{-6} per vessel-yr	1 vessel	1×10^{-6}
	Large / Rupture	9×10^{-6} per vessel-yr		9×10^{-6}
	1-inch hole	1×10^{-4} per vessel-yr		1×10^{-4}
Pump – dense phase CO_2	Large / Rupture	1×10^{-4} per pump-yr	1 pump	1×10^{-4}
	1-inch hole	5×10^{-4} per pump-yr		5×10^{-4}

Release frequencies shown above are per Carbon Capture facility, assuming the same hazards for all 4 facilities.

Pre-Combustion facility will be located adjacent to Gas Plant 32. It is likely the design will be different from the other 3 capture facilities. Due to uncertainty in the final designs, the same estimated equipment sizes and release frequencies have been assumed for all 4 capture facilities.

Table 4.2 US DOT Natural Gas Transmission Pipeline Ruptures by Cause of Release, Years 2002-2021

Cause	Pipeline Diameter (inches)						Total
	d=<4	4<d =<8	8<d =<12	12<d =<20	20<d =<28	d>28	
External Corrosion	1	5	7	19	13	15	60
Internal Corrosion	1	4	12	4	2	0	23
Total Corrosion	**2**	**9**	**19**	**23**	**15**	**15**	**83**
Ground Movement	1	0	5	8	5	9	28
Other Natural Force	0	0	0	0	1	0	1
Total Natural Force	**1**	**0**	**4**	**9**	**6**	**9**	**29**
External Impact Failure	11	23	24	19	9	4	90
Other External Impact	2	0	2	0	0	1	5
Total External Impact	**13**	**23**	**26**	**19**	**9**	**5**	**95**
Material failure of pipe or weld	2	5	2	15	13	9	46
Environmental Cracking	1	1	3	13	11	6	35
Total Material Failure	**3**	**6**	**5**	**28**	**24**	**15**	**81**
Equipment Failure	0	1	1	1	0	0	3
Incorrect Operation	0	0	1	2	0	0	3
Total Equipment/Operations	**0**	**1**	**2**	**3**	**0**	**0**	**6**
Miscellaneous	0	0	0	1	2	1	4
Unknown/ Under Investigation	0	1	0	2	0	3	6
Total Other	**0**	**1**	**0**	**3**	**2**	**4**	**10**
Total Number of Ruptures	**19**	**40**	**56**	**85**	**56**	**48**	**304**
Million mile-years	0.429	0.944	0.876	1.157	0.959	1.535	5.900
Ruptures per 1,000 mile-years	0.044	0.042	0.064	0.073	0.058	0.031	0.052
Adjusted Ruptures per 1,000 mile-years	0.169	0.110	0.088	0.073	0.058	0.031	0.075

US DOT pipeline data for years 2002 to 2021
Average pipeline diameter for US DOT natural gas transmission pipelines = 19-inches

Table 4.3 Predicted Release Frequencies for Pipeline Transfer

Equipment	Release Size	Failure Rate (per mile-yr)	Counts	Release Frequency (per year)
CO_2 12-inch transfer pipeline Section 32 to Compressor Station 49	Large / Rupture	8.8×10^{-5}	10.7 miles	9.4×10^{-4}
	Medium Hole 2-inch diam	1.6×10^{-4}	10.7 miles	1.7×10^{-3}
CO_2 12-inch distribution lines from CS 49 to sequestration field	Large / Rupture	8.8×10^{-5}	2.3 miles	2.0×10^{-4}
	Medium Hole 2-inch diam	1.6×10^{-4}	2.3 miles	3.7×10^{-4}
CO_2 9 x 6-inch lateral lines to sequestration injection wells	Large / Rupture	1.1×10^{-4}	1.3 miles	1.4×10^{-4}
	Medium Hole 2-inch diam	2.0×10^{-4}	1.3 miles	2.6×10^{-4}
Produced Gas 16-inch Transfer Pipeline Del Sur to SOX 32	Large / Rupture	4.4×10^{-5}	3.6 miles	1.6×10^{-4}
	Medium Hole 2-inch diam	7.8×10^{-5}	3.6 miles	2.8×10^{-4}

Table 4.4 Predicted Release Frequencies for CO_2 Injection Wells

Operational Phase	Failure Rate (per well-year)	Count	Release Frequency	
Injection Well Blowout Full casing diameter flow	1.3×10^{-5}	9 injection wells	1.1×10^{-4} /yr	1 in 9,000 yrs
Injection Well Blowout 2-inch diameter release	3.8×10^{-5}	9 injection wells	3.4×10^{-4} /yr	1 in 3,000 yrs
Wellhead Release 1-inch diameter release	2×10^{-4}	9 injection wells	1.8×10^{-3} /yr	1 in 560 yrs
Monitoring Well Blowout Full casing diameter flow	2.5×10^{-6}	4 monitoring wells	1.0×10^{-5} /yr	1 in 100,000 yrs
Monitoring Well Blowout 1-inch diameter release	2.3×10^{-5}	4 monitoring wells	9.0×10^{-5} /yr	1 in 11,000 yrs
Abandoned Well Release	5.0×10^{-8}	102 wells	5.1×10^{-6} /yr	1 in 200,000 yrs
Total Well Failure Rate			2.3×10^{-3} /yr	1 in 440 yrs

Table 4.5 Predicted Release Frequencies for Amine Truck Transportation and Storage

Equipment	Release Size	Failure Rate	Counts	Release Frequency (per year)
Truck Transportation	Large 5,600 gallons	0.1 x 0.26 MVMT	50 miles per visit 21 visits per year 4 facilities	1.1×10^{-4}
	Small 60 gallons	0.9 x 0.26 MVMT	50 miles per visit 21 visits per year 4 facilities	9.8×10^{-4}
Unloading Hose or Connection Failure	Unloading rate 2,000 lb/min for 1 min	4×10^{-6} per operation	84 per year	3.4×10^{-4}
	Small Failure 0.5-inch diam	4×10^{-5} per operation	84 per year	3.4×10^{-3}
Unloading error or equipment failure	Medium hole / connection 1-inch	1×10^{-5} per operation	84 per year	8.4×10^{-4}
Storage Tank	Rupture	1×10^{-6} per tank	8 tanks	8×10^{-6}
	Medium hole / connection 2-inch	1×10^{-4} per tank	8 tanks	8×10^{-4}
	Tank Overfill	1×10^{-4} per tank	8 tanks	8×10^{-4}

MVMT = million vehicle miles traveled

Table 4.6 Predicted Release Frequencies for Sulfuric Acid Truck Transportation and Storage

Equipment	Release Size	Failure Rate	Counts	Release Frequency (per year)
Truck Transportation	Large 3,000 gallons	0.1 x 0.36 MVMT	50 miles per visit 6 visit per year 4 facilities	4.3×10^{-5}
	Small 30 gallons	0.9 x 0.36 MVMT	50 miles per visit 6 visit per year 4 facilities	3.9×10^{-4}
Unloading Hose or Connection Failure	Unloading rate 2,000 lb/min for 1 min	4×10^{-6} per operation	24 per year	9.6×10^{-5}
	Small Failure 0.5-inch diam	4×10^{-5} per operation	24 per year	9.6×10^{-4}
Unloading error or equipment failure	Medium hole / connection 1-inch	1×10^{-5} per operation	24 per year	2.4×10^{-4}
Storage Tank	Rupture	1×10^{-6} per tank	4 tanks	4×10^{-6}
	Medium hole / connection 2-inch	1×10^{-4} per tank	4 tanks	4×10^{-4}
	Tank Overfill	1×10^{-4} per tank	4 tanks	4×10^{-4}
	Unloading into incompatible chemical tank	1×10^{-6} per delivery	24 per year	2.4×10^{-5}

MVMT = million vehicle miles traveled

5. CONSEQUENCES OF RELEASE

An accidental release of a hazardous material due to equipment or operational failure may result in a serious hazard to personnel or the environment. In the following section, the potential hazards associated with an accidental release are assessed. The potential hazard areas for each scenario are estimated using dispersion modelling software. Potential vulnerabilities of the public have been calculated by applying a probability that a person may suffer injury or fatality at a minimum defined concentration. Environmental exposure to carbon dioxide may also cause harm to plant or aquatic life.

5.1 Material Properties

A summary of stream compositions is shown in Table 2.1, and the material properties used to conduct consequence modeling are shown in Table 5.1. The following data has been selected to represent the worst-case hazards for analysis.

5.1.1 Properties of Carbon Dioxide

Carbon dioxide is a naturally occurring atmospheric gas, normally present in air at about 400 parts per million (400 ppm). It is an odorless, colorless gas under normal temperature and pressure. It doesn't burn, is heavier than air, and at high concentrations is both an asphyxiant and intoxicant. CO_2 is not very reactive and is nonflammable. The most common reaction is with water, to form carbonic acid.

Pure CO_2 has a critical temperature of about 88^{o}F (31^{o}C) and a critical pressure of 1070 psia (73 atm). At temperatures and pressures above these values, CO_2 is in a supercritical state as a dense phase "fluid" with properties between that of a liquid and a gas. Physical properties of CO_2 are summarized in Table 5.1, and the phase diagram shown in Figure 5.1.

Heat is released or absorbed in each of the phase changes across the solid-gas, solid-liquid and liquid-gas boundaries. On release, multiple phase changes occur. The expansion to atmospheric pressure causes a rapid cooling of the gas to minus 125^{o}F (-87^{o}C), and the formation of solid CO_2 (dry ice). As the release mixes with air, water vapor in the air condenses to form a visible fog. Dry ice particles within the air-carbon dioxide mixture may also contribute to the visible fog. The plume will remain visible until the diluted cloud has warmed sufficiently to sublime all the solid particles within it, and for the cloud temperature to be above the 100 % humidity level for the air-carbon dioxide mixture.

A large release of CO_2 will form a very cold dense plume which can travel significant distances, depending on wind and terrain. Under calm or low wind speed conditions, the plume will move downhill, settling into low-lying areas. This occurred following the February 2020 pipeline failure, when a large dense CO_2 plume migrated downhill towards the village of Satartia, Mississippi, approximately one mile from the pipeline.

5.1.2 Properties of Amine Solvents

Amine based solvents are widely used for H_2S and CO_2 extraction from gas streams. Solvents for CO_2 extraction from pre and post combustion gas streams have not yet been selected. However, all proposed solvents, including the proprietary solvents being considered, are amine based. Properties of MEA have been selected for analysis, as this is the most widely used amine solvent in the oil and gas industry.

MEA is a colorless oily liquid with a slight ammonia odor, combustible and stable under normal conditions. It is classified as a corrosive by the DOT, which can cause severe skin burns and eye damage on contact. MEA is typically diluted to about 30% with water for gas extraction. Physical properties of MEA are summarized in Table 5.1.

5.1.3 Properties of Sulfuric Acid

Sulfuric acid is an odorless, semi-oily liquid that ranges in appearance from clear to yellow. It has a density and viscosity greater than water which is why it is characterized as an oily solution. Concentrated sulfuric acid solutions have negligible vapor pressure at ambient temperature, and therefore do not form toxic vapor clouds, unless under high temperature or conditions that may create acid mist or spray.

Concentrated sulfuric acid is highly corrosive, and can cause severe chemical burns on contact with skin or eyes. It is a strong oxidizer, with powerful dehydrating properties, removing water from other chemical compounds. The dehydration reaction is highly exothermic (produces heat), and can result in acid spray or corrosive fumes. Sulfuric acid also reacts with numerous metals to produce flammable and potentially explosive hydrogen gas.

Inadvertent mixing of sulfuric acid with hydrochloric acid or sodium hypochlorite (bleach) may produce highly toxic gases. This has been the cause of several public impact events. Sulfuric acid is neutralized by mixing with the alkalis, such as caustic soda (sodium hydroxide), although reaction is exothermic and may cause high temperatures unless mixed under controlled conditions.

The physical properties of 96% sulfuric acid are summarized in Table 5.1.

5.1.4 Properties of Hydrogen Sulfide

Hydrogen sulfide is a flammable, colorless gas which has the smell of rotten eggs. H_2S will be present in the produced natural gas transferred from Del Sur Compressor Station to SOX 32 for treating and subsequent CO_2 capture. The concentration of H_2S is projected to be in the range of 2,500 ppm. The CO_2 concentration in the Del Sur produced gas is projected to be above 65%, making the gas non-flammable and potentially toxic for both H_2S and CO_2 exposure.

5.2 Toxicology of Hazardous Materials

A toxic, flammable or corrosive liquid release has the potential to cause harm to the public. The concentration and duration of exposure will determine the level of harm. Levels of concern have been selected for public exposure based on established emergency planning criteria, as described below.

For public emergency planning and response, Protective Action Criteria (PAC) have been established for numerous chemicals[48], which are published as Acute Emergency Guideline Levels (AEGLs), Emergency Response Planning Guidelines (ERPGs), or Temporary Emergency Exposure Limits (TEELs).

Three PAC concentrations represent the severity of hazardous material exposure, with Level 1 being the least and Level 3 being the most severe. The levels are established to estimate the concentrations of a substance above which it is predicted that the general population, including susceptible individuals, when exposed for more than one hour, could experience the following:

PAC-1 Could experience notable discomfort, irritation, or certain asymptomatic, non-sensory effects. However, these effects are not disabling and are transient and reversible upon cessation of exposure.

PAC-2 Could experience irreversible or other serious, long-lasting, adverse health effects or an impaired ability to escape.

PAC-3 Could experience life-threatening health effects or death.

IDLH Immediately Dangerous to Life or Health. The maximum airborne concentration of a substance to which a healthy worker can be exposed for as long as 30 minutes without impairment or the ability to escape.

Emergency exposure levels have been established for ethanol amines such as MEA, sulfuric acid, and hydrogen sulfide. However, no public emergency planning criteria have been established for CO_2. Levels have been selected as described below, based on the definitions of PAC levels and symptoms of exposure at various concentrations.

5.2.1 Carbon Dioxide Toxicology

Carbon dioxide gas is odorless, colorless, does not burn, is heavier than air, and at high concentrations is both an asphyxiant and intoxicant. High CO_2 concentrations will increase the concentration of CO_2 in the blood, which impacts the respiratory, cardiovascular and central nervous systems. It can also cause asphyxiation due to a decrease in oxygen concentration, although this is reported to be a secondary effect.

Symptoms from acute exposure to CO_2 gas in air are shown in Table 5.2 for various concentrations and duration of exposure. CO_2 gas can cause disorientation, confusion, and unconsciousness, which can be dangerous for persons caught in the plume, especially those who are driving. The effects of sub-lethal CO_2 exposure are rapidly reversible once the affected person or animal is removed from the elevated CO_2 concentrations.

A concentration of 0.5% is used by US agencies to define the CO_2 concentration in the workplace considered safe for a 40-hour week. An exposure of 3% CO_2 represents the onset of symptoms after a short exposure of 15 minutes. An exposure of 4% CO_2 (IDLH concentration) represents the maximum concentration that a healthy worker can be exposed to for as long as 30 minutes, before escape impairing effects may be experienced. The IDLH level is also often considered the minimum level for the onset of serious harm to the public. The minimum CO_2

concentration that may be immediately life threatening has been proposed as 7% by the US EPA[50].

No public emergency planning criteria have been established for CO_2. Public criteria have been selected based on the definitions of PAC levels and the IDLH as described above. A study performed by the US EPA in 2000 on fire suppressant risks[50], proposed a minimum level of 2% (20,000 ppm) CO_2 for public adverse impacts. Concentrations of 1% to 2% CO_2 correlate to the extent of the visible cloud due to condensed water vapor. This is the level that will clearly cause alarm, and within the visible cloud area there may be higher concentrations that may cause distress to vulnerable populations. A minimum level of concern for the public has been selected as 1% CO_2 due to the potential impact on vulnerable populations, uncertainty in dispersion, and the extent of a visible cloud.

The CO_2 concentration that may result in adverse health effects or an impaired ability to escape has been selected as 3%. As described in Table 5.2 Toxicological Effects of CO_2, at 3% concentration, breathing may increase to twice the normal rate, with an increase in blood pressure and pulse rate. This may impair the ability of vulnerable populations to escape.

The following CO_2 concentrations have been selected for public emergency criteria:

PAC-1 = 1% (10,000 ppm)
PAC-2 = 3% (30,000 ppm)
PAC-3 = 4% (40,000 ppm)

5.2.2 Amine Toxicology

Liquid or spray mist may produce tissue damage particularly on membranes of eyes and mouth. Inhalation of the spray mist may produce severe irritation of the respiratory tract, characterized by coughing, choking, or shortness of breath. Liquid contact causes local injury to skin, eyes, mouth and throat. First degree burns occur on short exposure, and secondary burns may occur on longer exposure. Personal protective equipment (PPE) should be worn for safe handling.

Emergency response thresholds for public exposure to MEA have been published by the DOE[48] as:

PAC-1 = 6 ppm
PAC-2 = 170 ppm
PAC-3 = 1,000 ppm

5.2.3 Sulfuric Acid Toxicology

Sulfuric acid injuries may occur due to contact with the skin or eyes. Liquid contact with the skin causes serious burns as the acid reacts with water in the skin. Liquid contact with the eyes may cause irreparable damage and blindness. Inhalation of the spray mist may produce severe irritation of the respiratory tract, characterized by coughing, choking, or shortness of breath. A spray may occur on release which then falls to the ground as the liquid droplets lose momentum. An aerosol of tiny droplets may form if the release is at high pressure.

Emergency response thresholds for public exposure to sulfuric acid have been published by the DOE[48] as PACs. For sulfuric acid, these are the same as the AEGLs, developed by the National Advisory Committee for the Development of Acute Exposure Guideline Levels for Hazardous Substances (NAC/AEGL committee). Exposure limits for aerosols and sprays are typically quoted by liquid weight in the air as milligrams per cubic meter (mg/m^3). The following sulfuric acid concentrations have been selected for public emergency criteria:

PAC-1 = 0.2 mg/m^3
PAC-2 = 8.7 mg/m^3
PAC-3 = 160 mg/m3

5.2.4 Hydrogen Sulfide Toxicity

Hydrogen sulfide is a highly irritant gas that attacks the nervous system and causes respiratory paralysis. At lower concentrations (between 0.2 ppm and 100 ppm by volume) H_2S has the easily recognizable smell of rotten eggs, which alerts people of the need to escape. Above an exposure level of about 30 ppm, eye and throat irritation becomes more severe, and may cause injury to sensitive populations. Above about 100 ppm the sense of smell is inhibited, and at lethal concentrations H_2S cannot be detected by smell. The toxicological effects of H_2S are summarized in Table 5.3.

The levels of public concern for significant injury and potential fatality for exposures of up to an hour are the ERPG levels 2 and 3, developed by the American Industrial Hygiene Association (AIHA). The ERPG-1 level is set as 0.1 ppm, which is the minimum concentration for the detection of odor. The DOE PAC level 1 is 0.5 ppm, which is a level for increasing discomfort, and has been selected for the level of potential public concern.

PAC-1 = 0.5 ppm
ERPG-2 = 30 ppm
ERPG-3 = 100 ppm

5.3 Environmental Toxicity

A release of CO_2 to the atmosphere has the potential to impact flora, fauna and surface waters. It is expected to have a similar impact on mammals as humans, with the effect dependent on the mammal behavior and body size[14] . Habitat in the Project vicinity is generally disturbed by oil and gas exploration and production. Surrounding properties include areas used for agriculture, grazing, and undeveloped private land. There may be insects, reptiles, and small mammals impacted by a potentially hazardous release.

The potential impact of CO_2 on plants and soils may occur due to a change in the soil acidity and root asphyxiation. Lake et al. (2012)[29] conducted an experiment to determine the impact of a pipeline rupture on plants. No significant impacts on plant biochemistry were observed, and plant growth was not affected 3 months later. It was concluded that the effects on plants of a catastrophic CO_2 leak are likely to be small and short term. Over a longer duration CO_2 release, there may be effects on local flora. This has been observed at locations where there are natural CO_2 seeps to the surface in geologically active areas.

A release of CO_2 into the environment could potentially affect surface waters during short-term or long-term releases. CO_2 reacts with water to form carbonic acid which increases the acidity of water. At a concentration of greater than 2% CO_2, the increase in acidity may kill fish in the water, and at 1%, the water may be mildly toxic, Saripalli et al. (2003)[38].

A study has been conducted on surface waters in the vicinity by Stantec (2022)[41]. As described in Section 2.4, no surface aquatic resources were identified that may be at risk due to a potentially hazardous release.

5.4 Selected Levels of Concern and Vulnerability Criteria

Public levels of concern have been selected based on public emergency response criteria. These have been selected as PAC-1 concentration, the minimum level for mild transient effects, PAC-2 concentration, which may result significant injury, and PAC-3 concentration, which is the minimum concentration which may result in serious harm or fatality.

Personnel exposed to a minimum level of concern are not necessarily injured. Personnel may be sheltered within buildings or cars, or be able to find shelter from exposure. This is called the vulnerability, and is the probability that a person exposed within the distance to a level of concern will suffer an injury or fatality.

Toxic exposures are not at the same level within the distance to a level of concern. As you get closer to the source of the release, the toxic concentration increases, until near the source there may be a potentially lethal concentration. Average vulnerabilities have therefore been estimated within the range for levels of concern.

5.4.1 Carbon Dioxide Levels of Concern

The release of dense phase CO_2 will vaporize to form a cold dense cloud which initially spreads in all directions, then downwind as it disperses. Physical barriers such as buildings and vehicles may significantly reduce the risk of exposure and ability of personnel to escape. Public levels of concern have been selected based on public emergency response criteria. These have been selected as PAC-1 concentration, the minimum level for mild transient effects, PAC-2, which may result significant injury, and PAC-3, which may result in serious health concerns.

Severity Level	CO_2 Concentration	Release Duration	Vulnerability In Vehicles or Buildings	Vulnerability Outdoors
Level of Public Concern	PAC-1 1%	Continuous release	0.25	1
Potential for Significant Injury	PAC-2 3%	Continuous release	0.25	1
Potential for Serious Harm or Fatality	PAC-3 4%	Continuous release	0.25	1

These severity levels represent the potential for levels of concern proposed by government agencies. However, a CO_2 concentration of 4% may not be life threatening for the majority of the population. The minimum CO_2 concentration that may be immediately life threatening has been proposed as 7% by the US EPA[50], and a CO_2 concentration of 10% or higher may cause

unconsciousness within a few minutes. The UKHSE[44] and the Dutch RIVM[4] have developed time-concentration equations for predicting the likelihood of fatality, which are consistent with those proposed by the US EPA. These time-concentration predictions give a conservative estimate of 50% fatality at 10% concentration of CO_2 for a 20 minute exposure in the general population. These vulnerabilities have been applied for the comparison of risks to established international criteria, as described in Sections 6 and 7.

5.4.2 Well Release Levels of Concern

A release from a CO_2 injection well will have the same levels of concern for toxic exposure as described above for a CO_2 release for personnel in the vicinity.

A review of reported hazards associated with CO_2-EOR well blowouts did not identify any reports of serious injury or fatality events. Two events were identified that required evacuation of nearby residents over a 20 year period, although one of these was reported to be due to H_2S being present in the naturally occurring CO_2.

5.4.3 Explosion Overpressure Levels of Concern

The catastrophic failure of a CO_2 process vessel may result in a BLEVE and explosion overpressure hazards. Personnel hazards include:

- The rapid transition of dense phase liquid from supercritical to atmospheric pressure can create shock waves that cause damage, fatalities, and injuries.
- The cold liquid released may freeze personnel in the immediate vicinity.
- Vessel fragments may be projected with force.

Most injuries and fatalities which result from an explosion overpressure occur due to falling masonry, equipment or flying glass, not directly from the explosion overpressure. Personnel within buildings are therefore more vulnerable to injury or fatality. Personnel outside can physically withstand much high levels of overpressure, and mainly suffer casualties due to debris. The effects of overpressure on personnel and equipment are summarized in Table 5.3.

The effects of overpressure have used to define the levels of concern for the public as follows:

Severity Level	Overpressure	Vulnerability In Buildings	Vulnerability Outdoors
Level of Public Concern Potential minor injury indoors	0.5 psi	0.5	0.1
Potential for Significant Injury	2 psi	0.5	0.2
Potential for Serious Harm or Fatality	3 psi	1	0.5

5.4.4 Ethanol Amine Levels of Concern

The hazards associated with an ethanol amine release incident will occur in close proximity to the release, due to contact or inhalation of a liquid spray or mist. Ethanol amine release incidents were reviewed from DOT and NRC records over a 20-year period. There were a total of 172 amine facility releases reported and no casualties, as listed in Table 3.1. There were a

total of 22 unloading release incidents, 2 of which resulted in minor injuries to employees, as listed in Table 3.3. No public personnel are anticipated within process or unloading areas.

During truck transit, a vehicle collision or equipment failure may result in an ethanol amine release. Over the 20-year period searched there were a total of 28 bulk truck release incidents, an average of 1.4 per year, with no reported injuries associated with amine exposure. Due to the possibility of public or response personnel being in the immediate vicinity of a release during transit, an estimate has been made of the likelihood of a truck incident and release on the Highway 33, adjacent to the Project area, as shown in Table 4.5. The likelihood of public injury due to a transportation release has been conservatively estimated as 1 in 100, due to very few amine injuries being reported from any release source.

5.4.5 Sulfuric Acid Levels of Concern

The hazards associated with a sulfuric acid release incident will occur in close proximity to the release, due to contact or inhalation of a liquid spray or mist. No public personnel are anticipated within process or unloading areas, and therefore no levels of public concern have been selected.

During truck transit, a vehicle collision or equipment failure may result in a sulfuric acid release. Over the 20-year period searched there were a total of 216 bulk truck release incidents, 13 of which resulted in reported casualties. Public personnel or emergency responders were exposed to sulfuric acid releases in 11 of the injury incidents, as listed in Table 3.4. Concentrated sulfuric acid is highly corrosive, and can cause severe chemical burns on contact with skin or eyes. An estimate has been made of the likelihood of a truck incident and release on the Highway 33, adjacent to the Project area, as shown in Table 4.5. The likelihood of public injury due to a transportation release has been estimated as 1 in 20, based on historical incident reports.

Inadvertent mixing of sulfuric acid with an incompatible chemical may occur due to a truck being unloaded into the wrong storage tank. The mixing of sulfuric acid with hydrochloric acid or sodium hypochlorite (bleach) may produce highly toxic gases. This has been the cause of several public impact events. However, bulk hydrochloric acid is not anticipated to be stored at the carbon capture facilities, and sodium hypochlorite will not be stored in bulk. It is therefore unlikely that a highly toxic gas will be released due to inadvertent mixing that could impact the public off-site. The likelihood of error will also be minimized by equipment design, personnel training, and the implementation of unloading procedures.

5.4.6 Hydrogen Sulfide Levels of Concern

The toxicological effects of hydrogen sulfide exposure are shown in Table 5.4. The severity level is dependent on both the duration and concentration of exposure.

The minimum level of concern for hydrogen sulfide exposure for the public has been selected as 0.5 ppm. This is the level where some mild transient discomfort may be experienced, and potential public alarm. The concentration which may result in significant health concerns is the ERPG-2 level of 30 ppm, and the minimum concentration that may result in serious harm or fatality is the ERPG-3 / IDLH level of 100 ppm.

Severity Level	H_2S Concentration	Vulnerability In Buildings	Vulnerability Outdoors
Level of Public Concern	PAC-1 0.5 ppm	0.25	1
Potential for Significant Injury	ERPG-2 30 ppm	0.25	1
Potential for Serious Harm or Fatality	ERPG-3 100 ppm	0.25	1

5.5 Modeling Hazardous Releases

Potentially hazard release scenarios have been identified as summarized in Table 3.4. The likelihoods of these scenarios have then been estimated based on historical data, generic failure rates, and analogous systems in Section 4. The methodologies for calculating the release rates and hazards of a potential release are described in the following section. Distances to potential casualties have been calculated as described below using published formulas and publicly available dispersion models. The dispersion calculations have been performed to hazardous levels of concern defined in Section 5.4 above. These methodologies are expected to provide conservative results.

5.5.1 Release Rate Calculations

Release rates were calculated using standard engineering equations for liquid and gas releases. It has been assumed that the releases are essentially continuous, and will develop to the maximum hazard condition before the source is isolated. Where the release rate is greater than the flow feeding the line, the flow rate has been assumed to be the maximum release rate.

Liquid Release Rate

Liquid release rates have been calculated using Bernoulli's flow equation, as described in the EPA Risk Management Program (RMP) Guidance for Offsite Consequence Analysis[51]. This assumes the fluid pressure is maintained in the vessel or pipeline, and fluid does not flash to two phase prior to release. A two phase release is initially determined by the sonic liquid outflow. As the liquid decompresses, the release rate decays rapidly.

Gas Release Rate

The equation for estimating the release rate of gas from a hole under choked conditions is described in the EPA RMP Guidance[51].

CO_2 Pipeline Release

When a pipeline ruptures, the dense phase gas will flow out of the pipeline at the speed of sound. The pressure and release rate decays rapidly as the pressure in the pipeline falls. As the pressure reduces, CO_2 remaining in the pipeline will transition from being a supercritical fluid phase, to a two-phase liquid and ultimately to gas phase. The released fluid will initially flash to a vapor-liquid with entrained aerosol, and then to a vapor-solid as the pipeline pressure reduces. Three phases may be present at any one time. Dry ice particles may be entrained in the escaping jet, increasing the density and potential size of the plume. Under some conditions, dry ice may rain-out.

The release rate decay was calculated over time using the Morrow decay model described in the TNO Yellow Book[13]. This model was initially developed for releases of LPG from long pipelines. The model is applicable as long as the pressure at the exit is higher than the triple point pressure (75 psig), when dry ice may form in the pipeline. Since maximum hazard distances are determined during the initial high release rate, solidification of CO_2 inside the pipeline below the triple point will not affect the hazard distance calculations[54].

For a full guillotine pipeline rupture, there will be flow from both ends of the pipeline break, doubling the calculated release rate.

Gas Transfer Pipeline Release

When a gas pipeline ruptures, the pressure and release rate decays rapidly over the first minute. The release rate decay was calculated using the Wilson decay model described in the TNO Yellow Book[13], which predicts the mass flow rate as a function of time.

Process Vessel or Pressurized Storage Tank Failure

For a vessel failure, the entire contents of the vessel and connecting lines are assumed to be released within 1 minute. For a hole sized failure, a continuous steady state release was assumed.

5.5.2 Momentum Dispersion

A high-pressure liquid or gas is released with an initial velocity of several hundreds of meters per second. The direction, amount of mixing with air and distance the jet travels are then mainly determined by the velocity of the jet. As the jet loses momentum by mixing with air or impingement, jet momentum will be low enough for the wind speed to have a significant effect in dispersion. Impingement of a jet may significantly reduce the initial behavior and velocity of the release. For example, a jet release within a carbon capture facility is likely to impact equipment, reducing the momentum of the release.

Dense phase CO_2 dispersion was modeled using the SLAB model. The model was developed by the Lawrence Livermore National Laboratory of the United States to simulate the dispersion of dense gases. The code for SLAB is publicly available from the US EPA website, and simulates denser-than-air gas releases for both horizontal and vertically jets.

5.5.3 Low-Momentum Vapor Dispersion

For toxic vapor releases at ground level, the SLAB model was primarily used for calculating heavy gas dispersion. In addition, vapor releases at ground level without significant momentum, the US Environmental Protection Agency and National Oceanic and Atmospheric Administration ALOHA[52] model was run for comparison. This is a publicly available model and is widely used for estimating release distances. Two types of dispersion may be modeled in ALOHA, neutrally buoyant and heavy gas release. A neutrally buoyant plume has approximately the same density as air, and has been used for dispersion of produced gas releases. This model is based on a simple approach described in Turner's Workbook (1974)[43]. The heavy gas model in ALOHA is based on a simplified form of the DEGADIS model developed by Spicer and Havens (1989)[40].

A heavy gas such as CO_2 will travel further along the ground due to gravity slumping. Under these conditions, topographical features can direct the flow of the gas, and gas can accumulate in lower lying areas. A flat-terrain is generally considered the worst-case for hazard distances, although there may be higher concentrations within depressions near to the release source.

Low momentum dispersion models are unable to predict the behavior of dense clouds in very low wind or calm conditions. Models do not accurately predict conditions of "calm" wind less than 1.5 m/s. This is the most hazardous condition for dense gas releases, and the models may therefore under-predict the hazard distances.

5.5.4 Boiling Liquid Expanding Vapor Explosion (BLEVE)

The sudden rupture of a tank or vessel containing dense phase CO_2 may cause a BLEVE. This involves a violent explosion due to the rapid flashing and expansion of vapor, and fragmentation of the vessel. If this occurs, there is the possibility for escalation to nearby equipment due to the explosion overpressure and flying debris.

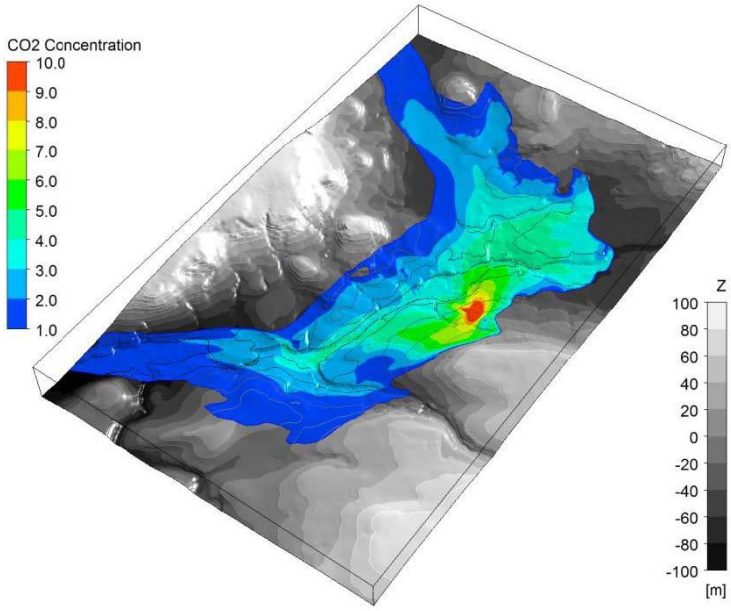
The calculation of explosion energy has been made using the change in internal energy at the storage conditions, compared to the internal energy of vapor at the triple point. The methodology used is as described in the 2010 book, Guidelines for Vapor Cloud Explosion, Pressure Vessel Burst, BLEVE and flash fire hazards, by CCPS[11].

5.5.5 CO_2 Release and Dispersion Model Verification

The properties and dispersion behavior of a large CO_2 release is complex and not well understood. There are few reports to compare theory to actual incidents. Depressurization of the pipeline on release results in a multiphase release, and determines the speed and release rate decay. Experiments and theoretical calculations have been performed by researchers to improve understanding, but there are many uncertainties associated with the source modeling, and dispersion behavior.

Experiments have been performed to better understand the behavior of a large dense CO_2 cloud. These have demonstrated that dispersion is initially determined by gravity spreading, not by wind speed or direction. The terrain can also have a large effect on the dispersion. Flat terrain is assumed for most dispersion models. A more realistic terrain can be applied with computational fluid dynamic (CFD) codes, though these are complex models. These simulate the impact of typical geographical features on flow dynamics. However, the many assumptions and uncertainties in the models still make it only an approximation.

For the EU CO2PipeHaz project, (2010-2013)[18] CFD dispersion modeling was performed to simulate a pipeline rupture. The results indicate that even with a wind speed of 5 m/s, the presence of the terrain has a large effect on the dispersion of the CO_2 cloud. Rather than being blown downwind, the cloud spread mostly in lateral directions, up and down the simulated valley. The simulated vapor cloud spread is depicted below. This behavior has been reported following the Satartia pipeline rupture in 2019, when the CO_2 cloud travelled down a valley to the village of Satartia 1 mile away.



CO_2 dispersion predictions using a CFD model.
Ref: Woolley et al, CO2PipeHaz Project, GHGT-12, 2014[55]

5.6 Calculation of Hazard Distances to Levels of Concern

Hazard distances for the identified release scenarios have been calculated to the vulnerability levels of concern defined in Section 5.4 above. These represent the minimum exposure levels that may result in a public exposure of concern.

The following assumptions were made in calculating the hazard distances:

- Two representative weather conditions have been selected for performing the dispersion calculations under worst-case and typical conditions; Stability Class F with wind speed of 1.5 m/s, and Stability Class D with wind speed of 4 m/s, as described in Section 2.6. Calm conditions of less than 0.5 m/s wind occur approximately 3% of the time, when the hazard distances may be greater.
- Typical industry shutdown systems and safeguards have been assumed in the calculation of release quantity and duration.
- Dense phased CO_2 will flash to a mixture of gas and dry ice particles on release. Solid particles are assumed to be entrained with no rainout, and will sublimate on dilution with air.
- Process releases were modeled assuming typical operating temperatures and pressures.
- A release is assumed to be continuous for the purpose of quantifying the maximum hazard distance, except where instantaneous
- Rural conditions have been applied for atmospheric dispersion of vapor clouds.
- No allowance was made for topography in the dispersion calculations. However, the ground slopes to the SE, and large dense gas releases of CO_2 may tend to drift downhill.

This may increase the risk to offsite populations in the agricultural areas and on the highway.

The direction and momentum of a release may significantly affect the hazard distances. For release scenarios where this would make a significant difference, conservative assumptions were made to calculate the worst-case hazard distance. High-momentum releases will have greater amount of initial air dilution and mixing, whereas low momentum releases will have a higher initial concentration due to less air entrainment. Jet impingement may occur which reduces the release momentum, such as when a release is directed downwards, towards objects, or two ends of a pipeline rupture are directed towards each other. An impinged jet results in a loss of momentum, less initial dilution and greater hazard distances.

Calm weather conditions of less than 0.5 m/s wind occur about 3% of the time. Vapor dispersion models do not adequately predict hazard distances at very low wind speeds, and under these conditions, hazard distances may be greater.

The calculation of hazard distances for each scenario to selected levels of concern for the public are described below, and the results are shown for each scenario in Tables 5.5 to 5.9.

5.6.1 Carbon Capture and Compression Release Hazard Distances

The carbon capture facilities will handle large quantities of feed gas from produced gas and post-combustion flue gas. On release, the feed gas will quickly disperse to below hazardous concentrations. After CO_2 is removed from the feed gas using amine absorption, the CO_2 gas flow is near 100% concentration and potentially more hazardous on release. Gas flows overhead from the CO_2 stripper and through the compression train are modeled as 100% CO_2, at increasing pressure. The stripper pressure will be in the order of about 20 psig with line diameters of about 24-inches. The pressure is increased through 4 stages of compression and dehydration to 1,300 psig with line diameters of about 8-inches. After compression, dense phase liquid CO_2 flows to a buffer drum prior to being pumped to the CO_2 transfer pipeline. The vessel has been assumed to contain 15 minutes of buffer capacity, and on failure could result in the greatest hazard distances.

A major line or vessel failure will result in rapid release of the section contents and automatic shutdown. It has been assumed that the vessel and connecting line contents will be released within 1 minute. A medium sized hole or connection failure has been modeled as a continuous release with a fully developed vapor cloud. Worst-case release scenarios are assumed to occur when the release is impinged and the momentum dissipates quickly.

Hazard distances to CO_2 levels of concern are shown in Table 5.5 for vessel failure scenarios, major line failures, and representative hole releases for a range of pressures in the capture facility.

5.6.2 CO_2 Pipeline Release Hazard Distances

A large hole or line rupture of the CO_2 pipeline will result in the rapid release of the entire pipeline contents. It has been assumed that the loss of pressure will activate the automatic SCADA shutdown system, limiting the release quantity to the pipeline contents. The release

rate will decay rapidly as the contents of the pipeline are released. Within seconds the release rate will have dropped to a fraction of the initial peak value. The maximum cloud size develops in the first few minutes to form a dense cold cloud which initially spreads in all directions.

On release, rapid pipeline depressurization results in multiphase release. Experiments and theoretical calculations indicate that solid CO_2 contents of up to about 36% by mass may occur. On mixing with air, the entrained dry-ice will sublimate reducing the temperature of the cloud.

The maximum discharge rate will occur in the first few seconds of the release, and reduce to about one-tenth the initial flow rate within 5 minutes. The release rate has been averaged over the first 5 minutes, and modeled as an instantaneous release for estimating hazard distances. Approximately 30% of the pipeline contents will be rapidly released in the first 5 minutes, then the release rate will gradually reduce. The initial rapid release may occur from both ends of a guillotine rupture, and the quantity has been doubled to account for this.

The hazards to personnel will be in the immediate vicinity when a failure occurs, and in the path of the dispersing gas cloud. Depending on the weather conditions and wind direction, a large release may impact public populations in areas such as the solar farm and nut farms to the east of Highway 33. Personnel in vehicles may also be impacted if a cloud of sufficient concentration causes vehicle engines to cut out. Oil production workers in non-Aera owned facilities may also be at risk of exposure.

A medium sized failure equivalent to a 1 or 2-inch hole, will be sustained by CO_2 within the pipeline, and is assumed to be a continuous horizontal jet release. The reduction of pipeline pressure may initiate an alarm and shutdown. Aera personnel in close proximity to the pipeline may be exposed to a hazardous CO_2 concentration, although the hazard is unlikely to impact public areas. Greater hazards may occur when there is calm or very low wind conditions, and in areas where the topography may inhibit dispersion of the dense cloud.

Hazard distances to CO_2 levels of concern for pipeline release scenarios are shown in Table 5.6.

5.6.3 Injection Well Release Hazard Distances

Four potential hazard scenarios have been identified:

- Full wellhead failure, resulting in a vertical jet blowout.
- Wellhead failure equivalent in size to a horizontal 2-inch diameter hole.
- Wellhead equipment failure, equivalent to a horizontal 1-inch diameter hole
- Well casing failure and migration to surface.

Hazard distances to CO_2 levels of concern for these scenarios are shown in Table 5.7 and described below.

Full Wellhead Failure with Vertical Jet

A worst-case wellhead failure may result in the release of CO_2 from an open well bore. This has been assumed to be directed vertically. The depth and diameter of the well bore has been used to estimate the initial release volume, and the release rate calculated assuming an open ended decompressing pipeline. The initial release rate has been calculated as an average of 10,000

lb/hr (74 kg/s) during the first minute. The initial flow rate declines quickly as CO_2 is released, and flow from the well is constrained by multiphase flow. Pressure and CO_2 flow from the formation into the well bore may extend the flow duration, and an average flow rate of 4,000 lb/hr (30 kg/s) has been estimated for the first hour.

The release will rapidly expand and cool, resulting in cooling below the freezing point and formation of dry ice. The release will cause a hazard to personnel in the immediate vicinity of the wellhead. The dense vertical jet has been modelled used the SLAB model to estimate downwind CO_2 concentrations. The vertical plume will slump to ground over 100 feet from the wellhead during average wind speeds during the day, with ground level concentrations up to about 3% of CO_2. The maximum hazard occurs in low wind conditions because the carbon dioxide may slump to the ground and accumulated within 50 feet of the wellhead.

2-inch Diameter Horizontal Wellhead Release

A wellhead failure the equivalent size to a 2-inch hole has been selected to represent a large blowout, with a narrow horizontal jet to represent the worst-case threat to personnel in the vicinity. The volume of CO_2 within the wellbore has been used to estimate the potential sustained flow as 1,300 lb/min (10 kg/s).

1-inch Diameter Release from Injection Equipment

A failure of wellhead injection equipment, connection or line, equivalent to a 1-inch hole has been selected to represent a medium sized blowout. A horizontal jet direction represents the worst-case threat to personnel.

Well casing failure and migration to surface

A well bore leak and migration to the surface is likely to be a low velocity diluted release, which may result in an accumulation of CO_2 in the immediate vicinity of the wellhead in calm wind conditions. Underground CO_2 migration from a well bore leak may also find a pathway to the surface via a monitoring or abandoned well bore. This scenario will result in a slow dissipated release and therefore has not been included in the analysis of acute hazards to personnel. However, if undetected, it may cause some local ground level hazards.

5.6.4 Leakage of CO_2 From Sequestration Reservoir

A release of CO_2 may occur due to leakage from the storage reservoir to the surface. This may be caused by leakage via wellbores, fault or fractures, caprock failure, or seismicity.

The rate of wellbore leakage has been simulated by Letellier et al[32]. They concluded that the rate of leakage from a single wellbore with high permeability due to poor quality construction may result in a CO_2 leakage rate of up to 210 lb/min (1.6 kg/s) at the caprock, assuming the plume has reached the wellbore. As the flow progresses through the wellbore, this is likely to be diverted by sinks above the caprock, resulting in a release in the range of 0.1 to 30 lb/min (0.001 to 0.23 kg/s). This release rate is highly unlikely to result in concentrations of concern to the public.

Letellier et al[32] also simulated leakage through a fault and concluded that the median rate for a highly permeable fault is in the range of 13 lb/min (0.1 kg/s). This is in the same order of magnitude as natural volcanic leaks measured in Latera, Italy, which have caused very little impact on the population or ecosystem.

CO_2 leakage from sequestration is likely to result in a slow dissipated release, which is unlikely to be acutely hazardous except if undetected vapors accumulate in low lying areas.

5.6.5 CO_2 BLEVE Hazard Distances

A catastrophic vessel failure may result in the almost instantaneous release of the entire contents. Rupture of a vessel containing pressurized, liquefied CO_2 may be regarded as a BLEVE, causing explosive overpressure with vessel fragments thrown as projectiles. Incidents have occurred due to accidental over-pressurization and / or vessel embrittlement.

Hazard distances for the dispersion of toxic CO_2 concentrations are greater than the localized overpressure hazard, although the overpressure will impact all directions, and personnel within buildings may be more vulnerable than those outside. There is also the possibility of a few large vessel fragments being projected significant distances, but the hazard to nearby populations is primarily due to toxic vapor dispersion.

Explosive release may occur due to the failure of a CO_2 storage tank, CO_2 buffer tank at one of the CO_2 Compression facilities, or a CO_2 cargo truck. The calculated explosion hazard distances to overpressure levels of concern are shown in Table 5.8.

5.6.6 Amine Transportation and Storage Hazards

Potential amine releases have not been modeled to estimate impact areas. The likelihood that an ethanol amine release will occur during transportation has been calculated from generic failure rate data, as described in Section 4.4. The probability that a release will result in injury to public personnel has been estimated as 1 in 100 incidents, based on historical incident reports.

5.6.7 Sulfuric Acid Transportation and Storage Hazards

Potential sulfuric acid releases have not been modeled to estimate impact areas. The likelihood that a sulfuric acid release will occur during transportation has been calculated from generic failure rate data, as described in Section 4.5. The probability that a release will result in injury to public personnel has been estimated as 1 in 20 incidents, based on historical incident reports.

5.6.8 Produced Gas Transfer Pipeline

The produced natural gas transfer line from Del Sur Compressor Station to SOX 32, is projected to contain about 65% CO_2 and 2,500 ppm H_2S. The high concentration of CO_2 makes the gas inflammable, although in the event of a large release, personnel in the vicinity may potentially be exposed to a toxic level of H_2S or CO_2. The 16-inch aboveground line will operate at about 170 psig, and contain a significant inventory of gas.

A potential failure of the produced gas transfer line has been modeled for potential toxic exposure to both H_2S and CO_2. Gas dispersion hazard distances to the levels of concern are shown in Tables 5.5 and 5.9 for a pipeline rupture and 2-inch failure. Hazard distances to levels of concern for H_2S are greater than those of CO_2 except in close proximity to a failure. Produced gas is diluted almost immediately on release to below 700 ppm H_2S, then becomes a more significant hazard than CO_2 when diluted to less than about 100 ppm, the IDLH value. The greater toxic hazard has been selected for calculations of potential impact.

Figure 5.1 Phase Diagram for CO_2

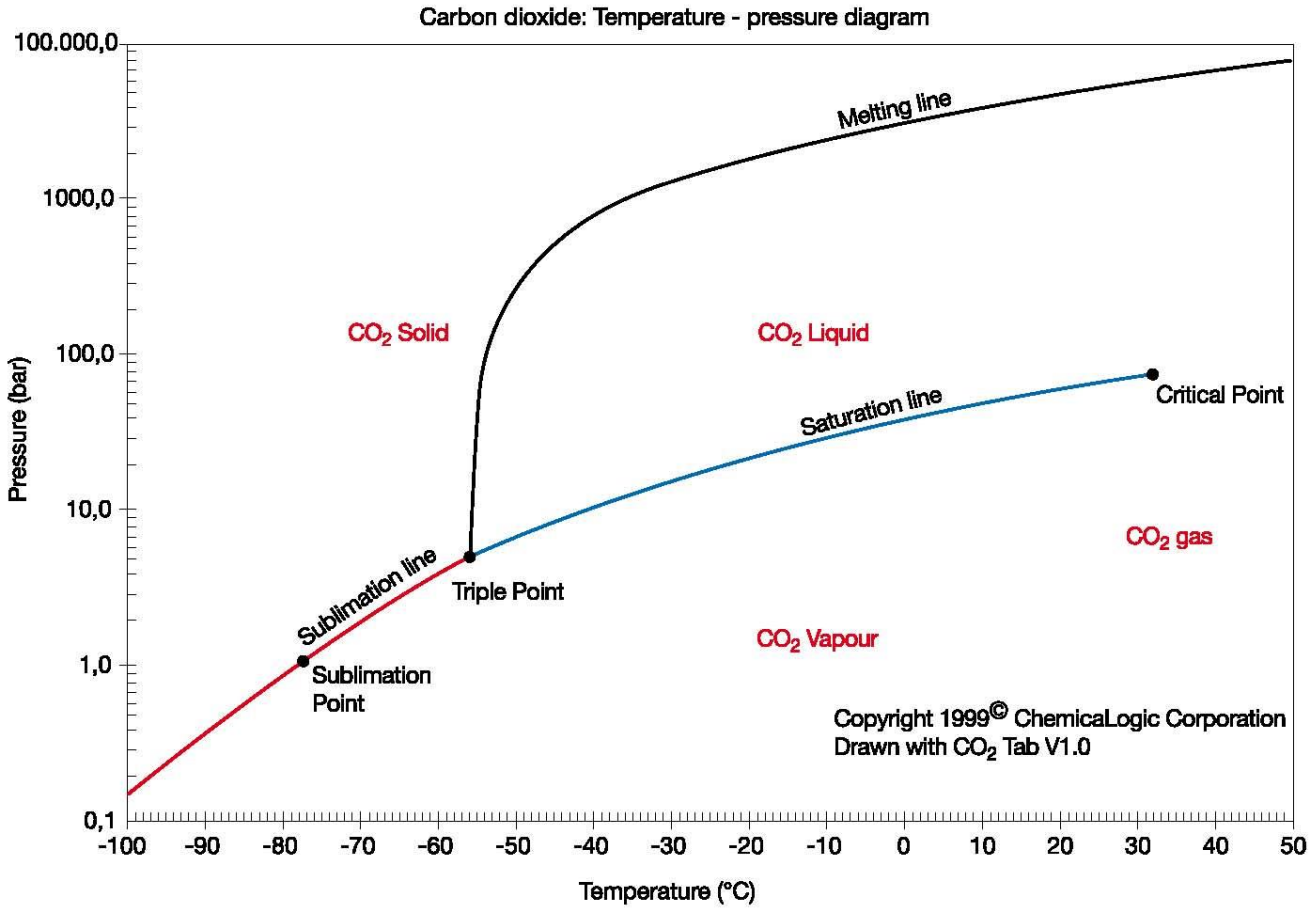


Diagram from IPCC Special Report 2005[26]

Table 5.1 Physical Properties of Chemicals

Property	Carbon Dioxide [26]	MEA	Sulfuric Acid 96%
Molecular Weight (g/gmol)	44.01	61.08	98.08
Formula	CO_2	$H_2NCH_2CH_2OH$	H_2SO_4
Boiling Point (at 1 atm)	-110.2°F (-78.5°C)	338°F (170°C)	554°F (290°C)
Melting Point	-110.2°F (-78.5°C)	51°F (10°C)	7°F (-14°C)
Flash Point (closed cup)		185 F (85 C)	
Triple Point temperature	-70°F (-56.5 °C)		
Triple Point pressure	75 psig (5.18 bar)		
Gas Phase			
Specific Gravity (Air=1)	1.51		3.4
Gas density (STP)	0.123 lb/ft^3 (1.976 kg/m^3)		
Cp/Cv	1.308		
Liquid Phase			
Specific Gravity (Water=1)		1.016	1.836
Vapor pressure (at 68°F)	848 psig (58.5 bar)	0.75 mmHg	0.001 mmHg
Liquid density (at -13°F and 218 psig)	66.2 lb/ft^3 (1060 kg/m^3)		
Liquid density (at 77°F and 1,300 psig)	50.6 lb/ft^3 (810 kg/m^3)		
Liquid density (at 100°F and 1,700 psig)	44.3 lb/ft^3 (710 kg/m^3)		
Solid Phase			
Density at freezing point	97.5 lb/ft^3 (1562 kg/m^3)		

Where STP = Standard Temperature and Pressure, 60^{o}F and 1 atm.

Table 5.2 Toxicological Effects of Carbon Dioxide

CO_2 Concentration in Air	Potential Health Effects 2010 Energy Institute CCS Guidance[16] and USEPA 2000[50]
1 %	Slight increase in breathing rate, possible drowsiness. Possible adverse effects on susceptible groups.
2 %	Breathing rate increases to 50 % above normal level. Prolonged exposure can cause headache, tiredness.
3 %	Breathing increases to twice normal rate and becomes labored. Weak narcotic effect. Impaired hearing, headache, increase in blood pressure and pulse rate.
4 %	IDLH – Maximum concentration from which one could escape without experiencing escape impairing or irreversible health effects within 30 minutes.
4-5 %	Breathing increases to approximately four times normal rate; symptoms of intoxication become evident and slight choking may be felt.
7 %	Minimum concentration that may be immediately life threatening, as proposed by the US EPA[50].
5-10%	Characteristic sharp odor noticeable. Very labored breathing, headache, visual impairment, and ringing in the ears. Judgment may be impaired, followed within minutes by loss of consciousness.
10-15 %	Within a few minutes exposure, dizziness, drowsiness, severe muscle twitching, unconsciousness. Possible fatality.
17-30%	Within one minute, loss of controlled and purposeful activity, unconsciousness, convulsions, coma, death.

IDLH levels are published by the National Institute for Occupational Safety and Health (NIOSH)

Table 5.3 Explosion Overpressure Hazards

Overpressure (psi)	Description of Human Impact	Description of Equipment Impact
0.5	Possible minor injury from broken glass or falling fixtures	Windows may be broken
1	Skin laceration from flying glass and other debris may require medical attention. Creates equivalent wind gust of 40 mph.	Internal damage to buildings. Glass breaks with force
3	May be blown off feet. Possible eardrum rupture. Serious injury inside buildings due to building damage.	Steel frame buildings may be distorted, partial collapse of walls Failure of storage tanks.
6	Eardrum rupture. Injury due to flying debris outdoors, or from being blown off feet Potential fatality within buildings.	Heavy damage to unreinforced buildings. Potential release from small process connections.
10	Threshold for lung hemorrhage. Potential fatality outdoors due to impact. Multiple fatalities within buildings.	Significant process equipment damage causing knock-on releases. Buildings totally destroyed

Table 5.4 Acute Exposure Criteria and Toxicological Effects of Hydrogen Sulfide

H_2S Concentration (ppm)	Potential Effects
0.02 to 0.1	Threshold of smell
0.1 to 30	Increasingly unpleasant rotten eggs odor. Eye and throat irritation.
15	*ACGIH Short-Term Exposure Limit (STEL) for 15 minutes exposure.
30	**ERPG-2 Maximum concentration below which it is believed that nearly all individuals could be exposed for up to one hour without irreversible health effects or impairment of the ability to escape.
100	**ERPG-3 Maximum concentration below which it is believed that nearly all individuals could be exposed for up to one hour without life threatening health effects. ***Immediately Dangerous to Life or Health (IDLH). Maximum concentration from which one could escape without experiencing escape impairing or irreversible health effects.
100 to 300	Loss of sense of smell. Throat and eye irritation within 2 to 15 minutes. Headache, nausea, blurred vision in 30 minutes. Difficulty breathing. Potential loss consciousness after 1 hour.
300 to 700	Difficulty breathing within 1 to 4 minutes. Collapse, unconsciousness within 15 minutes. May be fatal over about 30 minutes exposure.
700 to 1,000	Coughing, collapse and unconsciousness. May be fatal within several minutes.
1,000 to 2,000	Unconsciousness within 2 minutes, respiratory failure and death if not revived promptly.
2,000 +	Unconsciousness almost immediately. Respiratory failure and death within 5 minutes.

* American Conference of Governmental Industrial Hygienists (ACGIH)

** ERPG levels are Emergency Response Planning Guidelines, developed by the American Industrial Hygiene Association (AIHA). These were specifically developed for emergency response planning, and have been adopted by the US Environmental Protection Agency (EPA) to identify levels of concern for hazardous chemicals.

*** IDLH levels are published by the National Institute for Occupational Safety and Health (NIOSH). The IDLH is considered a maximum concentration above which only a highly reliable breathing apparatus is permitted.

Table 5.5 Carbon Capture Facility - CO_2 Dispersion Distances

Release Source	Release Rate / Quantity	Weather	Downwind Distance to CO_2 Concentration from Release (ft)					1% CO_2 Area of Concern (ft^2)
			1%	2%	3%	4%	7%	
16-inch Produced Gas Transfer From Del Sur Compressors to SOX 32 (170 psig, 66% CO_2)								
Pipeline Guillotine Rupture	4,000 lb/min for 3 mins (30 kg/s)	D/4	440	280	200	160	93	6.7×10^4
		F/1.5	890	560	410	320	190	6.6×10^5
2-inch hole	700 lb/min (5 kg/s)	D/4	190	82	49	33	20	6.5×10^3
		F/1.5	150	69	43	44	20	2.0×10^3
CO_2 Carbon Capture Process Vessel (20 psig)								
Vessel Rupture or line connection failure	2,900 lb (1,300 kg)	D/4	500	320	240	190	120	7.4×10^4
		F/1.5	760	540	430	350	230	4.7×10^5
2-inch hole or connection failure - Low pressure vessels or linework	130 lb/min (1 kg/s)	D/4	130	62	39	26	11	1.6×10^3
		F/1.5	120	56	33	26	10	1.3×10^3
CO_2 Gas Compression and Treating (150 to 500 psig)								
Major compressor, line or compression vessel	770 lb (350 kg)	D/4	260	160	120	100	63	1.7×10^4
		F/1.5	410	280	210	180	120	1.2×10^5
1-inch hole or connection failure	500 to 50 lb/min	D/4	250	98	56	39	20	5.3×10^3
		D/4	100	50	30	23	11	1.3×10^3
CO_2 Compression Buffer Vessel, Pump or Line (1,300 psig)								
Vessel Rupture or line connection failure	27,000 lb (12,000 kg)	D/4	690	420	300	240	150	3.1×10^5
		F/1.5	1,200	700	520	410	250	1.1×10^6
1-inch hole or connection failure	1,700 lb/min (13 kg/s)	D/4	420	280	220	180	130	2.9×10^4
		F/1.5	730	410	290	230	140	2.0×10^5

Table 5.6 Transfer Pipeline to Sequestration - CO_2 Dispersion Distances

Release Source	Release Rate / Quantity	Weather	Downwind Distance to CO_2 Concentration from Release (ft)					1% CO_2 Area of Concern (ft^2)
			1%	2%	3%	4%	7%	
12-inch Transfer Pipeline to Sequestration (1,700 psig)								
Pipeline Guillotine Rupture	550,000 lb (250 mt)	D/4	4,100	2,700	2,100	1,700	1,200	7.6×10^6
		F/1.5	4,400	2,800	2.100	1,700	1,100	1.4×10^7
2-inch hole	8,700 lb/min (66 kg/s)	D/4	980	650	500	410	280	2.1×10^5
		F/1.5	1,700	1,100	770	590	350	1.4×10^6
6-inch Distribution Line to CO_2 Injection Wells (1,700 psig)								
Pipeline Guillotine Rupture	130,000 lb (58 mt)	D/4	1,900	1,200	870	700	430	1.8×10^6
		F/1.5	2,300	1,400	1,100	860	550	4.0×10^6
1-inch hole	2,200 lb/min (17 kg/s)	D/4	500	340	270	220	160	4.1×10^4
		F/1.5	920	540	380	300	190	3.0×10^5

Table 5.7 CO_2 Injection Well Dispersion Distances

Release Source	Release	Weather	Downwind Distance to Concentration from Release (ft)					1% Area of Concern (ft^2)
			1%	2%	3%	4%	7%	
CO_2 Injection Well								
Well-blowout Full Casing Flow, vertical release	1 hour average flow 4,000 lb/min (30 kg/s)	D/4	460	300	210	0	0	6.2×10^4
		F/1.5	400	280	220	160	0	1.7×10^5
Well-blowout 2-inch horizontal release	1,300 lb/min (10 kg/s)	D/4	320	200	150	130	89	2.8×10^4
		F/1.5	620	360	260	200	130	2.3×10^5
Wellhead 1-inch connection failure	750 lb/min (5.7 kg/s)	D/4	220	140	100	82	54	1.4×10^4
		F/1.5	430	250	180	140	89	1.1×10^5

Table 5.8 CO_2 BLEVE Overpressure Hazard Distances

Release Source	BLEVE Quantity	Distance to Explosion Overpressure Level (ft)					Hazard Area to 0.5 psi (ft^2)	Hazard Area to 3 psi (ft^2)
		0.5 psi	1 psi	2 psi	3 psi	6 psi		
CO_2 Compression Buffer Drums								
Instantaneous Rupture	4,000 gals (12 mt)	330	180	120	90	60	3.4×10^5	2.5×10^4

Table 5.9 Hydrogen Sulfide Hazard Distances – Del Sur Produced Gas Transfer

Release Source	Total Gas Release Rate	Weather	Downwind Distance to H_2S Concentration from Release (ft)					0.5 ppm H_2S Area of Concern (ft^2)
			0.5 ppm	10 ppm	30 ppm	100 ppm	300 ppm	
16-inch Produced Gas Transfer From Del Sur Compressors to SOX 32 (170 psig, 2,500 ppm H_2S)								
Pipeline Guillotine Rupture	4,000 lb/min for 3 mins (30 kg/s)	D/4	6,900	1,100	520	230	78	4.6×10^6
		F/1.5	10,000	1,900	1,000	450	170	2.3×10^7
2-inch hole	700 lb/min (5 kg/s)	D/4	3,000	600	240	59	16	1.5×10^5
		F/1.5	3,300	670	190	52	16	1.1×10^6

6. CALCULATION OF RISK

The risks of a hazardous release to the public have been calculated by combining the likelihood of a release, as discussed in Section 4, the hazards of the event, as described in Section 5, and the number of personnel potentially exposed, as described in Sections 2 and 3. Total risks to the public have been summated to calculate the likelihood of exposure to a level of concern. Hazardous release event trees have been used to calculate the likelihood of public harm as described in Section 6.1 below.

The likelihoods of public exposure to harm have then been combined in three different ways; the risk to an individual, to groups of individuals, and to the surrounding public as a whole. However, how do we evaluate whether these risks are low and acceptable? Methodologies have been developed and applied by governments and organizations around the world to evaluate the tolerability of risk. These are described in Sections 6.2 and 6.3 below.

6.1 Hazardous Release Event Trees

A hazardous release may have several different outcomes, and event tree analysis has been used to calculate the likelihood of each potential outcome. The potential for harm will depend on the release location, duration of the release, wind direction and weather conditions at the time of the incident. These have been analyzed by identifying potential release events that may impact the public, calculating the likelihood that a release will cause harm, and summating the likelihoods for each scenario. An example incident event tree for a CO_2 pipeline failure is shown in Figure 6.1.

Pipeline risk has been calculated by dividing the pipeline route into segments with similar public population densities at risk, depending on the wind direction and time of day. The location and number of public populations have been described in Section 2.3. For each event tree outcome, the number of personnel exposed has been calculated using the hazard distances and impact areas to the levels of concern described in Section 5. The likelihood that a hazard will occur, and the population densities within impact areas to CO_2 levels of concern, have been summed for each scenario and pipeline segment to calculate the risk.

Pipeline risk to specific populations, such as workers at the solar farm and the Highway 33 residential property, have been calculated by estimating the length of pipeline from which a release may impact the area or building. The likelihood of wind blowing towards the population, the likelihood of public personnel being present, and the areas where different CO_2 concentrations may occur, have been combined to calculate the risk to each population group.

To avoid double counting casualties within a range of exposure concentrations, the probability of harm for the greater severity level has been subtracted from the lesser severity levels before being summed.

6.2 Methodologies for the Assessment of Risk

There are numerous types of risk in our lives. Risk is the likelihood of experiencing harm, which may be to us, to those around us, to our property, or to our surroundings. QRA has been used in this study to calculate the potential acute hazards to the public due to a hazardous material release and quantify the likelihood of this occurring. Risk is a measure of:

- The *likelihood* of a hazardous material release; and,
- The *consequence*, in terms of public safety, of a hazardous material release.

The likelihood of a hazardous release is derived from historical data on how often accidents and releases occur. The probability that a release will result in public harm is calculated from historical incident reports, calculation of potential worst-case release quantities, modeling of how large an area may be impacted, and how likely public personnel will be in the area of impact.

The risks have been calculated in terms of three potential levels of harm:

- Could experience discomfort or minor injury. The effects are transient and reversible upon cessation of exposure.
- Could experience irreversible or other serious health effects that may require hospitalization.
- Could experience life threatening health effects or fatality.

To assess risks to the public from a proposed hazardous development, various governments and organizations around the world have used the calculation of individual risk and societal risk. Many international corporations have adopted these assessment techniques to evaluate proposed projects, identify causes of risk, select risk mitigation options, and assess the risk tolerability.

Individual and societal risk are calculated and presented in different ways, depending on the type of hazard source and jurisdiction. Risks associated with a fixed facility are often assessed differently to a transportation route, which may impact a large number of individuals along the route. A transportation route may also impact a wide range of route distances, from a short pipeline route of say 1 mile, to a long interstate pipeline of several hundred miles. Risk criteria need to be able to consistently compare different sized projects.

In addition to the calculation of individual and societal risk, a combined total individual risk has also been considered for this project, although there are no established criteria to evaluate if the risks are low or negligible compared to other tolerable risks. The three types of risks are described as follows:

Individual Risk

Individual risk represents the annual risk to a person at a specific location due to potential exposure to hazardous materials. The risk may be presented as plots of equal risk contours from a fixed facility on a map, or as risk transects which represent risk as a function of distance

from a transportation risk source. Different jurisdictions also prescribe slightly different calculation methods, which may include the risk to an individual present at that location 24-hours per day with no protection from buildings, or an occupancy factor which includes the duration individuals are present and either outside or inside a building.

In this study, the individual risk has been calculated by estimating the likely duration that public personnel may be present. The risks of exposure to three levels of concern have been calculated in terms of the likelihood of exposure per year, and the highest individual risks have been identified.

Societal Risk

Societal risk represents the risk to a number of people from the same event. Societal risk is often presented in a graphical way using F-N curves, also called risk profiles. Societal risk F-N curves are shown below to illustrate established risk criteria. F-N curves are plots of cumulative frequency (F) of all events leading to the number (N) or more casualties. The left axis (y-axis) represents frequency (F) or likelihood of an event. For example, 1×10^{-4} per year (1.0E-04 in scientific notation) represents once in 10,000 years of occurring. The bottom axis (x-axis) represents the number of casualties (N) that may occur at the cumulative frequency. A logarithmic plot is normally used because the frequency and number of casualties range over several orders of magnitude.

Combined Individual Risk

The combined individual risk is the likelihood that any public individual may be exposed to a given level of hazardous material harm during one year. All risks associated with the Project are summed, including; the carbon capture facilities, pipeline transportation, and CO_2 injection wells.

6.3 Risk Criteria

The United States federal and California state governments have not adopted individual and societal risk thresholds to define the tolerability of hazardous material risks. This decision is left to local governments and organizations for specific projects. The purpose of establishing tolerability criteria levels is to provide a consistent basis to assess the risks of hazardous materials to the public. Individual and societal risk thresholds adopted by governments and organizations around the world are described below, to provide a basis to compare the risks associated with the CarbonFrontier CCS Project to generally accepted risk criteria.

6.3.1 Development of Risk Criteria

The first comprehensive process industry risk analyses were conducted in the United Kingdom (UK) and the Netherlands in the 1970's and 1980's. From these studies the first risk tolerability criteria were developed. The UK and the Netherlands have led the international effort to develop both individual and societal risk criteria. Other countries, regulatory authorities and companies have based their own use and development of risk criteria on the precedents established in these two countries.

The development of risk criteria is described in the CCPS book, Guidelines for Developing Quantitative Safety Risk Criteria (2009)[9]. This book primarily focuses on the use of individual and societal risk criteria for fixed facilities.

Risk criteria have also been applied to transportation of hazardous materials to assess the tolerability of risk, and to compare the relative risk of transportation modes and routes. The criteria have less consensus internationally than those developed for fixed facilities, and to date, these have mainly been used for pipeline risk assessment, with some limited application for truck transportation routes.

Most risk criteria have been developed as risk of fatality. This is not due to a lack of concern for potential hazards that may cause injury. Data on fatalities are widely recorded and not open to interpretation. In any industrial activity, measures that reduce the risk of fatality will also reduce injuries in proportion. Studies have been performed on the ratios of serious injuries to minor or first aid injury as reported in Lees[31]. The ratios of fatality to serious injury to minor injury are in the order of 1 to 200 to 2,000.

6.3.2 Individual Risk Criteria

Individual risk is typically measured as the likelihood of fatality per year. International criteria have been based on risk levels that are deemed a tolerable increase in the risk of fatality. An increase of one in a million per year has been considered a very small addition to individual risk compared to other accepted risks. The following jurisdictions have established individual risk of fatality criteria for public populations:

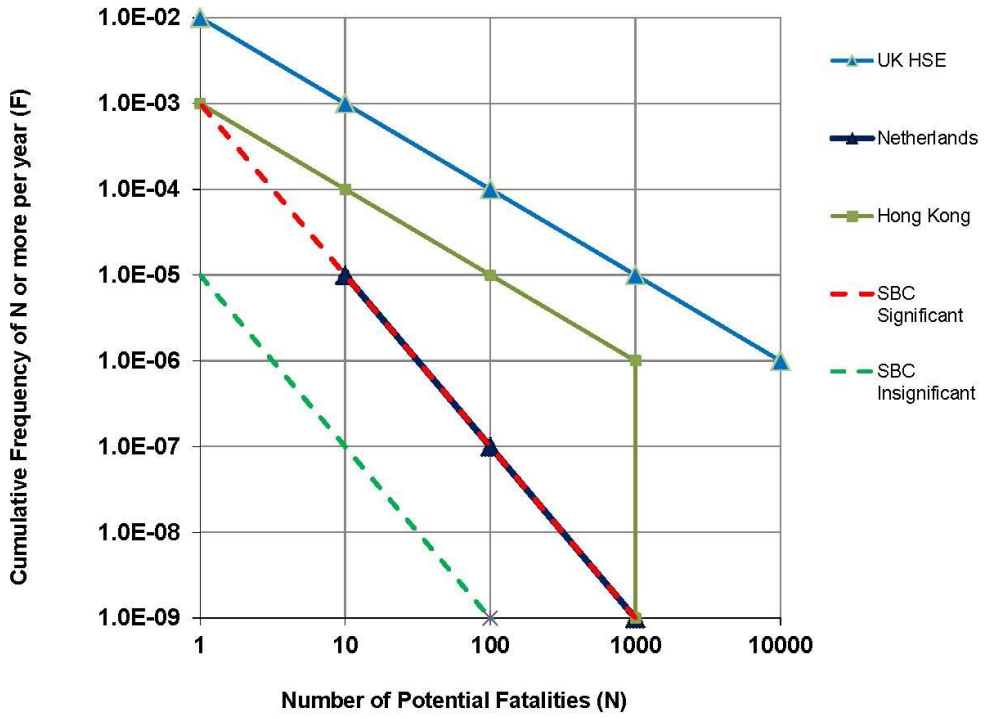
Jurisdiction	Broadly Acceptable Public Risk of Fatality per year	
United Kingdom[9]	1×10^{-6} per year	1 in 1,000,000 years
Netherlands[9]	1×10^{-6} per year	1 in 1,000,000 years
Hong Kong[9]	1×10^{-5} per year	1 in 100,000 years
Santa Barbara County, CA[37]	1×10^{-6} per year	1 in 1,000,000 years
California Department of Education[6]	1×10^{-6} per year	1 in 1,000,000 years

No individual risk criteria have been established for the risk of serious injury (potential hospitalization) or minor injury.

6.3.3 Societal Risk Criteria

Societal risk criteria have less consensus internationally than those developed for individual risk tolerability. The application of criteria also varies widely, making direct comparisons almost meaningless. For example, the UKHSE maximum level of tolerability is used as an initial guide from where reductions in risk must be implemented. However, the Santa Barbara County (SBC) insignificant risk criteria (the dashed green line on the graph below), is effectively used as the maximum societal risk criteria, above which public impacts must be reduced or avoided by implementation of mitigation measures.

A summary of fixed facility societal risk criteria is illustrated as follows:



Transportation societal risk criteria have been applied to assess the tolerability of risk, and to compare the relative risk of transportation modes and routes.

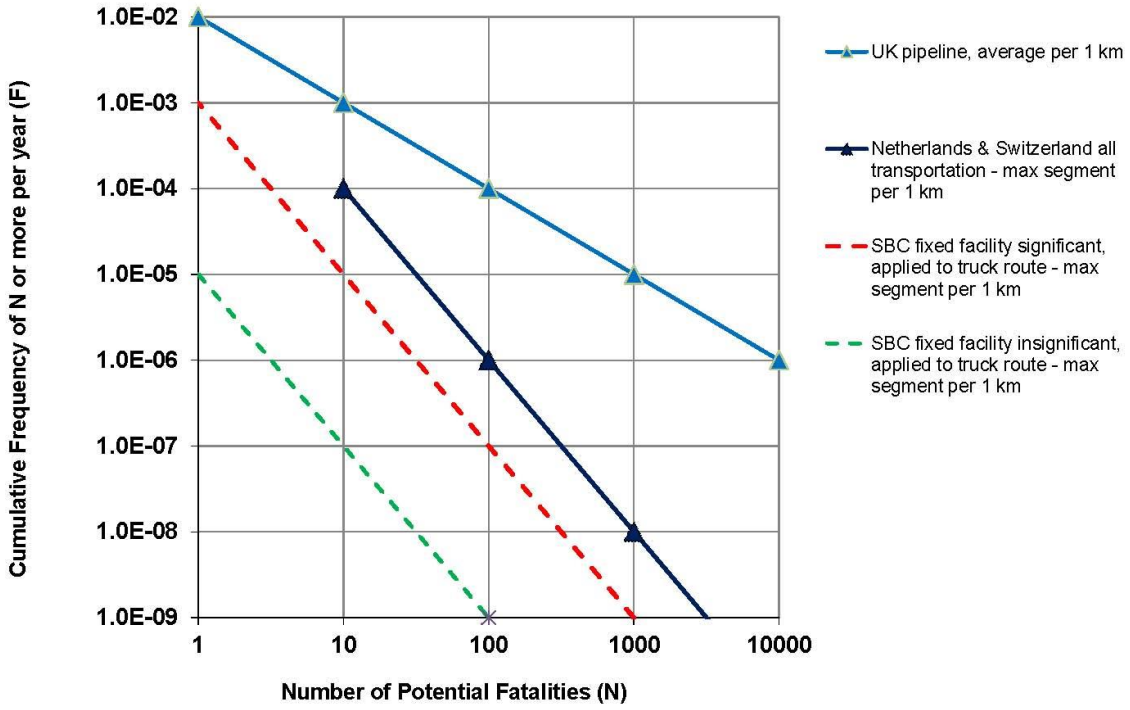
Three approaches have been adopted internationally,

- Summation of risk to a community on the transportation route.
- Average societal risk per unit distance on the transportation route.
- Calculation of the maximum risk per unit distance on the transportation route.

The Netherlands, UK and Swiss authorities have developed societal risk criteria for transportation routes by establishing a route length that is “equivalent” to the public risk of a single major industrial facility. The risk is calculated on a per-unit-length-of-pipeline, road or rail segment basis. The criteria differ in how the risk is calculated and what risk level is “equivalent” to a fixed facility, but use the same principle of establishing a route length for assessing the tolerability of transportation networks of different sizes.

The Netherlands selected transportation criteria on a 1-kilometer (0.62 mile) basis and set the levels as one order of magnitude (10 times) higher than for fixed facilities. This effectively equates the highest 100-meter (328 feet) transportation route risk to a fixed facility risk. The UKHSE has applied the same level of societal risk for a single fixed facility, to the average per 1-kilometer risk of a pipeline affecting a community. This equates an average 1-kilometer pipeline segment to a fixed facility.

A summary of transportation societal risk criteria is illustrated as follows:



Note: 1 km = 1 kilometer

The only societal risk criteria established for risk of injury is the SBC public injury profile. This has been defined for three regions, similarly to the risk of fatality, and is set at two orders of magnitude higher (100 times higher), than the respective fatality profiles. This effectively equates 100 serious injuries to 1 fatality for the risk tolerability ranges. This is consistent with the accident pyramid used in industrial accident prevention theory[31], where 1 fatality may occur for every 200 serious injuries.

Figure 6.1 Example Event Tree – CO_2 Pipeline Segment Failure

CO_2 Pipeline Failure Rate (per mile-yr)	Segment Length (miles)	Day / Night and Weather (Probability)	Wind Direction (Probability)	Potential Impacts (per year)
			½ NW, N, NE, E, ½ SE	Agricultural fields 25 workers per square mile Day Hwy-33 public impact
			0.42	1.3×10^{-5} /yr
		Day D/4		
		0.5	½ SE, S, SW, W, ½ NW	Medium density day oil production field activity 30 workers per square mile
			0.58	1.8×10^{-5} /yr
			½ NW, N, NE, E, ½ SE	Night Hwy-33 public impact
			0.42	4.2×10^{-6} /yr
Large / Guillotine Failure Rate	Segment ID C-6	Night D/4		
8.8×10^{-5} / mile-yr	0.706 miles	0.16	½ SE, S, SW, W, ½ NW	Medium density night oil production field activity 3 workers per square mile
			0.58	5.8×10^{-6} /yr
			½ NW, N, NE, E, ½ SE	Night Hwy-33 public impact
			0.42	8.9×10^{-6} /yr
		Night F/1.5		
		0.34	½ SE, S, SW, W, ½ NW	Medium density night oil production field activity 3 workers per square mile l
			0.58	1.3×10^{-5} /yr

7. RISK RESULTS AND MITIGATION

The risks have been quantified for each process system and for the CarbonFrontier CCS Project as a whole, to rank the various contributors of public risk due to acute hazard exposure. The risks have been calculated by estimating the likelihood and consequence of potential release scenarios.

The selection of release frequencies has been performed using conservative assumptions due to the high degree of uncertainty. There is limited experience in handling dense phase CO_2, so frequencies were developed using best available data from analogous industries. There is also uncertainty in the modeling of hazard distances and concentrations for large CO_2 releases. The calculated risks are therefore likely to be conservative.

7.1 Potential Risks to Public Populations

The following release scenarios may impact public areas at a hazardous material concentration of concern:

Produced Gas Transfer Pipeline

A release from the produced gas transfer pipeline may result in toxic hazards due to both CO_2 and H_2S dispersion. Hazards associated with CO_2 are greater than H_2S in close proximity to the pipeline. As the cloud disperses, concentrations of H_2S are more of a concern, and these have been applied for hazards on Highway 33.

No public areas would be impacted by a worst-case release at a level that could cause significant injury or fatality. A worst-case release may impact the public on Highway 33 and some areas to the east of Highway 33 at an H_2S concentration of 0.5 to 5 ppm. A worst-case event may cause some discomfort due to an unpleasant odor, which will be a brief exposure for personnel driving along the highway.

Carbon Capture and Compression

A large release of CO_2 at a carbon capture and compression facility may impact oil production areas adjacent to the facility. A release of liquefied CO_2 will have the greatest hazard distances of 1,200 feet to a 1% CO_2 concentration under low wind conditions at night. The carbon capture and compression facility at SG 2868 is approximately 1,500 feet from Highway 33, which is the closest capture facility to public populations. No potential public impact associated with carbon capture and compression facilities has been identified.

CO_2 Pipeline Transfer to Sequestration

The proposed CO_2 pipeline route runs parallel to Highway 33, about 2,000 to 3,000 feet distance from the road in the closest areas. In the event of a large release, the cold dense cloud will initially spread laterally, then disperse downwind. With a southwesterly wind (blowing towards the northeast), the cloud may drift over the highway and into agricultural areas to the east of the highway. The concentration at the highway may be in the range of 1% to 2% CO_2, with some areas up to 3% CO_2. The maximum extent of the cloud will reduce within the first 10 minutes as the initial high CO_2 release rate from the pipeline rapidly decays.

Wonderful Nut Farms operate a solar panel area to the west of Highway 33, in close proximity to the proposed pipeline. Public personnel working in the area may be exposed to a concentration of CO_2 greater than 4%, which may result in fatalities. If the wind is directed towards the solar panel area during the day, concentrations may exceed 7% up to 1,200 feet from the release, with a crosswind width of 1,400 feet.

Oil field production workers in areas operated by Berry Petroleum and Team Operating may be exposed to CO_2 in the event of a large pipeline failure. Berry Petroleum, in Section 19 of South Belridge, may be exposed to a level of concern between 1 and 3% CO_2 if a failure occurs in the vicinity and the wind is blowing from the east or north-east. Workers within the Team Operating area in North Belridge may be exposed to a concentration of 1% to 10% CO_2, if a distribution pipeline failure occurs in the vicinity and wind is directed towards the Team Operating area.

CO_2 Sequestration Injection Wells

A major well blowout during calm weather conditions may result in a hazardous CO_2 cloud drifting towards the oil field production area operated by Team Operating. A release at the two closest CO_2 injection wells during adverse weather conditions is highly unlikely to impact neighboring workers, and the risk has been estimated at 1 in 69 million years.

Leakage of CO_2 from Sequestration Reservoir

A leakage of CO_2 from the sequestration reservoir to the surface may occur via a wellbore or through the confining caprock. The leak rate is likely to be low and the release will dissipate quickly. No public personnel will be in the immediate vicinity of the sequestration field.

Amine Truck Transportation

The hazards associated with an ethanol amine release may occur in the immediate vicinity due to contact or inhalation of a liquid spray or mist. During truck transit on the highway, a vehicle collision or equipment failure may result in a release that has the potential to impact public or response personnel with the corrosive liquid. There is no public access to hazardous material unloading and storage areas, and therefore there is no potential for public exposure associated with these operations.

Sulfuric Acid Truck Transportation

The hazards associated with a sulfuric acid release may occur in the immediate vicinity due to contact or inhalation of a liquid spray or mist. Concentrated sulfuric acid is highly corrosive, and can cause severe chemical burns on contact with skin or eyes. During truck transit on the highway, a vehicle collision or equipment failure may result in a release that has the potential to impact public or response personnel. There is no public access to hazardous material unloading and storage areas, and therefore there is no potential for public exposure associated with these operations.

7.2 Aggregate Individual Risk Assessment

The overall hazards to the public from all proposed operations are shown in Table 7.1 for levels of concern, potential injury and potential fatality. These represent the risk of potential exposure, not that harm will occur. For example, the risk of significant injury is the concentration above which the general population, including susceptible individuals, could experience serious health effects or an impaired ability to escape. Most individual will experience breathlessness, with an increase in blood pressure and pulse rate, though without experiencing significant injury that may require hospitalization. The combined individual risks from all identified release sources are summarized as follows:

Release Source	Population Groups Exposed	Level of Concern	Potential for Significant Injury	Potential for Serious Harm or Fatality
		Likelihood	Likelihood	Likelihood
Produced Gas Transfer - Pipeline Rupture	Vehicles on Hwy-33	1 in 56,000 years	-	-
Carbon Capture and Compression	None	-	-	-
CO_2 Pipeline Transfer – Pipeline Rupture	Vehicles on Hwy-33 Agricultural workers Solar panel workers Berry and Team oil field workers	1 in 2,900 years	1 in 27,000 years	1 in 300,000 years
CO_2 Injection Wells	Team Operating oil field workers	1 in 69 million years	-	-
Leakage of CO_2 from Sequestration Reservoir	None	-	-	-
Amine Truck Transportation	50-mile road traffic from Bakersfield	1 in 92,000 years	-	-
Sulfuric Acid Truck Transportation	50-mile road traffic from Bakersfield	1 in 59,000 years	1 in 250,000 years	1 in 4.6 million years
Total Risk of Public Exposure		**1 in 2,700 years**	**1 in 24,000 years**	**1 in 190,000 years**

The primary source of risk is the CO_2 transfer pipeline from South Belridge carbon capture facilities to North Belridge geologic sequestration. This contributes to 88% of the aggregate risk of exposure to a level of concern for all public populations in the vicinity. A major CO_2 pipeline failure is the primary source that may impact public populations to a concentration that may cause significant injury or fatality.

The combined likelihood of public exposure to a concentration that may cause public concern is 1 in 2,700 years.

7.3 Individual Risk Assessment

Individual risk is typically measured as the likelihood of fatality per year. International criteria have been based on risk levels that are deemed a tolerable increase in the risk of fatality, as discussed in Section 6.3 above. An increase of one in a million per year has been considered a very small addition to individual risk compared to other accepted risks. In order to compare the highest individual risks for the current Project against established international risk criteria, the individual risk of fatality has been calculated.

Hazardous material exposures are not at the same level within the distance to a level of concern. As you get closer to the source of the release, the toxic concentration increases, until near the source there may be a potentially lethal concentration. Average vulnerabilities have therefore been estimated within the range for levels of concern.

The level of concern for serious injury or fatality has been selected for CO_2 as 4% concentration. However, a CO_2 concentration of 4% may not be life threatening for the majority of the population. The minimum CO_2 concentration that may be immediately life threatening has been proposed as 7% by the US EPA[(50)]. A vulnerability of 50% has been applied for public exposure to concentrations of CO_2 greater than 4%.

Individual risk of fatality is the measure that is most widely used to evaluate the tolerability of risk. The highest individual risks of fatality have been identified as follows:

Population Group	Individual Risk of Fatality		International Maximum Tolerable Risk
	Frequency	Likelihood	
Workers at the solar panels	3.9×10^{-7} per year	1 in 2,500,000 years	1 in 1,000,000 years
Team Operating oil field workers	5.6×10^{-7} per year	1 in 1,800,000 years	1 in 1,000,000 years

The highest individual risk of fatality is associated with oil field workers at the neighboring Team Operating facility in North Belridge. This risk is less than all internationally established tolerability criteria.

7.4 Societal Risk Assessment

Public societal risks have also been calculated for the highest risk pipeline segment for comparison to established societal criteria that have been deemed a tolerable. Societal risk represents the risk to a number of people from the same event, and is often presented graphically on a logarithmic plot. Societal risks have been calculated for potentially fatal events and serious injury events as described in Section 6.

The highest risks to the public have identified as being due to the potential exposure to CO_2 if a significant pipeline failure was to occur in North Belridge. Team Operating LLC operate a number of wells in North Belridge, which are within about 700 feet at the closest point of the proposed pipeline distribution line.

Societal risks for transportation routes are typically calculated on a route length basis for assessing the tolerability of transportation routes of different sizes and types. Societal risks for the highest risk pipeline segment have been calculated for the proposed Project, and plotted on graphs for comparison to established criteria. These have been calculated for both the risk of potential fatality and the risk of serious injury, as shown in Figures 7.2 and 7.3. The societal risks associated with the proposed CarbonFrontier CCS Project are less than all internationally established tolerability criteria.

7.5 Risk Management and Mitigation

Many risk mitigation measures have been incorporated into the provisional design of the CarbonFrontier CCS Project. The following measures have been applied in the calculation of risks:

General Equipment Design, Control and Monitoring

- The CO_2 pipeline, carbon capture and compression facilities, unloading, storage and injection equipment will be designed according to best industry practices, API RPs and Standards, DOT Part 195 design and construction, and National Association of Corrosion Engineers (NACE) Standards.
- Leak detection and monitoring systems will use electronic SCADA systems for pipeline flow and injection well control.
- Emergency shutdowns to be initiated automatically and manually.
- Monitoring of CO_2 pipeline composition for water content to ensure no free water.
- Appropriate design of blowdown vessels and vents to safely depressurize the CO_2 pipeline in an emergency, or for maintenance.
- Vehicle impact protection along the pipeline and at injection well sites.

Safety Management

CO_2 pipelines in the US are normally under federal operations guidelines (49 CFR 195). Requirements include training, inspections, safety integration, public education, damage prevention programs, communication, facility security and leak detection. It is uncertain if the intra-field pipeline will be regulated under DOT requirements, although the safety management will generally follow DOT guidelines if not specifically under DOT authority.

Aera Energy would operate the field under its well-established and proven management system that incorporates many processes, plans and programs to ensure public and worker health and safety, environmental protection, regulatory compliance, and community involvement. These programs include Spill Prevention, Incident Response, Site Safety, Site Security, Pollution Prevention, Species Protection, Environmental Compliance, Environmental Training, Safety Training, and Community Involvement.

CO_2 Injection Well Design and Maintenance

The technologies and practices associated with geological CO_2 sequestration are all in current commercial operation, and have been so for several decades. These are utilized in CO_2-EOR projects, acid gas disposal injection with CO_2 and underground natural gas storage facilities. Operators have achieved wellbore integrity at levels equivalent to those seen for conventional oil and gas wells.

A summary of CO_2-EOR injection well technology and operating practices was prepared by Meyer for the API[34]. Engineering advances made in the CO_2 injection well design include:

- Corrosion resistant materials such as stainless and alloy steels (316 SS, nickel, Monel, CRA, etc.) for piping and metal component trim,
- Swell resistant elastomer materials such as Buna-N and Nitrile rubbers for downhole packers, and Teflon (PTFE) and Nylon for seals,
- Acid resistant specialty cements and additives, and;
- Automatic control systems to regulate flow and provide real-time monitoring capable of initiating well shutdowns should an unsafe condition be detected.

Periodic Mechanical Integrity Testing (MIT) will be performed on injection wells according to regulations to ensure well integrity. This will include pressure-testing to ensure casing integrity, and testing for potential fluid migration behind the casing, tubing, or packer by use of radioactive, acoustic or thermal detection.

Injection and Reservoir Monitoring

Injection and monitoring wells will be equipped with downhole devices and equipment to evaluate the mechanical integrity of the wells and monitor growth of the CO_2 plume as it dissipates within the sequestration layer. Monitoring equipment will include continuous pressure, temperature and/or distributed acoustic sensors.

Surface Monitoring

Air, soil and vegetation sampling is proposed to identify any potential failures. Surface air monitoring will be conducted using continuous CO_2 monitors at the injection wellheads, and the use of mobile detectors at other infrastructure. Soil gas monitoring will also be conducted at the injection wellheads. Annual vegetation monitoring will be conducted using satellite imagery and field verification.

Emergency Response

An effective emergency response plan will reduce the risk to public and on-site personnel. Specific emergency response procedures will be developed for a CO_2 release, including;

- Emergency response procedures, and training in CO_2 hazards and behavior on release.
- Evacuation plans.
- Shelter in place planning.
- Public communications and emergency hazard warning plan.
- Operations personnel are trained in the Emergency Action Plans (EAPs) and Pre-Incident Planning and Emergency Response Guidelines (PIPERs).
- Annual review of EAPs and PIPERs, and quarterly table top drills.

Figure 7.1 Map of CO_2 Pipeline Rupture – Potential Daytime Hazard Distances

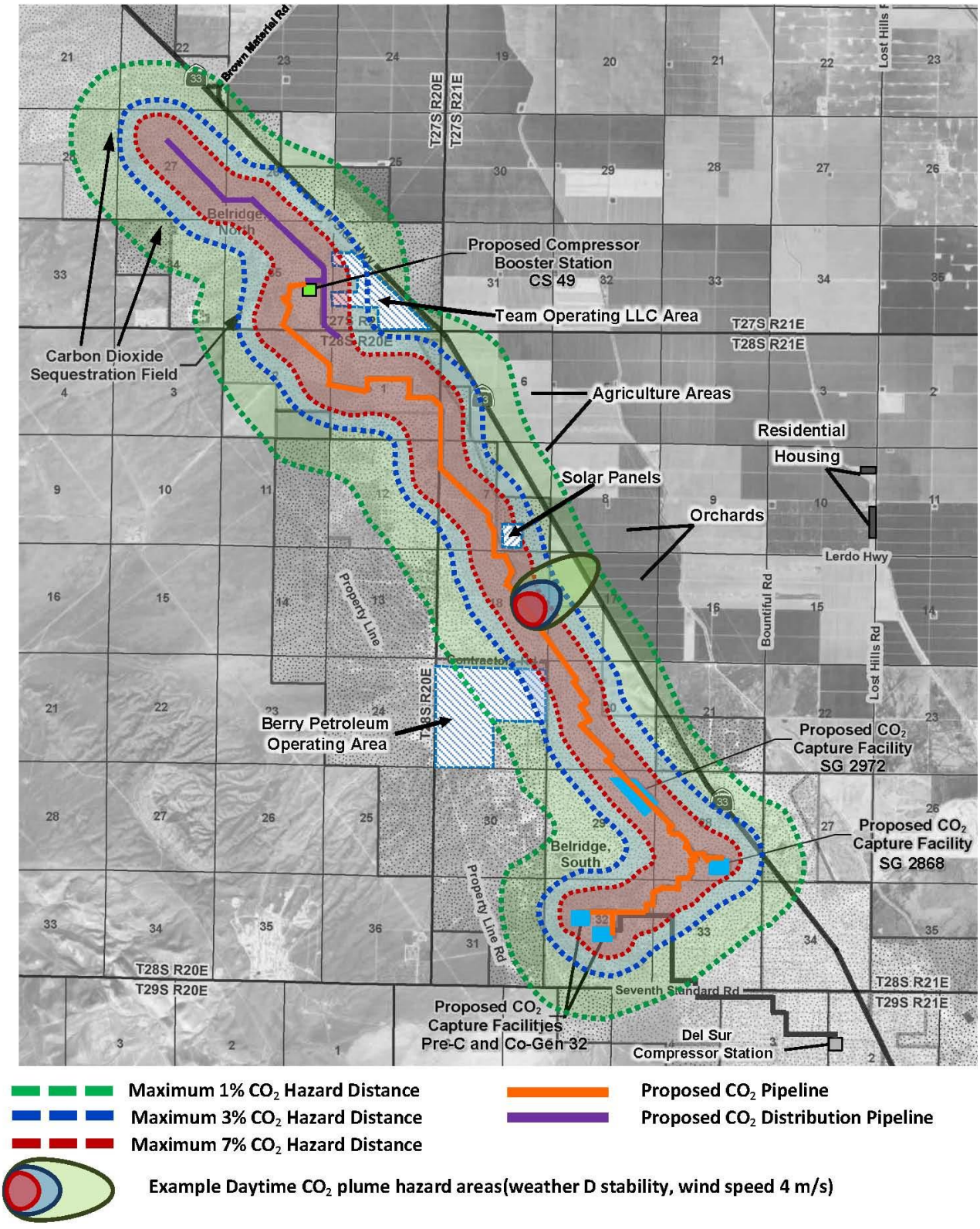


Table 7.1 Summary of Acute Public Exposure Risks by Release Source

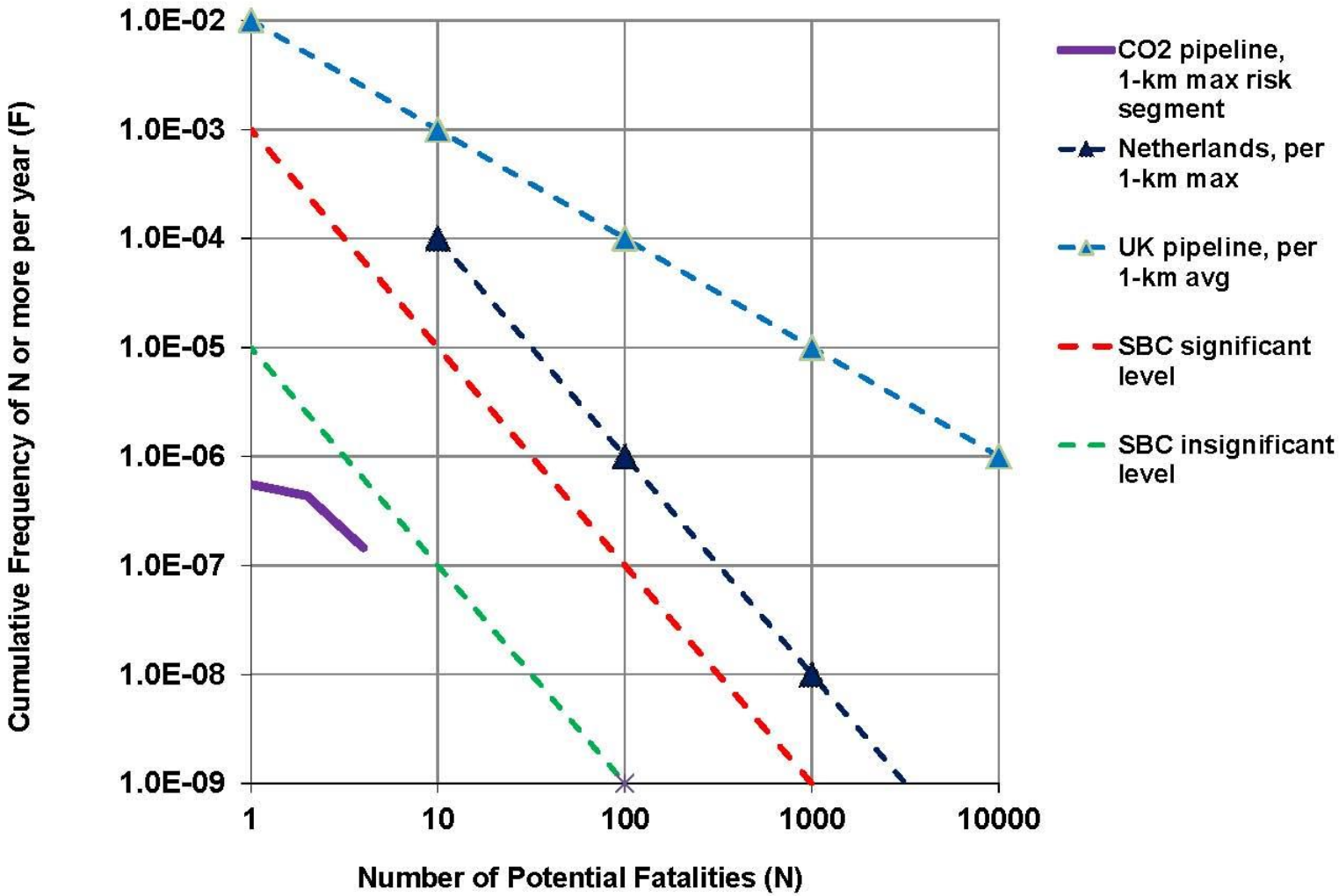
Release Source	Population Group Exposed	Level of Concern**		Potential Injury***		Potential Fatality****		Comments
		Frequency (per year)	Likelihood	Frequency (per year)	Likelihood	Frequency (per year)	Likelihood	
Produced Gas Transfer – 16-in Pipeline from Del Sur Compressor Station to SOX 32								
Pipeline Rupture - H_2S/CO_2 release	Day Hwy-33 traffic	8.9×10^{-6}	1 in 110,000 yrs	None	-	None	-	Exposure duration less than level of concern. Up to 150 persons may experience short H_2S exposure for 7 to 15 seconds at 0.5 to 5 ppm.
Pipeline Rupture - H_2S/CO_2 release	Night Hwy-33 traffic	8.9×10^{-6}	1 in 110,000 yrs	None	-	None	-	Exposure duration less than level of concern. Up to 17 persons, short H_2S exposure of 20 to 40 seconds at 0.5 to 5 ppm.
Carbon Capture and Compression Facilities								
CCS Facilities	None					None	-	
CO_2 Transfer – 12-in Pipeline from Section 32 Capture Facilities to North Belridge Sequestration								
Pipeline Rupture or large release	Day Hwy-33 traffic	5.4×10^{-5}	1 in 19,000 yrs	2.7×10^{-6}	1 in 370,000 yrs	None	-	Exposure duration less than level of concern. Up to 150 persons, may experience short CO_2 exposure for 30 seconds at 1 to 3% CO_2
Pipeline Rupture or large release	Night Hwy-33 traffic	5.4×10^{-5}	1 in 19,000 yrs	2.7×10^{-6}	1 in 370,000 yrs	None	-	Exposure duration less than level of concern. Up to 17 persons, may experience short CO_2 exposure for up to 1 minute at 1 to 3% CO_2
Pipeline Rupture or large release	Agricultural workers	1.1×10^{-4}	1 in 9,100 yrs	None	-	None	-	Likelihood of impacting an agricultural worker to an exposure of CO_2 between 1% and 2%.
Pipeline Rupture or large release	Workers at solar panels	6.6×10^{-6}	1 in 150,000 yrs	2.3×10^{-6}	1 in 430,000 yrs	1.6×10^{-6}	1 in 640,000 yrs	Likelihood of exposing workers at the solar panels to a CO_2 concentration of 1 to 10% that may cause concern, injury or fatality.

Table 7.1 Summary of Acute Public Exposure Risks by Release Source (continued)

Release Source	Population Group Exposed	Level of Concern**		Potential Injury***		Potential Fatality****		Comments
		Frequency (per year)	Likelihood	Frequency (per year)	Likelihood	Frequency (per year)	Likelihood	
CO_2 Transfer – 12-in Pipeline from Section 32 Capture Facilities to North Belridge Sequestration								
Pipeline rupture or medium sized release	Berry Petroleum oil field workers	3.7×10^{-5}	1 in 27,000 yrs	1.2×10^{-5}	1 in 82,000 yrs	None	-	Likelihood of exposing neighboring oil field workers to a CO_2 concentration of 1 to 3% that may cause concern or injury.
Pipeline rupture or medium sized release	Team Operating oil field workers	7.0×10^{-5}	1 in 14,000 yrs	1.7×10^{-5}	1 in 57,000 yrs	3.4×10^{-6}	1 in 300,000 yrs	Likelihood of exposing neighboring oil field workers to a CO_2 concentration of 1 to 10% that may cause concern or injury.
CO_2 Sequestration Injection Wells								
Injection well blowout	Team Operating oil field workers	1.5×10^{-8}	1 in 69 million yrs	None	-	None	-	Likelihood of exposing neighboring oil field workers to a CO_2 concentration of 1 to 2% that may cause concern.
Leakage of CO_2 from Sequestration Reservoir								
Wellbore or caprock leakage	None	None	-	-	-	-	-	No public hazard. Slow dissipated release.
Amine Truck Transportation and Storage								
Amine truck release	50-mile road traffic	1.1×10^{-5}	1 in 92,000 yrs	None	-	None	-	Likelihood of exposing the public or response personnel on the 50-mile highway route from Bakersfield.
Sulfuric Acid Truck Transportation and Storage								
Sulfuric acid truck release	50-mile road traffic	1.7×10^{-5}	1 in 59,000 yrs	4.3×10^{-6}	1 in 250,000 yrs	2.2×10^{-7}	1 in 4.6 million yrs	Likelihood of exposing the public or response personnel on the 50-mile highway route from Bakersfield.
All CarbonFrontier Project Operations								
Total	Aggregate Public Risk	3.8×10^{-4}	1 in 2,700 yrs	4.2×10^{-5}	1 in 24,000 yrs	5.1×10^{-6}	1 in 190,000 yrs	Aggregate likelihoods of exposing the public to a CO_2 concentration that may cause concern, injury or fatality.

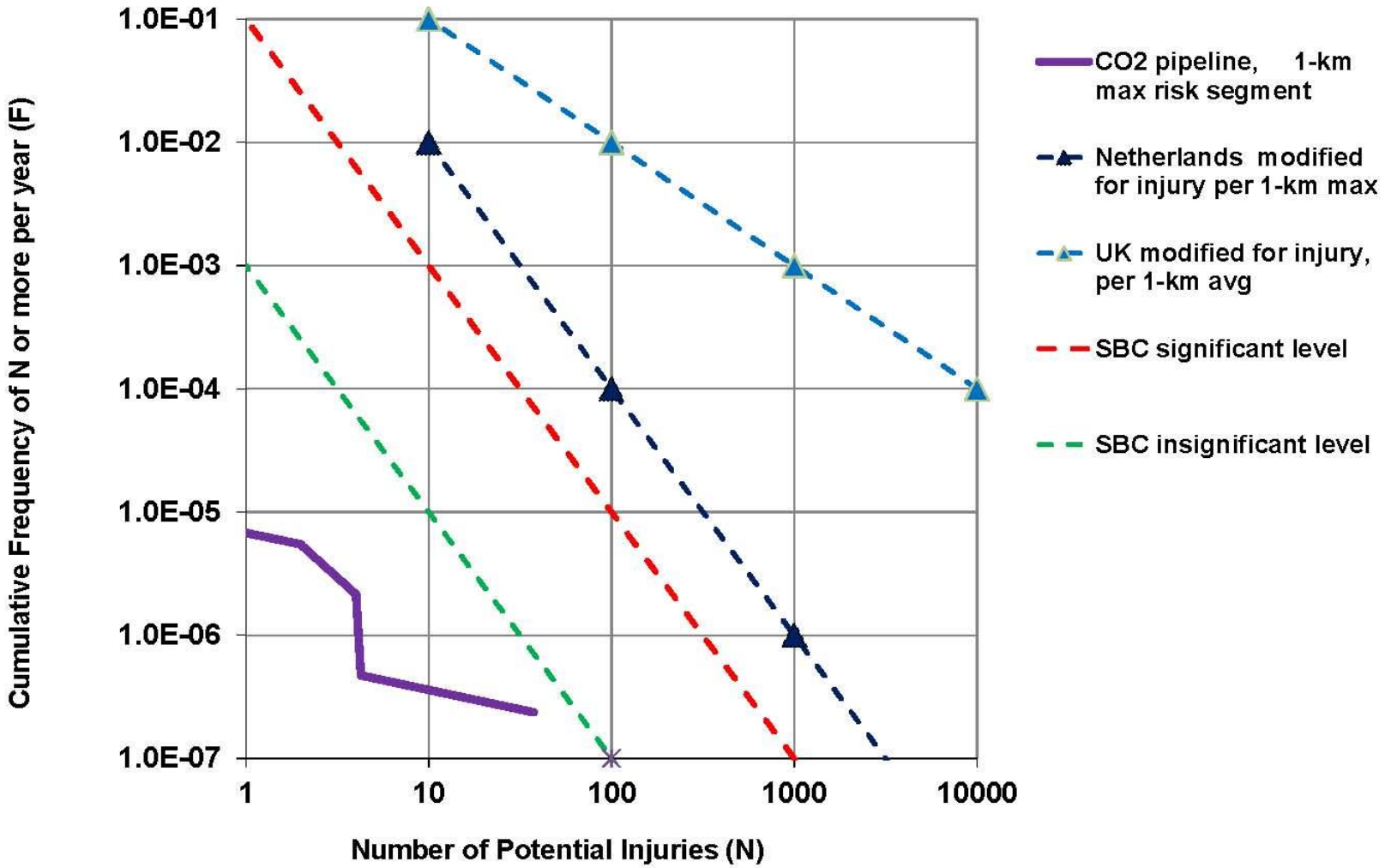
** Level of public concern: CO_2 exposure = 1%, H_2S exposure= 0.5 ppm
*** Level of potential injury: CO_2 exposure = 3%, H_2S exposure= 30 ppm
**** Level of potential fatality: CO_2 exposure = 4%, H_2S exposure= 100 ppm

Figure 7.2 Societal Risk of CO_2 Potential Fatality Impacts –Pipeline Highest 1-Kilometer Segment



Note: The highest risk pipeline segment is in North Belridge, where Team Operating LLC operate oil production wells.
Values shown by dashed lines are established societal risk criteria as described in Section 6.
1-km = 1-kilometer (0.62 miles).

Figure 7.3 Societal Risk of CO_2 Potential Serious Injury Impacts –Pipeline Highest 1-Kilometer Segment



Note: The highest risk pipeline segment is in North Belridge, where Team Operating LLC operate oil production wells.
Values shown by dashed lines are established societal risk criteria as described in Section 6.
1-km = 1-kilometer (0.62 miles).

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APPENDIX A

ACRONYMS AND ABBREVIATIONS

AADT	Annual Average Daily Traffic
ACGIH	American Conference of Governmental Industrial Hygienists
ADM	Archer Daniels Midland
AEGL	Acute Exposure Guideline Level
Aera	Aera Energy LLC
AIHA	American Industrial Hygiene Association
ALARP	As Low As Reasonably Practicable
ALOHA	Areal Locations of Hazardous Atmospheres
AoR	Aera of Review
ANSI	American National Standards Institute
API	American Petroleum Institute
bbl	barrel
BLEVE	Boiling Liquid Expanding Vapor Explosion
BOEM	US Bureau of Ocean Energy Management
BTS	Bureau of Transportation Statistics
^{o}C	degree Celsius
CalGEM	California Geologic Energy Management Division
CalTrans	California Department of Transportation
CARB	California Air Resources Board
CCPS	Center for Chemical Process Safety
CCS	Carbon Capture and Sequestration
CFR	Code of Federal Regulations
CO_2	carbon dioxide
Cogen	Co-Generation
CS	Compressor Station
DEA	diethanolamine
DOGGR	Division of Oil, Gas, and Geothermal Resources
DOT	US Department of Transportation
DRC	Dixon Risk Consulting
EAP	Emergency Action Plan
EGIG	European Gas Pipeline Incident Group
EHS	Extremely Hazardous Substance

EOR	enhanced oil recovery
EPA	US Environmental Protection Agency
^{o}F	degree Fahrenheit
FEMA	Federal Emergency Management Agency
ft	feet / foot
FMCSA	Federal Motor Carrier Safety Administration
g	acceleration due to gravity
GCCSI	Global CCS Institute
HDPE	high-density polyethylene
HMIRS	Hazardous Materials Incident Reporting System
H_2S	hydrogen sulfide
IDLH	Immediately Dangerous to Life and Health
IEA	International Energy Agency
IOP	Internal Operating Permit
LPG	liquefied petroleum gas
m/s	meters/second
MAOP	maximum allowable operating pressure
MDEA	methyl diethanolamine
MEA	monoethanolamine
MIT	Mechanical Integrity Test
MMBtu	million British thermal unit
MMSCF	million standard cubic feet
MM mt	million metric tons
mph	miles per hour
mt	metric ton
MVMT	million vehicle miles traveled
MW	molecular weight
NACE	National Association of Corrosion Engineers
NIOSH	National Institute for Occupational Safety and Health
NRC	National Response Center
OSHA	US Occupational Safety and Health Administration
PAC	Protective Action Criteria
PGA	Peak Ground Acceleration
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIPER	Pre-Incident Planning and Emergency Response Guidelines
Project	CarbonFrontier CCS Project
PPE	Personal Protective Equipment
ppm	parts per million

psi	pounds per square inch
psig	pounds per square inch gauge
PSM	Process Safety Management
QRA	Quantitative Risk Assessment
RIVM	Rijksinstituut voor Volksgezondheid en Milieu (Dutch National Institute for Public Health and Environment)
RMP	Risk Management Program
RQ	Reportable Quantity
RRC	Texas Railroad Commission
SCADA	Supervisory Control and Data Acquisition
SINTEF	Norwegian Foundation for Scientific and Industrial Research
SG	Steam Generator
SOSS	south of Seventh Standard Road
SOX 32	Sulferox Plant 32
Stantec	Stantec Consulting Services Inc.
TEEL	Temporary Emergency Exposure Limit
TEG	triethylene glycol
TNO	Toegepast Natuurwetenschappelijk Onderzoek (The Netherlands Organization for Applied Scientific Research)
UIC	Underground Injection Control
UKHSE	UK Health and Safety Executive
USGS	United States Geological Survey

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Appendix G
Hydrology and Water Supply

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G.1 Preliminary Hydrology Study

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Stantec

AERA
CARBONFRONTIER
PROJECT

Preliminary Hydrology Study

June 28, 2023

Prepared for:
Aera Energy LLC
10000 Ming Avenue
Bakersfield, CA 93311

Prepared by:
Stantec Consulting Services Inc.
2646 Santa Maria Way, Suite 107
Santa Maria, CA 93455

Project Number:
185805372

Revision	Description	Author	Date	Quality Check	Date	Independent Review	Date
0	Finalized	JC/ES	6/26/23	BH	6/26/23	CT	6/26/23

The conclusions in the Report titled Aera CarbonFrontier Project – Preliminary Hydrology Study are Stantec's professional opinion, as of the time of the Report, and concerning the scope described in the Report. The opinions in the document are based on conditions and information existing at the time the scope of work was conducted and do not take into account any subsequent changes. The Report relates solely to the specific project for which Stantec was retained and the stated purpose for which the Report was prepared. The Report is not to be used or relied on for any variation or extension of the project, or for any other project or purpose, and any unauthorized use or reliance is at the recipient's own risk.

Stantec has assumed all information received from Aera Energy LLC (the "Client") and third parties in the preparation of the Report to be correct. While Stantec has exercised a customary level of judgment or due diligence in the use of such information, Stantec assumes no responsibility for the consequences of any error or omission contained therein.

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Prepared by: 

Signature

Jesus Corona-Perez

Printed Name

Reviewed by: 

Signature

Buddy Hain, IV, P.E.

Printed Name

Approved by: 

Signature

Eric Snelling

Printed Name

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APPENDIX B NOAA ATLAS DATA

APPENDIX C GEOHECMAS REPORT

APPENDIX D SCOUR CALCULATIONS

Acronyms / Abbreviations

cfs	Cubic Feet Per Second
Ft	Feet
HSG	Hydrologic Soil Group
NRCS	Natural Resources Conservation Service
NOAA	National Oceanic and Atmospheric Administration
SCS	Soil Conservation Service
SR	State Route
Study Area	The pre-determined portion of the total Project area chosen for hydrologic testing where an increase in impervious area is likely.
USACE	United States Army Corp of Engineers
USGS	United States Geologic Survey
WGS	World Geodetic System of 1984

1.0 PROJECT INFORMATION

The proposed Aera CarbonFrontier Project (the "Project") is located within the Central Valley portion of unincorporated western Kern County, California. The Project will capture carbon dioxide in the South Belridge Oil Field and transport the carbon dioxide via pipeline to the North Belridge Oil Field for geologic sequestration. Together, the two Belridge oil fields cover an area that is approximately 13 miles long and three miles wide.

The purpose of this report is to provide a preliminary hydrology study of the proposed improvements. This includes a pre-development versus post-development peak runoff comparison and a scour analysis at major drainageway crossings. Stantec performed a hydrology study for the area of the proposed project features, referred to hereinafter as the "Study Area", and centered 35.501525°, 119.751895° (World Geodetic System of 1984 [WGS 84]). Refer to Figure 1.

1.1 SITE CHARACTERISTICS

The Hydrologic Soil Group (HSG) was determined using the Natural Resources Conservation Service (NRCS) Web Soil Survey. Due to the extents of the Study Area, the HSG for the subbasins located in close proximity to the Project vary from HSG A to HSG C. The northern half of the Study Area consists primarily of HSG A with pockets of HSG B and HSG C. The southern half of the Study Area consists primarily of HSG A for the subbasins located in the hills west of the Project location and primarily of HSG C for the subbasins located in the valley. The extents of the tributary watersheds can be found in Appendix C.

1.2 PRE-DEVELOPMENT

The site is currently an oil field with a large amount of open space and minimal impervious area. The impervious area consists primarily of roads, parking lots, and buildings. Runoff from the hills to the west of the Study Area drains to the Project Site and ultimately continues east past State Route (SR) 33 (West Side Highway).

The runoff from the hills to the west follows major drainageways down to the valley which then disperses into smaller drainageways before reaching the Project Site or being routed through the Study Area. Chico Martinez Creek is the only major creek that currently still runs across the southern end of the Study Area.

1.3 POST-DEVELOPMENT

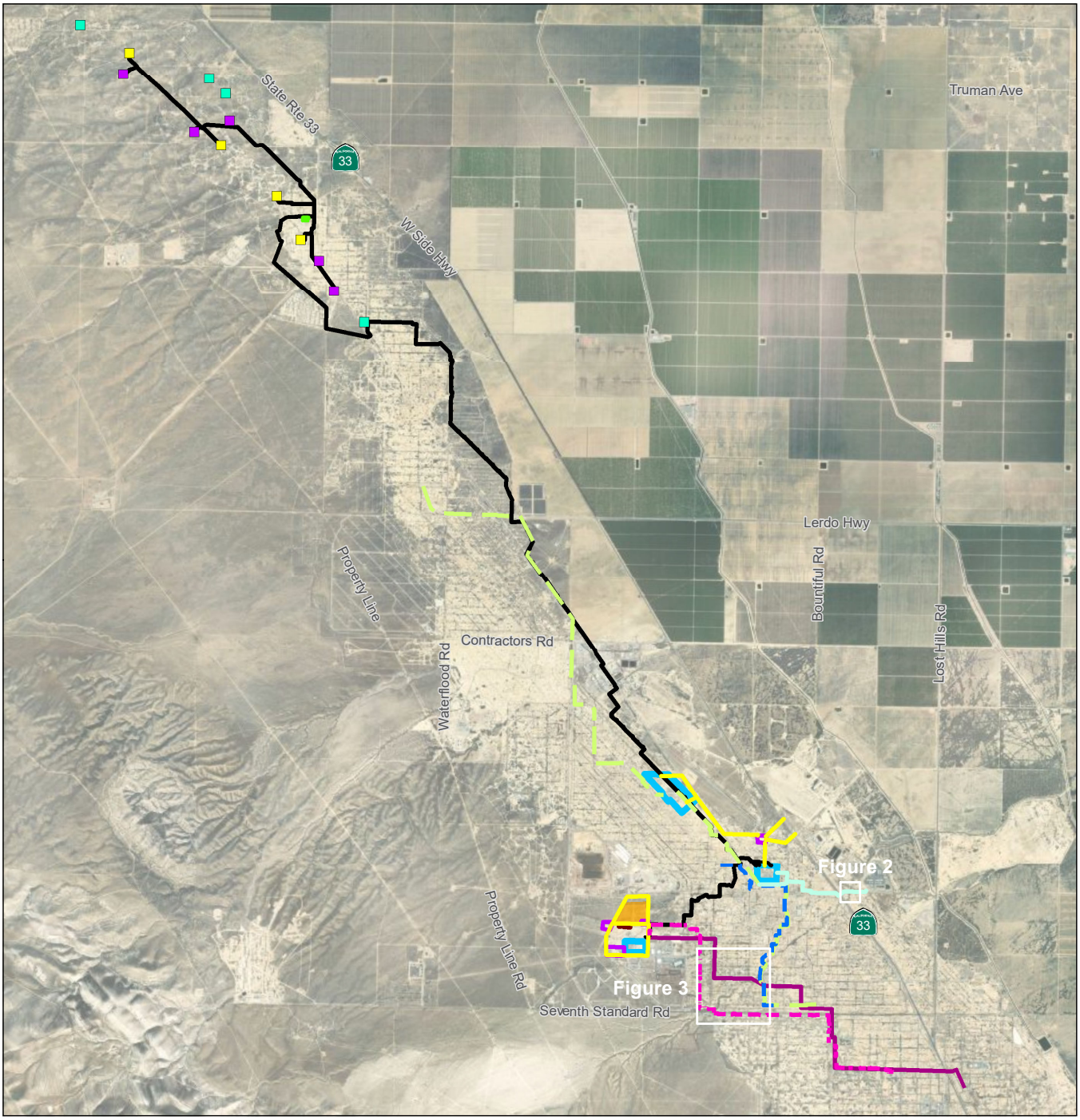
1.3.1 Onsite Drainage

The proposed improvements would add a minimal amount of impervious area to the overall Project Site. The increase of impervious area would come from the addition of facilities associated with the transportation and sequestration of carbon dioxide.

There are currently no proposed improvements for the on-site drainage due to the minimal addition of impervious areas.

1.3.2 Offsite Drainage

The addition of the proposed facilities does not appear to have an impact on the drainage of off-site flows, as all new facilities will be located within the existing oil fields.





Notes

1. Coordinate System: NAD 1983 StatePlane California V FIPS 0405 Feet
2. Data Sources: CalGEM 2019, Stantec 2022.
3. Background: Sources: Esri, GEBCO, NOAA, National Geographic, Garmin, HERE, Geonames.org, and other contributors
Source: Esri, Maxar, Earthstar Geographics, and the GIS User Community
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors

- Study Area

Project Components

- Proposed CO_2 Injection Wells
- Existing Oil Wells to be Converted to CO_2 Injection Wells
- Proposed Monitoring Wells
- Existing Del Sur Gas Line to Gas Plant 32
- Existing Steam Line Routes
- Proposed CO_2 Pipelines
- Potential Produced Water Lines Routes
- Potential Power Line Routes
- Potential Steam Line Routes
- Tulare CVR to GP32 (Optional)
- Proposed Compressor Booster Station
- Potential Substation Locations
- Pre-Combustion Facilities
- Proposed CO_2 Capture Facility
- Proposed Staging Area Adjacent to Gas Plant 32

0 0.625 1.25 Miles

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Stantec AERA

Project Location
Kern County,
California

Prepared by DL on 2023-06-28
TR by SET on 2023-06-28
IR by ES on 2023-06-28

Client/Project 185805407

Aera Energy LLC
Aera CarbonFrontier Project

Figure No.
1

Title
Project Location

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2.0 HYDROLOGY ANALYSIS

2.1 MODEL SETUP

The hydrology model was set up to only include the watersheds within the Study Area where an increase in impervious area is likely. The watersheds were delineated using United States Geological Survey (USGS) contour topography as more precise contour topography was not available.

Due to the large size of the watersheds within the Study Area, the modeling software GeoHECHMS was used to determine the peak flows. The GeoHECHMS software is a hydrology modeling software developed by CivilGEO that runs on the United States Army Corps of Engineers (USACE) HEC-HMS software. Modeling for this Project used HEC-HMS version 4.5.

The Soil Conservation Service (SCS) Curve Number infiltration (loss) method and the SCS Unit Hydrograph runoff (transform) method were used in GeoHECHMS for determining the stormwater runoff. The Kinematic Wave routing method was used for routing the stormwater.

Additionally, the following parameters were also used for model setup:

- Storm Type: Type I 24-hour
- Storm Duration: 24 hours
- Rainfall Depth (10-year, 24-hour storm):
  1.65 inches
- Rainfall Depth (100-year, 24-hour storm):
  2.99 inches

For this study, peak flow rates were determined for both the 10-year, 24-hour storm and the 100-year, 24-hour storm. Rainfall data was determined using the National Oceanic and Atmospheric Administration (NOAA) Atlas 14.

2.2 TIME OF CONCENTRATION

The time of concentration was determined in GeoHECHMS, using the SCS TR-55 method. The time of concentration for each subbasin can be found in the GeoHECHMS report in Appendix C.

3.0 SCOUR ANALYSIS

3.1 Model Setup

The possibility of scour occurring where the proposed pipelines crossed major drainageways was considered. Possible major drainageway crossings in the Study Area were selected using the USGS contour topography as well as aerial imagery of the Project Site. Given this and the peak flows calculated

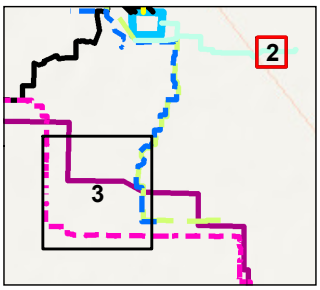
during the hydrology analysis, it was determined that there are three major drainageway crossings with potential for significant scour located along the Chico Martinez Creek.

The crossing with potential for significant scour includes a proposed water line that will cross over the Chico Martinez Creek just north of Roustabout Rd. as well as two aboveground gas lines, one existing and one proposed, that will cross Chico Martinez Creek north of 7th Standard Road. Figures 2 and 3 show an aerial view of these major crossings.

A scour analysis was performed at these locations using two separate methods: the Blodgett method and the Pemberton and Lara method.

Soil profiles were created using information provided by the NRCS Web Soil Survey. The peak flow calculated for Chico Martinez Creek in the hydrology calculations was then inputted into a GeoHECRAS model to obtain the flow width at this location. GeoHECRAS is a software developed by CivilGEO that runs on the USACE HEC-RAS software. Modeling for this Project used HEC-RAS version 6.1. The soil profiles, peak flows, and flow widths were then used to obtain the scour depth per the general scour methods.





Pipeline Creek Crossing Locations

Potential Produced Water Lines Routes

0 60 120 Feet

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Project Location	Prepared by DL on 2023-06-28
Kern County,	TR by SET on 2023-06-28
California	IR by ES on 2023-06-28
Client/Project	185805407

Aera Energy LLC
Aera CarbonFrontier Project

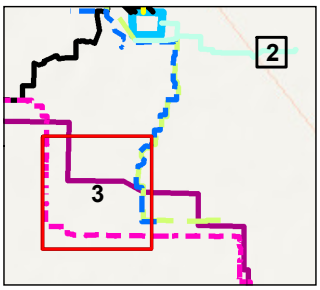
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Title
Major Crossing: Proposed Water Line Crossing Chico Martinez Creek

Notes
1. Coordinate System: NAD 1983 StatePlane California V FIPS 0405 Feet
2. Data Sources: CalGEM 2019, Stantec 2022.
3. Background: Sources: Esri, GEBCO, NOAA, National Geographic, Garmin, HERE, Geonames.org, and other contributors
Source: Esri, Maxar, Earthstar Geographics, and the GIS User Community
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors

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- Pipeline Creek Crossing Locations
- Existing Del Sur Gas Line to Gas Plant 32
- Existing Steam Line Routes
- Potential Steam Line Routes
- Tulare CVR to GP32 (Optional)

0 225 450 Feet
(At original document size of 8.5x11)
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N

Stantec AERA

Project Location
Kern County,
California

Prepared by DL on 2023-06-28
TR by SET on 2023-06-28
IR by ES on 2023-06-28

Client/Project
185805407

Aera Energy LLC
Aera CarbonFrontier Project

Figure No.
3

Title
Major Crossing: Proposed and Existing Gas Line Crossing Chico Martinez Creek

Notes
1. Coordinate System: NAD 1983 StatePlane California V FIPS 0405 Feet
2. Data Sources: CalGEM 2019, Stantec 2022.
3. Background: Sources: Esri, GEBCO, NOAA, National Geographic, Garmin, HERE, Geonames.org, and other contributors
Source: Esri, Maxar, Earthstar Geographics, and the GIS User Community
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors

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4.0 RESULTS

4.1 PEAK FLOW RUNOFF

Table 1 summarizes the pre-development versus post-development peak runoffs for the 10-year, 24-hour and 100-year, 24- hour storms in cubic feet per second (cfs). The detailed peak flow analysis can be found in Appendix C.

Table 1. Pre and Post Development Peak Runoff Flows

Junction	Pre 10-year Peak Runoff (cfs)	Post 10-year Peak Runoff (cfs)	Pre 100-year Peak Runoff (cfs)	Post 100-year Peak Runoff (cfs)
Junction-01	23.65	23.68	253.84	254.04
Junction-04	7.56	14.58	13.71	26.44
Junction-05	10.23	14.71	19.22	27.28
Junction-06	82.75	82.75	688.43	688.43
Junction-13	65.72	65.72	522.24	522.24

The junctions shown in Table 1 represent the discharge points for the watersheds tributary to the Study Area. Junction-06, specifically, represents the flow for Chico Martinez Creek, which crosses through the Project Site.

Table 1 shows that the proposed improvements within the watersheds for Junction-01, 06, and 13 will have negligible effects on peak flow runoff, due to the negligible amount of new impervious area within these watersheds.

The peak flow runoff for Junction-04 and Junction-05 increase significantly for the post-development conditions. This is because the watersheds tributary to these junctions are relatively small and that it was assumed that these two watersheds would be where most of the new impervious area would be added. Although the final site plans for the new facilities have not been developed at this time, their proposed locations are known. To be conservative with post-development peak flow runoff, it was assumed that the entire boundary of these locations would consist of an impervious surface. This, however, may not be the case once the site plans are developed. If the amount of new impervious area actually created within these watersheds is determined to affect on-site drainage characteristics , , a peak flow management will be used in these locations to help reduce the post-development peak flow runoff.

4.2 SCOUR

4.2.1 Scour Depth

Table 2 below summarizes the scour depths in feet (ft) found using the general scour methods. The table includes scour depth for both the 10-year, 24-hour storm and the 100-year, 24-hour storm. The detailed scour analysis can be found in Appendix D.

Table 2. Scour Depths Using General Scour Methods

Crossing	Storm Event	Blodgett Method Scour Depth (ft)	Pemberton and Lara (Lacey) Scour Depth (ft)	Pemberton and Lara (Blench) Scour Depth (ft)
Water Line	10-Year	11.9	2.1	1.9
Water Line	100-Year	11.9	4.3	3.3
Tulare CVR to Gas Plant 32	10-Year	10.8	1.8	2.9
Tulare CVR to Gas Plant 32	100-Year	10.8	3.7	1.6
Existing Del Sur Gas Line	10-Year	10.8	1.77	0.5
Existing Del Sur Gas Line	100-Year	10.8	3.7	1.6
Existing and Proposed Steam Line	10-Year	10.8	1.77	0.5
Existing and Proposed Steam Line	100-Year	10.8	3.7	1.6

Table 2 shows that the maximum scour depth for all four crossings occurs when the Blodgett general scour method is applied, which is significantly higher than the results obtained using the other methods. The Blodgett method does not consider peak flow or flow width when calculating scour depth. This method only uses the median size of bed material. The soils found in these locations are primarily loam/sandy loam types, which consist of small particles and have a potential for significant scouring.

Additionally, the USGS topography used lacks precision in these relatively flat areas and thus might result in wider flow widths, which in turn results in lower scouring depths when using the Pemberton and Lara methods. Because the Blodgett method only uses median size of bed material, it results in the same scour depth for both the 10-year and 100-year storms.

4.2.2 Chico Martinez Creek

In addition to determining the scour depth potential at the four crossings listed above, the flow width Chico Martinez Creek was determined for the two aboveground gas pipelines. Table 3 summarizes the results of the GeoHECRAS model.

Table 3. Flow Widths For Aboveground Gas Pipeline Crossings

Crossing	Storm Event	Flow Width (ft)
Tulare CVR to GP 32	10-Year	109
Tulare CVR to GP 32	100-Year	265
Existing Del Sur Gas Line	10-Year	181
Existing Del Sur Gas Line	100-Year	264

Table 3 shows the flow widths along Chico Martinez Creek for both the 10-year, 24-hour storm and the 100-year, 24-hour storm. The typical design storm in Kern County, is the 10-year storm. Stantec recommends additional geotechnical study within these areas to develop site-specific recommendations regarding proposed pipe support foundation design and embedment depth for areas within the 100-year storm scour area.

Due to the lack of precision in the topography, the flow widths may be larger than what would be expected to occur for the given storm events. It is recommended that higher precision topography be obtained at these crossing locations to better approximate the recommended setbacks from the creek.

5.0 CONCLUSION

This report has provided a preliminary hydrology study and scour analysis of the proposed Project Site.

The hydrologic analysis has revealed that a negligible amount of impervious area will be added throughout most of the Study Area. However, there are a couple of locations with relatively small watersheds that may require the use of peak flow management structures in order to mitigate the peak flow runoff for post- development conditions. This will depend on the final site plan of the proposed facilities and how much impervious area is added.

The scour analysis results show that the proposed waterline should be placed at a depth of 12 foot at the Chico Martinez Creek crossing. The analysis also shows that pipe supports for the two aboveground pipelines should be embedded 11 feet into the ground at their respective creek crossing. It is recommended that a site-specific geotechnical study be completed to provide pipe support foundation design and embedment information for proposed pipe supports. It is also recommended that the more precise topography be obtained for the crossing locations to better approximate scour and setback distances.

APPENDICES

Appendix A Web Soil Survey

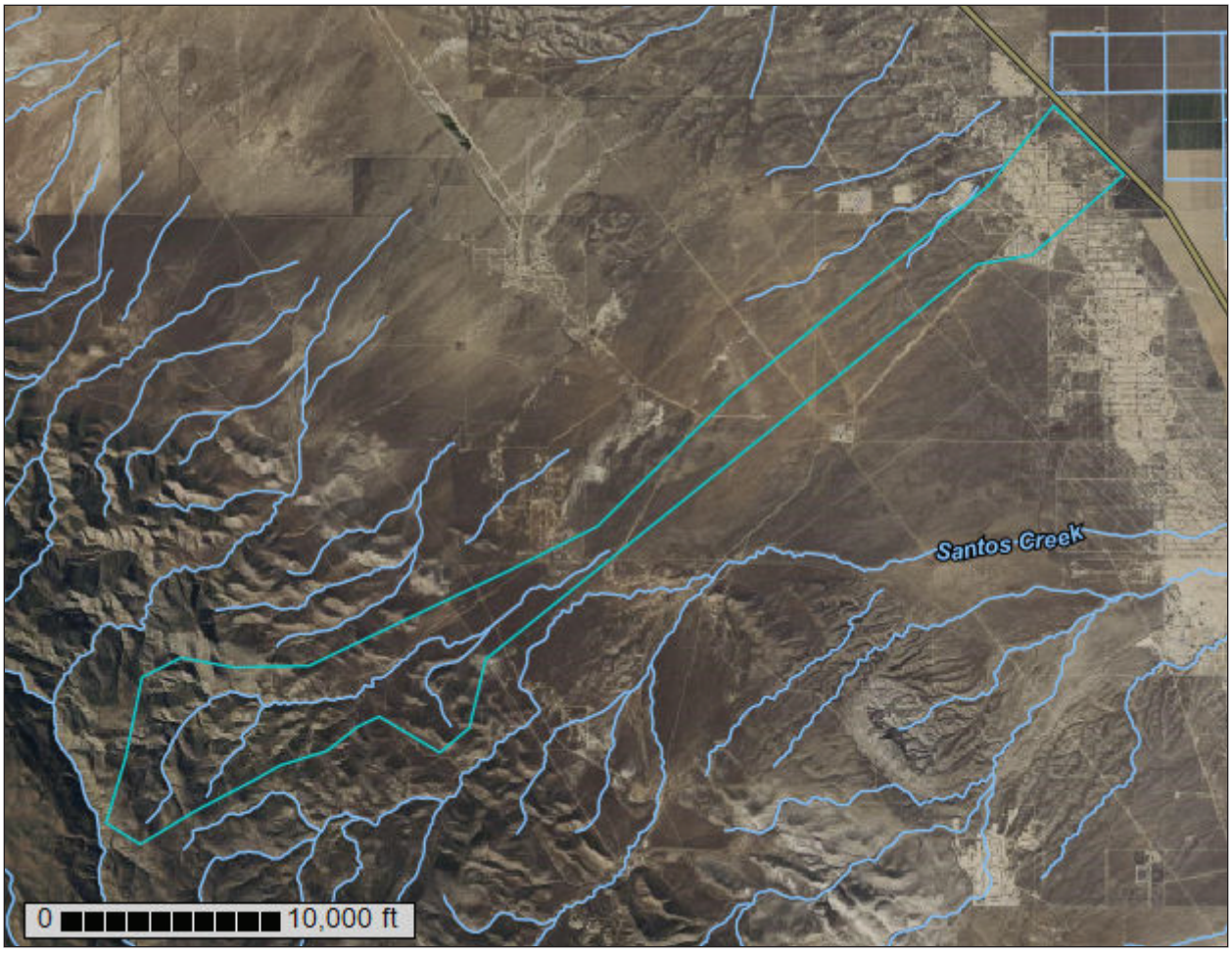
United States Department of Agriculture

NRCS

Natural Resources Conservation Service

A product of the National Cooperative Soil Survey, a joint effort of the United States Department of Agriculture and other Federal agencies, State agencies including the Agricultural Experiment Stations, and local participants

Custom Soil Resource Report for Kern County, California, Northwestern Part



January 12, 2023

Preface

Soil surveys contain information that affects land use planning in survey areas. They highlight soil limitations that affect various land uses and provide information about the properties of the soils in the survey areas. Soil surveys are designed for many different users, including farmers, ranchers, foresters, agronomists, urban planners, community officials, engineers, developers, builders, and home buyers. Also, conservationists, teachers, students, and specialists in recreation, waste disposal, and pollution control can use the surveys to help them understand, protect, or enhance the environment.

Various land use regulations of Federal, State, and local governments may impose special restrictions on land use or land treatment. Soil surveys identify soil properties that are used in making various land use or land treatment decisions. The information is intended to help the land users identify and reduce the effects of soil limitations on various land uses. The landowner or user is responsible for identifying and complying with existing laws and regulations.

Although soil survey information can be used for general farm, local, and wider area planning, onsite investigation is needed to supplement this information in some cases. Examples include soil quality assessments (http://www.nrcs.usda.gov/wps/portal/nrcs/main/soils/health/) and certain conservation and engineering applications. For more detailed information, contact your local USDA Service Center (https://offices.sc.egov.usda.gov/locator/app?agency=nrcs) or your NRCS State Soil Scientist (http://www.nrcs.usda.gov/wps/portal/nrcs/detail/soils/contactus/?cid=nrcs142p2_053951).

Great differences in soil properties can occur within short distances. Some soils are seasonally wet or subject to flooding. Some are too unstable to be used as a foundation for buildings or roads. Clayey or wet soils are poorly suited to use as septic tank absorption fields. A high water table makes a soil poorly suited to basements or underground installations.

The National Cooperative Soil Survey is a joint effort of the United States Department of Agriculture and other Federal agencies, State agencies including the Agricultural Experiment Stations, and local agencies. The Natural Resources Conservation Service (NRCS) has leadership for the Federal part of the National Cooperative Soil Survey.

Information about soils is updated periodically. Updated information is available through the NRCS Web Soil Survey, the site for official soil survey information.

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How Soil Surveys Are Made

Soil surveys are made to provide information about the soils and miscellaneous areas in a specific area. They include a description of the soils and miscellaneous areas and their location on the landscape and tables that show soil properties and limitations affecting various uses. Soil scientists observed the steepness, length, and shape of the slopes; the general pattern of drainage; the kinds of crops and native plants; and the kinds of bedrock. They observed and described many soil profiles. A soil profile is the sequence of natural layers, or horizons, in a soil. The profile extends from the surface down into the unconsolidated material in which the soil formed or from the surface down to bedrock. The unconsolidated material is devoid of roots and other living organisms and has not been changed by other biological activity.

Currently, soils are mapped according to the boundaries of major land resource areas (MLRAs). MLRAs are geographically associated land resource units that share common characteristics related to physiography, geology, climate, water resources, soils, biological resources, and land uses (USDA, 2006). Soil survey areas typically consist of parts of one or more MLRA.

The soils and miscellaneous areas in a survey area occur in an orderly pattern that is related to the geology, landforms, relief, climate, and natural vegetation of the area. Each kind of soil and miscellaneous area is associated with a particular kind of landform or with a segment of the landform. By observing the soils and miscellaneous areas in the survey area and relating their position to specific segments of the landform, a soil scientist develops a concept, or model, of how they were formed. Thus, during mapping, this model enables the soil scientist to predict with a considerable degree of accuracy the kind of soil or miscellaneous area at a specific location on the landscape.

Commonly, individual soils on the landscape merge into one another as their characteristics gradually change. To construct an accurate soil map, however, soil scientists must determine the boundaries between the soils. They can observe only a limited number of soil profiles. Nevertheless, these observations, supplemented by an understanding of the soil-vegetation-landscape relationship, are sufficient to verify predictions of the kinds of soil in an area and to determine the boundaries.

Soil scientists recorded the characteristics of the soil profiles that they studied. They noted soil color, texture, size and shape of soil aggregates, kind and amount of rock fragments, distribution of plant roots, reaction, and other features that enable them to identify soils. After describing the soils in the survey area and determining their properties, the soil scientists assigned the soils to taxonomic classes (units). Taxonomic classes are concepts. Each taxonomic class has a set of soil characteristics with precisely defined limits. The classes are used as a basis for comparison to classify soils systematically. Soil taxonomy, the system of taxonomic classification used in the United States, is based mainly on the kind and character of soil properties and the arrangement of horizons within the profile. After the soil

scientists classified and named the soils in the survey area, they compared the individual soils with similar soils in the same taxonomic class in other areas so that they could confirm data and assemble additional data based on experience and research.

The objective of soil mapping is not to delineate pure map unit components; the objective is to separate the landscape into landforms or landform segments that have similar use and management requirements. Each map unit is defined by a unique combination of soil components and/or miscellaneous areas in predictable proportions. Some components may be highly contrasting to the other components of the map unit. The presence of minor components in a map unit in no way diminishes the usefulness or accuracy of the data. The delineation of such landforms and landform segments on the map provides sufficient information for the development of resource plans. If intensive use of small areas is planned, onsite investigation is needed to define and locate the soils and miscellaneous areas.

Soil scientists make many field observations in the process of producing a soil map. The frequency of observation is dependent upon several factors, including scale of mapping, intensity of mapping, design of map units, complexity of the landscape, and experience of the soil scientist. Observations are made to test and refine the soil-landscape model and predictions and to verify the classification of the soils at specific locations. Once the soil-landscape model is refined, a significantly smaller number of measurements of individual soil properties are made and recorded. These measurements may include field measurements, such as those for color, depth to bedrock, and texture, and laboratory measurements, such as those for content of sand, silt, clay, salt, and other components. Properties of each soil typically vary from one point to another across the landscape.

Observations for map unit components are aggregated to develop ranges of characteristics for the components. The aggregated values are presented. Direct measurements do not exist for every property presented for every map unit component. Values for some properties are estimated from combinations of other properties.

While a soil survey is in progress, samples of some of the soils in the area generally are collected for laboratory analyses and for engineering tests. Soil scientists interpret the data from these analyses and tests as well as the field-observed characteristics and the soil properties to determine the expected behavior of the soils under different uses. Interpretations for all of the soils are field tested through observation of the soils in different uses and under different levels of management. Some interpretations are modified to fit local conditions, and some new interpretations are developed to meet local needs. Data are assembled from other sources, such as research information, production records, and field experience of specialists. For example, data on crop yields under defined levels of management are assembled from farm records and from field or plot experiments on the same kinds of soil.

Predictions about soil behavior are based not only on soil properties but also on such variables as climate and biological activity. Soil conditions are predictable over long periods of time, but they are not predictable from year to year. For example, soil scientists can predict with a fairly high degree of accuracy that a given soil will have a high water table within certain depths in most years, but they cannot predict that a high water table will always be at a specific level in the soil on a specific date.

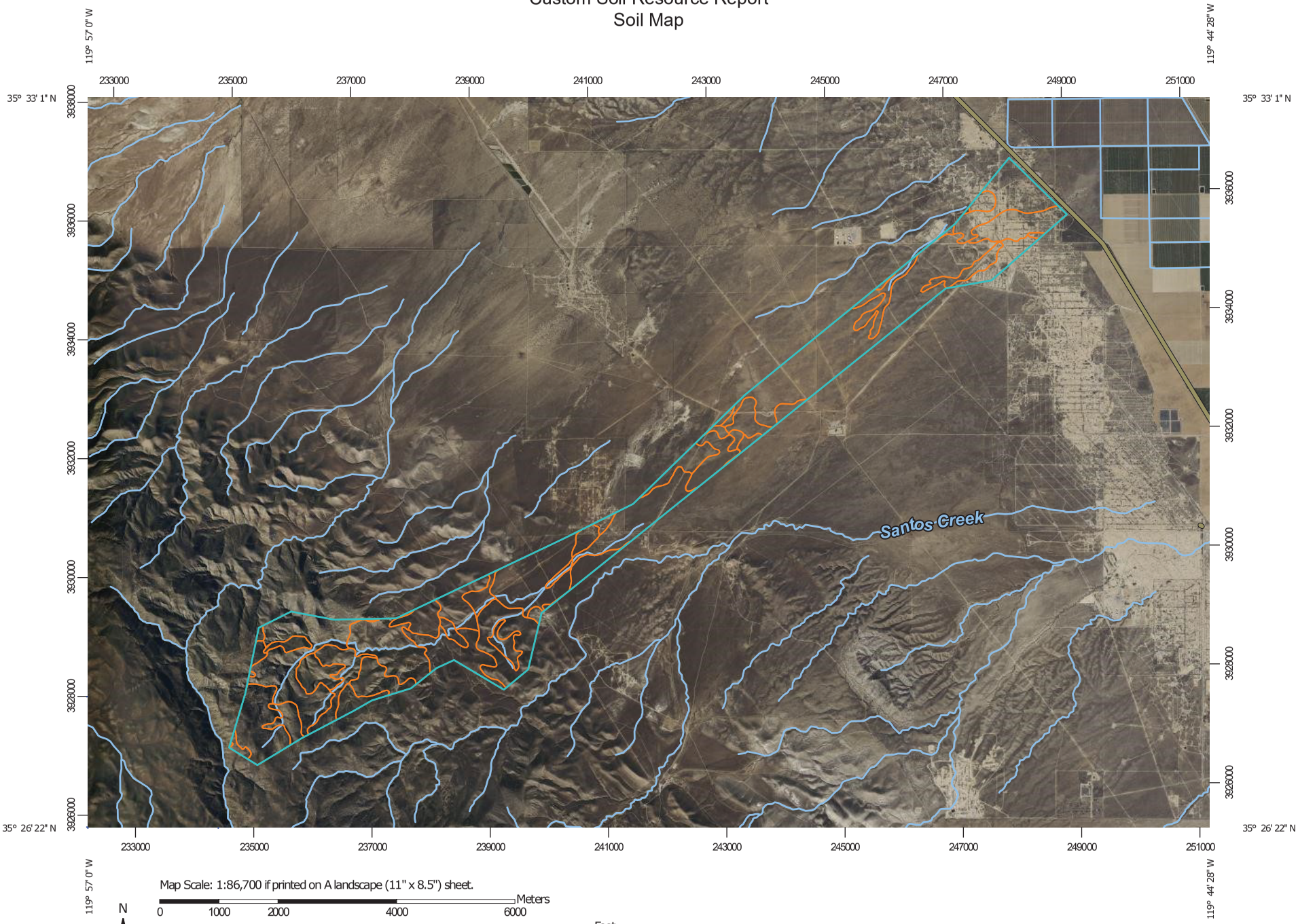
After soil scientists located and identified the significant natural bodies of soil in the survey area, they drew the boundaries of these bodies on aerial photographs and

identified each as a specific map unit. Aerial photographs show trees, buildings, fields, roads, and rivers, all of which help in locating boundaries accurately.

Soil Map

The soil map section includes the soil map for the defined area of interest, a list of soil map units on the map and extent of each map unit, and cartographic symbols displayed on the map. Also presented are various metadata about data used to produce the map, and a description of each soil map unit.

Custom Soil Resource Report
Soil Map



MAP LEGEND

Area of Interest (AOI)
- Area of Interest (AOI)

Soils
- Soil Map Unit Polygons
- Soil Map Unit Lines
- Soil Map Unit Points

Special Point Features
- Blowout
- Borrow Pit
- Clay Spot
- Closed Depression
- Gravel Pit
- Gravelly Spot
- Landfill
- Lava Flow
- Marsh or swamp
- Mine or Quarry
- Miscellaneous Water
- Perennial Water
- Rock Outcrop
- Saline Spot
- Sandy Spot
- Severely Eroded Spot
- Sinkhole
- Slide or Slip
- Sodic Spot
- Spoil Area
- Stony Spot
- Very Stony Spot
- Wet Spot
- Other
- Special Line Features

Water Features
- Streams and Canals

Transportation
- Rails
- Interstate Highways
- US Routes
- Major Roads
- Local Roads

Background
- Aerial Photography

MAP INFORMATION

The soil surveys that comprise your AOI were mapped at 1:24,000.

Please rely on the bar scale on each map sheet for map measurements.

Source of Map: Natural Resources Conservation Service
Web Soil Survey URL:
Coordinate System: Web Mercator (EPSG:3857)

Maps from the Web Soil Survey are based on the Web Mercator projection, which preserves direction and shape but distorts distance and area. A projection that preserves area, such as the Albers equal-area conic projection, should be used if more accurate calculations of distance or area are required.

This product is generated from the USDA-NRCS certified data as of the version date(s) listed below.

Soil Survey Area: Kern County, California, Northwestern Part
Survey Area Data: Version 15, Sep 1, 2022

Soil map units are labeled (as space allows) for map scales 1:50,000 or larger.

Date(s) aerial images were photographed: Mar 12, 2022—Mar 22, 2022

The orthophoto or other base map on which the soil lines were compiled and digitized probably differs from the background imagery displayed on these maps. As a result, some minor shifting of map unit boundaries may be evident.

Map Unit Legend

Map Unit Symbol	Map Unit Name	Acres in AOI	Percent of AOI
102	Aido clay 30 to 50 percent slopes	363.5	8.7%
111	Ayar-Hillbrick-Aido complex, 30 to 50 percent slopes	14.3	0.3%
115	Bitterwater sandy loam, 9 to 15 percent slopes	2.2	0.1%
117	Bitterwater gravelly sandy loam, 15 to 50 percent slope s	214.0	5.1%
118	Bitterwater-Delgado association, 9 to 30 percent slopes	155.8	3.7%
119	Bitterwater-Delgado association, 30 to 75 percent slope s	94.6	2.3%
162	Hillbrick-Rock outcrop complex, 15 to 50 percent slopes	187.8	4.5%
163	Hillbrick-Rock outcrop complex, 50 to 75 percent slopes	389.0	9.4%
167	Kecksroad silty clay loam, 15 to 50 percent slopes	113.9	2.7%
169	Kettleman loam, 15 to 50 percent slopes	23.9	0.6%
171	Kettleman-Delgado-Rock outcrop complex, 15 to 50 percen t slopes	229.7	5.5%
172	Kilmer-Hillbrick complex, 15 to 50 percent slopes, MLRA 15	96.5	2.3%
174	Kimberlina fine sandy loam, 0 to 2 percent slopes MLRA 17	439.8	10.6%
175	Kimberlina sandy loam, 2 to 5 percent slopes	293.0	7.0%
176	Kimberlina sandy loam, 5 to 9 percent slopes	1.4	0.0%
196	Milham sandy loam, 0 to 2 percent slopes MLRA 17	174.1	4.2%
197	Milham sandy loam, 2 to 5 percent slopes	1,094.4	26.3%
198	Milham sandy loam, 5 to 9 percent slopes	8.9	0.2%
211	Panoche clay loam, 0 to 2 percent slopes	230.2	5.5%
212	Panoche clay loam, 2 to 5 percent slopes	5.1	0.1%
217	Pits	11.1	0.3%

Map Unit Symbol	Map Unit Name	Acres in AOI	Percent of AOI
235	Twisselman clay, 0 to 2 percent slopes	13.1	0.3%
250	Xerorthents, very gravelly, 50 to 75 percent slopes	0.7	0.0%
253	Yribarren clay loam, 2 to 5 percent slopes	0.0	0.0%
Totals for Area of Interest		**4,157.6**	**100.0%**

Map Unit Descriptions

The map units delineated on the detailed soil maps in a soil survey represent the soils or miscellaneous areas in the survey area. The map unit descriptions, along with the maps, can be used to determine the composition and properties of a unit.

A map unit delineation on a soil map represents an area dominated by one or more major kinds of soil or miscellaneous areas. A map unit is identified and named according to the taxonomic classification of the dominant soils. Within a taxonomic class there are precisely defined limits for the properties of the soils. On the landscape, however, the soils are natural phenomena, and they have the characteristic variability of all natural phenomena. Thus, the range of some observed properties may extend beyond the limits defined for a taxonomic class. Areas of soils of a single taxonomic class rarely, if ever, can be mapped without including areas of other taxonomic classes. Consequently, every map unit is made up of the soils or miscellaneous areas for which it is named and some minor components that belong to taxonomic classes other than those of the major soils.

Most minor soils have properties similar to those of the dominant soil or soils in the map unit, and thus they do not affect use and management. These are called noncontrasting, or similar, components. They may or may not be mentioned in a particular map unit description. Other minor components, however, have properties and behavioral characteristics divergent enough to affect use or to require different management. These are called contrasting, or dissimilar, components. They generally are in small areas and could not be mapped separately because of the scale used. Some small areas of strongly contrasting soils or miscellaneous areas are identified by a special symbol on the maps. If included in the database for a given area, the contrasting minor components are identified in the map unit descriptions along with some characteristics of each. A few areas of minor components may not have been observed, and consequently they are not mentioned in the descriptions, especially where the pattern was so complex that it was impractical to make enough observations to identify all the soils and miscellaneous areas on the landscape.

The presence of minor components in a map unit in no way diminishes the usefulness or accuracy of the data. The objective of mapping is not to delineate pure taxonomic classes but rather to separate the landscape into landforms or landform segments that have similar use and management requirements. The delineation of such segments on the map provides sufficient information for the development of resource plans. If intensive use of small areas is planned, however, onsite investigation is needed to define and locate the soils and miscellaneous areas.

An identifying symbol precedes the map unit name in the map unit descriptions. Each description includes general facts about the unit and gives important soil properties and qualities.

Soils that have profiles that are almost alike make up a *soil series*. Except for differences in texture of the surface layer, all the soils of a series have major horizons that are similar in composition, thickness, and arrangement.

Soils of one series can differ in texture of the surface layer, slope, stoniness, salinity, degree of erosion, and other characteristics that affect their use. On the basis of such differences, a soil series is divided into *soil phases*. Most of the areas shown on the detailed soil maps are phases of soil series. The name of a soil phase commonly indicates a feature that affects use or management. For example, Alpha silt loam, 0 to 2 percent slopes, is a phase of the Alpha series.

Some map units are made up of two or more major soils or miscellaneous areas. These map units are complexes, associations, or undifferentiated groups.

A *complex* consists of two or more soils or miscellaneous areas in such an intricate pattern or in such small areas that they cannot be shown separately on the maps. The pattern and proportion of the soils or miscellaneous areas are somewhat similar in all areas. Alpha-Beta complex, 0 to 6 percent slopes, is an example.

An *association* is made up of two or more geographically associated soils or miscellaneous areas that are shown as one unit on the maps. Because of present or anticipated uses of the map units in the survey area, it was not considered practical or necessary to map the soils or miscellaneous areas separately. The pattern and relative proportion of the soils or miscellaneous areas are somewhat similar. Alpha-Beta association, 0 to 2 percent slopes, is an example.

An *undifferentiated group* is made up of two or more soils or miscellaneous areas that could be mapped individually but are mapped as one unit because similar interpretations can be made for use and management. The pattern and proportion of the soils or miscellaneous areas in a mapped area are not uniform. An area can be made up of only one of the major soils or miscellaneous areas, or it can be made up of all of them. Alpha and Beta soils, 0 to 2 percent slopes, is an example.

Some surveys include *miscellaneous areas*. Such areas have little or no soil material and support little or no vegetation. Rock outcrop is an example.

Kern County, California, Northwestern Part

102—Aido clay 30 to 50 percent slopes

Map Unit Setting

National map unit symbol: hkgc
Elevation: 1,400 to 3,000 feet
Mean annual precipitation: 9 inches
Mean annual air temperature: 64 degrees F
Frost-free period: 200 to 260 days
Farmland classification: Not prime farmland

Map Unit Composition

Aido and similar soils: 85 percent
Minor components: 15 percent
Estimates are based on observations, descriptions, and transects of the mapunit.

Description of Aido

Setting

Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Convex
Across-slope shape: Convex
Parent material: Residuum weathered from sandstone and shale

Typical profile

A - 0 to 10 inches: clay
C - 10 to 26 inches: clay
Cr - 26 to 60 inches: weathered bedrock

Properties and qualities

Slope: 30 to 50 percent
Depth to restrictive feature: 20 to 40 inches to paralithic bedrock
Drainage class: Well drained
Runoff class: Very high
Capacity of the most limiting layer to transmit water (Ksat): Moderately low to moderately high (0.06 to 0.20 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Calcium carbonate, maximum content: 5 percent
Maximum salinity: Nonsaline to very slightly saline (0.0 to 2.0 mmhos/cm)
Available water supply, 0 to 60 inches: Low (about 3.9 inches)

Interpretive groups

Land capability classification (irrigated): None specified
Land capability classification (nonirrigated): 6e
Hydrologic Soil Group: D
Ecological site: R015XF001CA - Clayey Hills 10-14" P.Z.
Hydric soil rating: No

Minor Components

Hillbrick

Percent of map unit: 5 percent
Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Hydric soil rating: No

Kilmer

Percent of map unit: 5 percent
Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Hydric soil rating: No

Rock outcrop

Percent of map unit: 5 percent
Hydric soil rating: No

111—Ayar-Hillbrick-Aido complex, 30 to 50 percent slopes

Map Unit Setting

National map unit symbol: hkgn
Elevation: 200 to 3,500 feet
Mean annual precipitation: 8 to 25 inches
Mean annual air temperature: 59 to 64 degrees F
Frost-free period: 200 to 330 days
Farmland classification: Not prime farmland

Map Unit Composition

Ayar and similar soils: 35 percent
Hillbrick and similar soils: 25 percent
Aido and similar soils: 20 percent
Minor components: 20 percent
Estimates are based on observations, descriptions, and transects of the mapunit.

Description of Ayar

Setting

Landform: Mountains, hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Mountainflank, side slope
Down-slope shape: Concave
Across-slope shape: Convex
Parent material: Residuum weathered from sandstone and shale

Typical profile

A - 0 to 11 inches: silty clay
C - 11 to 44 inches: clay
R - 44 to 54 inches: bedrock

Properties and qualities

Slope: 30 to 50 percent
Depth to restrictive feature: 40 to 60 inches to lithic bedrock
Drainage class: Well drained
Runoff class: Very high
Capacity of the most limiting layer to transmit water (Ksat): Moderately low to moderately high (0.06 to 0.20 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Calcium carbonate, maximum content: 15 percent
Maximum salinity: Nonsaline to very slightly saline (0.0 to 2.0 mmhos/cm)
Available water supply, 0 to 60 inches: Moderate (about 7.1 inches)

Interpretive groups

Land capability classification (irrigated): None specified
Land capability classification (nonirrigated): 6e
Hydrologic Soil Group: C
Ecological site: R015XF001CA - Clayey Hills 10-14" P.Z.
Hydric soil rating: No

Description of Hillbrick

Setting

Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Parent material: Residuum weathered from sandstone and shale

Typical profile

A - 0 to 15 inches: sandy loam
R - 15 to 25 inches: unweathered bedrock

Properties and qualities

Slope: 30 to 50 percent
Depth to restrictive feature: 10 to 20 inches to lithic bedrock
Drainage class: Well drained
Runoff class: Medium
Capacity of the most limiting layer to transmit water (Ksat): Moderately high to high (0.20 to 1.98 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Calcium carbonate, maximum content: 5 percent
Maximum salinity: Nonsaline to very slightly saline (0.0 to 2.0 mmhos/cm)
Available water supply, 0 to 60 inches: Very low (about 1.5 inches)

Interpretive groups

Land capability classification (irrigated): None specified
Land capability classification (nonirrigated): 6e

Hydrologic Soil Group: D
Ecological site: R015XF034CA - Limy Upland (shallow) 9-12" P.Z.
Hydric soil rating: No

Description of Aido

Setting

Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Convex
Across-slope shape: Convex
Parent material: Residuum weathered from sandstone and shale

Typical profile

A - 0 to 10 inches: clay
C - 10 to 26 inches: clay
Cr - 26 to 60 inches: weathered bedrock

Properties and qualities

Slope: 30 to 50 percent
Depth to restrictive feature: 20 to 40 inches to paralithic bedrock
Drainage class: Well drained
Runoff class: Very high
Capacity of the most limiting layer to transmit water (Ksat): Moderately low to moderately high (0.06 to 0.20 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Calcium carbonate, maximum content: 5 percent
Maximum salinity: Nonsaline to very slightly saline (0.0 to 2.0 mmhos/cm)
Available water supply, 0 to 60 inches: Low (about 3.9 inches)

Interpretive groups

Land capability classification (irrigated): None specified
Land capability classification (nonirrigated): 6e
Hydrologic Soil Group: D
Ecological site: R015XF001CA - Clayey Hills 10-14" P.Z.
Hydric soil rating: No

Minor Components

Shallow sandy soil

Percent of map unit: 10 percent
Landform: Mountains, hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Mountainflank, side slope
Down-slope shape: Concave
Across-slope shape: Convex
Hydric soil rating: No

Bluestone

Percent of map unit: 10 percent
Landform: Hillslopes, hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave

Across-slope shape: Convex
Hydric soil rating: No

115—Bitterwater sandy loam, 9 to 15 percent slopes

Map Unit Setting

National map unit symbol: hkgs
Elevation: 600 to 2,500 feet
Mean annual precipitation: 5 to 8 inches
Mean annual air temperature: 63 to 66 degrees F
Frost-free period: 250 to 275 days
Farmland classification: Not prime farmland

Map Unit Composition

Bitterwater and similar soils: 80 percent
Minor components: 20 percent
Estimates are based on observations, descriptions, and transects of the mapunit.

Description of Bitterwater

Setting

Landform: Hillslopes
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Parent material: Residuum weathered from sandstone and/or shale

Typical profile

A - 0 to 23 inches: sandy loam
C - 23 to 60 inches: sandy loam
Cr - 60 to 70 inches: weathered bedrock

Properties and qualities

Slope: 9 to 15 percent
Depth to restrictive feature: 40 to 60 inches to paralithic bedrock
Drainage class: Well drained
Runoff class: Low
Capacity of the most limiting layer to transmit water (Ksat): High (1.98 to 5.95 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Calcium carbonate, maximum content: 10 percent
Maximum salinity: Nonsaline to very slightly saline (0.0 to 2.0 mmhos/cm)
Available water supply, 0 to 60 inches: Moderate (about 6.6 inches)

Interpretive groups

Land capability classification (irrigated): None specified
Land capability classification (nonirrigated): 7e
Hydrologic Soil Group: A
Ecological site: R015XG008CA - Loamy 5-8" P.Z.
Hydric soil rating: No

Minor Components

Kettleman

Percent of map unit: 7 percent
Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Hydric soil rating: No

Bitterwater, gravelly sandy loam

Percent of map unit: 7 percent
Landform: Hillslopes
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Hydric soil rating: No

Unnamed, shallower bedrock

Percent of map unit: 3 percent
Landform: Hillslopes
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Hydric soil rating: No

Unnamed, soils with subsoil

Percent of map unit: 3 percent
Landform: Hillslopes
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Hydric soil rating: No

117—Bitterwater gravelly sandy loam, 15 to 50 percent slope s

Map Unit Setting

National map unit symbol: hkgv
Elevation: 600 to 2,000 feet

Mean annual precipitation: 5 to 8 inches
Mean annual air temperature: 63 to 66 degrees F
Frost-free period: 250 to 275 days
Farmland classification: Not prime farmland

Map Unit Composition

Bitterwater and similar soils: 85 percent
Minor components: 15 percent
Estimates are based on observations, descriptions, and transects of the mapunit.

Description of Bitterwater

Setting

Landform: Hillslopes
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Parent material: Residuum weathered from sandstone and/or shale

Typical profile

A - 0 to 23 inches: sandy loam
C - 23 to 60 inches: sandy loam
Cr - 60 to 70 inches: weathered bedrock

Properties and qualities

Slope: 15 to 50 percent
Depth to restrictive feature: 40 to 60 inches to paralithic bedrock
Drainage class: Well drained
Runoff class: Medium
Capacity of the most limiting layer to transmit water (Ksat): High (1.98 to 5.95 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Calcium carbonate, maximum content: 10 percent
Maximum salinity: Nonsaline to very slightly saline (0.0 to 2.0 mmhos/cm)
Available water supply, 0 to 60 inches: Moderate (about 6.6 inches)

Interpretive groups

Land capability classification (irrigated): None specified
Land capability classification (nonirrigated): 7e
Hydrologic Soil Group: A
Ecological site: R015XG008CA - Loamy 5-8" P.Z.
Hydric soil rating: No

Minor Components

Kettleman

Percent of map unit: 8 percent
Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Hydric soil rating: No

Bitterwater, sandy loam

Percent of map unit: 7 percent
Landform: Hillslopes
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Hydric soil rating: No

118—Bitterwater-Delgado association, 9 to 30 percent slopes

Map Unit Setting

National map unit symbol: hkgw
Elevation: 300 to 2,500 feet
Mean annual precipitation: 5 to 8 inches
Mean annual air temperature: 63 to 66 degrees F
Frost-free period: 230 to 300 days
Farmland classification: Not prime farmland

Map Unit Composition

Bitterwater and similar soils: 60 percent
Delgado and similar soils: 30 percent
Minor components: 10 percent
Estimates are based on observations, descriptions, and transects of the mapunit.

Description of Bitterwater

Setting

Landform: Hillslopes
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Parent material: Residuum weathered from sandstone and/or shale

Typical profile

A - 0 to 23 inches: sandy loam
C - 23 to 60 inches: sandy loam
Cr - 60 to 70 inches: weathered bedrock

Properties and qualities

Slope: 9 to 30 percent
Depth to restrictive feature: 40 to 60 inches to paralithic bedrock
Drainage class: Well drained
Runoff class: Medium
Capacity of the most limiting layer to transmit water (Ksat): High (1.98 to 5.95 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None

Calcium carbonate, maximum content: 10 percent
Maximum salinity: Nonsaline to very slightly saline (0.0 to 2.0 mmhos/cm)
Available water supply, 0 to 60 inches: Moderate (about 6.6 inches)

Interpretive groups

Land capability classification (irrigated): None specified
Land capability classification (nonirrigated): 7e
Hydrologic Soil Group: A
Ecological site: R015XG008CA - Loamy 5-8" P.Z.
Hydric soil rating: No

Description of Delgado

Setting

Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Parent material: Residuum weathered from sandstone and shale

Typical profile

A - 0 to 2 inches: gravelly sandy loam
C - 2 to 14 inches: gravelly sandy loam
R - 14 to 24 inches: unweathered bedrock

Properties and qualities

Slope: 9 to 30 percent
Depth to restrictive feature: 7 to 20 inches to lithic bedrock
Drainage class: Somewhat excessively drained
Runoff class: Medium
Capacity of the most limiting layer to transmit water (Ksat): High (1.98 to 5.95 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Calcium carbonate, maximum content: 3 percent
Maximum salinity: Nonsaline to very slightly saline (0.0 to 2.0 mmhos/cm)
Available water supply, 0 to 60 inches: Very low (about 1.6 inches)

Interpretive groups

Land capability classification (irrigated): None specified
Land capability classification (nonirrigated): 7s
Hydrologic Soil Group: D
Ecological site: R015XG009CA - Shallow Loamy 5-8
Hydric soil rating: No

Minor Components

Kettleman

Percent of map unit: 5 percent
Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Hydric soil rating: No

Rock outcrop
Percent of map unit: 5 percent
Hydric soil rating: No

119—Bitterwater-Delgado association, 30 to 75 percent slope s

Map Unit Setting
National map unit symbol: hkgx
Elevation: 300 to 2,500 feet
Mean annual precipitation: 5 to 8 inches
Mean annual air temperature: 63 to 66 degrees F
Frost-free period: 230 to 300 days
Farmland classification: Not prime farmland

Map Unit Composition
Bitterwater and similar soils: 60 percent
Delgado and similar soils: 25 percent
Minor components: 15 percent
Estimates are based on observations, descriptions, and transects of the mapunit.

Description of Bitterwater

Setting
Landform: Hillslopes
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Parent material: Residuum weathered from sandstone and/or shale

Typical profile
A - 0 to 23 inches: sandy loam
C - 23 to 60 inches: sandy loam
Cr - 60 to 70 inches: weathered bedrock

Properties and qualities
Slope: 30 to 75 percent
Depth to restrictive feature: 40 to 60 inches to paralithic bedrock
Drainage class: Well drained
Runoff class: Medium
Capacity of the most limiting layer to transmit water (Ksat): High (1.98 to 5.95 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Calcium carbonate, maximum content: 10 percent
Maximum salinity: Nonsaline to very slightly saline (0.0 to 2.0 mmhos/cm)
Available water supply, 0 to 60 inches: Moderate (about 6.6 inches)

Interpretive groups

Land capability classification (irrigated): None specified
Land capability classification (nonirrigated): 7e
Hydrologic Soil Group: A
Ecological site: R015XG008CA - Loamy 5-8" P.Z.
Hydric soil rating: No

Description of Delgado

Setting

Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Parent material: Residuum weathered from sandstone and shale

Typical profile

A - 0 to 2 inches: gravelly sandy loam
C - 2 to 14 inches: gravelly sandy loam
R - 14 to 24 inches: unweathered bedrock

Properties and qualities

Slope: 30 to 75 percent
Depth to restrictive feature: 7 to 20 inches to lithic bedrock
Drainage class: Somewhat excessively drained
Runoff class: Medium
Capacity of the most limiting layer to transmit water (Ksat): Moderately high to high (1.42 to 5.95 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Calcium carbonate, maximum content: 3 percent
Maximum salinity: Nonsaline to very slightly saline (0.0 to 2.0 mmhos/cm)
Available water supply, 0 to 60 inches: Very low (about 1.6 inches)

Interpretive groups

Land capability classification (irrigated): None specified
Land capability classification (nonirrigated): 7s
Hydrologic Soil Group: D
Ecological site: R015XG009CA - Shallow Loamy 5-8
Hydric soil rating: No

Minor Components

Kettleman

Percent of map unit: 8 percent
Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Hydric soil rating: No

Rock outcrop

Percent of map unit: 7 percent
Hydric soil rating: No

162—Hillbrick-Rock outcrop complex, 15 to 50 percent slopes

Map Unit Setting

National map unit symbol: hkj9
Elevation: 900 to 3,500 feet
Mean annual precipitation: 8 to 10 inches
Mean annual air temperature: 61 degrees F
Frost-free period: 200 to 250 days
Farmland classification: Not prime farmland

Map Unit Composition

Hillbrick and similar soils: 75 percent
Rock outcrop: 15 percent
Minor components: 10 percent
Estimates are based on observations, descriptions, and transects of the mapunit.

Description of Hillbrick

Setting

Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Parent material: Residuum weathered from sandstone and shale

Typical profile

A - 0 to 15 inches: sandy loam
R - 15 to 25 inches: unweathered bedrock

Properties and qualities

Slope: 15 to 50 percent
Depth to restrictive feature: 10 to 20 inches to lithic bedrock
Drainage class: Well drained
Runoff class: Medium
Capacity of the most limiting layer to transmit water (Ksat): Moderately high to high (0.20 to 1.98 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Calcium carbonate, maximum content: 5 percent
Maximum salinity: Nonsaline to very slightly saline (0.0 to 2.0 mmhos/cm)
Available water supply, 0 to 60 inches: Very low (about 1.5 inches)

Interpretive groups

Land capability classification (irrigated): None specified
Land capability classification (nonirrigated): 7e
Hydrologic Soil Group: D
Ecological site: R015XF034CA - Limy Upland (shallow) 9-12" P.Z.

Hydric soil rating: No

Description of Rock Outcrop

Setting

Landform: Mountains, hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Mountainflank, side slope
Down-slope shape: Concave
Across-slope shape: Convex
Parent material: Sandstone and shale

Interpretive groups

Land capability classification (irrigated): None specified
Land capability classification (nonirrigated): 8
Hydric soil rating: No

Minor Components

Kilmer

Percent of map unit: 4 percent
Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Hydric soil rating: No

Aido

Percent of map unit: 3 percent
Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Convex
Across-slope shape: Convex
Hydric soil rating: No

Soils that lack carbonates

Percent of map unit: 3 percent
Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Hydric soil rating: No

163—Hillbrick-Rock outcrop complex, 50 to 75 percent slopes

Map Unit Setting

National map unit symbol: hkjb

Elevation: 900 to 3,500 feet
Mean annual precipitation: 8 to 10 inches
Mean annual air temperature: 61 degrees F
Frost-free period: 200 to 250 days
Farmland classification: Not prime farmland

Map Unit Composition

Hillbrick and similar soils: 65 percent
Rock outcrop: 15 percent
Minor components: 20 percent
Estimates are based on observations, descriptions, and transects of the mapunit.

Description of Hillbrick

Setting

Landform: Mountains, hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Mountainflank, side slope
Down-slope shape: Concave
Across-slope shape: Convex
Parent material: Residuum weathered from sandstone and shale

Typical profile

A - 0 to 15 inches: sandy loam
R - 15 to 25 inches: unweathered bedrock

Properties and qualities

Slope: 50 to 75 percent
Depth to restrictive feature: 10 to 20 inches to lithic bedrock
Drainage class: Well drained
Runoff class: Medium
Capacity of the most limiting layer to transmit water (Ksat): Moderately high to high (0.20 to 1.98 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Calcium carbonate, maximum content: 5 percent
Maximum salinity: Nonsaline to very slightly saline (0.0 to 2.0 mmhos/cm)
Available water supply, 0 to 60 inches: Very low (about 1.5 inches)

Interpretive groups

Land capability classification (irrigated): None specified
Land capability classification (nonirrigated): 7e
Hydrologic Soil Group: D
Ecological site: R015XF034CA - Limy Upland (shallow) 9-12" P.Z.
Hydric soil rating: No

Description of Rock Outcrop

Setting

Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Parent material: Sandstone and shale

Interpretive groups

Land capability classification (irrigated): None specified
Land capability classification (nonirrigated): 8
Hydric soil rating: No

Minor Components

Kilmer

Percent of map unit: 7 percent
Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Hydric soil rating: No

Aido

Percent of map unit: 7 percent
Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Convex
Across-slope shape: Convex
Hydric soil rating: No

Unnamed, soils that lack carbonates

Percent of map unit: 6 percent
Landform: Mountains, hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Mountainflank, side slope
Down-slope shape: Concave
Across-slope shape: Convex
Hydric soil rating: No

167—Kecksroad silty clay loam, 15 to 50 percent slopes

Map Unit Setting

National map unit symbol: hkjg
Elevation: 450 to 1,100 feet
Mean annual precipitation: 5 to 7 inches
Mean annual air temperature: 61 to 63 degrees F
Frost-free period: 225 to 275 days
Farmland classification: Not prime farmland

Map Unit Composition

Kecksroad and similar soils: 85 percent
Minor components: 10 percent
Estimates are based on observations, descriptions, and transects of the mapunit.

Description of Kecksroad

Setting

Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Parent material: Residuum weathered from sedimentary rock

Typical profile

A - 0 to 11 inches: silty clay loam
Btk - 11 to 36 inches: clay
Cr - 36 to 60 inches: weathered bedrock

Properties and qualities

Slope: 15 to 50 percent
Depth to restrictive feature: 20 to 40 inches to paralithic bedrock
Drainage class: Well drained
Runoff class: Very high
Capacity of the most limiting layer to transmit water (Ksat): Moderately low to moderately high (0.06 to 0.20 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Calcium carbonate, maximum content: 10 percent
Maximum salinity: Nonsaline to very slightly saline (0.0 to 2.0 mmhos/cm)
Available water supply, 0 to 60 inches: Low (about 5.8 inches)

Interpretive groups

Land capability classification (irrigated): None specified
Land capability classification (nonirrigated): 7e
Hydrologic Soil Group: D
Ecological site: R015XG008CA - Loamy 5-8" P.Z.
Hydric soil rating: No

Minor Components

Twisselman

Percent of map unit: 3 percent
Landform: Alluvial fans
Landform position (two-dimensional): Footslope
Landform position (three-dimensional): Base slope
Down-slope shape: Linear
Across-slope shape: Linear
Hydric soil rating: No

Kettleman

Percent of map unit: 3 percent
Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Hydric soil rating: No

Bitterwater

Percent of map unit: 2 percent
Landform: Hillslopes
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Hydric soil rating: No

Rock outcrop

Percent of map unit: 2 percent
Hydric soil rating: No

169—Kettleman loam, 15 to 50 percent slopes

Map Unit Setting

National map unit symbol: hkjj
Elevation: 500 to 2,000 feet
Mean annual precipitation: 5 to 7 inches
Mean annual air temperature: 63 to 64 degrees F
Frost-free period: 240 to 270 days
Farmland classification: Not prime farmland

Map Unit Composition

Kettleman and similar soils: 80 percent
Minor components: 20 percent
Estimates are based on observations, descriptions, and transects of the mapunit.

Description of Kettleman

Setting

Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Parent material: Residuum weathered from sedimentary rock

Typical profile

A - 0 to 12 inches: loam
C - 12 to 22 inches: loam
Cr - 22 to 60 inches: weathered bedrock

Properties and qualities

Slope: 15 to 50 percent
Depth to restrictive feature: 20 to 40 inches to paralithic bedrock
Drainage class: Well drained
Runoff class: High
Capacity of the most limiting layer to transmit water (Ksat): Moderately high (0.20 to 0.57 in/hr)

Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Calcium carbonate, maximum content: 10 percent
Gypsum, maximum content: 3 percent
Maximum salinity: Nonsaline to very slightly saline (0.0 to 2.0 mmhos/cm)
Available water supply, 0 to 60 inches: Low (about 3.4 inches)

Interpretive groups

Land capability classification (irrigated): None specified
Land capability classification (nonirrigated): 7e
Hydrologic Soil Group: C
Ecological site: R015XG008CA - Loamy 5-8" P.Z.
Hydric soil rating: No

Minor Components

Kettleman, gravelly loam

Percent of map unit: 5 percent
Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Hydric soil rating: No

Rock outcrop

Percent of map unit: 5 percent
Hydric soil rating: No

Bitterwater

Percent of map unit: 5 percent
Landform: Hillslopes
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Hydric soil rating: No

Delgado

Percent of map unit: 5 percent
Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Hydric soil rating: No

171—Kettleman-Delgado-Rock outcrop complex, 15 to 50 percen t slopes

Map Unit Setting

National map unit symbol: hkjl
Elevation: 300 to 2,000 feet
Mean annual precipitation: 5 to 7 inches
Mean annual air temperature: 64 degrees F
Frost-free period: 230 to 260 days
Farmland classification: Not prime farmland

Map Unit Composition

Kettleman and similar soils: 45 percent
Delgado and similar soils: 30 percent
Rock outcrop: 15 percent
Minor components: 10 percent
Estimates are based on observations, descriptions, and transects of the mapunit.

Description of Kettleman

Setting

Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Parent material: Residuum weathered from sedimentary rock

Typical profile

A - 0 to 12 inches: loam
C - 12 to 22 inches: loam
Cr - 22 to 60 inches: weathered bedrock

Properties and qualities

Slope: 15 to 50 percent
Depth to restrictive feature: 20 to 40 inches to paralithic bedrock
Drainage class: Well drained
Runoff class: High
Capacity of the most limiting layer to transmit water (Ksat): Moderately high (0.20 to 0.57 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Calcium carbonate, maximum content: 10 percent
Gypsum, maximum content: 3 percent
Maximum salinity: Nonsaline to very slightly saline (0.0 to 2.0 mmhos/cm)
Available water supply, 0 to 60 inches: Low (about 3.4 inches)

Interpretive groups

Land capability classification (irrigated): None specified

Land capability classification (nonirrigated): 7e
Hydrologic Soil Group: C
Ecological site: R015XG008CA - Loamy 5-8" P.Z.
Hydric soil rating: No

Description of Delgado

Setting

Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Parent material: Residuum weathered from sedimentary rock

Typical profile

A - 0 to 2 inches: gravelly sandy loam
C - 2 to 10 inches: gravelly sandy loam
R - 10 to 20 inches: unweathered bedrock

Properties and qualities

Slope: 15 to 50 percent
Depth to restrictive feature: 7 to 20 inches to lithic bedrock
Drainage class: Somewhat excessively drained
Runoff class: Medium
Capacity of the most limiting layer to transmit water (Ksat): High (1.98 to 5.95 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Calcium carbonate, maximum content: 5 percent
Maximum salinity: Nonsaline to very slightly saline (0.0 to 2.0 mmhos/cm)
Available water supply, 0 to 60 inches: Very low (about 0.9 inches)

Interpretive groups

Land capability classification (irrigated): None specified
Land capability classification (nonirrigated): 7e
Hydrologic Soil Group: D
Ecological site: R015XG009CA - Shallow Loamy 5-8
Hydric soil rating: No

Description of Rock Outcrop

Setting

Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Parent material: Sedimentary rock

Interpretive groups

Land capability classification (irrigated): None specified
Land capability classification (nonirrigated): 8
Hydric soil rating: No

Minor Components

Bitterwater

Percent of map unit: 5 percent

Landform: Hillslopes
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Hydric soil rating: No

Soils deeper than 40 inches
Percent of map unit: 5 percent
Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Hydric soil rating: No

172—Kilmer-Hillbrick complex, 15 to 50 percent slopes, MLRA 15

Map Unit Setting
National map unit symbol: 2xgtd
Elevation: 1,080 to 3,350 feet
Mean annual precipitation: 7 to 14 inches
Mean annual air temperature: 59 to 64 degrees F
Frost-free period: 240 to 330 days
Farmland classification: Not prime farmland

Map Unit Composition
Kilmer and similar soils: 45 percent
Hillbrick and similar soils: 40 percent
Minor components: 15 percent
Estimates are based on observations, descriptions, and transects of the mapunit.

Description of Kilmer

Setting
Landform: Mountains, hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Mountainflank, side slope
Down-slope shape: Concave
Across-slope shape: Convex
Parent material: Residuum weathered from sandstone and shale

Typical profile
A1 - 0 to 5 inches: loam
A2 - 5 to 14 inches: clay loam
C - 14 to 32 inches: loam
R - 32 to 42 inches: unweathered bedrock

Properties and qualities

Slope: 15 to 50 percent
Depth to restrictive feature: 20 to 40 inches to lithic bedrock
Drainage class: Well drained
Runoff class: Very high
Capacity of the most limiting layer to transmit water (Ksat): Very low to low (0.00 to 0.01 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Calcium carbonate, maximum content: 10 percent
Maximum salinity: Nonsaline to very slightly saline (0.0 to 2.0 mmhos/cm)
Available water supply, 0 to 60 inches: Low (about 5.1 inches)

Interpretive groups

Land capability classification (irrigated): None specified
Land capability classification (nonirrigated): 6e
Hydrologic Soil Group: C
Ecological site: R015XE020CA - Fine Loamy 9-13
Hydric soil rating: No

Description of Hillbrick

Setting

Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Convex
Across-slope shape: Convex
Parent material: Residuum weathered from sandstone and shale

Typical profile

A - 0 to 4 inches: loam
C - 4 to 15 inches: loam
R - 15 to 25 inches: bedrock

Properties and qualities

Slope: 15 to 50 percent
Depth to restrictive feature: 10 to 20 inches to lithic bedrock
Drainage class: Well drained
Runoff class: Medium
Capacity of the most limiting layer to transmit water (Ksat): High (1.98 to 5.95 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Calcium carbonate, maximum content: 5 percent
Maximum salinity: Nonsaline to very slightly saline (0.0 to 2.0 mmhos/cm)
Available water supply, 0 to 60 inches: Low (about 3.1 inches)

Interpretive groups

Land capability classification (irrigated): None specified
Land capability classification (nonirrigated): 7e
Hydrologic Soil Group: D
Ecological site: R015XF034CA - Limy Upland (shallow) 9-12" P.Z.
Hydric soil rating: No

Minor Components

Rock outcrop

Percent of map unit: 5 percent
Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Convex
Across-slope shape: Convex
Hydric soil rating: No

Aramburu

Percent of map unit: 3 percent
Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Convex
Across-slope shape: Convex
Ecological site: R015XF036CA - SHALY FINE LOAMY
Hydric soil rating: No

Mendi

Percent of map unit: 3 percent
Landform: Hillslopes, ridges
Landform position (two-dimensional): Backslope, summit
Landform position (three-dimensional): Side slope, crest
Down-slope shape: Concave
Across-slope shape: Convex
Ecological site: R015XE020CA - Fine Loamy 9-13
Hydric soil rating: No

Choice

Percent of map unit: 2 percent
Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Convex
Across-slope shape: Convex
Ecological site: R015XF001CA - Clayey Hills 10-14" P.Z.
Hydric soil rating: No

San timoteo

Percent of map unit: 2 percent
Landform: Hillslopes
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Convex
Across-slope shape: Convex
Hydric soil rating: No

174—Kimberlina fine sandy loam, 0 to 2 percent slopes MLRA 17

Map Unit Setting

National map unit symbol: 2ss96
Elevation: 120 to 1,160 feet
Mean annual precipitation: 4 to 8 inches
Mean annual air temperature: 63 to 64 degrees F
Frost-free period: 240 to 300 days
Farmland classification: Prime farmland if irrigated

Map Unit Composition

Kimberlina and similar soils: 85 percent
Minor components: 15 percent
Estimates are based on observations, descriptions, and transects of the mapunit.

Description of Kimberlina

Setting

Landform: Alluvial fans
Landform position (three-dimensional): Talf
Down-slope shape: Linear
Across-slope shape: Linear
Parent material: Alluvium derived from igneous and sedimentary rock

Typical profile

Ap - 0 to 9 inches: fine sandy loam
C - 9 to 45 inches: fine sandy loam
2C - 45 to 71 inches: silt loam

Properties and qualities

Slope: 0 to 2 percent
Depth to restrictive feature: More than 80 inches
Drainage class: Well drained
Runoff class: Very low
Capacity of the most limiting layer to transmit water (Ksat): Moderately high to high (0.57 to 1.98 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: RareNone
Frequency of ponding: None
Calcium carbonate, maximum content: 10 percent
Maximum salinity: Nonsaline to slightly saline (0.3 to 4.0 mmhos/cm)
Sodium adsorption ratio, maximum: 4.0
Available water supply, 0 to 60 inches: Moderate (about 8.7 inches)

Interpretive groups

Land capability classification (irrigated): 1
Land capability classification (nonirrigated): 7e
Hydrologic Soil Group: A
Ecological site: R017XY906CA - Non-Alkali San Joaquin Valley Desert

Hydric soil rating: No

Minor Components

Wasco

Percent of map unit: 7 percent
Landform: Alluvial fans
Landform position (three-dimensional): Talf
Down-slope shape: Linear
Across-slope shape: Linear
Hydric soil rating: No

Milham

Percent of map unit: 6 percent
Landform: Alluvial fans
Landform position (three-dimensional): Talf
Down-slope shape: Linear
Across-slope shape: Linear
Hydric soil rating: No

Unnamed

Percent of map unit: 2 percent
Landform: Flood plains
Landform position (three-dimensional): Talf
Down-slope shape: Linear
Across-slope shape: Linear
Hydric soil rating: Yes

175—Kimberlina sandy loam, 2 to 5 percent slopes

Map Unit Setting

National map unit symbol: hkjq
Elevation: 120 to 1,000 feet
Mean annual precipitation: 4 to 8 inches
Mean annual air temperature: 63 to 64 degrees F
Frost-free period: 190 to 300 days
Farmland classification: Prime farmland if irrigated

Map Unit Composition

Kimberlina and similar soils: 85 percent
Minor components: 15 percent
Estimates are based on observations, descriptions, and transects of the mapunit.

Description of Kimberlina

Setting

Landform: Alluvial fans
Landform position (three-dimensional): Tread
Down-slope shape: Linear
Across-slope shape: Linear
Parent material: Alluvium derived from igneous and sedimentary rock

Typical profile

Ap - 0 to 9 inches: sandy loam
C - 9 to 45 inches: fine sandy loam
2C - 45 to 71 inches: stratified silt loam to sandy clay loam

Properties and qualities

Slope: 2 to 5 percent
Depth to restrictive feature: More than 80 inches
Drainage class: Well drained
Runoff class: Very low
Capacity of the most limiting layer to transmit water (Ksat): Moderately high to high (0.57 to 1.98 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Calcium carbonate, maximum content: 10 percent
Maximum salinity: Nonsaline to slightly saline (0.0 to 4.0 mmhos/cm)
Available water supply, 0 to 60 inches: Moderate (about 7.6 inches)

Interpretive groups

Land capability classification (irrigated): 2e
Land capability classification (nonirrigated): 7e
Hydrologic Soil Group: A
Ecological site: R017XY906CA - Non-Alkali San Joaquin Valley Desert
Hydric soil rating: No

Minor Components

Wasco

Percent of map unit: 5 percent
Landform: Alluvial fans
Landform position (three-dimensional): Tread
Down-slope shape: Linear
Across-slope shape: Linear
Hydric soil rating: No

Milham

Percent of map unit: 5 percent
Landform: Alluvial fans
Landform position (three-dimensional): Tread
Down-slope shape: Linear
Across-slope shape: Linear
Hydric soil rating: No

Panoche

Percent of map unit: 5 percent
Landform: Alluvial fans
Landform position (three-dimensional): Tread
Down-slope shape: Linear
Across-slope shape: Linear
Hydric soil rating: No

176—Kimberlina sandy loam, 5 to 9 percent slopes

Map Unit Setting

National map unit symbol: hkjr
Elevation: 120 to 1,000 feet
Mean annual precipitation: 4 to 8 inches
Mean annual air temperature: 63 to 64 degrees F
Frost-free period: 190 to 300 days
Farmland classification: Farmland of statewide importance

Map Unit Composition

Kimberlina and similar soils: 85 percent
Minor components: 15 percent
Estimates are based on observations, descriptions, and transects of the mapunit.

Description of Kimberlina

Setting

Landform: Alluvial fans
Landform position (three-dimensional): Tread
Down-slope shape: Linear
Across-slope shape: Linear
Parent material: Alluvium derived from igneous and sedimentary rock

Typical profile

A - 0 to 9 inches: sandy loam
C - 9 to 45 inches: fine sandy loam
2C - 45 to 71 inches: stratified silt loam to sandy clay loam

Properties and qualities

Slope: 5 to 9 percent
Depth to restrictive feature: More than 80 inches
Drainage class: Well drained
Runoff class: Low
Capacity of the most limiting layer to transmit water (Ksat): Moderately high to high (0.57 to 1.98 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Calcium carbonate, maximum content: 10 percent
Maximum salinity: Nonsaline to slightly saline (0.0 to 4.0 mmhos/cm)
Available water supply, 0 to 60 inches: Moderate (about 7.6 inches)

Interpretive groups

Land capability classification (irrigated): 3e
Land capability classification (nonirrigated): 7e
Hydrologic Soil Group: A
Ecological site: R017XY906CA - Non-Alkali San Joaquin Valley Desert
Hydric soil rating: No

Minor Components

Kettleman
Percent of map unit: 4 percent
Landform: Hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Side slope
Down-slope shape: Concave
Across-slope shape: Convex
Hydric soil rating: No

Panoche
Percent of map unit: 4 percent
Landform: Alluvial fans
Landform position (three-dimensional): Tread
Down-slope shape: Linear
Across-slope shape: Linear
Hydric soil rating: No

Elkhills
Percent of map unit: 4 percent
Landform: Erosion remnants
Landform position (three-dimensional): Tread
Down-slope shape: Linear
Across-slope shape: Linear
Hydric soil rating: No

Milham
Percent of map unit: 3 percent
Landform: Alluvial fans
Landform position (three-dimensional): Tread
Down-slope shape: Linear
Across-slope shape: Linear
Hydric soil rating: No

196—Milham sandy loam, 0 to 2 percent slopes MLRA 17

Map Unit Setting
National map unit symbol: 2ss91
Elevation: 200 to 1,200 feet
Mean annual precipitation: 5 to 8 inches
Mean annual air temperature: 63 to 65 degrees F
Frost-free period: 250 to 300 days
Farmland classification: Prime farmland if irrigated

Map Unit Composition
Milham and similar soils: 85 percent
Minor components: 15 percent
Estimates are based on observations, descriptions, and transects of the mapunit.

Description of Milham

Setting

Landform: Terraces, fan remnants, plains, alluvial fans
Landform position (three-dimensional): Tread, rise
Down-slope shape: Linear
Across-slope shape: Linear
Parent material: Alluvium derived from igneous and sedimentary rock

Typical profile

Ap - 0 to 4 inches: sandy loam
Bk - 4 to 10 inches: sandy loam
Btk1 - 10 to 22 inches: loam
Btk2 - 22 to 49 inches: clay loam
2Ck - 49 to 60 inches: sandy loam

Properties and qualities

Slope: 0 to 2 percent
Depth to restrictive feature: More than 80 inches
Drainage class: Well drained
Runoff class: Medium
Capacity of the most limiting layer to transmit water (Ksat): Moderately high (0.20 to 0.60 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: Rare
Frequency of ponding: None
Calcium carbonate, maximum content: 10 percent
Gypsum, maximum content: 1 percent
Maximum salinity: Nonsaline to moderately saline (0.0 to 8.0 mmhos/cm)
Sodium adsorption ratio, maximum: 25.0
Available water supply, 0 to 60 inches: High (about 9.1 inches)

Interpretive groups

Land capability classification (irrigated): 1
Land capability classification (nonirrigated): 7c
Hydrologic Soil Group: C
Ecological site: R017XG043CA - Loamy 6-8" P.Z.
Hydric soil rating: No

Minor Components

Panoche

Percent of map unit: 5 percent
Landform: Alluvial fans
Landform position (three-dimensional): Tread
Down-slope shape: Linear
Across-slope shape: Linear
Hydric soil rating: No

Kimberlina

Percent of map unit: 5 percent
Landform: Alluvial fans
Landform position (three-dimensional): Talf
Down-slope shape: Linear
Across-slope shape: Linear
Hydric soil rating: No

Garces

Percent of map unit: 5 percent
Landform: Rims on basin floors
Landform position (three-dimensional): Talf
Down-slope shape: Linear
Across-slope shape: Linear
Hydric soil rating: No

197—Milham sandy loam, 2 to 5 percent slopes

Map Unit Setting

National map unit symbol: hkkf
Elevation: 200 to 1,200 feet
Mean annual precipitation: 5 to 7 inches
Mean annual air temperature: 63 to 64 degrees F
Frost-free period: 250 to 300 days
Farmland classification: Prime farmland if irrigated

Map Unit Composition

Milham and similar soils: 80 percent
Minor components: 20 percent
Estimates are based on observations, descriptions, and transects of the mapunit.

Description of Milham

Setting

Landform: Terraces, alluvial fans
Landform position (three-dimensional): Tread
Down-slope shape: Linear
Across-slope shape: Linear
Parent material: Alluvium derived from igneous and sedimentary rock

Typical profile

Ap - 0 to 10 inches: sandy loam
Btk - 10 to 49 inches: clay loam
2Ck - 49 to 60 inches: stratified sandy loam to sandy clay loam

Properties and qualities

Slope: 2 to 5 percent
Depth to restrictive feature: More than 80 inches
Drainage class: Well drained
Runoff class: Medium
Capacity of the most limiting layer to transmit water (Ksat): Moderately high (0.20 to 0.57 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Calcium carbonate, maximum content: 10 percent
Maximum salinity: Nonsaline to moderately saline (0.0 to 8.0 mmhos/cm)
Available water supply, 0 to 60 inches: Moderate (about 8.7 inches)

Interpretive groups

Land capability classification (irrigated): 2e
Land capability classification (nonirrigated): 7e
Hydrologic Soil Group: C
Ecological site: R017XG043CA - Loamy 6-8" P.Z.
Hydric soil rating: No

Minor Components

Panoche

Percent of map unit: 7 percent
Landform: Alluvial fans
Landform position (three-dimensional): Tread
Down-slope shape: Linear
Across-slope shape: Linear
Hydric soil rating: No

Kimberlina

Percent of map unit: 7 percent
Landform: Alluvial fans
Landform position (three-dimensional): Tread
Down-slope shape: Linear
Across-slope shape: Linear
Hydric soil rating: No

Unnamed, subsoils with mod. coarse tex.

Percent of map unit: 6 percent
Landform: Terraces, alluvial fans
Landform position (three-dimensional): Tread
Down-slope shape: Linear
Across-slope shape: Linear
Hydric soil rating: No

198—Milham sandy loam, 5 to 9 percent slopes

Map Unit Setting

National map unit symbol: hkkg
Elevation: 200 to 1,200 feet
Mean annual precipitation: 5 to 7 inches
Mean annual air temperature: 63 to 64 degrees F
Frost-free period: 250 to 300 days
Farmland classification: Farmland of statewide importance

Map Unit Composition

Milham and similar soils: 85 percent
Minor components: 10 percent
Estimates are based on observations, descriptions, and transects of the mapunit.

Description of Milham

Setting

Landform: Terraces, alluvial fans
Landform position (three-dimensional): Tread
Down-slope shape: Linear
Across-slope shape: Linear
Parent material: Alluvium derived from igneous and sedimentary rock

Typical profile

Ap - 0 to 10 inches: sandy loam
Btk - 10 to 49 inches: clay loam
2Ck - 49 to 60 inches: stratified sandy loam to sandy clay loam

Properties and qualities

Slope: 5 to 9 percent
Depth to restrictive feature: More than 80 inches
Drainage class: Well drained
Runoff class: High
Capacity of the most limiting layer to transmit water (Ksat): Moderately high (0.20 to 0.57 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Calcium carbonate, maximum content: 10 percent
Maximum salinity: Nonsaline to moderately saline (0.0 to 8.0 mmhos/cm)
Available water supply, 0 to 60 inches: Moderate (about 8.7 inches)

Interpretive groups

Land capability classification (irrigated): 3e
Land capability classification (nonirrigated): 7e
Hydrologic Soil Group: C
Ecological site: R017XG043CA - Loamy 6-8" P.Z.
Hydric soil rating: No

Minor Components

Panoche

Percent of map unit: 5 percent
Landform: Alluvial fans
Landform position (three-dimensional): Tread
Down-slope shape: Linear
Across-slope shape: Linear
Hydric soil rating: No

Kimberlina

Percent of map unit: 5 percent
Landform: Alluvial fans
Landform position (three-dimensional): Tread
Down-slope shape: Linear
Across-slope shape: Linear
Hydric soil rating: No

211—Panoche clay loam, 0 to 2 percent slopes

Map Unit Setting

National map unit symbol: 2ycb1
Elevation: 270 to 890 feet
Mean annual precipitation: 6 to 9 inches
Mean annual air temperature: 62 to 65 degrees F
Frost-free period: 305 to 326 days
Farmland classification: Prime farmland if irrigated

Map Unit Composition

Panoche, clay loam, and similar soils: 87 percent
Minor components: 13 percent
Estimates are based on observations, descriptions, and transects of the mapunit.

Description of Panoche, Clay Loam

Setting

Landform: Alluvial fans
Landform position (three-dimensional): Tread
Down-slope shape: Linear
Across-slope shape: Linear
Parent material: Alluvium derived from calcareous sedimentary rock

Typical profile

Ap - 0 to 7 inches: clay loam
Bw - 7 to 16 inches: loam
Bk1 - 16 to 27 inches: loam
Bk2 - 27 to 43 inches: loam
Bk3 - 43 to 57 inches: loam
Bk4 - 57 to 72 inches: sandy loam

Properties and qualities

Slope: 0 to 2 percent
Depth to restrictive feature: More than 80 inches
Drainage class: Well drained
Runoff class: Low
Capacity of the most limiting layer to transmit water (Ksat): Moderately low (0.01 to 0.14 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: Very rareNone
Frequency of ponding: None
Calcium carbonate, maximum content: 4 percent
Gypsum, maximum content: 2 percent
Maximum salinity: Nonsaline to slightly saline (0.0 to 4.0 mmhos/cm)
Sodium adsorption ratio, maximum: 8.0
Available water supply, 0 to 60 inches: High (about 9.4 inches)

Interpretive groups

Land capability classification (irrigated): 1

Land capability classification (nonirrigated): 7c
Hydrologic Soil Group: C
Ecological site: R017XY905CA - Dry Alluvial Fans and Terraces
Hydric soil rating: No

Minor Components

Calflax
Percent of map unit: 4 percent
Landform: Fan skirts
Landform position (three-dimensional): Tread
Down-slope shape: Linear
Across-slope shape: Linear
Hydric soil rating: No

Cerini
Percent of map unit: 3 percent
Landform: Alluvial fans
Landform position (three-dimensional): Tread
Down-slope shape: Linear
Across-slope shape: Linear
Hydric soil rating: No

Ciervo
Percent of map unit: 2 percent
Landform: Fan skirts
Landform position (three-dimensional): Tread
Down-slope shape: Linear
Across-slope shape: Linear
Hydric soil rating: No

Posochanet
Percent of map unit: 2 percent
Landform: Fan skirts
Landform position (three-dimensional): Tread
Down-slope shape: Linear
Across-slope shape: Linear
Hydric soil rating: No

Kimberlina
Percent of map unit: 1 percent
Landform: Alluvial fans
Landform position (three-dimensional): Talf
Down-slope shape: Linear
Across-slope shape: Linear
Hydric soil rating: No

Wasco
Percent of map unit: 1 percent
Landform: Alluvial fans
Landform position (three-dimensional): Tread
Down-slope shape: Linear
Across-slope shape: Linear
Hydric soil rating: No

212—Panoche clay loam, 2 to 5 percent slopes

Map Unit Setting

National map unit symbol: hkkx
Elevation: 200 to 1,300 feet
Mean annual precipitation: 5 to 7 inches
Mean annual air temperature: 63 degrees F
Frost-free period: 250 to 300 days
Farmland classification: Prime farmland if irrigated

Map Unit Composition

Panoche and similar soils: 85 percent
Estimates are based on observations, descriptions, and transects of the mapunit.

Description of Panoche

Setting

Landform: Alluvial fans
Landform position (three-dimensional): Tread
Down-slope shape: Linear
Across-slope shape: Linear
Parent material: Alluvium derived from igneous and sedimentary rock

Typical profile

Ap - 0 to 16 inches: clay loam
C - 16 to 60 inches: loam

Properties and qualities

Slope: 2 to 5 percent
Depth to restrictive feature: More than 80 inches
Drainage class: Well drained
Runoff class: Low
Capacity of the most limiting layer to transmit water (Ksat): Moderately high to high (0.57 to 1.98 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Calcium carbonate, maximum content: 5 percent
Maximum salinity: Nonsaline to very slightly saline (0.0 to 2.0 mmhos/cm)
Available water supply, 0 to 60 inches: High (about 9.7 inches)

Interpretive groups

Land capability classification (irrigated): 2e
Land capability classification (nonirrigated): 7e
Hydrologic Soil Group: B
Ecological site: R017XG043CA - Loamy 6-8" P.Z.
Hydric soil rating: No

217—Pits

Map Unit Composition

Pits: 100 percent
Estimates are based on observations, descriptions, and transects of the mapunit.

235—Twisselman clay, 0 to 2 percent slopes

Map Unit Setting

National map unit symbol: hkln
Elevation: 200 to 1,000 feet
Mean annual precipitation: 5 inches
Mean annual air temperature: 64 degrees F
Frost-free period: 250 to 275 days
Farmland classification: Prime farmland if irrigated

Map Unit Composition

Twisselman and similar soils: 85 percent
Estimates are based on observations, descriptions, and transects of the mapunit.

Description of Twisselman

Setting

Landform: Alluvial fans
Landform position (three-dimensional): Tread
Down-slope shape: Linear
Across-slope shape: Linear
Parent material: Alluvium derived from sedimentary rock

Typical profile

A - 0 to 14 inches: clay
C - 14 to 60 inches: clay

Properties and qualities

Slope: 0 to 2 percent
Depth to restrictive feature: More than 80 inches
Drainage class: Well drained
Runoff class: High
Capacity of the most limiting layer to transmit water (Ksat): Moderately low to moderately high (0.06 to 0.20 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: Rare
Frequency of ponding: None
Calcium carbonate, maximum content: 10 percent
Gypsum, maximum content: 5 percent
Maximum salinity: Nonsaline to slightly saline (0.0 to 4.0 mmhos/cm)
Sodium adsorption ratio, maximum: 10.0
Available water supply, 0 to 60 inches: High (about 9.1 inches)

Interpretive groups

Land capability classification (irrigated): 2s
Land capability classification (nonirrigated): 7s
Hydrologic Soil Group: C
Ecological site: R017XY906CA - Non-Alkali San Joaquin Valley Desert
Hydric soil rating: No

250—Xerorthents, very gravelly, 50 to 75 percent slopes

Map Unit Setting

National map unit symbol: hkm4
Elevation: 2,000 to 3,000 feet
Mean annual precipitation: 8 to 12 inches
Mean annual air temperature: 57 to 61 degrees F
Frost-free period: 200 to 250 days
Farmland classification: Not prime farmland

Map Unit Composition

Xerorthents and similar soils: 85 percent
Estimates are based on observations, descriptions, and transects of the mapunit.

Description of Xerorthents

Setting

Landform: Mountains, hills
Landform position (two-dimensional): Backslope
Landform position (three-dimensional): Mountainflank, side slope
Down-slope shape: Concave
Across-slope shape: Convex
Parent material: Residuum weathered from shale

Properties and qualities

Slope: 50 to 75 percent
Depth to restrictive feature: 40 to 60 inches to lithic bedrock
Drainage class: Somewhat excessively drained
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None

Interpretive groups

Land capability classification (irrigated): None specified
Land capability classification (nonirrigated): 7e
Ecological site: R015XY013CA - Loamy Mountains <20"ppt
Hydric soil rating: No

253—Yribarren clay loam, 2 to 5 percent slopes

Map Unit Setting

National map unit symbol: hkm7
Elevation: 300 to 1,200 feet
Mean annual precipitation: 5 to 8 inches
Mean annual air temperature: 64 to 66 degrees F
Frost-free period: 250 to 300 days
Farmland classification: Prime farmland if irrigated

Map Unit Composition

Yribarren and similar soils: 85 percent
Estimates are based on observations, descriptions, and transects of the mapunit.

Description of Yribarren

Setting

Landform: Alluvial fans
Landform position (three-dimensional): Tread
Down-slope shape: Linear
Across-slope shape: Linear
Parent material: Alluvium derived from sedimentary rock

Typical profile

A - 0 to 7 inches: loam
Btk - 7 to 19 inches: clay
C - 19 to 22 inches: loam
2C - 22 to 60 inches: stratified fine sandy loam to sandy clay loam

Properties and qualities

Slope: 2 to 5 percent
Depth to restrictive feature: More than 80 inches
Drainage class: Well drained
Runoff class: Very high
Capacity of the most limiting layer to transmit water (Ksat): Very low to moderately low (0.00 to 0.06 in/hr)
Depth to water table: More than 80 inches
Frequency of flooding: None
Frequency of ponding: None
Calcium carbonate, maximum content: 10 percent
Gypsum, maximum content: 5 percent
Maximum salinity: Nonsaline to moderately saline (0.0 to 8.0 mmhos/cm)
Sodium adsorption ratio, maximum: 20.0
Available water supply, 0 to 60 inches: Moderate (about 6.5 inches)

Interpretive groups

Land capability classification (irrigated): 3e
Land capability classification (nonirrigated): 7e
Hydrologic Soil Group: D
Ecological site: R017XG043CA - Loamy 6-8" P.Z.
Hydric soil rating: No

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Appendix B NOAA Atlas Data



NOAA Atlas 14, Volume 6, Version 2
Location name: Mc Kittrick, California, USA*
Latitude: 35.4568°, Longitude: -119.8196°
Elevation: 1069.6 ft**
• source: ESRI Maps
•• source: USGS

POINT PRECIPITATION FREQUENCY ESTIMATES

Sanja Perica, Sarah Dietz, Sarah Heim, Lillian Hiner, Kazungu Maitaria, Deborah Martin, Sandra Pavlovic, Ishani Roy, Carl Trypaluk, Dale Unruh, Fenglin Yan, Michael Yekta, Tan Zhao, Geoffrey Bonnin, Daniel Brewer, Li-Chuan Chen, Tye Parzybok, John Yarchoan

NOAA, National Weather Service, Silver Spring, Maryland

PF_tabular | PF_graphical | Maps_&_aerials

PF tabular

PDS-based point precipitation frequency estimates with 90% confidence intervals (in inches)[1]

Duration	1	2	5	10	25	50	100	200	500	1000
5-min	0.057 (0.049-0.066)	0.072 (0.062-0.084)	0.095 (0.082-0.112)	0.118 (0.100-0.140)	0.154 (0.126-0.191)	0.188 (0.150-0.239)	0.228 (0.176-0.299)	0.277 (0.206-0.375)	0.355 (0.251-0.508)	0.429 (0.291-0.639)
10-min	0.081 (0.070-0.095)	0.103 (0.089-0.120)	0.136 (0.117-0.160)	0.169 (0.144-0.200)	0.221 (0.180-0.274)	0.270 (0.214-0.343)	0.327 (0.252-0.429)	0.397 (0.295-0.538)	0.509 (0.360-0.728)	0.615 (0.417-0.916)
15-min	0.098 (0.085-0.115)	0.124 (0.107-0.145)	0.165 (0.142-0.194)	0.204 (0.174-0.242)	0.268 (0.218-0.331)	0.326 (0.259-0.415)	0.396 (0.305-0.519)	0.480 (0.357-0.651)	0.616 (0.436-0.880)	0.743 (0.504-1.11)
30-min	0.136 (0.117-0.159)	0.172 (0.148-0.201)	0.228 (0.196-0.268)	0.282 (0.240-0.335)	0.370 (0.302-0.459)	0.452 (0.359-0.574)	0.548 (0.422-0.718)	0.664 (0.494-0.901)	0.853 (0.603-1.22)	1.03 (0.698-1.53)
60-min	0.192 (0.166-0.224)	0.243 (0.210-0.284)	0.322 (0.277-0.379)	0.399 (0.339-0.473)	0.523 (0.427-0.647)	0.638 (0.507-0.811)	0.773 (0.596-1.01)	0.937 (0.698-1.27)	1.20 (0.851-1.72)	1.45 (0.985-2.16)
2-hr	0.284 (0.246-0.332)	0.356 (0.308-0.417)	0.469 (0.403-0.551)	0.577 (0.491-0.685)	0.751 (0.613-0.930)	0.912 (0.724-1.16)	1.10 (0.849-1.44)	1.33 (0.990-1.81)	1.70 (1.20-2.43)	2.05 (1.39-3.05)
3-hr	0.350 (0.303-0.410)	0.440 (0.379-0.515)	0.579 (0.498-0.680)	0.711 (0.605-0.845)	0.926 (0.755-1.15)	1.12 (0.891-1.43)	1.35 (1.04-1.77)	1.63 (1.21-2.21)	2.08 (1.47-2.97)	2.49 (1.69-3.71)
6-hr	0.474 (0.410-0.555)	0.601 (0.519-0.704)	0.796 (0.684-0.935)	0.979 (0.833-1.16)	1.27 (1.04-1.57)	1.53 (1.22-1.95)	1.84 (1.42-2.41)	2.20 (1.64-2.99)	2.78 (1.97-3.97)	3.30 (2.24-4.92)
12-hr	0.602 (0.520-0.703)	0.771 (0.665-0.902)	1.02 (0.881-1.20)	1.26 (1.07-1.50)	1.63 (1.33-2.01)	1.95 (1.55-2.48)	2.32 (1.79-3.04)	2.75 (2.05-3.73)	3.42 (2.42-4.88)	4.02 (2.72-5.99)
24-hr	0.763 (0.668-0.890)	0.996 (0.870-1.16)	1.34 (1.17-1.57)	1.65 (1.43-1.95)	2.12 (1.78-2.58)	2.53 (2.08-3.14)	2.99 (2.40-3.80)	3.51 (2.74-4.58)	4.31 (3.24-5.84)	5.00 (3.64-7.01)
2-day	0.899 (0.786-1.05)	1.24 (1.08-1.44)	1.72 (1.50-2.01)	2.14 (1.85-2.53)	2.78 (2.33-3.38)	3.31 (2.72-4.11)	3.90 (3.13-4.95)	4.55 (3.56-5.93)	5.51 (4.14-7.48)	6.33 (4.61-8.88)
3-day	0.966 (0.845-1.13)	1.37 (1.20-1.61)	1.95 (1.70-2.29)	2.46 (2.12-2.90)	3.20 (2.68-3.89)	3.81 (3.13-4.74)	4.48 (3.60-5.69)	5.22 (4.08-6.81)	6.29 (4.73-8.54)	7.19 (5.23-10.1)
4-day	1.03 (0.902-1.20)	1.49 (1.30-1.74)	2.13 (1.85-2.49)	2.68 (2.32-3.16)	3.49 (2.93-4.25)	4.17 (3.42-5.17)	4.89 (3.93-6.22)	5.69 (4.45-7.42)	6.84 (5.14-9.29)	7.81 (5.68-11.0)
7-day	1.19 (1.04-1.39)	1.70 (1.49-1.99)	2.42 (2.11-2.84)	3.04 (2.63-3.59)	3.95 (3.31-4.81)	4.70 (3.86-5.84)	5.51 (4.42-7.00)	6.39 (5.00-8.34)	7.68 (5.77-10.4)	8.75 (6.37-12.3)
10-day	1.29 (1.13-1.51)	1.83 (1.60-2.14)	2.58 (2.25-3.02)	3.23 (2.79-3.81)	4.18 (3.50-5.08)	4.95 (4.07-6.15)	5.79 (4.65-7.36)	6.71 (5.25-8.76)	8.05 (6.05-10.9)	9.16 (6.66-12.8)
20-day	1.60 (1.40-1.87)	2.23 (1.95-2.61)	3.10 (2.70-3.63)	3.85 (3.33-4.54)	4.92 (4.12-5.99)	5.79 (4.76-7.20)	6.73 (5.40-8.56)	7.75 (6.06-10.1)	9.23 (6.94-12.5)	10.4 (7.60-14.7)
30-day	1.88 (1.65-2.20)	2.59 (2.26-3.03)	3.56 (3.10-4.16)	4.38 (3.78-5.16)	5.55 (4.65-6.75)	6.50 (5.34-8.07)	7.51 (6.03-9.54)	8.60 (6.73-11.2)	10.2 (7.65-13.8)	11.5 (8.35-16.1)
45-day	2.28 (2.00-2.66)	3.08 (2.69-3.60)	4.17 (3.63-4.88)	5.08 (4.39-5.99)	6.37 (5.34-7.75)	7.40 (6.08-9.19)	8.49 (6.82-10.8)	9.67 (7.56-12.6)	11.3 (8.53-15.4)	12.7 (9.26-17.8)
60-day	2.65 (2.32-3.09)	3.52 (3.08-4.11)	4.69 (4.09-5.49)	5.67 (4.90-6.69)	7.04 (5.90-8.57)	8.12 (6.68-10.1)	9.27 (7.44-11.8)	10.5 (8.21-13.7)	12.2 (9.20-16.6)	13.7 (9.94-19.2)

Precipitation frequency (PF) estimates in this table are based on frequency analysis of partial duration series (PDS).

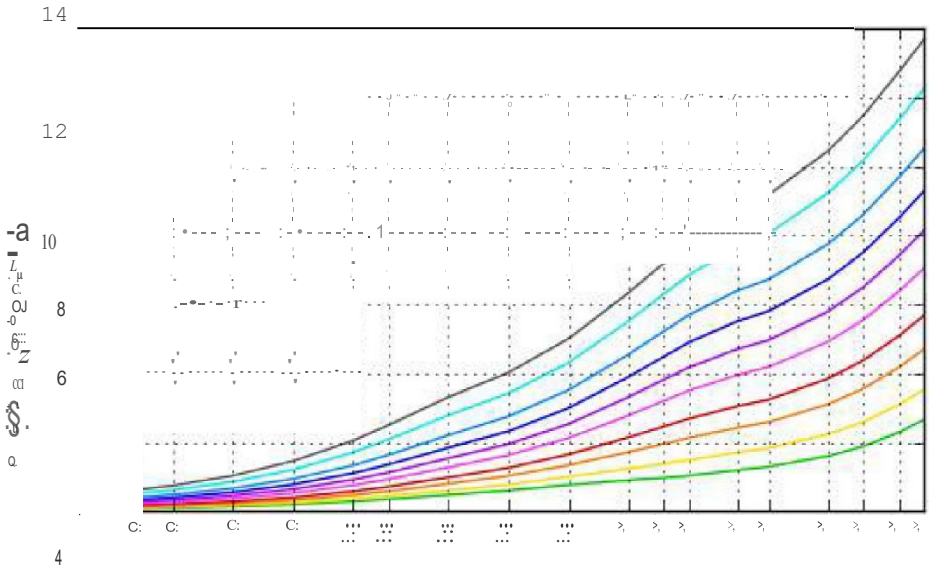
Numbers in parenthesis are PF estimates at lower and upper bounds of the 90% confidence interval. The probability that precipitation frequency estimates (for a given duration and average recurrence interval) will be greater than the upper bound (or less than the lower bound) is 5%. Estimates at upper bounds are not checked against probable maximum precipitation (PMP) estimates and may be higher than currently valid PMP values.

Please refer to NOAA Atlas 14 document for more information.

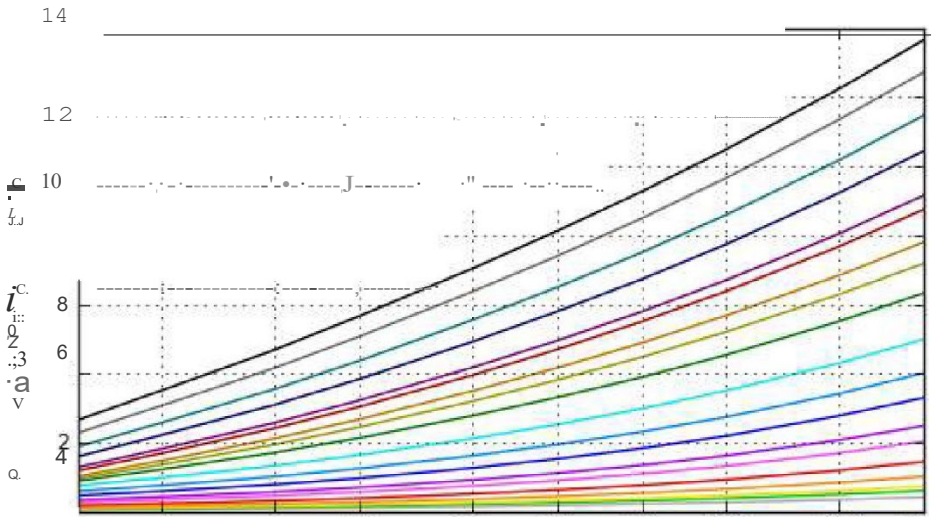
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PF graphical

PDS-based depth-duration-frequency (DDF) curves
Latitude: 35.4568°, longitude: -119.8196°



A 'll'r e r• c m,rice inLeM1 (years,.
1
2
15
10
25
50
100
:mo
500
1000



Duration	
5-mln	2–day
1 o-m n	3-.oay
15--mln	4--day
30-imln	7-.0ay
•6o-mn	10-day
2-nr	20-day
3,-hr	30-day
6-nr	45-tiay



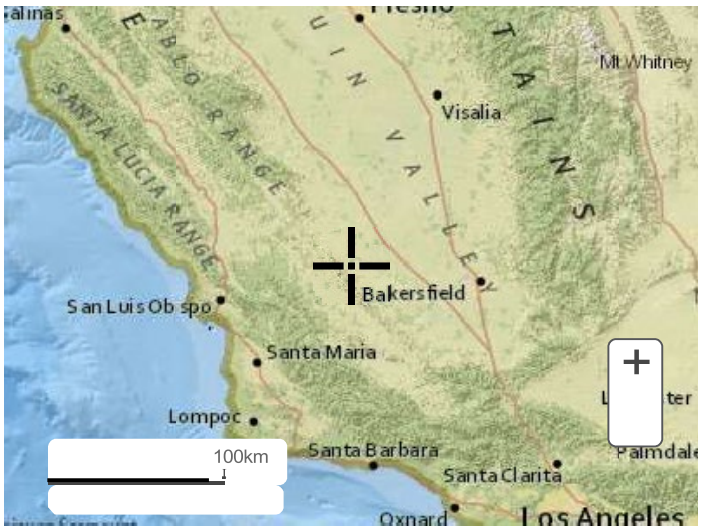
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Maps & aerials

Small scale terrain



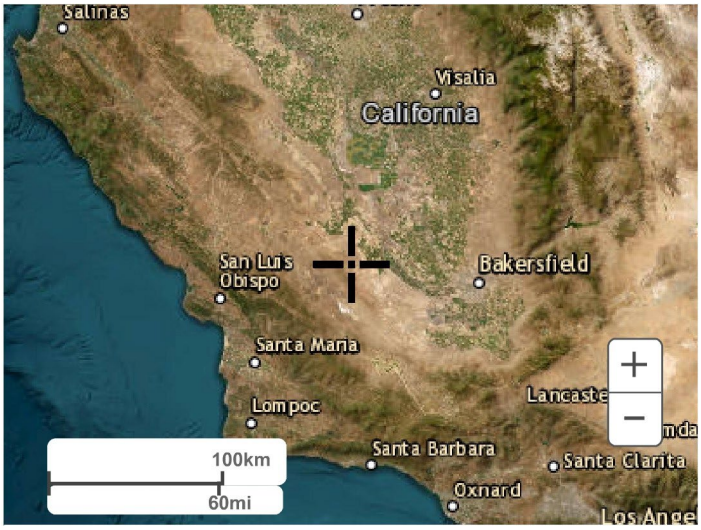
Large scale terrain



Large scale map



Large scale aerial



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US DePartment of Commerce
National Oceanic and AtmosPheric Administration
National Weather Service
National Water Center
1325 East West Highway
Silver Spring, MD 20910
Questions?: HDSC.Questions@noaa.gov

Disclaimer

Appendix C GeoHECHMS Report

CarbonFrontier Carbon Capture and Sequestration

Preliminary Hydrology Study

Prepared for:

Aera Energy LLC

Prepared by:

Stantec
2646 Santa Maria Way, Suite 107
Santa Maria, California 93455-1776

June 2023

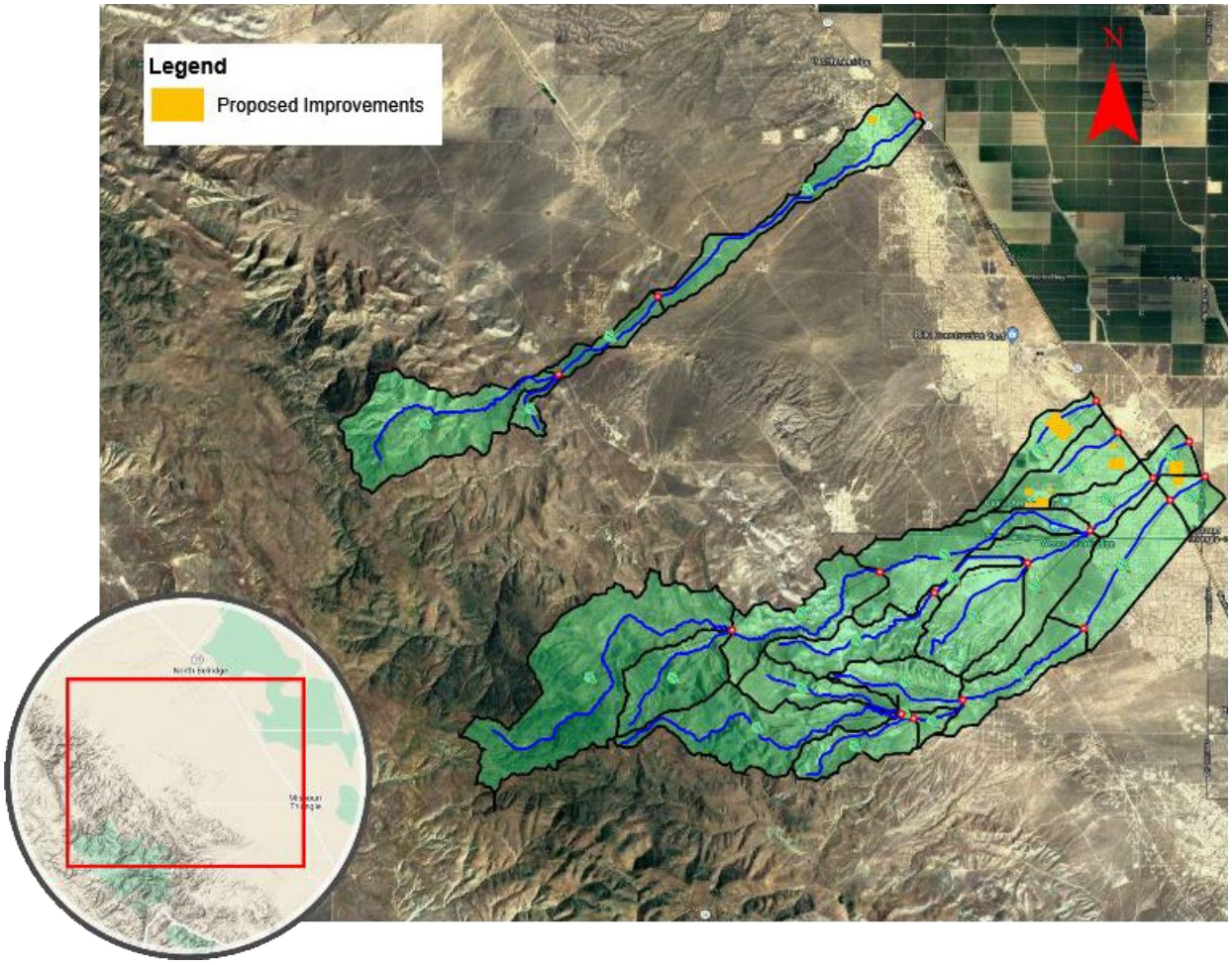
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Project Description

The project is located at **Unnamed Road, McKittrick, CA 93251.** The site is 22,967.685 acres in size.



Purpose

The purpose of this hydrology study is to determine the peak runoff rates for pre-development and post-development conditions.

Methodology Used

The HEC-HMS version 4.5 computer software was used in this hydrology study. The **SCS Curve Number**

infiltration (loss) method and **SCS Unit Hydrograph** runoff (transform) method was used for determining the stormwater runoff**.** The **Kinematic Wave** routing method was used for routing the stormwater**.**

The following scenarios were analyzed in this hydrology study:

Existing Conditions 100yr

This scenario contains:

- 25 delineated subbasin areas and corresponding lag time flow paths.
- 25 routing reaches.
- 18 connecting junctions.

Existing Conditions 10yr

This scenario contains:

- 25 delineated subbasin areas and corresponding lag time flow paths.
- 25 routing reaches.
- 18 connecting junctions.

Proposed Development 100yr

This scenario contains:

- 25 delineated subbasin areas and corresponding lag time flow paths.
- 25 routing reaches.
- 18 connecting junctions.

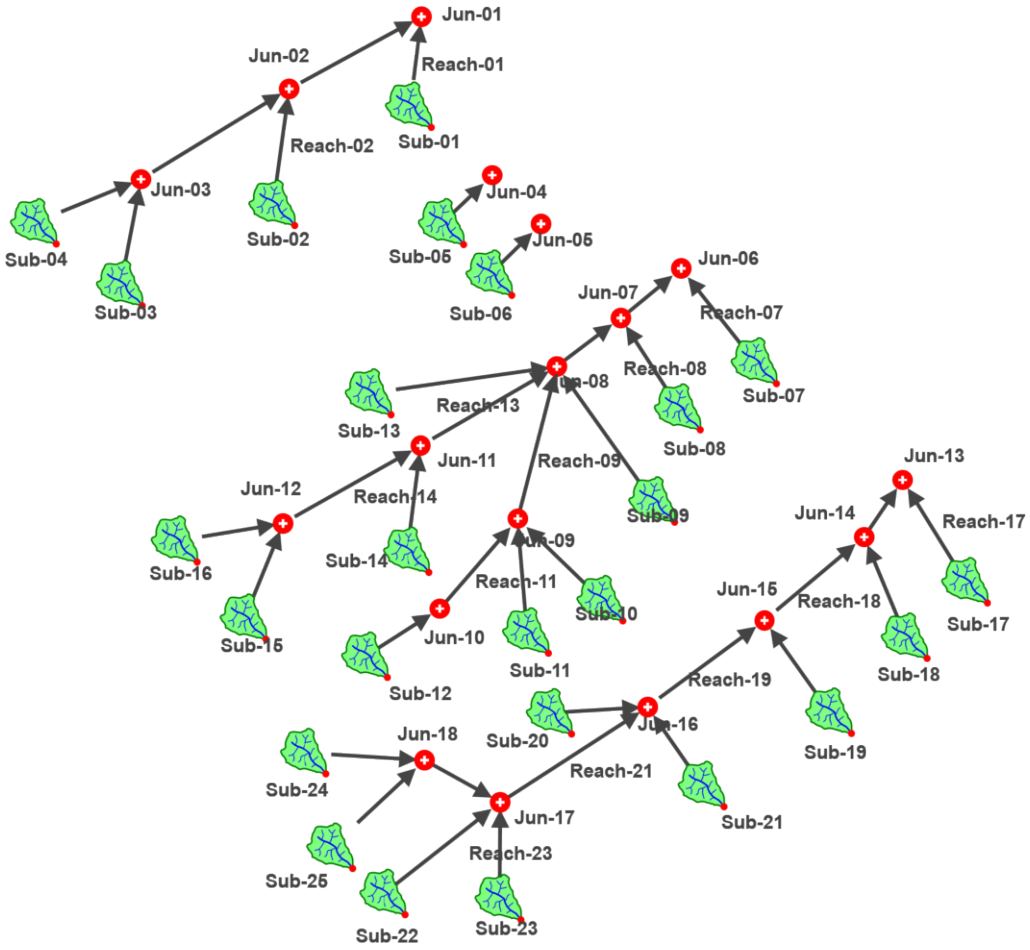
Proposed Development 10 yr

This scenario contains:

- 25 delineated subbasin areas and corresponding lag time flow paths.
- 25 routing reaches.
- 18 connecting junctions.

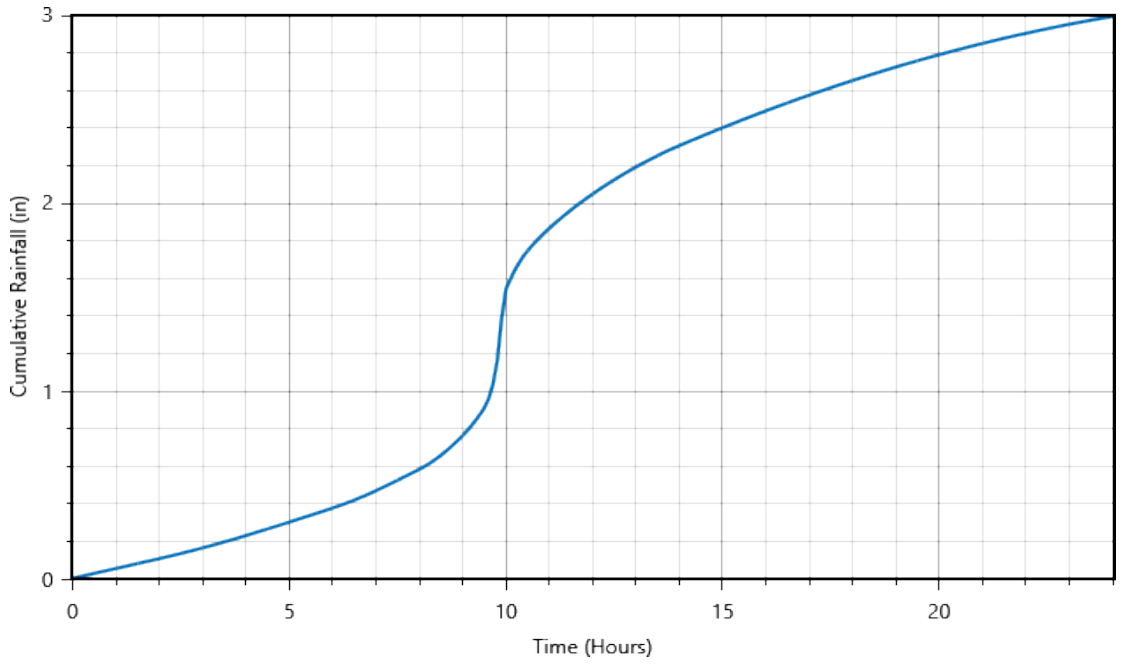
Existing Conditions 100yr

Watershed Routing Diagram



Design Storm

Precipitation type: SCS Storm
SCS storm distribution: Type I
Rainfall depth: 2.99 in



Watershed Summary

Subbasin ID	Drainage Area (acres)	Initial Abstraction (in)	Curve Number	Impervious Surface (%)	Lag Time (minutes)	Peak Discharge (cfs)
Sub-01	1,269.566	1.23	61.84	1.10	107.15	46.22
Sub-02	337.798	2.28	46.74	0.15	50.54	1.81
Sub-03	169.707	2.61	43.39	0.12	32.39	0.39
Sub-04	1,961.124	0.86	70.00	0.09	58.02	221.35
Sub-05	685.814	1.94	50.82	4.68	125.36	13.71
Sub-06	856.439	1.86	51.75	6.67	198.99	19.22
Sub-07	269.771	1.05	65.60	10.71	98.48	25.53
Sub-08	503.505	1.48	57.53	8.38	395.42	14.19
Sub-09	1,130.587	2.84	41.33	0.94	67.09	6.55
Sub-10	1,153.361	1.94	50.79	1.30	55.92	12.39
Sub-11	161.318	4.26	31.97	1.51	40.10	2.01
Sub-12	952.517	3.33	37.51	0.52	34.22	4.46
Sub-13	1,426.690	3.40	37.06	2.54	649.32	5.65
Sub-14	1,158.859	2.01	49.91	0.23	43.12	10.40
Sub-15	1,054.808	0.70	74.04	0.23	30.66	256.17
Sub-16	3,426.802	0.76	72.40	0.26	59.76	492.32
Sub-17	337.184	0.97	67.43	10.46	80.39	39.46
Sub-18	1,474.591	1.47	57.69	3.55	96.69	40.88
Sub-19	787.670	2.86	41.19	1.53	66.54	7.46
Sub-20	714.148	2.82	41.47	0.54	30.83	3.66
Sub-21	140.608	0.83	70.73	0.65	37.22	22.43
Sub-22	624.791	0.70	74.21	0.15	26.62	164.39
Sub-23	13.631	1.27	61.18	1.28	30.66	0.63
Sub-24	662.076	1.57	56.09	0.15	31.77	12.20
Sub-25	1,694.320	0.65	75.41	0.25	53.90	337.38

Subbasins

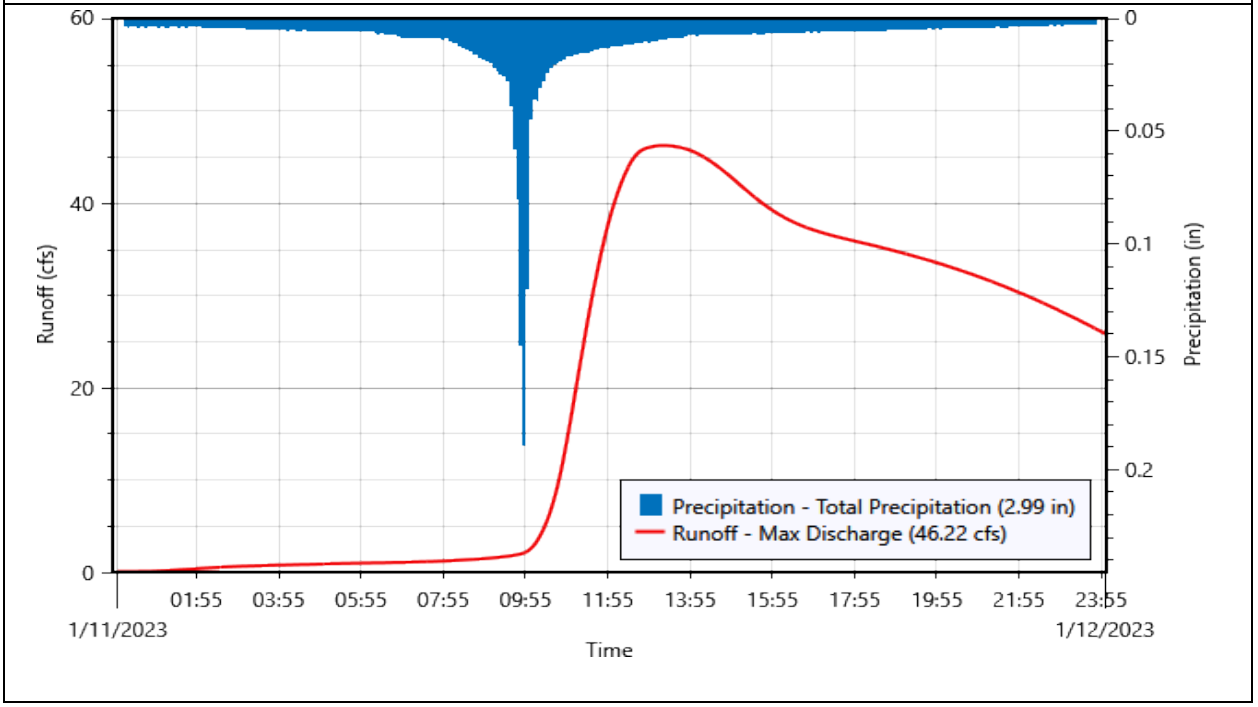
Subbasin ID:	**Sub-01**			
Scenario:	**Existing Conditions 100yr**		**Depth**	**Volume**
Peak discharge:	46.22 cfs	**Time of peak:**	11 Jan 2023, 01:15	
Drainage area:	1,269.566 acres	**Total rainfall:**	2.99 in	316.33401 ac-ft
Initial abstraction:	1.23 in	**Losses:**	2.57 in	271.98653 ac-ft
Curve Number:	61.84	**Precip excess:**	0.42 in	44.34748 ac-ft
Impervious surface:	1.10%	**Direct runoff:**	0.38 in	39.80 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	107.15 minutes	**Total runoff:**	0.38 in	39.80 ac-ft

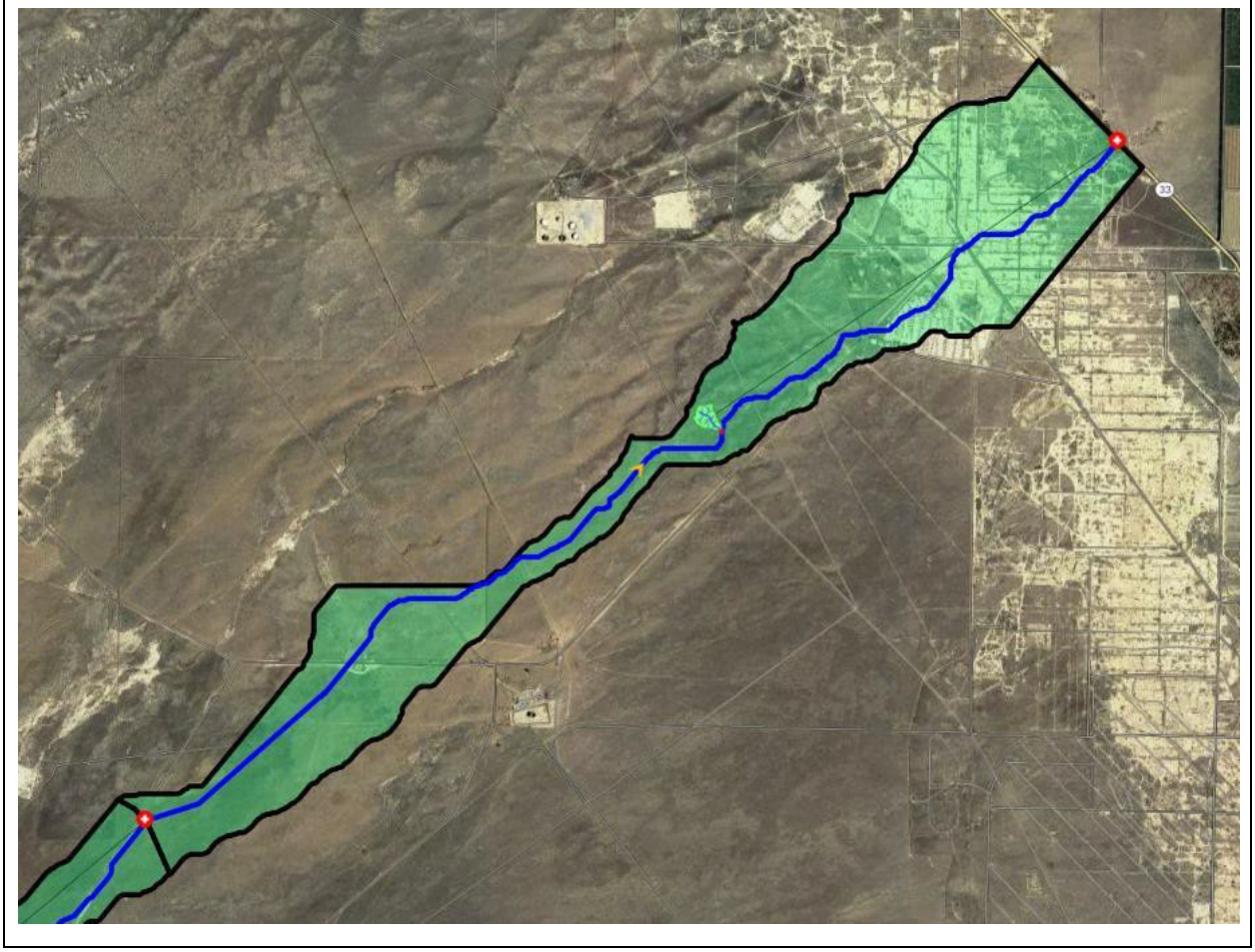
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
2.200	0.17	77.00	Developed, Medium Density
72.954	5.75	73.69	Agricultural, Cultivated Crops
12.818	1.01	73.61	Developed, Low Density
248.559	19.58	68.81	Developed, Open Space
2.419	0.19	77.00	Undeveloped, Barren Land
930.614	73.30	58.81	Undeveloped, Grassland
1,269.566	**100.00**	**61.84**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
45.65	99.01	0.01330	0.4284	Sheet Flow
13.66	1,732.24	0.01717	4.3269	Shallow Concentrated Flow
119.26	26,180.93	0.01221	3.6493	Channel Flow
178.57	**28,012.18**	**Total**	**Lag Time = 107.15 minutes**	





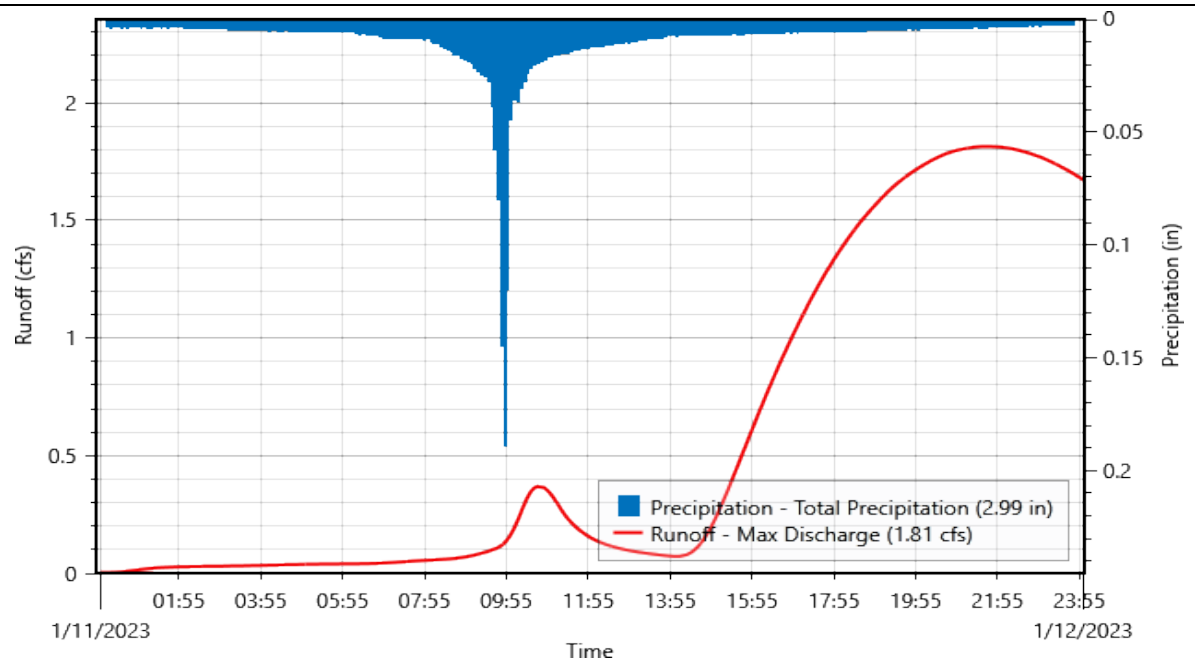
Subbasin ID:	Sub-02			
Scenario:	Existing Conditions 100yr		Depth	Volume
Peak discharge:	1.81 cfs	**Time of peak:**	11 Jan 2023, 09:40	
Drainage area:	337.798 acres	**Total rainfall:**	2.99 in	84.16650 ac-ft
Initial abstraction:	2.28 in	**Losses:**	2.94 in	82.86976 ac-ft
Curve Number:	46.74	**Precip excess:**	0.05 in	1.29675 ac-ft
Impervious surface:	0.15%	**Direct runoff:**	0.04 in	1.15 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	50.54 minutes	**Total runoff:**	0.04 in	1.15 ac-ft

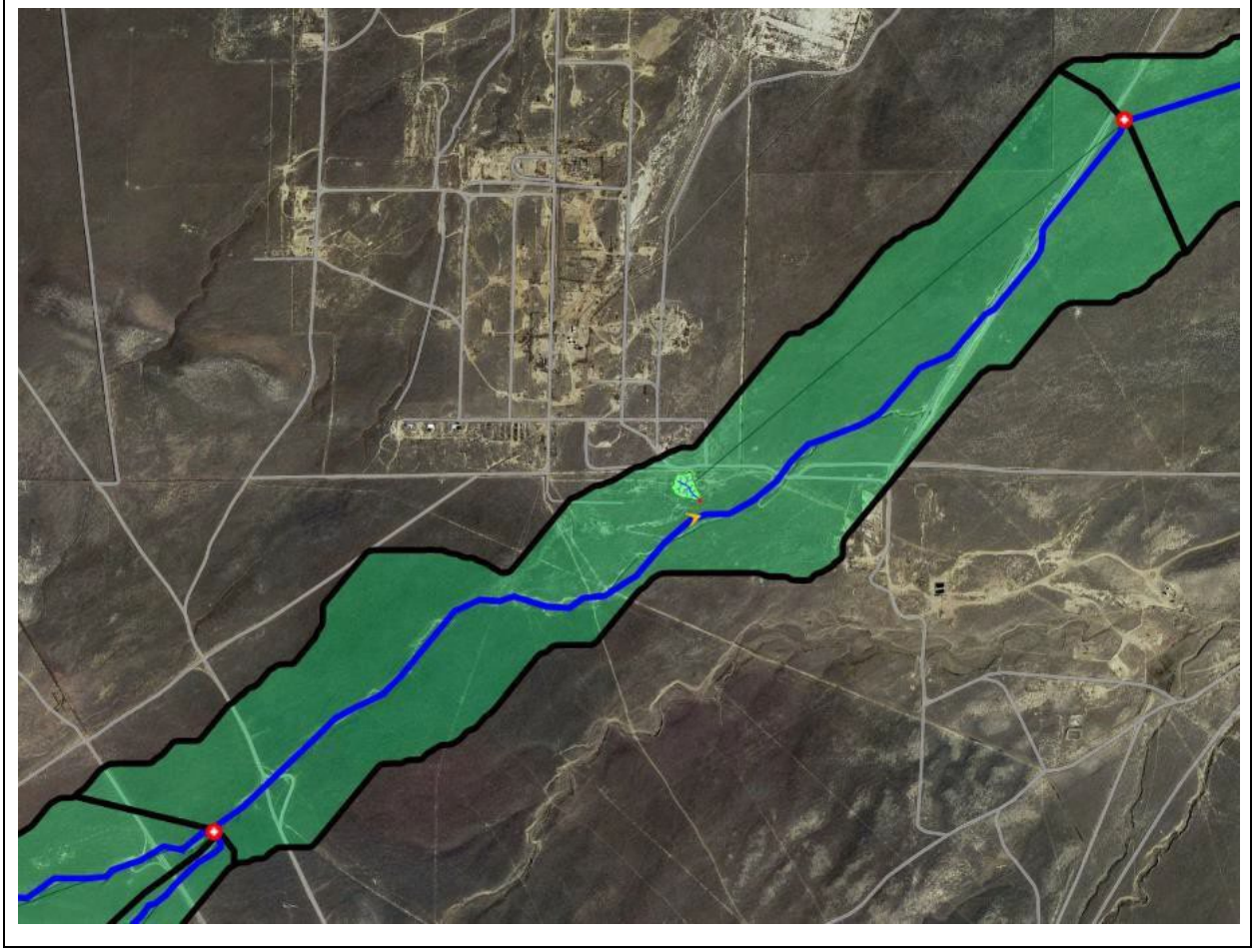
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
29.531	8.74	54.73	Developed, Open Space
308.267	91.26	45.97	Undeveloped, Grassland
337.798	**100.00**	**46.74**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
30.41	100.00	0.03745	0.7190	Sheet Flow
14.64	1,422.09	0.02620	5.3456	Shallow Concentrated Flow
39.18	10,516.23	0.01825	4.4614	Channel Flow
84.23	**12,038.32**	**Total**	**Lag Time = 50.54 minutes**	





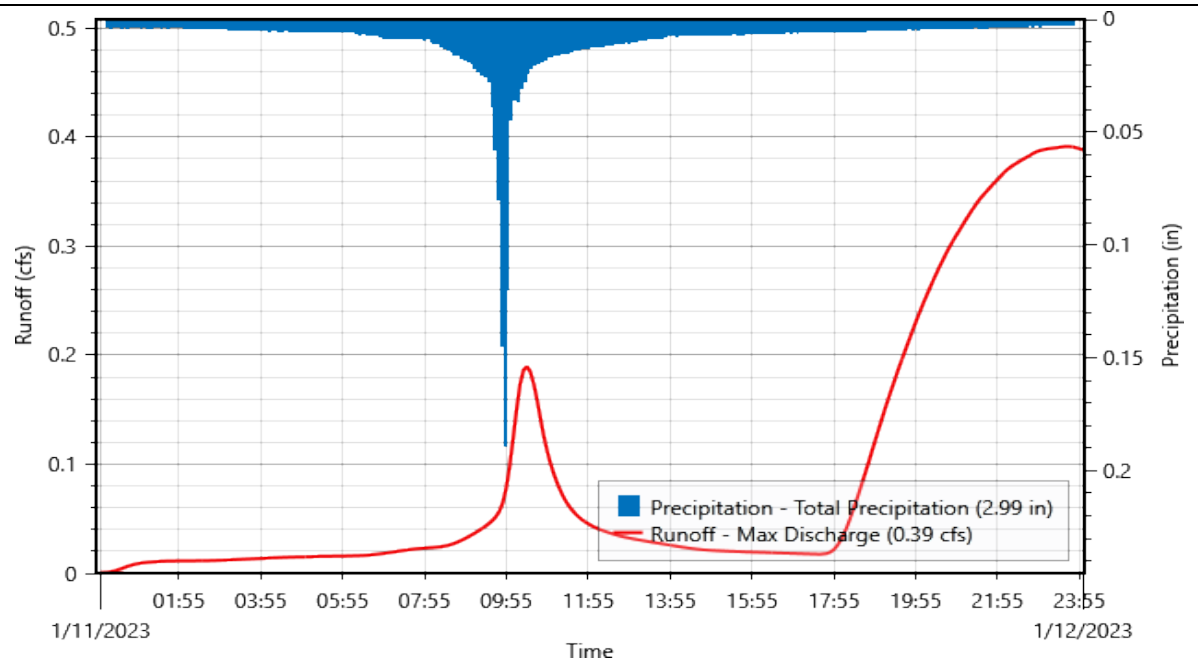
Subbasin ID:	Sub-03			
Scenario:	Existing Conditions 100yr		Depth	Volume
Peak discharge:	0.39 cfs	**Time of peak:**	11 Jan 2023, 11:35	
Drainage area:	169.707 acres	**Total rainfall:**	2.99 in	42.29056 ac-ft
Initial abstraction:	2.61 in	**Losses:**	2.98 in	42.08788 ac-ft
Curve Number:	43.39	**Precip excess:**	0.01 in	0.20268 ac-ft
Impervious surface:	0.12%	**Direct runoff:**	0.01 in	0.18 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	32.39 minutes	**Total runoff:**	0.01 in	0.18 ac-ft

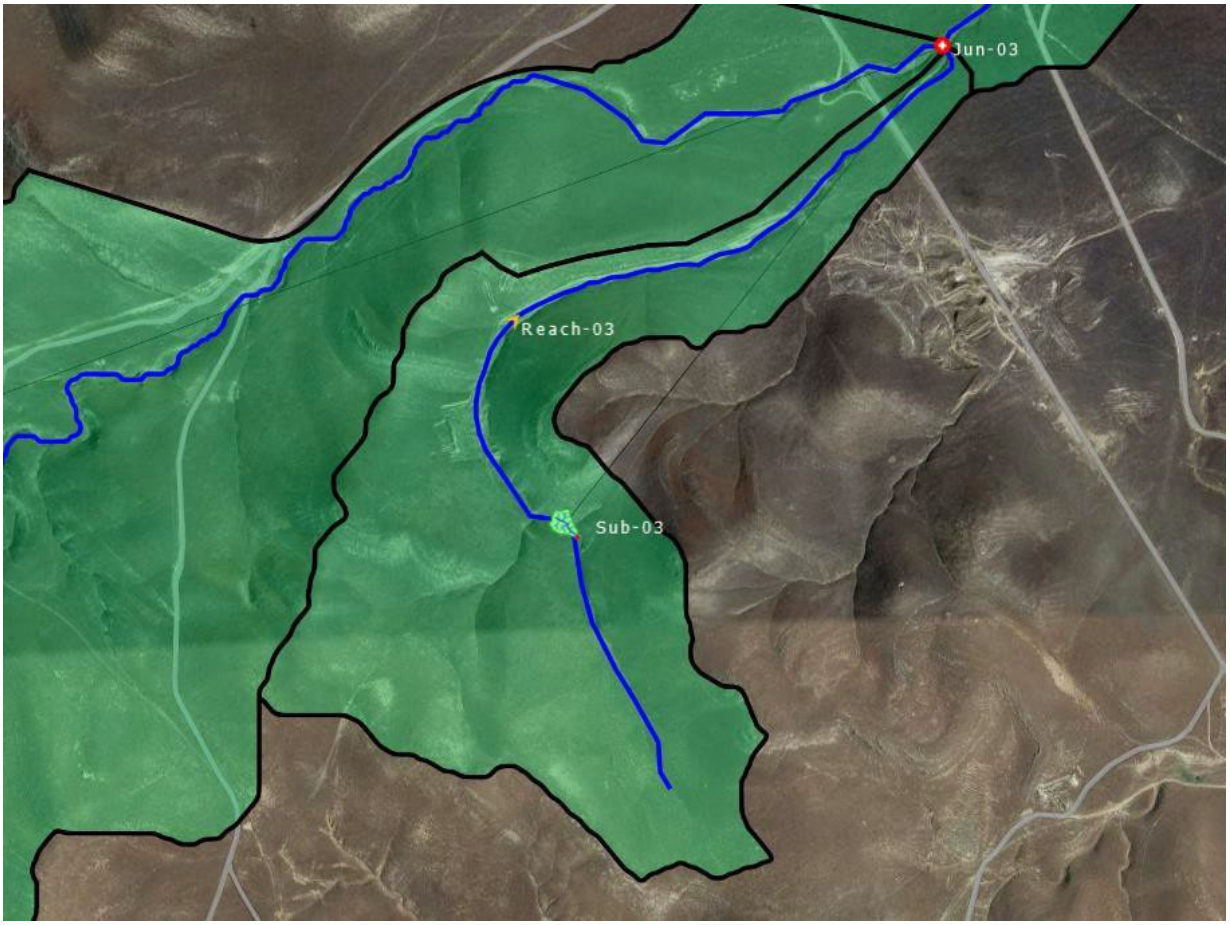
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
1.174	0.69	79.00	Developed, Open Space
168.533	99.31	43.14	Undeveloped, Grassland
169.707	**100.00**	**43.39**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
33.11	110.46	0.03693	0.7140	Sheet Flow
3.55	740.31	0.12053	11.4645	Shallow Concentrated Flow
17.32	6,423.63	0.03486	6.1655	Channel Flow
53.98	**7,274.40**	**Total**	**Lag Time = 32.39 minutes**	




Jun-03
Reach-03
Sub-03

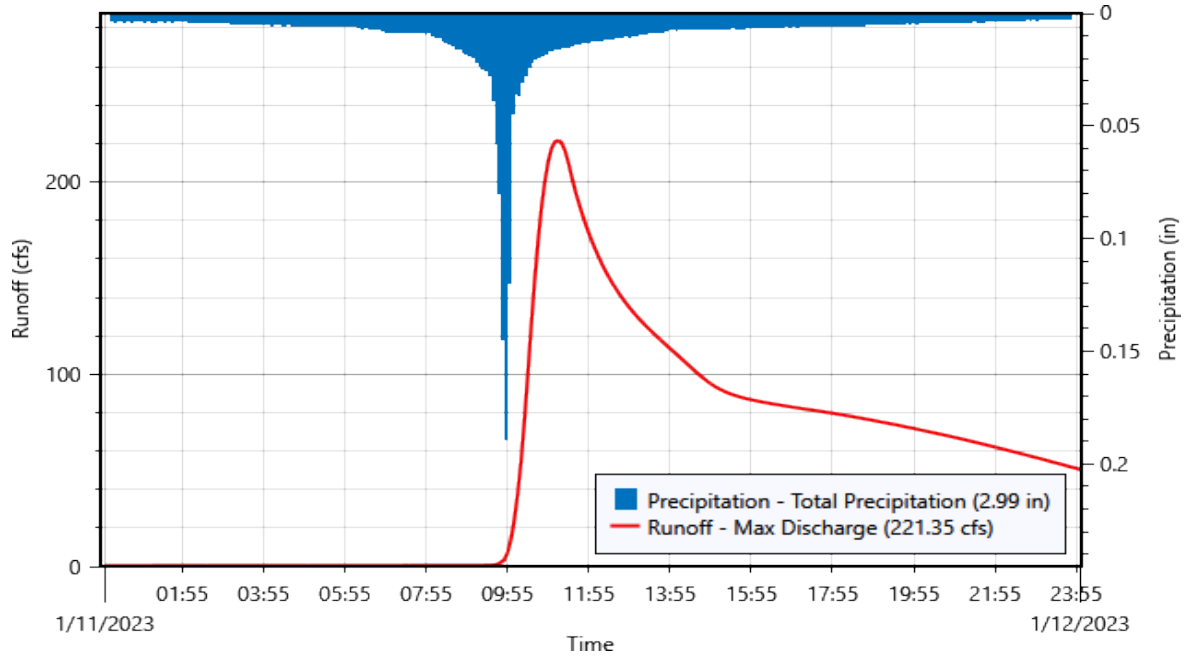
Subbasin ID:	**Sub-04**			
Scenario:	**Existing Conditions 100yr**		**Depth**	**Volume**
Peak discharge:	221.35 cfs	**Time of peak:**	11 Jan 2023, 11:10	
Drainage area:	1,961.124 acres	**Total rainfall:**	2.99 in	488.65369 ac-ft
Initial abstraction:	0.86 in	**Losses:**	2.28 in	372.74816 ac-ft
Curve Number:	70.00	**Precip excess:**	0.71 in	115.90553 ac-ft
Impervious surface:	0.09%	**Direct runoff:**	0.68 in	110.97 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	58.02 minutes	**Total runoff:**	0.68 in	110.97 ac-ft

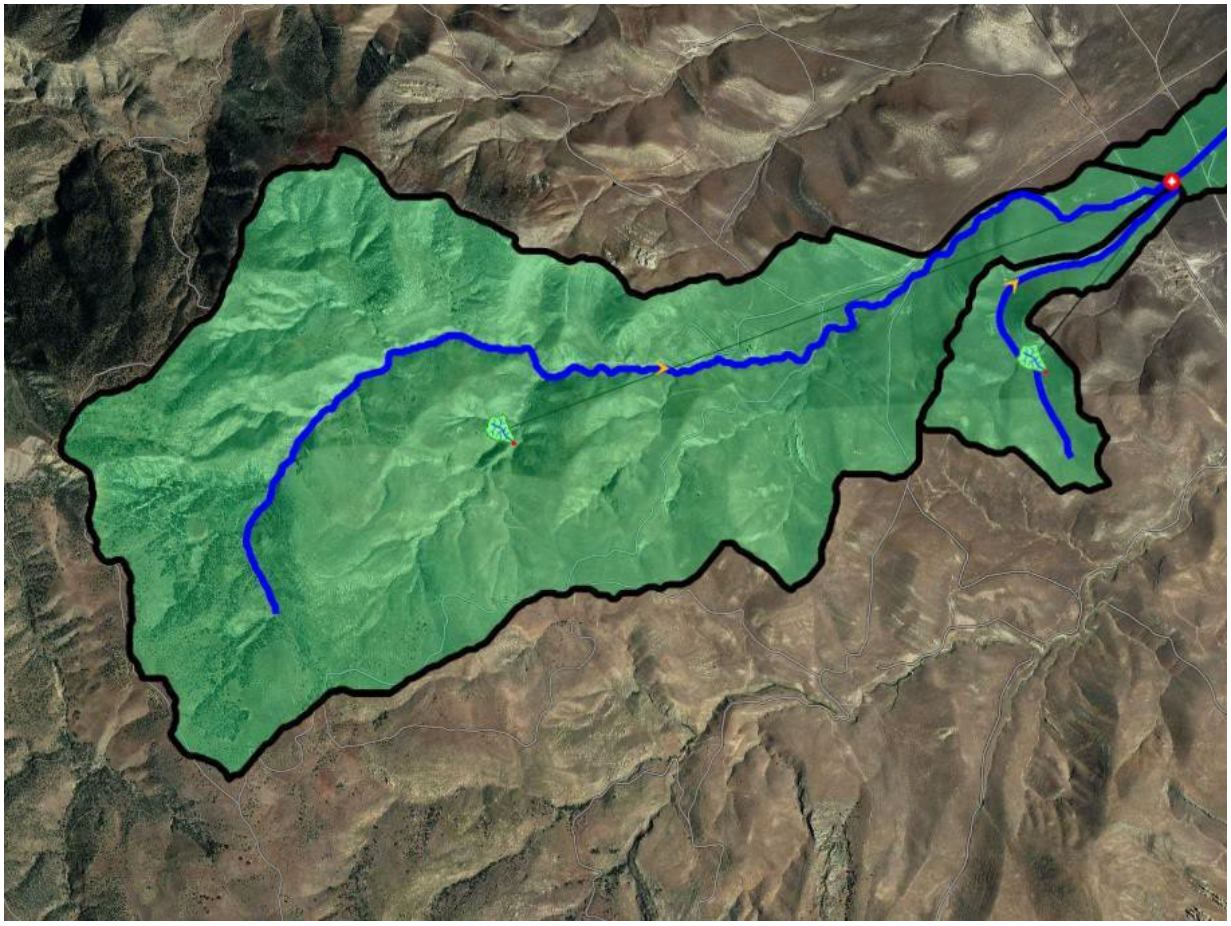
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
0.431	0.02	91.30	Developed, Medium Density
150.381	7.67	71.94	Undeveloped, Shrub/Scrub
0.305	0.02	74.40	Developed, Low Density
75.153	3.83	71.78	Developed, Open Space
1.186	0.06	88.55	Undeveloped, Barren Land
1,733.667	88.40	69.74	Undeveloped, Grassland
1,961.124	**100.00**	**70.00**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
30.90	112.95	0.04590	0.7959	Sheet Flow
13.24	3,235.61	0.16593	13.4514	Shallow Concentrated Flow
5.71	4,473.99	0.15548	13.0208	Channel Flow
46.85	15,930.03	0.02929	5.6514	Channel Flow
96.70	**23,752.58**	**Total**	**Lag Time = 58.02 minutes**	





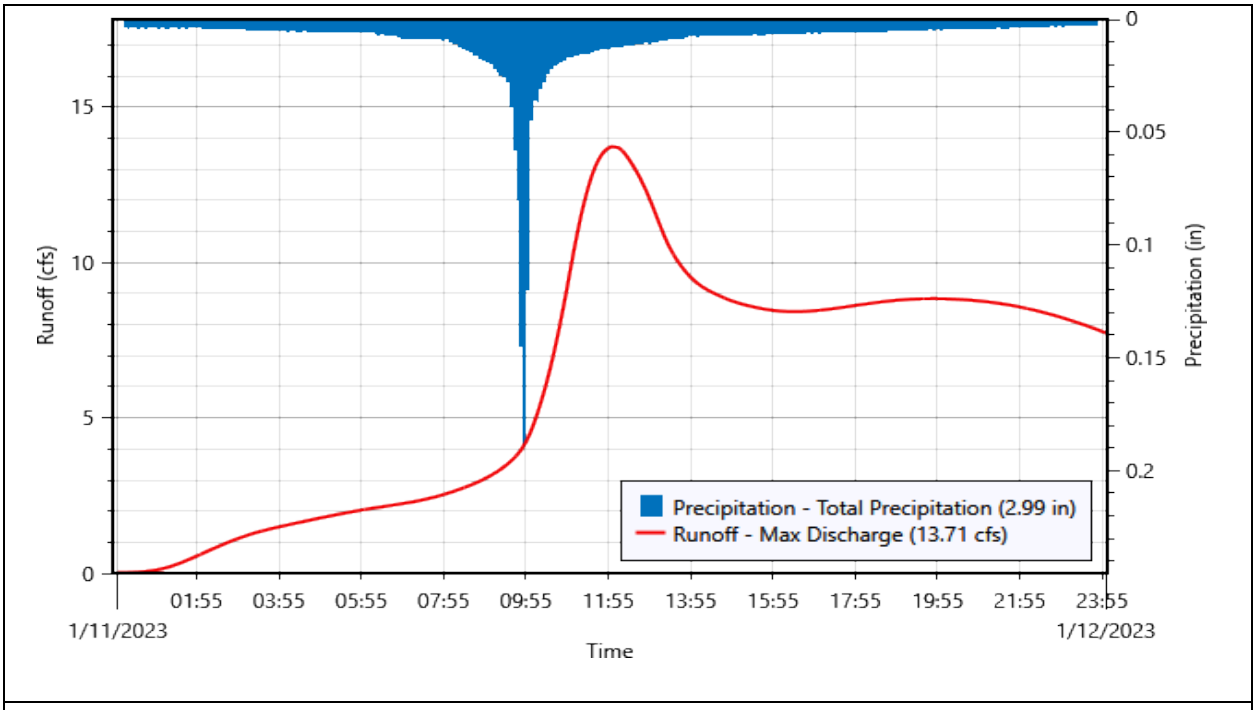
Subbasin ID:	Sub-05			
Scenario:	Existing Conditions 100yr		Depth	Volume
Peak discharge:	13.71 cfs	**Time of peak:**	11 Jan 2023, 12:05	
Drainage area:	685.814 acres	**Total rainfall:**	2.99 in	170.88447 ac-ft
Initial abstraction:	1.94 in	**Losses:**	2.75 in	157.28816 ac-ft
Curve Number:	50.82	**Precip excess:**	0.24 in	13.59631 ac-ft
Impervious surface:	4.68%	**Direct runoff:**	0.21 in	12.00 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	125.36 minutes	**Total runoff:**	0.21 in	12.00 ac-ft

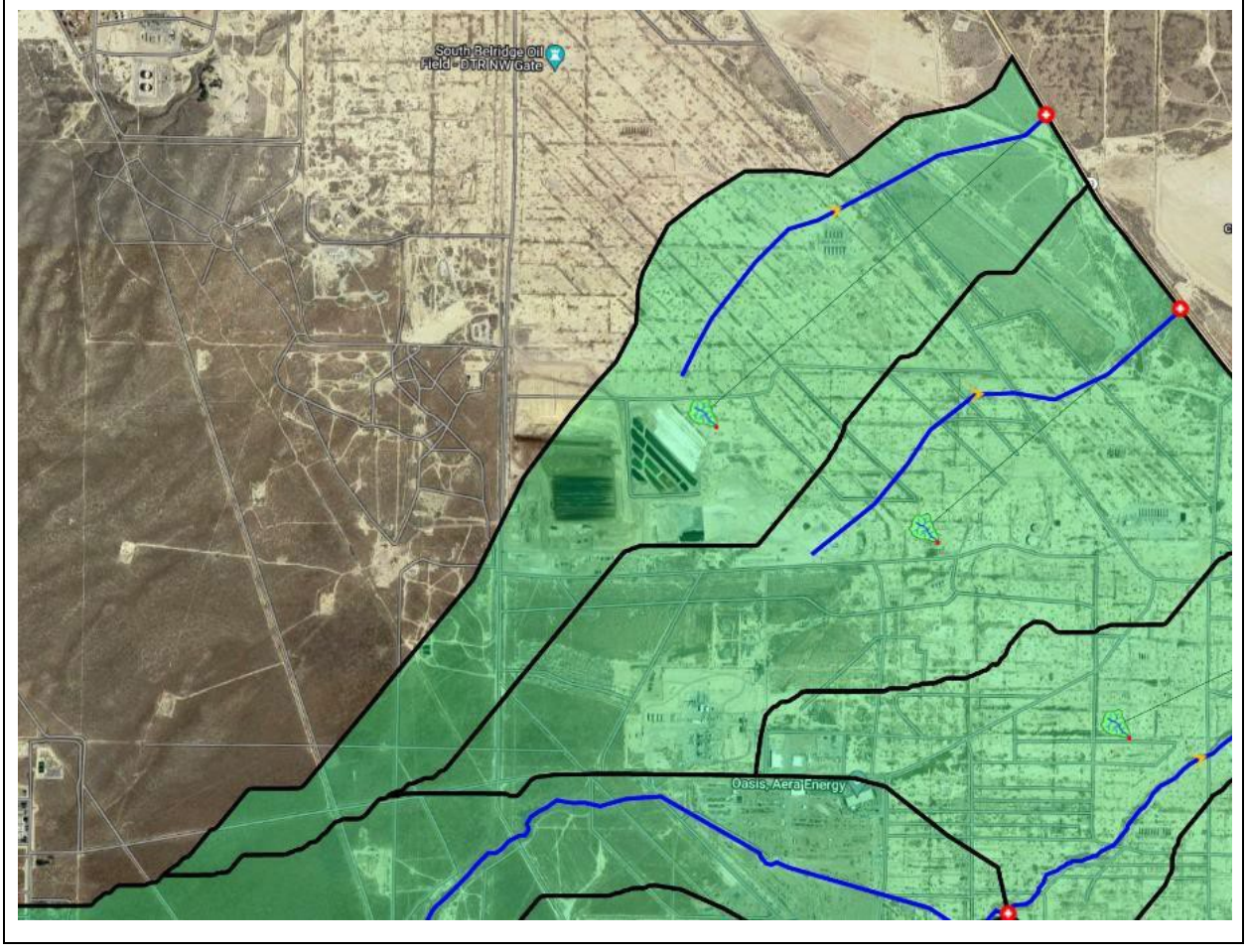
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
68.817	10.03	67.00	Agricultural, Cultivated Crops
17.830	2.60	77.74	Developed, Medium Density
42.537	6.20	78.26	Undeveloped, Barren Land
32.828	4.79	63.81	Developed, Low Density
201.828	29.43	57.17	Developed, Open Space
3.731	0.54	30.00	Undeveloped, Shrub/Scrub
0.288	0.04	100.00	Open Water
11.792	1.72	89.57	Developed, High Density
306.163	44.64	34.93	Undeveloped, Grassland
685.814	**100.00**	**50.82**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
51.04	100.00	0.01026	0.3762	Sheet Flow
84.98	9,730.86	0.01400	3.9073	Shallow Concentrated Flow
10.33	2,732.44	0.01773	4.3971	Channel Flow
62.57	3,381.56	0.00074	0.8982	Channel Flow
208.92	**15,944.86**	**Total**	**Lag Time = 125.36 minutes**	


Runoff (cfs)
Precipitation (in)
Time
1/11/2023
1/12/2023
Precipitation - Total Precipitation (2.99 in)
Runoff - Max Discharge (13.71 cfs)


South Belridge Oil Field - DTR NW Gate
Oasis, Aera Energy

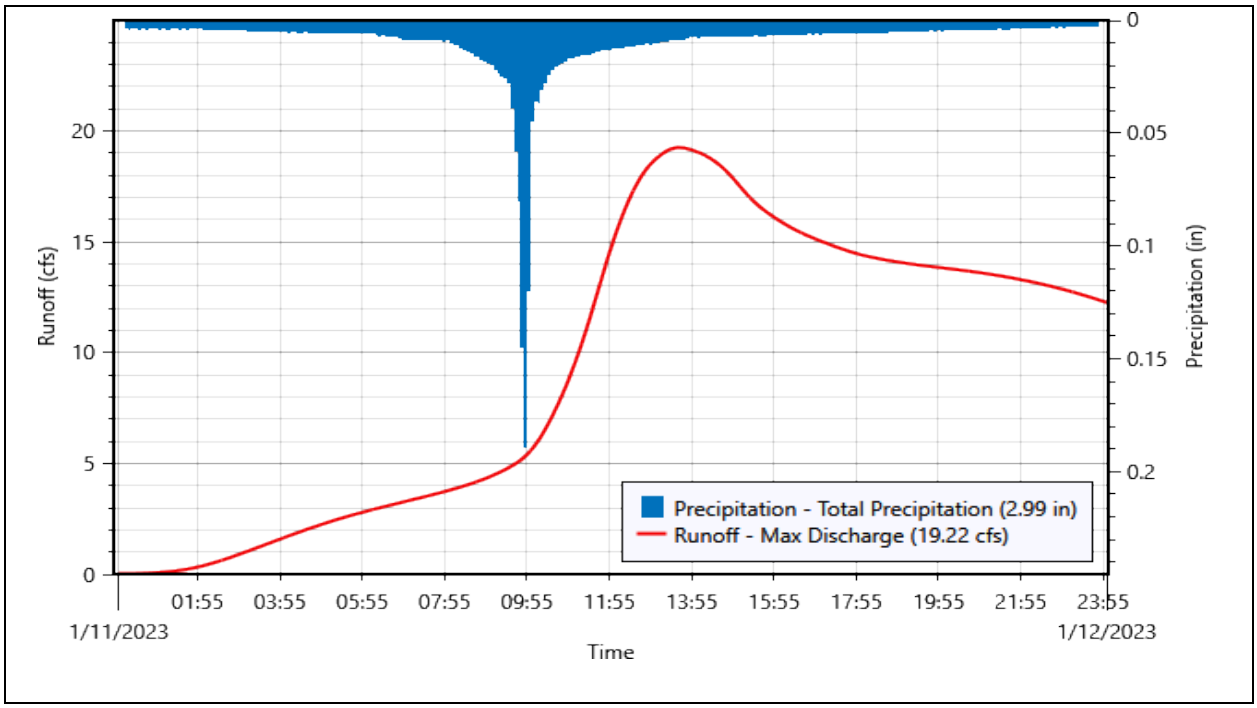
Subbasin ID:	Sub-06			
Scenario:	Existing Conditions 100yr		Depth	Volume
Peak discharge:	19.22 cfs	**Time of peak:**	11 Jan 2023, 01:35	
Drainage area:	856.439 acres	**Total rainfall:**	2.99 in	213.39828 ac-ft
Initial abstraction:	1.86 in	**Losses:**	2.68 in	191.02828 ac-ft
Curve Number:	51.75	**Precip excess:**	0.31 in	22.37000 ac-ft
Impervious surface:	6.67%	**Direct runoff:**	0.26 in	18.44 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	198.99 minutes	**Total runoff:**	0.26 in	18.44 ac-ft

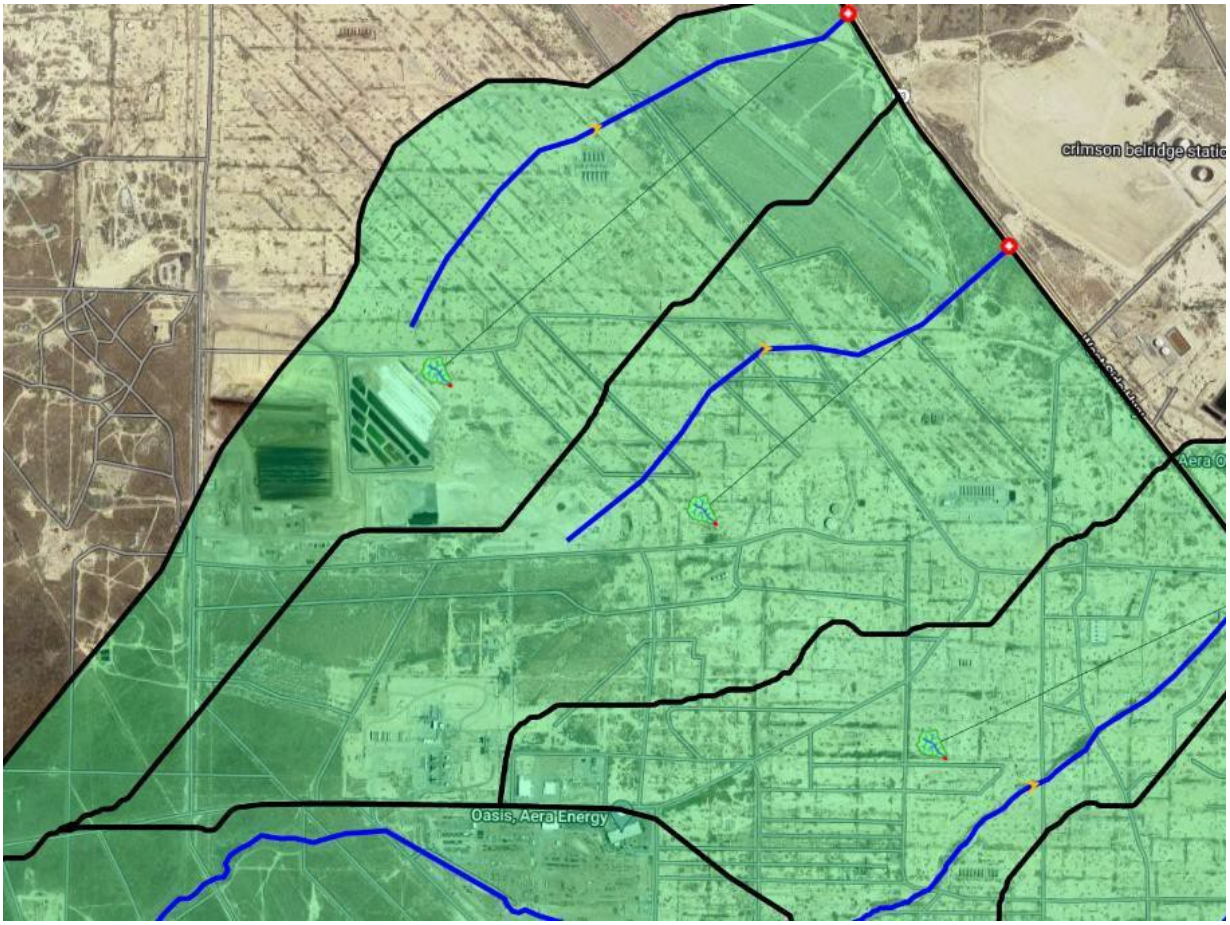
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
18.520	2.16	78.52	Developed, Medium Density
40.292	4.70	67.00	Agricultural, Cultivated Crops
0.191	0.02	30.00	Undeveloped, Shrub/Scrub
68.504	8.00	66.60	Developed, Low Density
7.679	0.90	89.48	Developed, High Density
305.373	35.66	61.82	Developed, Open Space
32.256	3.77	78.97	Undeveloped, Barren Land
383.625	44.79	35.15	Undeveloped, Grassland
856.439	**100.00**	**51.75**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
42.34	100.00	0.01637	0.4753	Sheet Flow
56.02	6,131.50	0.01279	3.7342	Shallow Concentrated Flow
2.24	757.49	0.12183	11.5262	Shallow Concentrated Flow
231.04	6,158.14	0.00018	0.4458	Channel Flow
331.64	**13,147.13**	**Total**	**Lag Time = 198.99 minutes**	


Runoff (cfs)
Precipitation (in)
Time
1/11/2023
1/12/2023
Precipitation - Total Precipitation (2.99 in)
Runoff - Max Discharge (19.22 cfs)


Oasis, Aera Energy

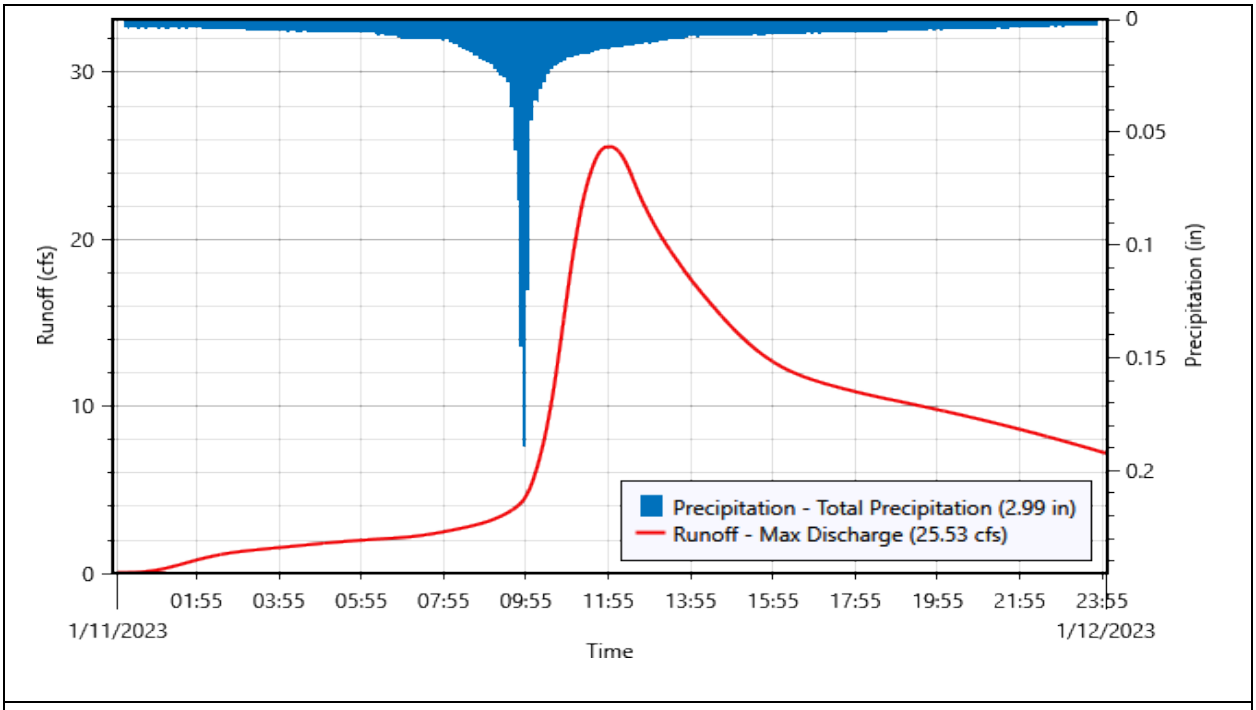
Subbasin ID:	Sub-07			
Scenario:	Existing Conditions 100yr		Depth	Volume
Peak discharge:	25.53 cfs	**Time of peak:**	11 Jan 2023, 11:55	
Drainage area:	269.771 acres	**Total rainfall:**	2.99 in	67.21520 ac-ft
Initial abstraction:	1.05 in	**Losses:**	2.20 in	49.50065 ac-ft
Curve Number:	65.60	**Precip excess:**	0.79 in	17.71454 ac-ft
Impervious surface:	10.71%	**Direct runoff:**	0.74 in	16.56 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	98.48 minutes	**Total runoff:**	0.74 in	16.56 ac-ft

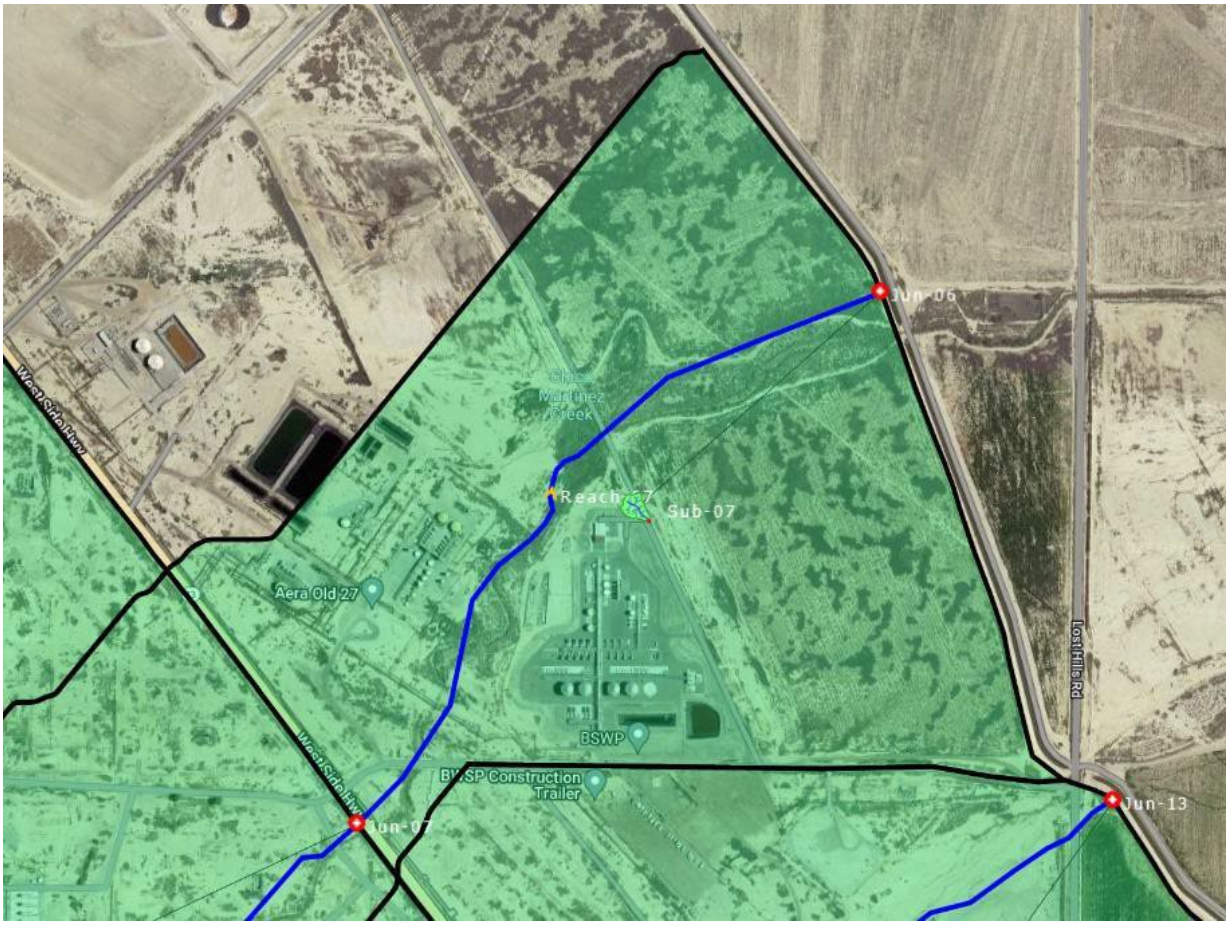
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
9.365	3.47	78.39	Developed, Medium Density
7.664	2.84	30.00	Undeveloped, Shrub/Scrub
17.372	6.44	67.37	Developed, Low Density
12.494	4.63	89.14	Developed, High Density
43.223	16.02	56.26	Developed, Open Space
5.238	1.94	77.67	Undeveloped, Barren Land
29.711	11.01	41.49	Undeveloped, Grassland
144.704	53.64	71.71	Agricultural, Cultivated Crops
269.771	**100.00**	**65.60**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
62.62	95.81	0.00565	0.2792	Sheet Flow
1.69	168.18	0.01057	3.3952	Shallow Concentrated Flow
0.84	253.65	0.09785	10.3295	Shallow Concentrated Flow
33.38	2,278.13	0.00118	1.1339	Channel Flow
1.39	551.42	0.03999	6.6036	Channel Flow
64.20	1,275.51	0.00010	0.3284	Channel Flow
164.12	**4,622.70**	**Total**	**Lag Time = 98.48 minutes**	


Runoff (cfs)
Precipitation (in)
Time
1/11/2023
1/12/2023
Precipitation - Total Precipitation (2.99 in)
Runoff - Max Discharge (25.53 cfs)


Jun-06
Reach-7
Sub-07
Aera Old 27
BSWP
Jun-07
Jun-13
Lost Hills Rd

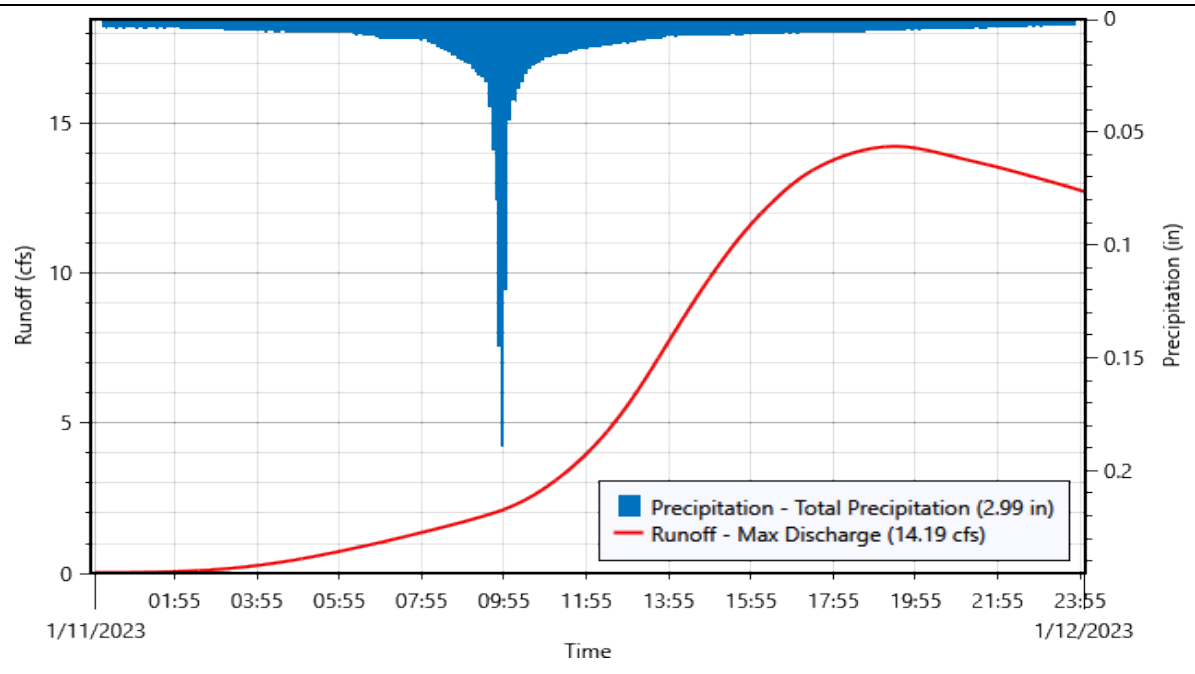
Subbasin ID:	**Sub-08**			
Scenario:	**Existing Conditions 100yr**		**Depth**	**Volume**
Peak discharge:	14.19 cfs	**Time of peak:**	11 Jan 2023, 07:25	
Drainage area:	503.505 acres	**Total rainfall:**	2.99 in	125.45242 ac-ft
Initial abstraction:	1.48 in	**Losses:**	2.50 in	105.08259 ac-ft
Curve Number:	57.53	**Precip excess:**	0.49 in	20.36983 ac-ft
Impervious surface:	8.38%	**Direct runoff:**	0.30 in	12.56 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	395.42 minutes	**Total runoff:**	0.30 in	12.56 ac-ft

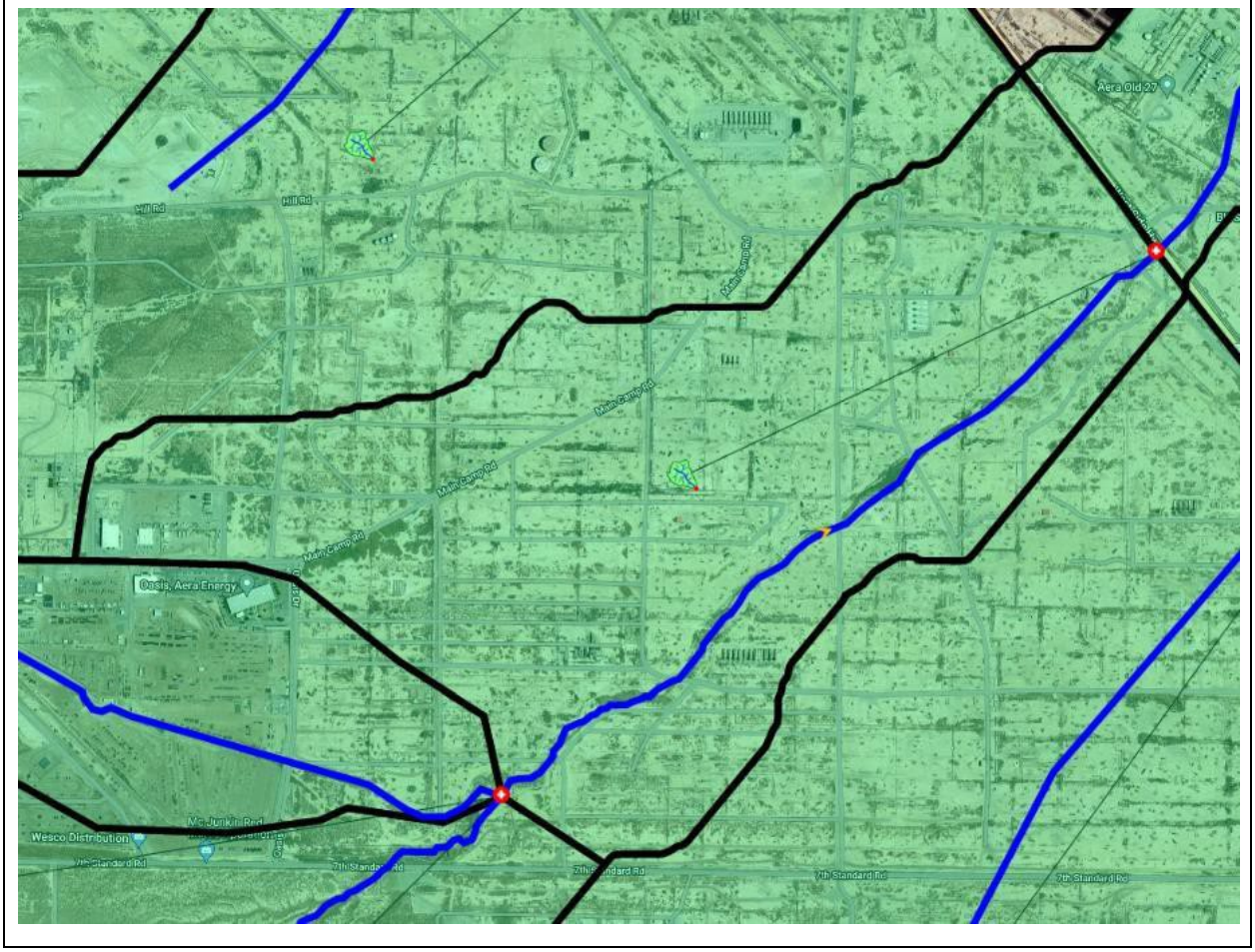
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
9.083	1.80	80.87	Developed, Medium Density
32.953	6.54	70.08	Developed, Low Density
4.702	0.93	89.23	Developed, High Density
9.827	1.95	87.02	Undeveloped, Barren Land
151.885	30.17	41.68	Undeveloped, Grassland
295.055	58.60	62.08	Developed, Open Space
503.505	**100.00**	**57.53**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
52.03	100.00	0.00978	0.3674	Sheet Flow
49.64	4,709.72	0.00961	3.2380	Shallow Concentrated Flow
2.39	661.27	0.08149	9.4267	Shallow Concentrated Flow
9.76	489.72	0.00269	1.7139	Shallow Concentrated Flow
545.21	3,425.21	0.00001	0.1271	Channel Flow
659.03	**9,385.92**	**Total**	**Lag Time = 395.42 minutes**	




Aera Old 27
Hill Rd
Main Camp Rd
Oasis, Aera Energy
Wesco Distribution
7th Standard Rd

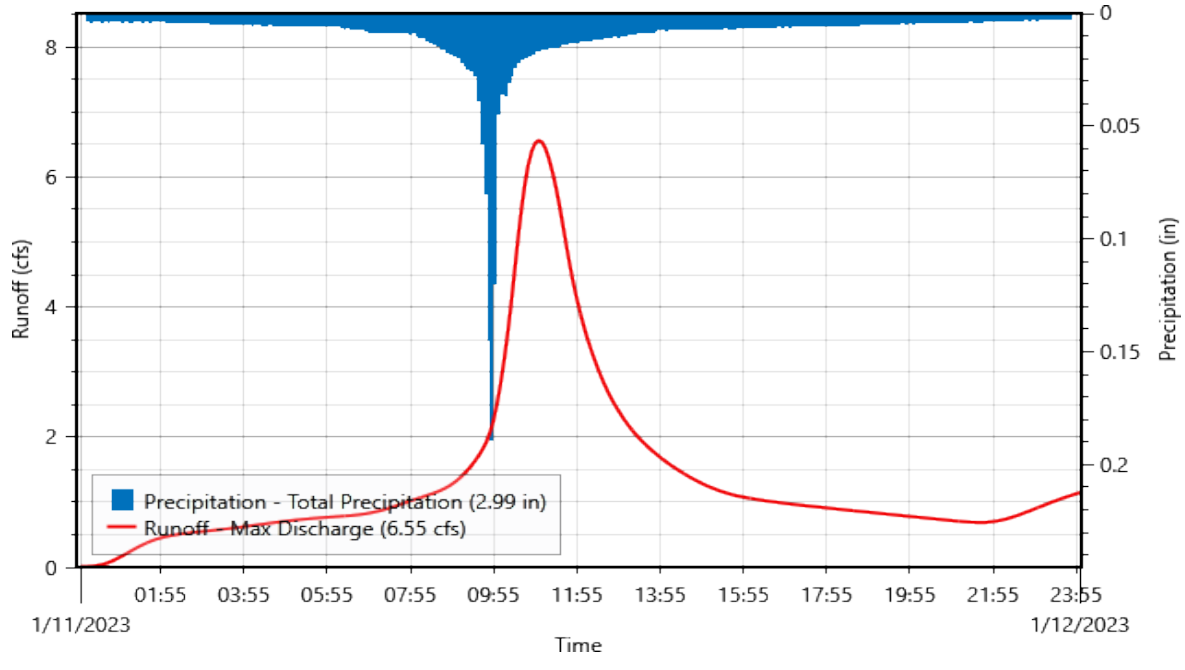
Subbasin ID:	Sub-09			
Scenario:	Existing Conditions 100yr		Depth	Volume
Peak discharge:	6.55 cfs	**Time of peak:**	11 Jan 2023, 11:00	
Drainage area:	1,130.587 acres	**Total rainfall:**	2.99 in	281.69785 ac-ft
Initial abstraction:	2.84 in	**Losses:**	2.96 in	278.90352 ac-ft
Curve Number:	41.33	**Precip excess:**	0.03 in	2.79434 ac-ft
Impervious surface:	0.94%	**Direct runoff:**	0.03 in	2.65 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	67.09 minutes	**Total runoff:**	0.03 in	2.65 ac-ft

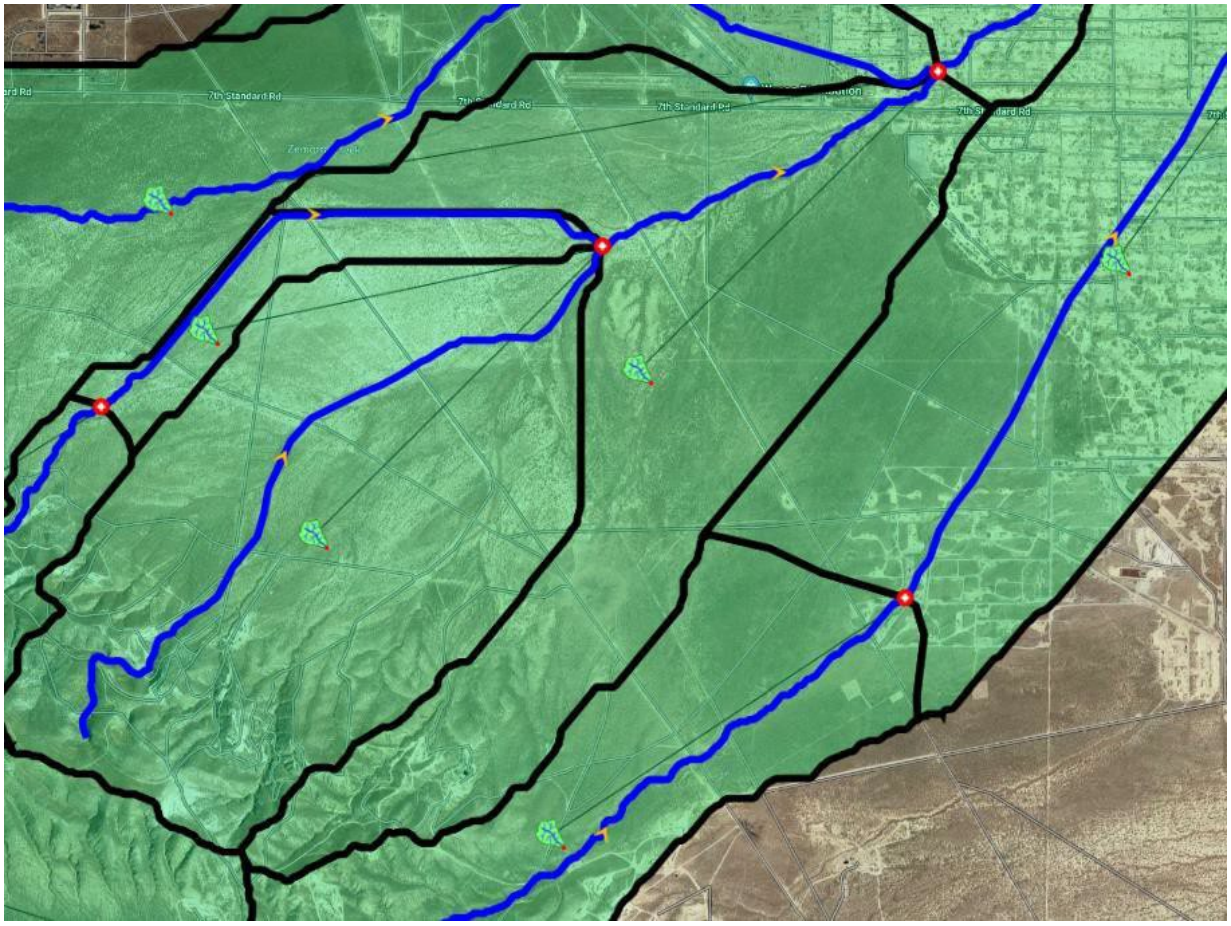
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
1.638	0.14	82.99	Developed, Medium Density
49.357	4.37	35.62	Undeveloped, Shrub/Scrub
4.469	0.40	61.00	Developed, Low Density
0.293	0.03	89.00	Developed, High Density
80.882	7.15	53.22	Developed, Open Space
3.542	0.31	77.00	Undeveloped, Barren Land
990.407	87.60	40.34	Undeveloped, Grassland
1,130.587	**100.00**	**41.33**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
16.78	99.98	0.16549	1.5113	Sheet Flow
0.86	365.47	0.19372	14.5341	Shallow Concentrated Flow
8.54	4,728.14	0.04703	9.2075	Channel Flow
60.10	7,738.83	0.01770	4.3931	Shallow Concentrated Flow
25.53	5,047.31	0.00990	3.2859	Channel Flow
111.81	**17,979.73**	**Total**	**Lag Time = 67.09 minutes**	




7th Standard Rd
7th Standard Rd
7th Standard Rd

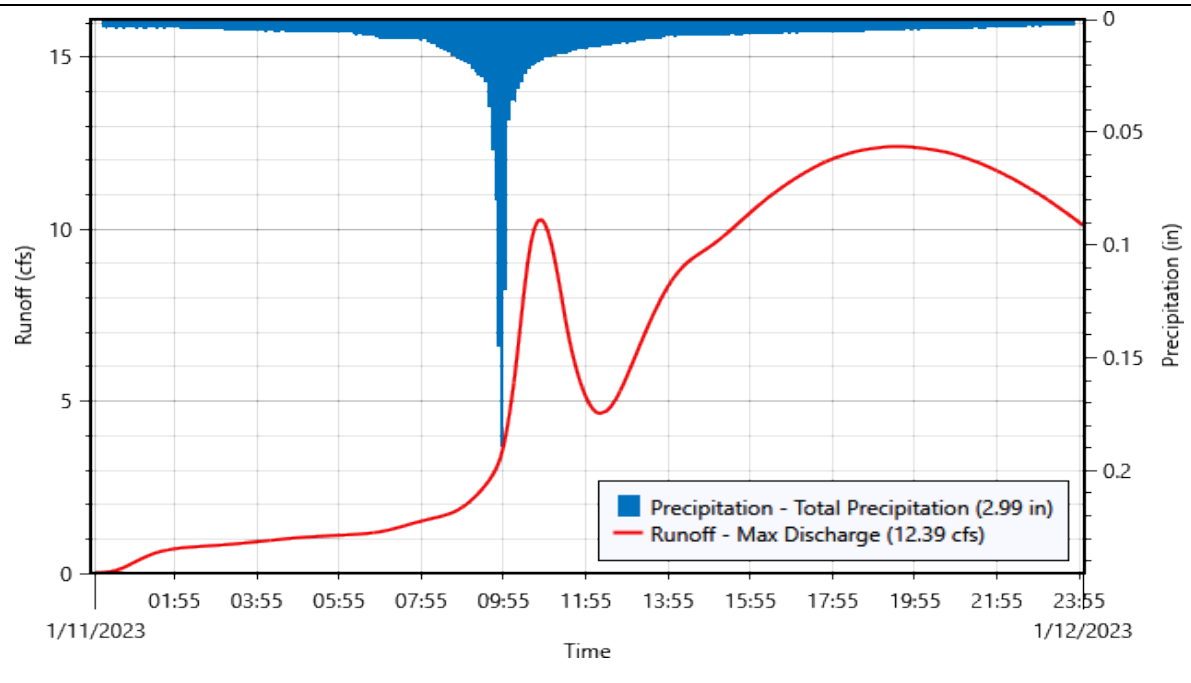
Subbasin ID:	**Sub-10**			
Scenario:	**Existing Conditions 100yr**		**Depth**	**Volume**
Peak discharge:	12.39 cfs	**Time of peak:**	11 Jan 2023, 07:30	
Drainage area:	1,153.361 acres	**Total rainfall:**	2.99 in	287.37487 ac-ft
Initial abstraction:	1.94 in	**Losses:**	2.85 in	273.90003 ac-ft
Curve Number:	50.79	**Precip excess:**	0.14 in	13.47484 ac-ft
Impervious surface:	1.30%	**Direct runoff:**	0.13 in	12.50 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	55.92 minutes	**Total runoff:**	0.13 in	12.50 ac-ft

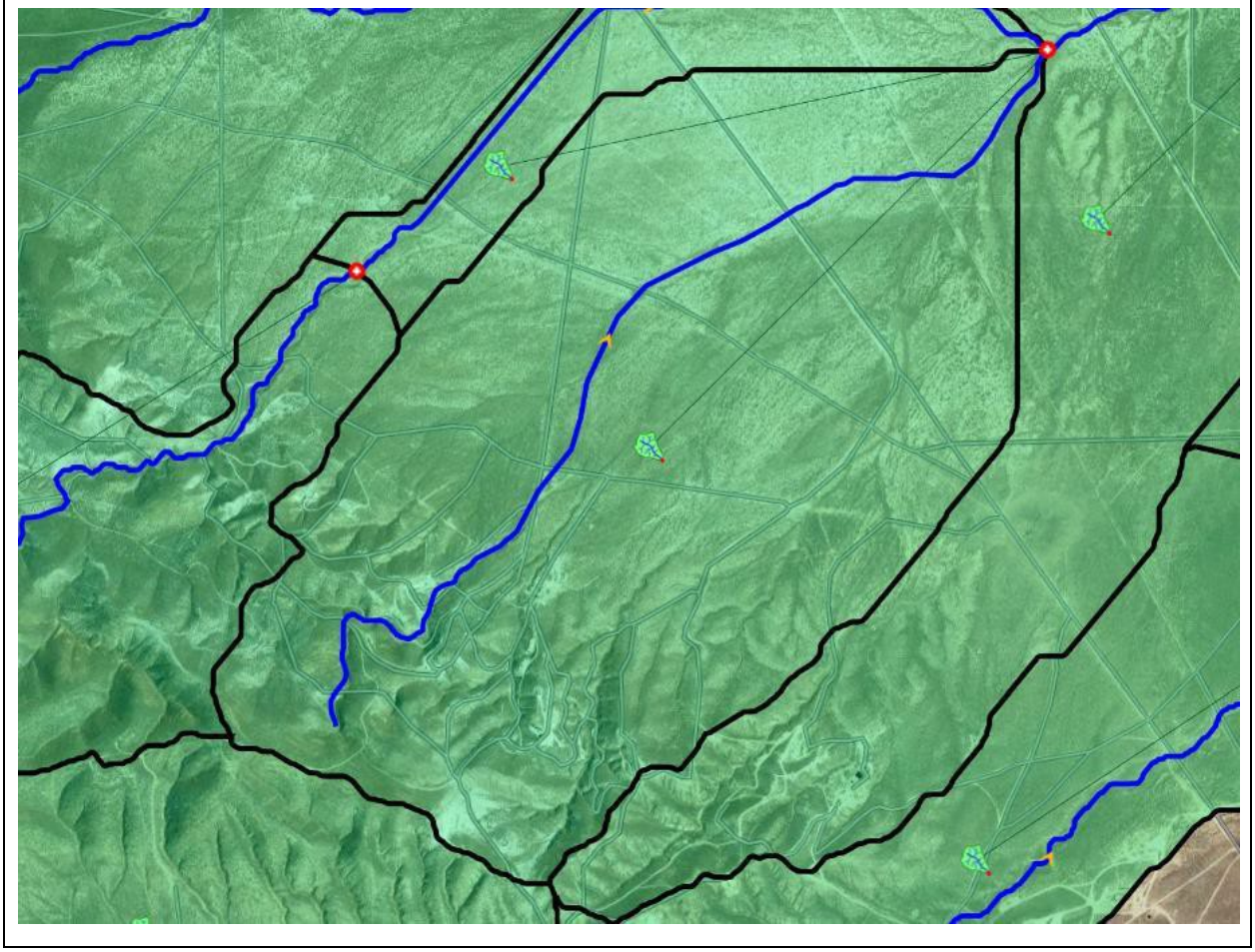
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
10.397	0.90	79.49	Developed, Medium Density
59.382	5.15	50.07	Undeveloped, Shrub/Scrub
3.103	0.27	80.28	Developed, Low Density
151.032	13.09	67.65	Developed, Open Space
2.360	0.20	91.00	Undeveloped, Barren Land
927.088	80.38	47.56	Undeveloped, Grassland
1,153.361	**100.00**	**50.79**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
21.17	100.00	0.09259	1.1304	Sheet Flow
2.60	1,127.24	0.20010	14.7716	Shallow Concentrated Flow
9.39	4,900.89	0.06895	8.6712	Channel Flow
0.40	386.93	0.23496	16.0068	Channel Flow
42.25	2,796.45	0.00111	1.0981	Channel Flow
17.39	4,299.00	0.01549	4.1093	Channel Flow
93.20	**13,610.51**	**Total**	**Lag Time = 55.92 minutes**	





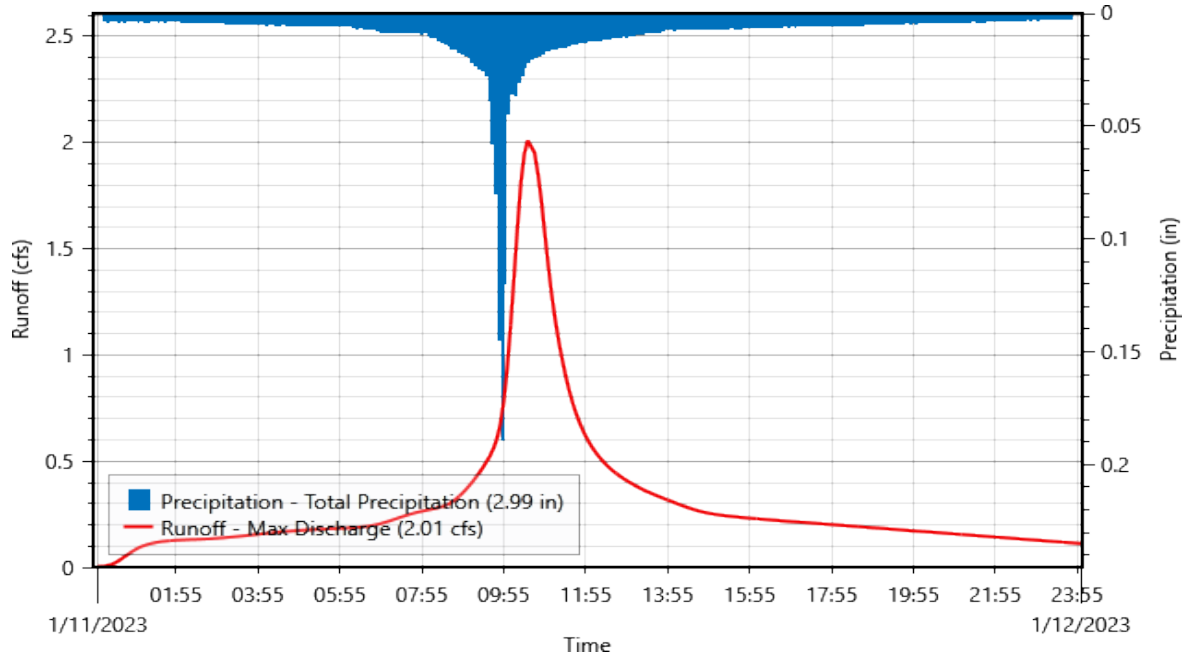
Subbasin ID:	Sub-11		Depth	Volume
Scenario:	Existing Conditions 100yr			
Peak discharge:	2.01 cfs	**Time of peak:**	11 Jan 2023, 10:30	
Drainage area:	161.318 acres	**Total rainfall:**	2.99 in	40.20155 ac-ft
Initial abstraction:	4.26 in	**Losses:**	2.94 in	39.59450 ac-ft
Curve Number:	31.97	**Precip excess:**	0.05 in	0.60704 ac-ft
Impervious surface:	1.51%	**Direct runoff:**	0.04 in	0.60 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	40.10 minutes	**Total runoff:**	0.04 in	0.60 ac-ft

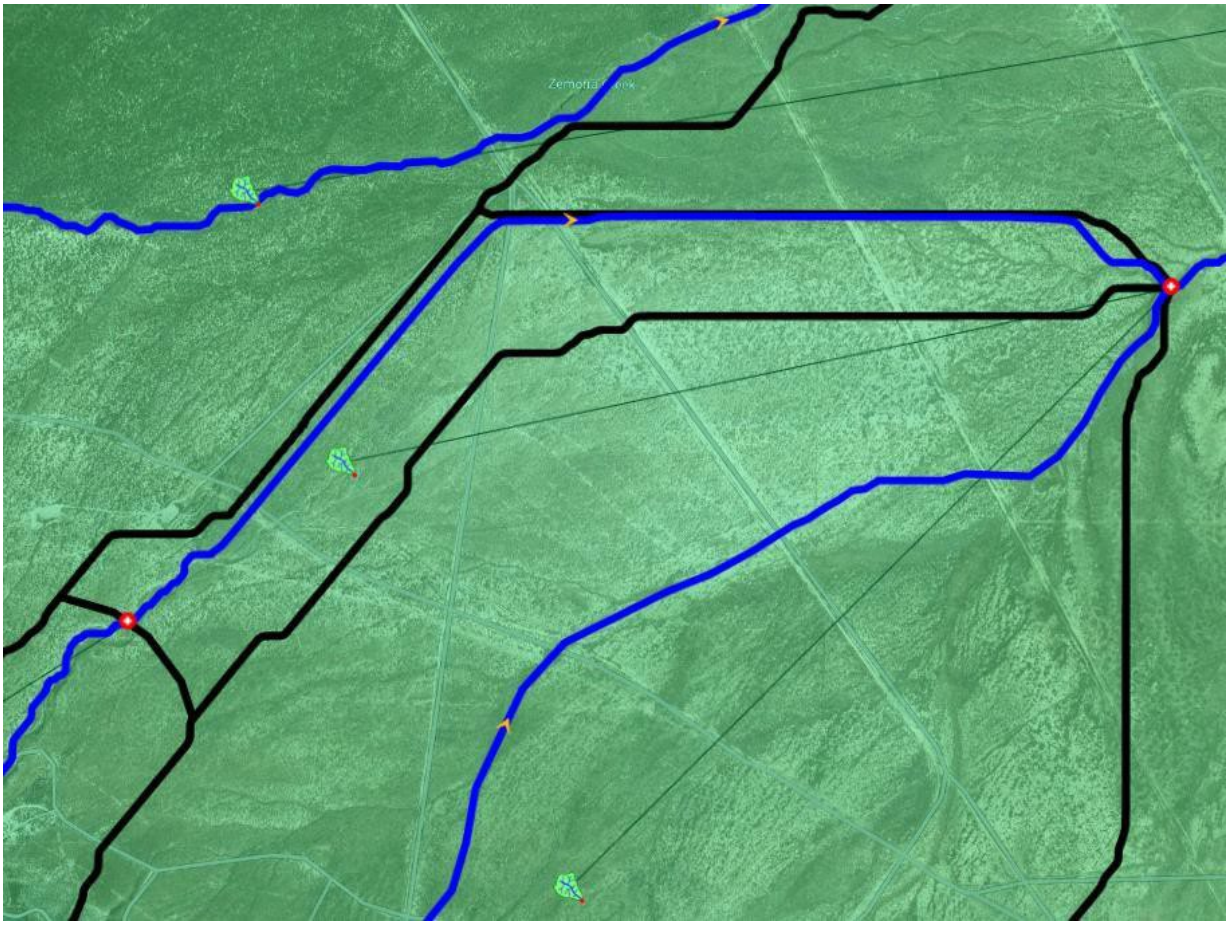
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
4.560	2.83	77.00	Developed, Medium Density
4.792	2.97	49.00	Developed, Open Space
151.966	94.20	30.08	Undeveloped, Grassland
161.318	**100.00**	**31.97**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
28.76	100.00	0.04304	0.7707	Sheet Flow
6.52	1,112.40	0.03107	5.8206	Shallow Concentrated Flow
31.55	8,418.65	0.01804	4.4358	Channel Flow
66.83	**9,631.05**	**Total**	**Lag Time = 40.10 minutes**	





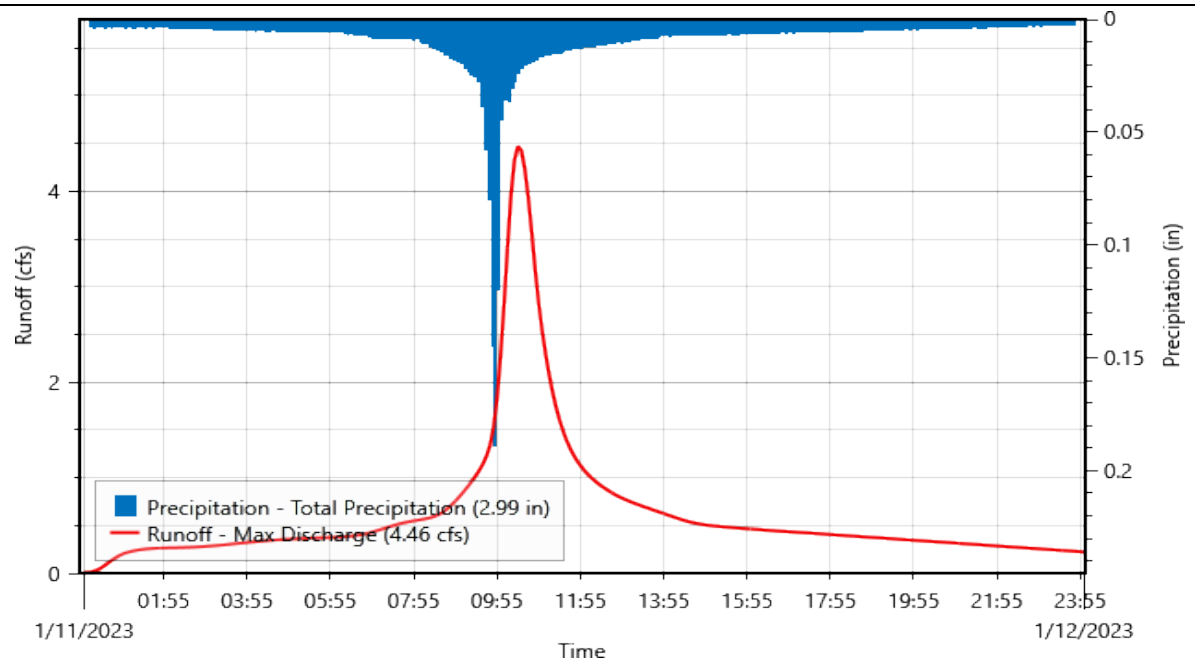
Subbasin ID:	Sub-12			
Scenario:	Existing Conditions 100yr		Depth	Volume
Peak discharge:	4.46 cfs	**Time of peak:**	11 Jan 2023, 10:25	
Drainage area:	952.517 acres	**Total rainfall:**	2.99 in	237.33423 ac-ft
Initial abstraction:	3.33 in	**Losses:**	2.97 in	236.10009 ac-ft
Curve Number:	37.51	**Precip excess:**	0.02 in	1.23414 ac-ft
Impervious surface:	0.52%	**Direct runoff:**	0.02 in	1.22 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	34.22 minutes	**Total runoff:**	0.02 in	1.22 ac-ft

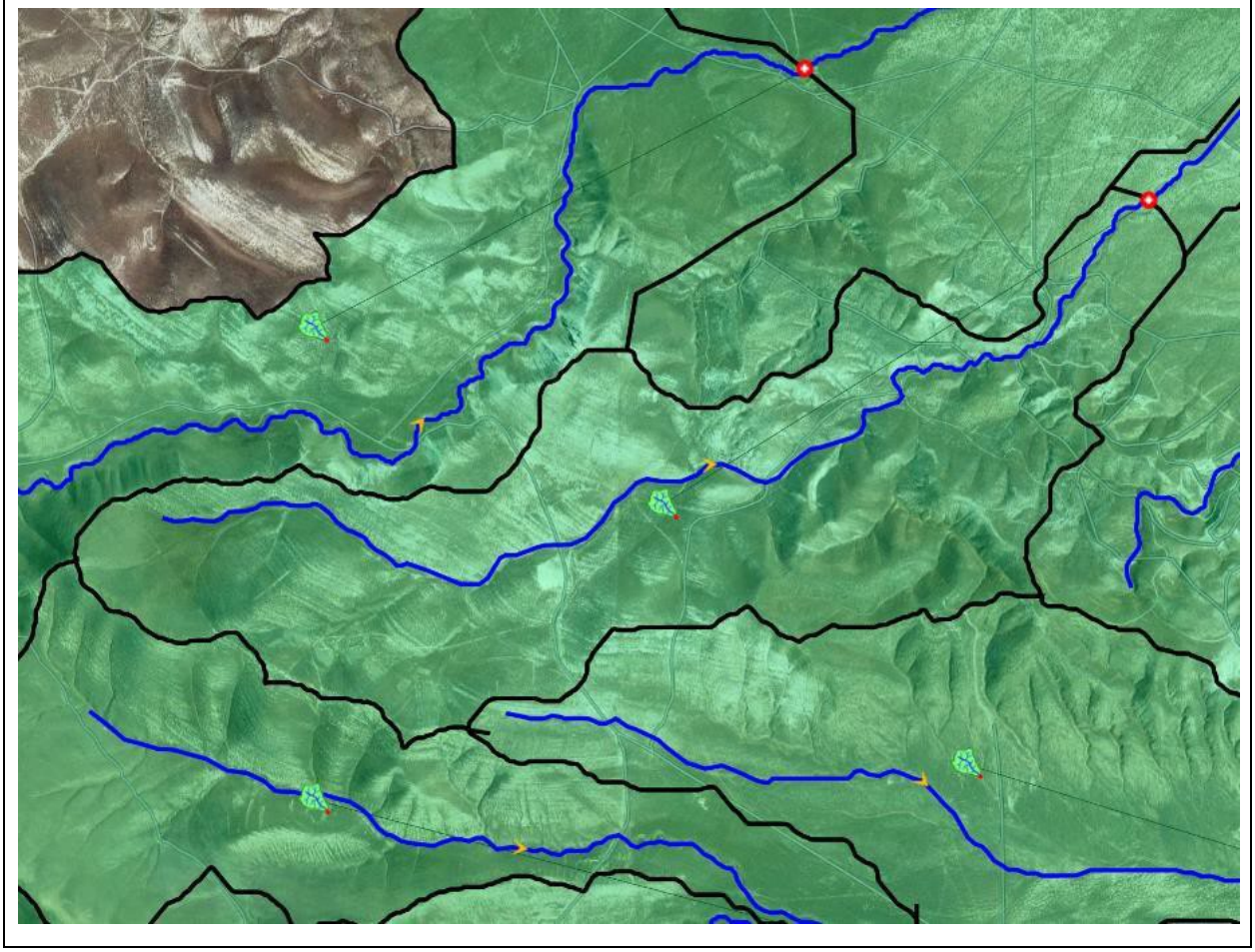
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
2.973	0.31	80.98	Developed, Medium Density
103.318	10.85	38.00	Undeveloped, Shrub/Scrub
0.143	0.02	75.00	Developed, Low Density
0.294	0.03	92.00	Developed, High Density
75.514	7.93	56.10	Developed, Open Space
770.275	80.87	35.42	Undeveloped, Grassland
952.517	**100.00**	**37.51**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
11.42	100.00	0.43323	2.4452	Sheet Flow
1.09	682.84	0.41878	21.3698	Shallow Concentrated Flow
1.93	655.49	0.12346	11.6028	Shallow Concentrated Flow
3.76	2,062.80	0.07622	9.1166	Channel Flow
38.83	14,034.51	0.03310	6.0076	Channel Flow
57.03	**17,535.64**	**Total**	**Lag Time = 34.22 minutes**	





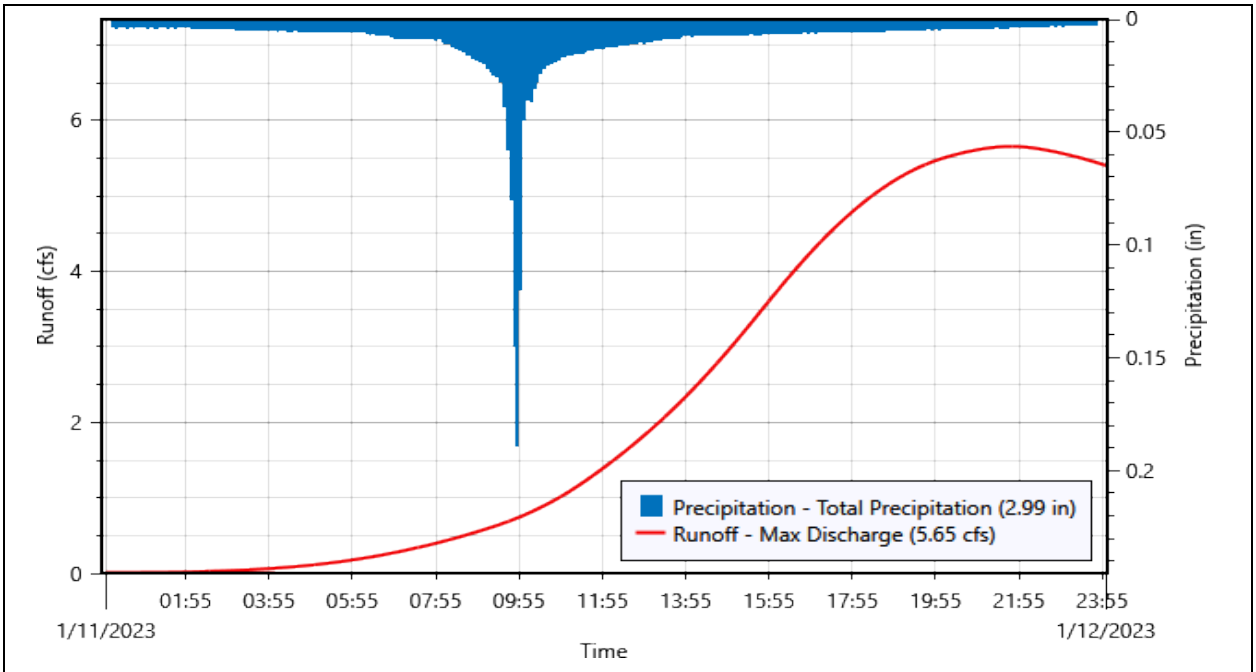
Subbasin ID:	Sub-13			
Scenario:	Existing Conditions 100yr		Depth	Volume
Peak discharge:	5.65 cfs	**Time of peak:**	11 Jan 2023, 09:45	
Drainage area:	1,426.690 acres	**Total rainfall:**	2.99 in	355.48308 ac-ft
Initial abstraction:	3.40 in	**Losses:**	2.91 in	346.45381 ac-ft
Curve Number:	37.06	**Precip excess:**	0.08 in	9.02927 ac-ft
Impervious surface:	2.54%	**Direct runoff:**	0.04 in	4.54 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	649.32 minutes	**Total runoff:**	0.04 in	4.54 ac-ft

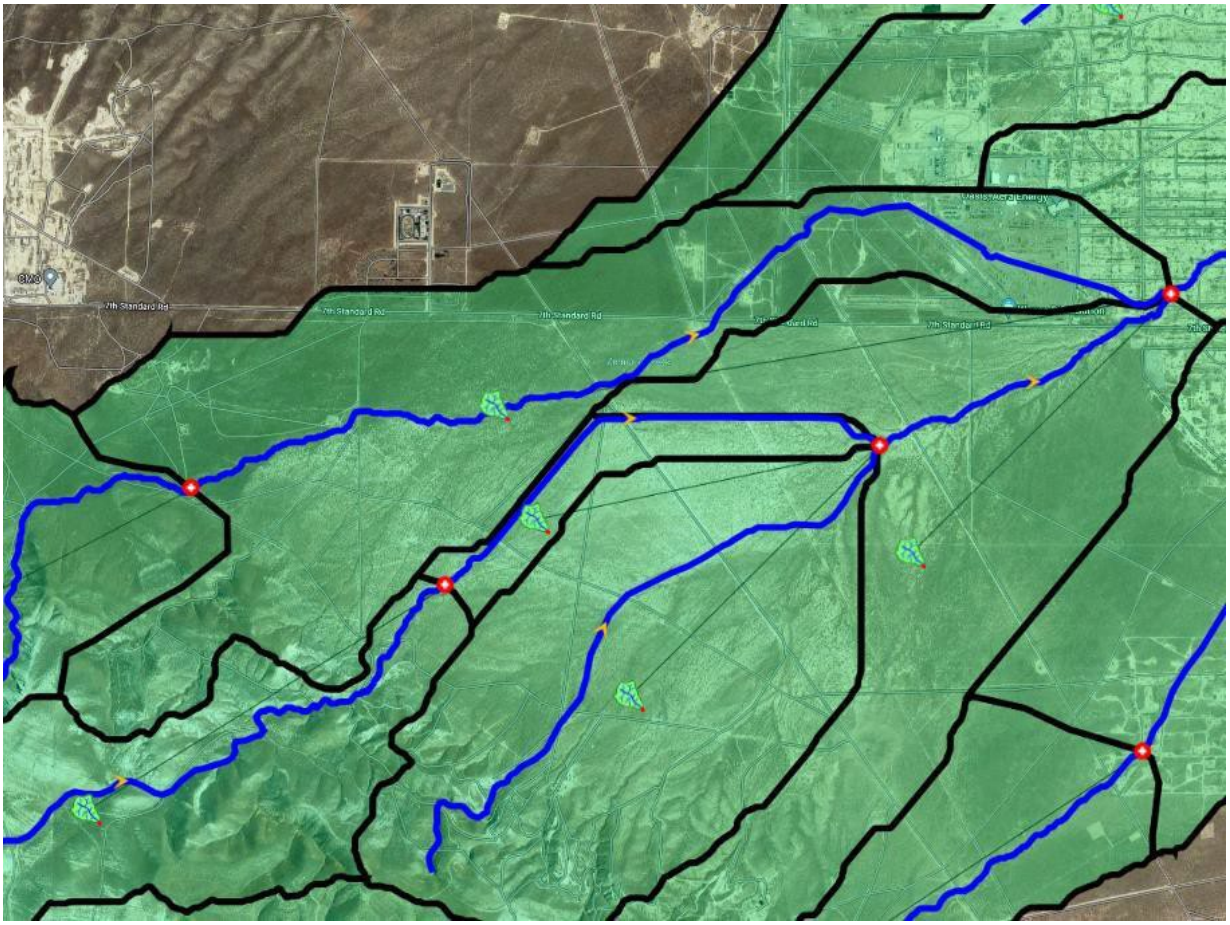
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
17.729	1.24	77.00	Developed, Medium Density
3.229	0.23	67.00	Agricultural, Cultivated Crops
80.460	5.64	37.13	Undeveloped, Shrub/Scrub
17.221	1.21	61.00	Developed, Low Density
15.586	1.09	89.00	Developed, High Density
152.768	10.71	52.06	Developed, Open Space
3.509	0.25	77.00	Undeveloped, Barren Land
1,136.188	79.64	33.14	Undeveloped, Grassland
1,426.690	**100.00**	**37.06**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
20.36	100.00	0.10212	1.1872	Sheet Flow
0.80	390.34	0.25255	16.5951	Shallow Concentrated Flow
8.53	4,253.88	0.06305	8.2916	Channel Flow
15.47	2,983.05	0.03970	6.5798	Shallow Concentrated Flow
43.39	10,314.70	0.01432	3.9513	Channel Flow
0.39	285.53	0.13608	12.1816	Channel Flow
993.25	6,239.98	0.00001	0.1044	Channel Flow
1,082.19	**24,567.48**	**Total**	**Lag Time = 649.32 minutes**	


Runoff (cfs)
Precipitation (in)
Time
1/11/2023
1/12/2023
Precipitation - Total Precipitation (2.99 in)
Runoff - Max Discharge (5.65 cfs)



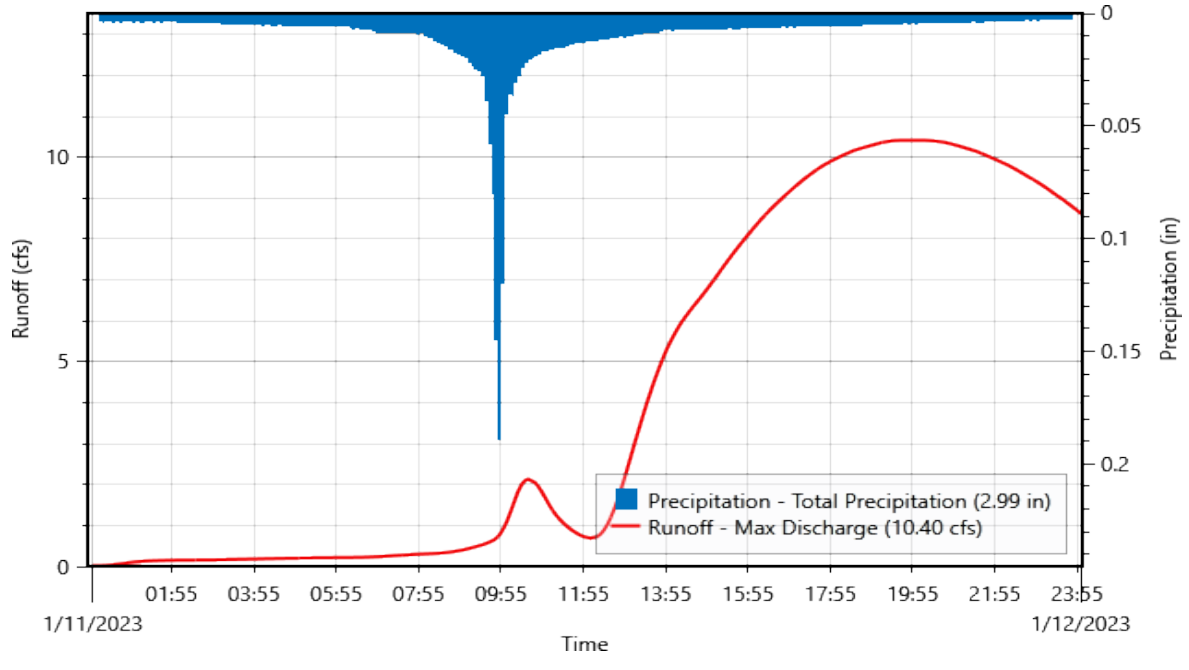
Subbasin ID:	**Sub-14**			
Scenario:	**Existing Conditions 100yr**		**Depth**	**Volume**
Peak discharge:	10.40 cfs	**Time of peak:**	11 Jan 2023, 08:10	
Drainage area:	1,158.859 acres	**Total rainfall:**	2.99 in	288.74628 ac-ft
Initial abstraction:	2.01 in	**Losses:**	2.90 in	279.68233 ac-ft
Curve Number:	49.91	**Precip excess:**	0.09 in	9.06395 ac-ft
Impervious surface:	0.23%	**Direct runoff:**	0.09 in	8.42 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	43.12 minutes	**Total runoff:**	0.09 in	8.42 ac-ft

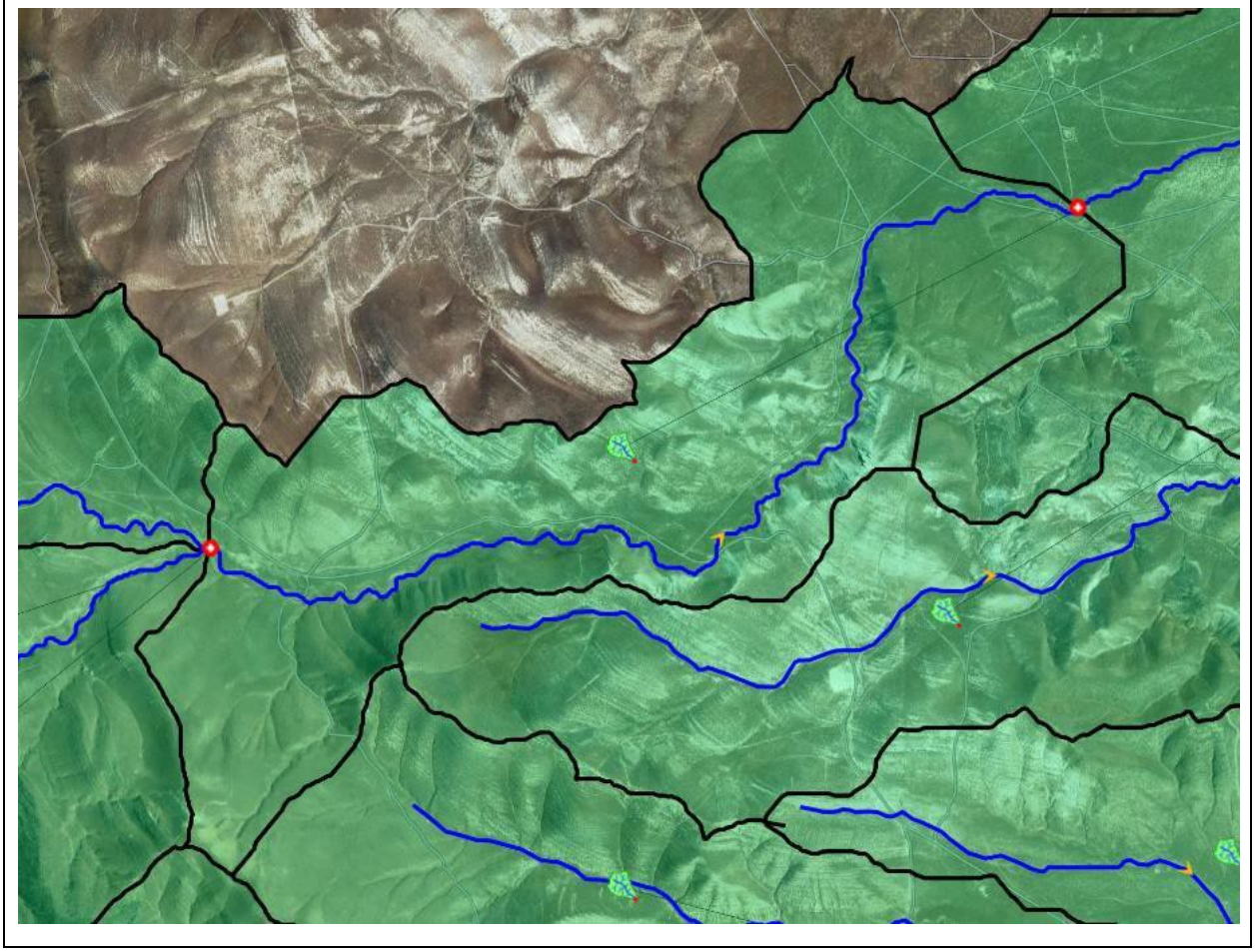
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
128.595	11.10	40.16	Undeveloped, Shrub/Scrub
0.289	0.02	61.00	Developed, Low Density
89.373	7.71	62.75	Developed, Open Space
940.602	81.17	50.02	Undeveloped, Grassland
1,158.859	**100.00**	**49.91**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
15.07	100.00	0.21650	1.7286	Sheet Flow
1.46	911.67	0.41691	21.3220	Shallow Concentrated Flow
2.49	2,157.30	0.19089	14.4277	Channel Flow
2.91	1,629.56	0.07940	9.3053	Channel Flow
49.93	15,884.87	0.02564	5.2879	Channel Flow
71.86	**20,683.40**	**Total**	**Lag Time = 43.12 minutes**	





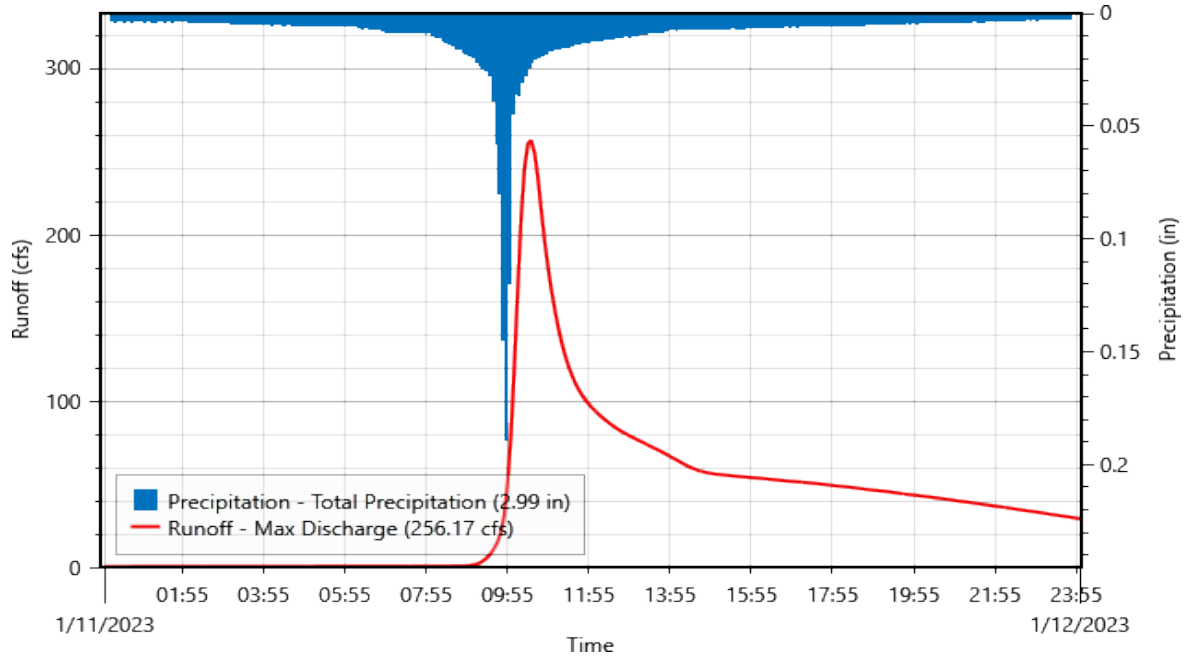
Subbasin ID:	Sub-15			
Scenario:	Existing Conditions 100yr		Depth	Volume
Peak discharge:	256.17 cfs	**Time of peak:**	11 Jan 2023, 10:30	
Drainage area:	1,054.808 acres	**Total rainfall:**	2.99 in	262.81700 ac-ft
Initial abstraction:	0.70 in	**Losses:**	2.08 in	182.86948 ac-ft
Curve Number:	74.04	**Precip excess:**	0.91 in	79.94753 ac-ft
Impervious surface:	0.23%	**Direct runoff:**	0.89 in	78.40 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	30.66 minutes	**Total runoff:**	0.89 in	78.40 ac-ft

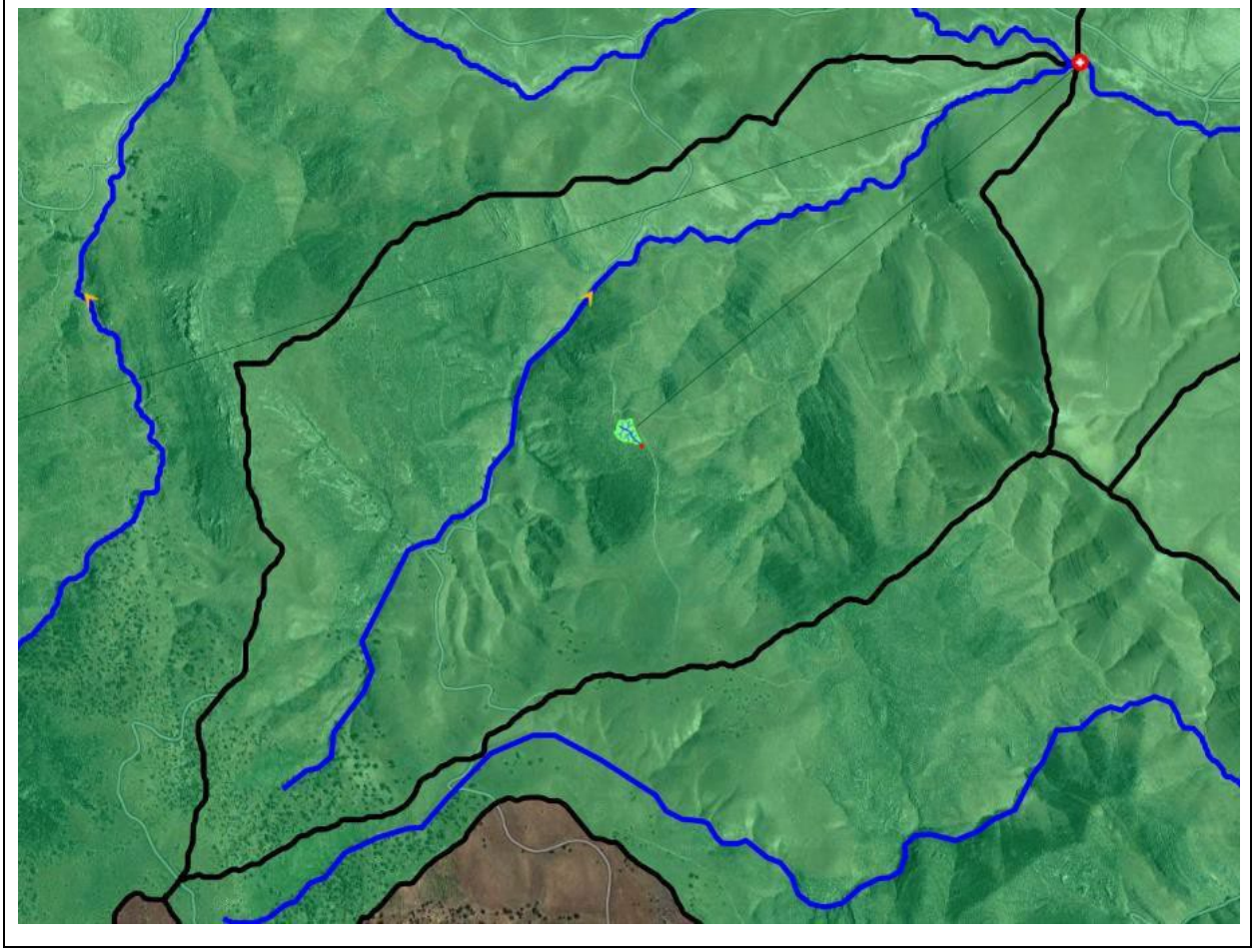
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
0.440	0.04	90.67	Developed, Medium Density
314.541	29.82	70.23	Undeveloped, Shrub/Scrub
3.839	0.36	84.20	Developed, Low Density
56.493	5.36	82.98	Developed, Open Space
679.496	64.42	74.98	Undeveloped, Grassland
1,054.808	**100.00**	**74.04**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
25.00	100.00	0.06109	0.9182	Sheet Flow
2.53	1,452.21	0.35050	19.5503	Shallow Concentrated Flow
1.74	1,776.43	0.26336	16.9464	Channel Flow
21.82	11,269.67	0.06761	8.5864	Channel Flow
51.09	**14,598.31**	**Total**	**Lag Time = 30.66 minutes**	





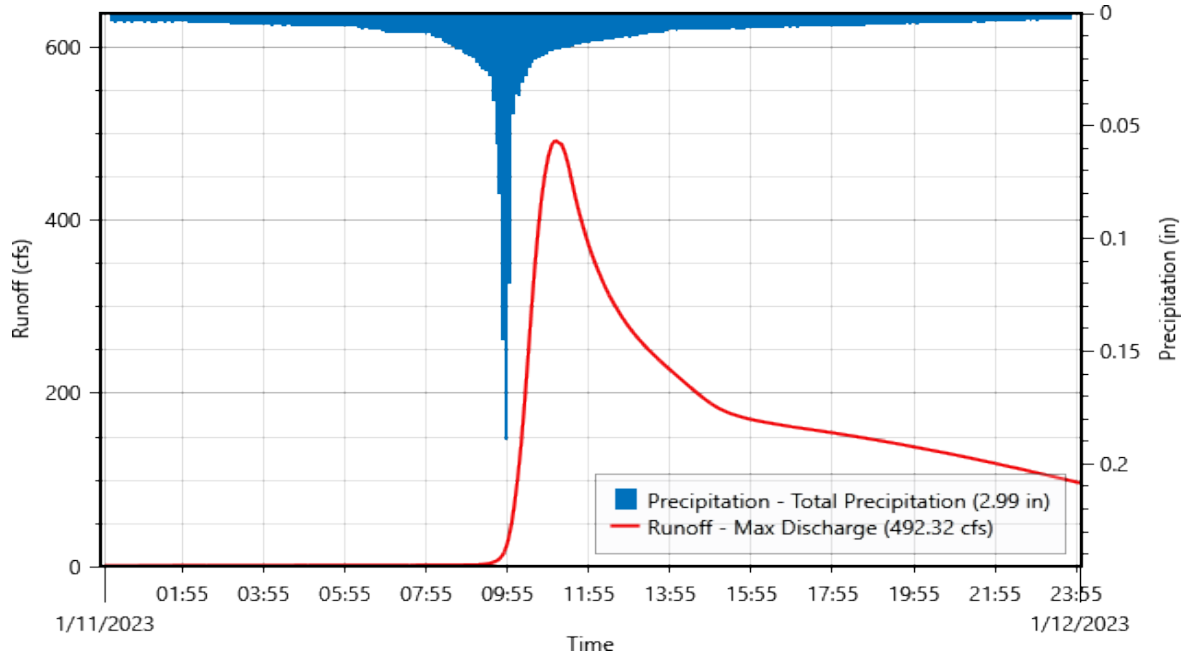
Subbasin ID:	Sub-16			
Scenario:	Existing Conditions 100yr		Depth	Volume
Peak discharge:	492.32 cfs	**Time of peak:**	11 Jan 2023, 11:05	
Drainage area:	3,426.802 acres	**Total rainfall:**	2.99 in	853.84828 ac-ft
Initial abstraction:	0.76 in	**Losses:**	2.16 in	617.20714 ac-ft
Curve Number:	72.40	**Precip excess:**	0.83 in	236.64114 ac-ft
Impervious surface:	0.26%	**Direct runoff:**	0.79 in	226.93 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	59.76 minutes	**Total runoff:**	0.79 in	226.93 ac-ft

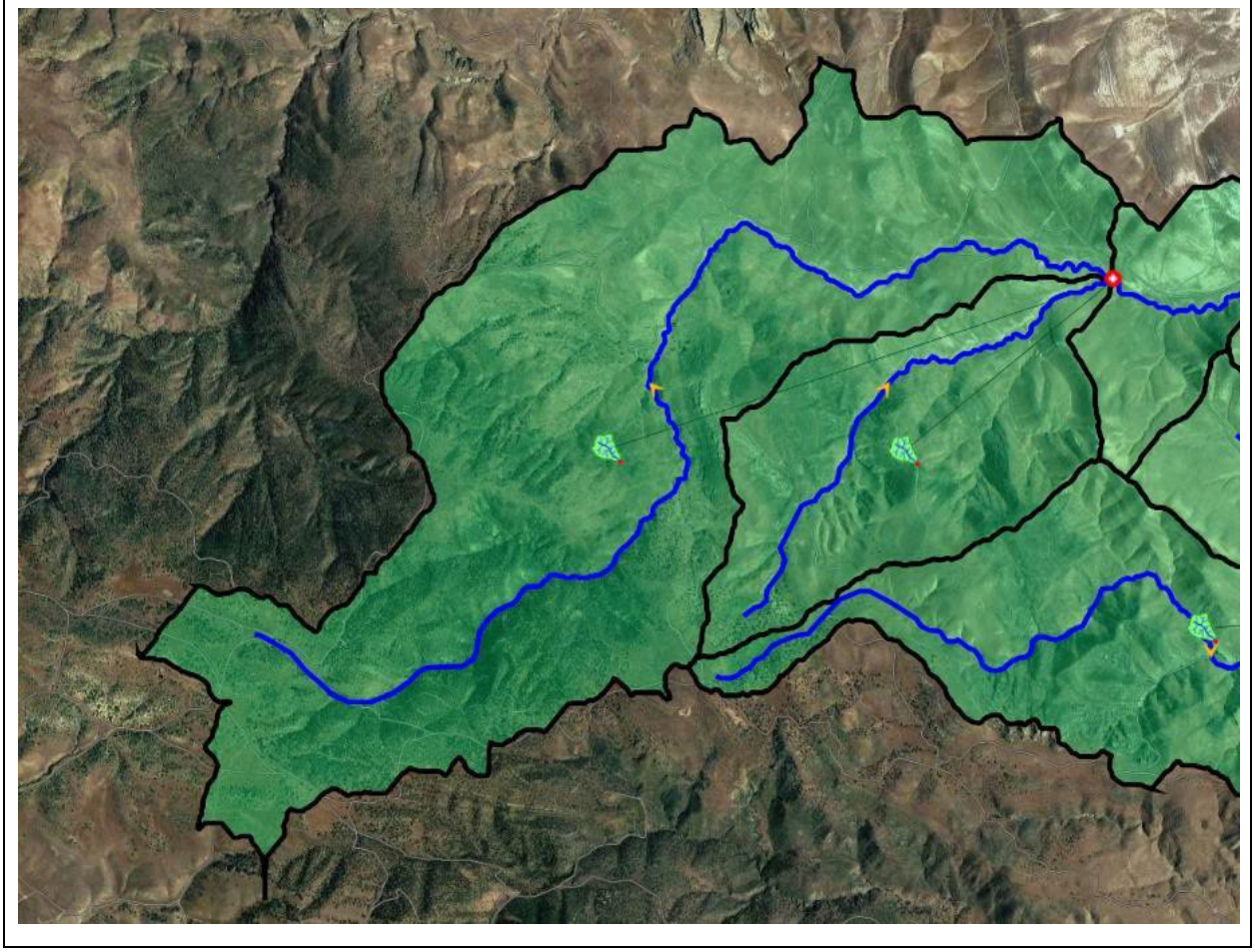
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
1.435	0.04	90.36	Developed, Medium Density
1,371.868	40.03	69.50	Undeveloped, Shrub/Scrub
7.071	0.21	85.60	Developed, Low Density
212.323	6.20	80.36	Developed, Open Space
1,834.106	53.52	73.58	Undeveloped, Grassland
3,426.802	**100.00**	**72.40**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
19.42	100.00	0.11493	1.2594	Sheet Flow
1.56	667.95	0.19509	14.5854	Shallow Concentrated Flow
13.71	2,461.83	0.03444	6.1282	Shallow Concentrated Flow
8.43	4,539.75	0.07343	8.9483	Channel Flow
9.74	7,174.45	0.13760	12.2496	Channel Flow
46.74	18,531.20	0.03983	6.5902	Channel Flow
99.60	**33,475.18**	**Total**	**Lag Time = 59.76 minutes**	





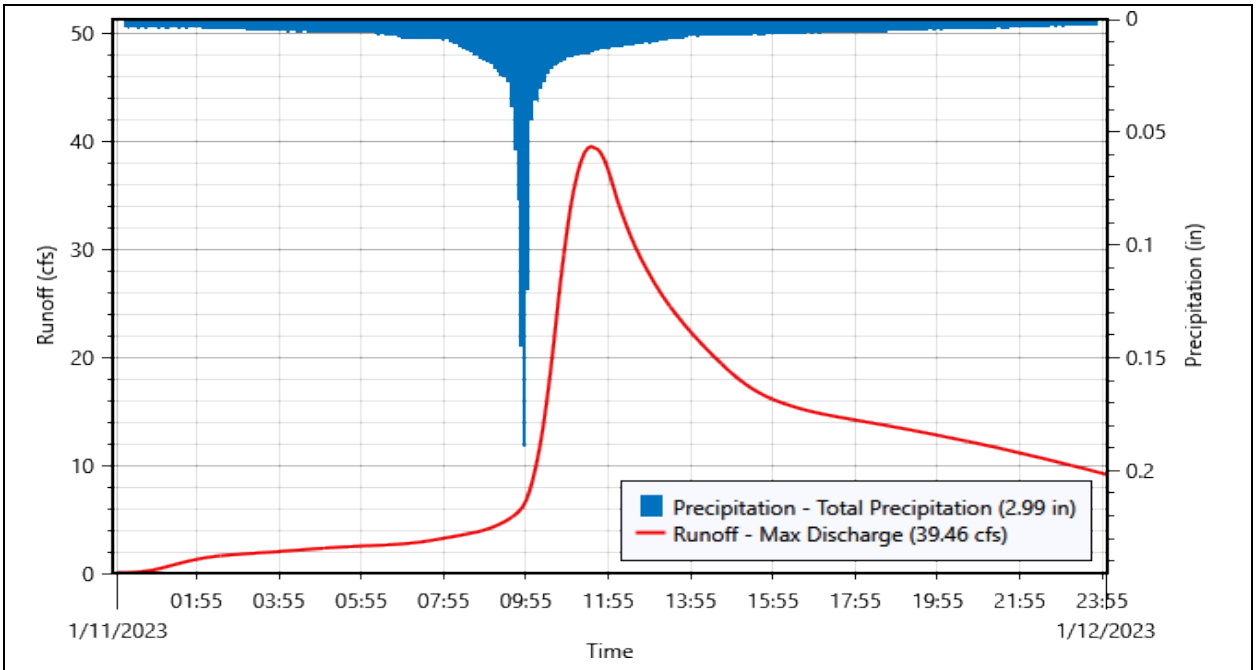
Subbasin ID:	Sub-17			
Scenario:	Existing Conditions 100yr		Depth	Volume
Peak discharge:	39.46 cfs	**Time of peak:**	11 Jan 2023, 11:30	
Drainage area:	337.184 acres	**Total rainfall:**	2.99 in	84.00704 ac-ft
Initial abstraction:	0.97 in	**Losses:**	2.14 in	60.23474 ac-ft
Curve Number:	67.43	**Precip excess:**	0.85 in	23.77230 ac-ft
Impervious surface:	10.46%	**Direct runoff:**	0.80 in	22.55 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	80.39 minutes	**Total runoff:**	0.80 in	22.55 ac-ft

Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
11.293	3.35	79.56	Developed, Medium Density
11.056	3.28	57.09	Undeveloped, Shrub/Scrub
67.566	20.04	78.79	Agricultural, Cultivated Crops
47.927	14.21	72.20	Developed, Low Density
0.803	0.24	90.30	Developed, High Density
1.132	0.34	86.00	Undeveloped, Barren Land
45.684	13.55	49.39	Undeveloped, Grassland
151.725	45.00	65.89	Developed, Open Space
337.184	**100.00**	**67.43**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
51.35	100.00	0.01011	0.3736	Sheet Flow
17.31	2,002.38	0.01428	3.9466	Shallow Concentrated Flow
0.33	116.98	0.13224	12.0085	Shallow Concentrated Flow
61.55	2,055.00	0.00119	1.1398	Shallow Concentrated Flow
3.43	792.14	0.01352	3.8394	Channel Flow
133.97	**5,066.50**	**Total**	**Lag Time = 80.39 minutes**	


Runoff (cfs)
Precipitation (in)
Time
1/11/2023
1/12/2023
Precipitation - Total Precipitation (2.99 in)
Runoff - Max Discharge (39.46 cfs)


BSWP
Jun-13
Reach-17
Sub-17
Jun-14
Lost Hills Rd
Entrance A

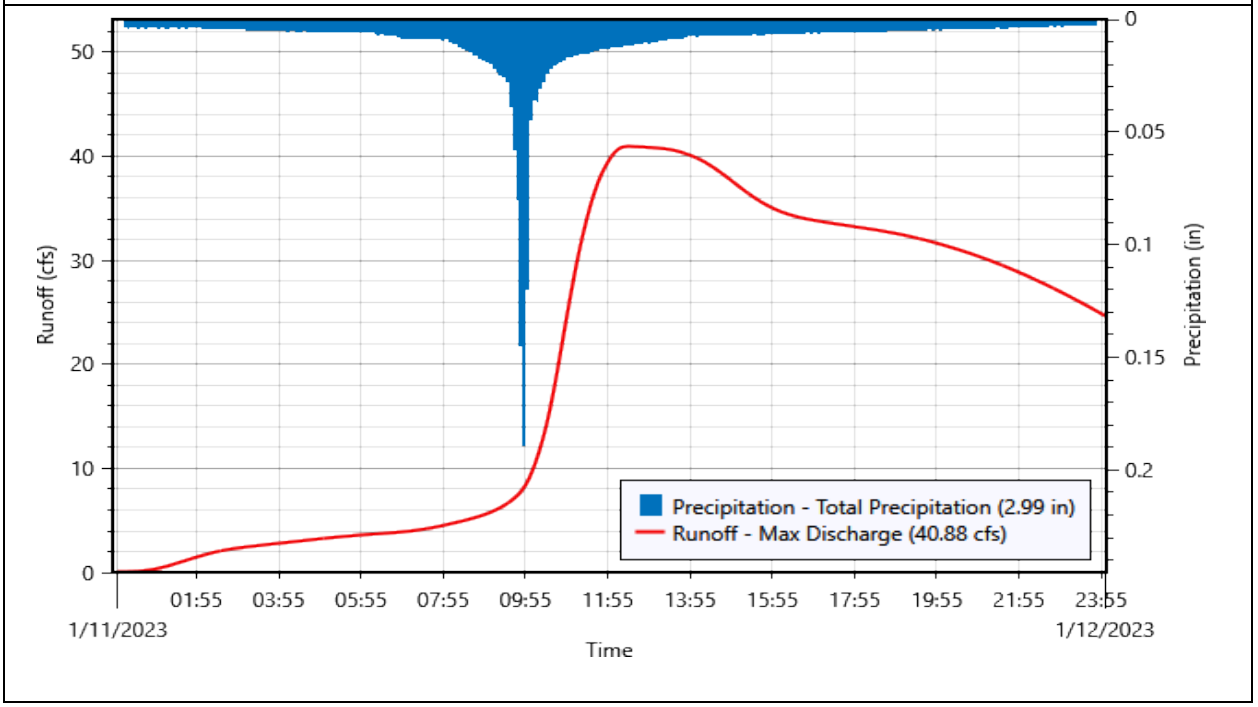
Subbasin ID:	Sub-18			
Scenario:	Existing Conditions 100yr		Depth	Volume
Peak discharge:	40.88 cfs	**Time of peak:**	11 Jan 2023, 12:25	
Drainage area:	1,474.591 acres	**Total rainfall:**	2.99 in	367.41118 ac-ft
Initial abstraction:	1.47 in	**Losses:**	2.63 in	323.44166 ac-ft
Curve Number:	57.69	**Precip excess:**	0.36 in	43.96953 ac-ft
Impervious surface:	3.55%	**Direct runoff:**	0.33 in	40.02 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	96.69 minutes	**Total runoff:**	0.33 in	40.02 ac-ft

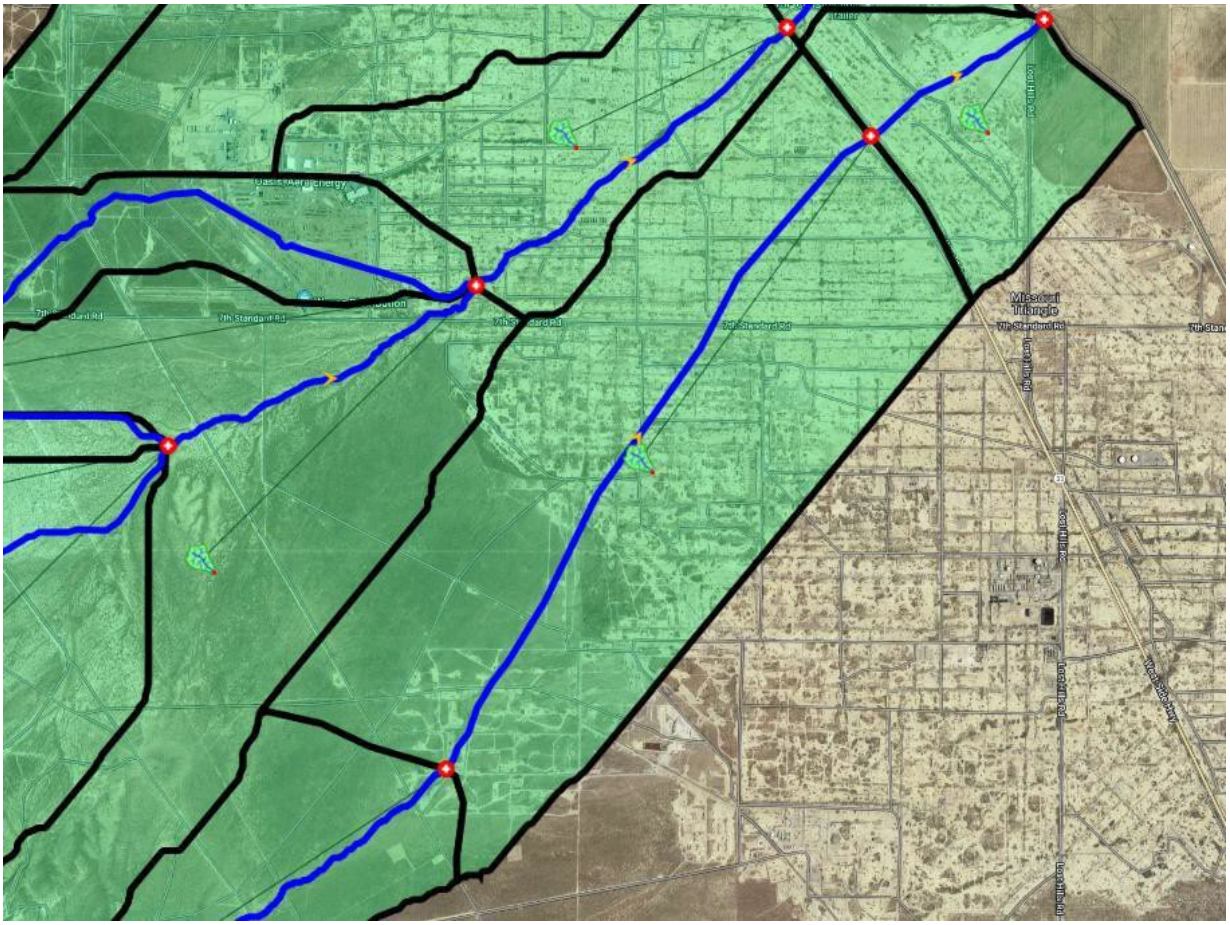
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
3.985	0.27	88.87	Developed, Medium Density
5.873	0.40	43.83	Undeveloped, Shrub/Scrub
60.728	4.12	78.75	Developed, Low Density
0.093	0.01	92.00	Developed, High Density
624.729	42.37	71.04	Developed, Open Space
3.600	0.24	89.56	Undeveloped, Barren Land
775.583	52.60	45.08	Undeveloped, Grassland
1,474.591	**100.00**	**57.69**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
47.88	100.00	0.01204	0.4077	Sheet Flow
16.47	2,024.74	0.01613	4.1935	Shallow Concentrated Flow
47.40	10,905.83	0.01341	3.8241	Channel Flow
49.39	438.84	0.00002	0.1541	Channel Flow
161.14	**13,469.41**	**Total**	**Lag Time = 96.69 minutes**	




7th Standard Rd
Missouri Triangle
Loop H Rd

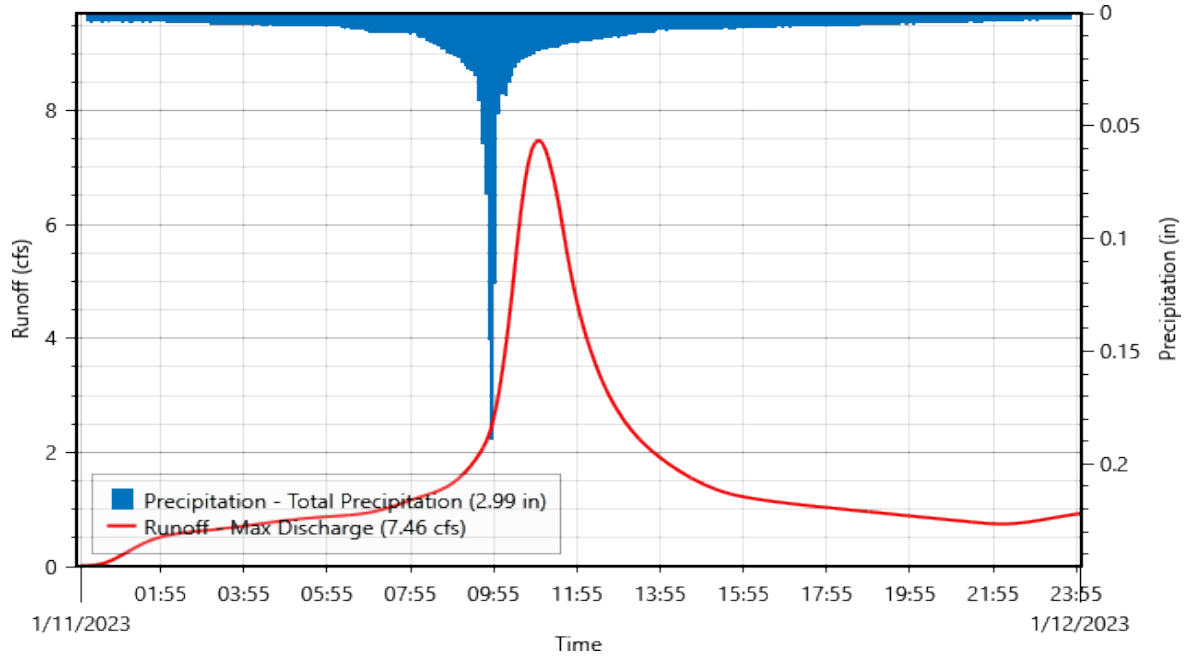
Subbasin ID:	Sub-19			
Scenario:	Existing Conditions 100yr		Depth	Volume
Peak discharge:	7.46 cfs	**Time of peak:**	11 Jan 2023, 11:00	
Drainage area:	787.670 acres	**Total rainfall:**	2.99 in	196.25562 ac-ft
Initial abstraction:	2.86 in	**Losses:**	2.94 in	193.17709 ac-ft
Curve Number:	41.19	**Precip excess:**	0.05 in	3.07852 ac-ft
Impervious surface:	1.53%	**Direct runoff:**	0.05 in	2.96 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	66.54 minutes	**Total runoff:**	0.05 in	2.96 ac-ft

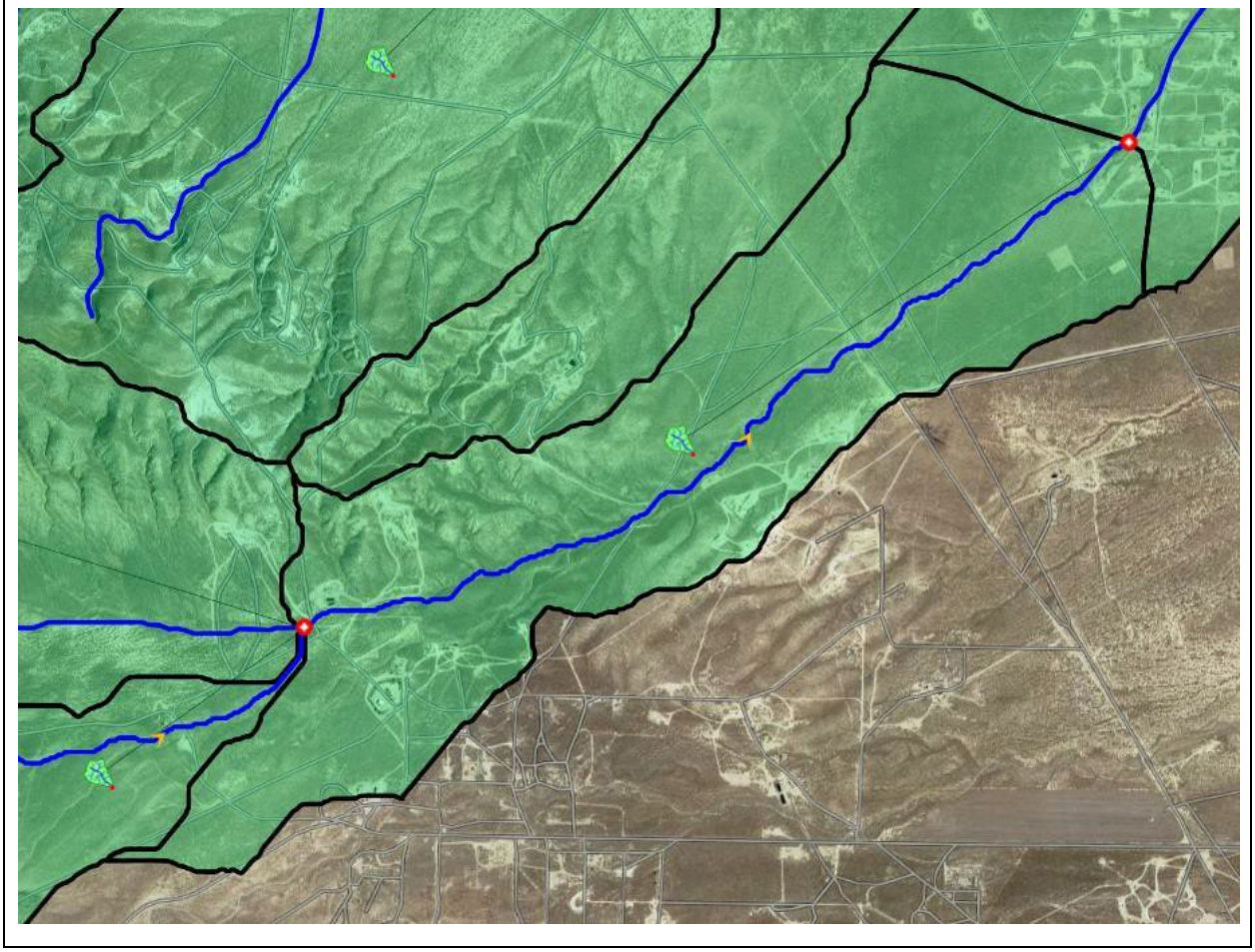
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
1.108	0.14	85.00	Developed, Medium Density
3.612	0.46	36.54	Undeveloped, Shrub/Scrub
0.954	0.12	61.03	Developed, Low Density
92.294	11.72	56.80	Developed, Open Space
0.138	0.02	77.00	Undeveloped, Barren Land
689.564	87.54	39.02	Undeveloped, Grassland
787.670	**100.00**	**41.19**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
29.59	100.00	0.04010	0.7440	Sheet Flow
29.99	4,469.59	0.02372	5.0858	Shallow Concentrated Flow
13.10	1,472.11	0.00320	1.8666	Channel Flow
38.21	10,337.14	0.01854	4.4965	Channel Flow
110.89	**16,378.84**	**Total**	**Lag Time = 66.54 minutes**	





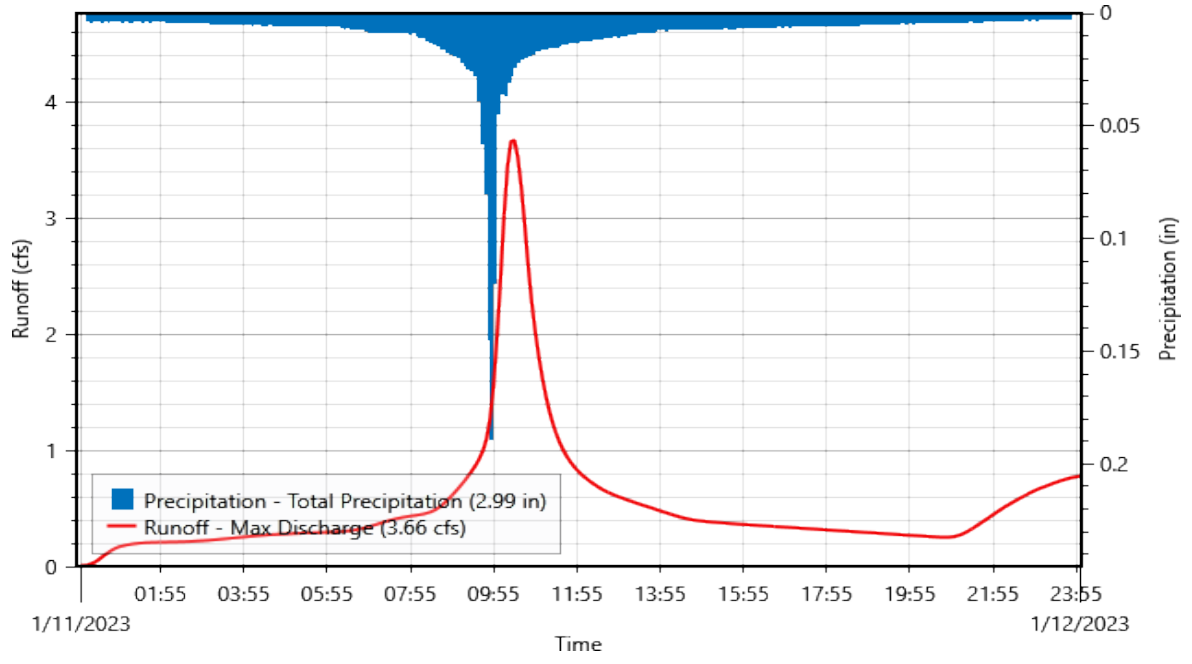
Subbasin ID:	Sub-20			
Scenario:	Existing Conditions 100yr		Depth	Volume
Peak discharge:	3.66 cfs	**Time of peak:**	11 Jan 2023, 10:25	
Drainage area:	714.148 acres	**Total rainfall:**	2.99 in	177.94885 ac-ft
Initial abstraction:	2.82 in	**Losses:**	2.97 in	176.86816 ac-ft
Curve Number:	41.47	**Precip excess:**	0.02 in	1.08069 ac-ft
Impervious surface:	0.54%	**Direct runoff:**	0.02 in	1.04 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	30.83 minutes	**Total runoff:**	0.02 in	1.04 ac-ft

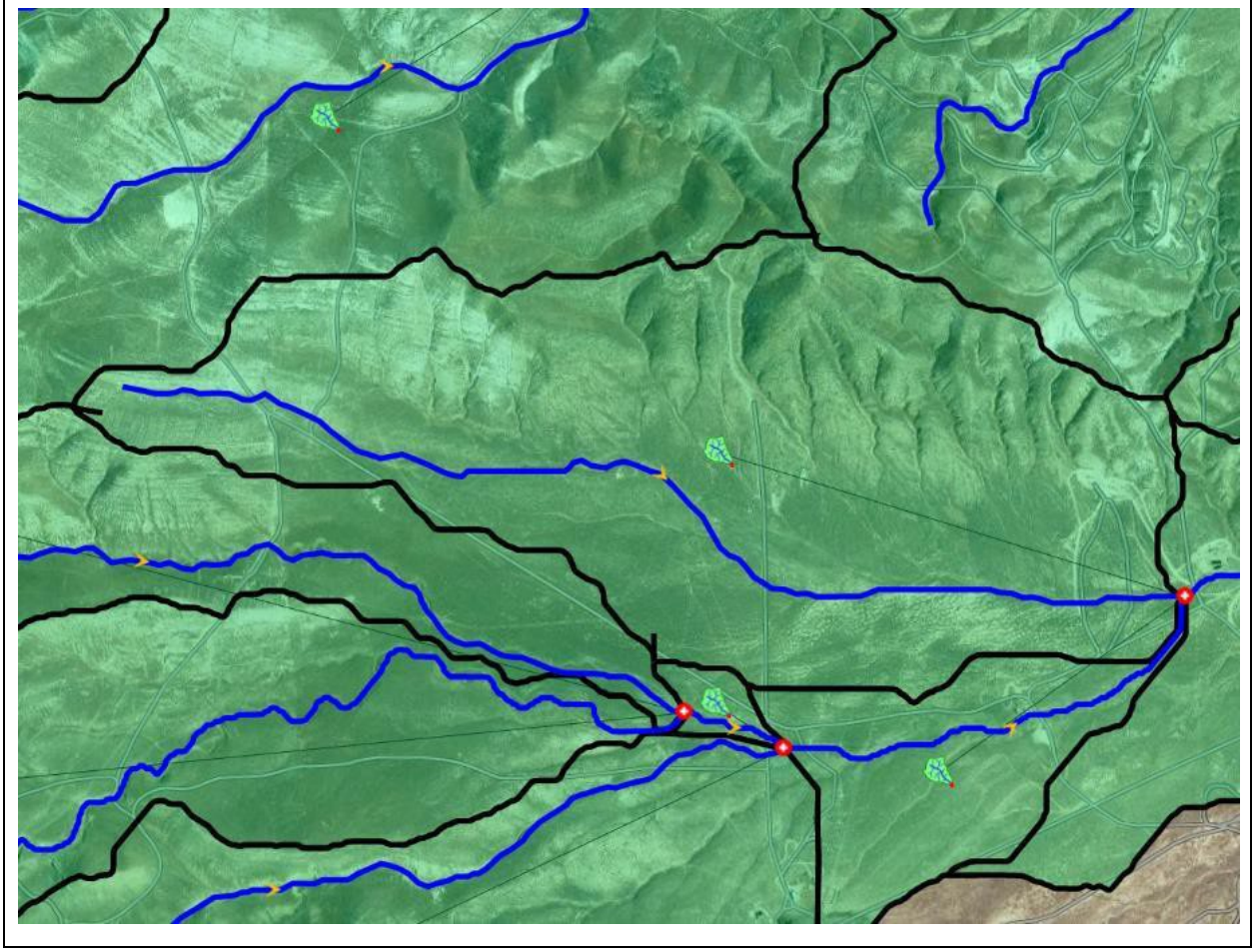
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
1.599	0.22	79.30	Developed, Medium Density
24.804	3.47	30.65	Undeveloped, Shrub/Scrub
0.430	0.06	61.00	Developed, Low Density
60.511	8.47	56.19	Developed, Open Space
626.805	87.77	40.37	Undeveloped, Grassland
714.148	**100.00**	**41.47**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
16.55	100.00	0.17144	1.5382	Sheet Flow
1.01	456.12	0.21931	15.4645	Shallow Concentrated Flow
0.89	623.85	0.12498	11.6744	Channel Flow
18.86	7,625.25	0.04142	6.7210	Channel Flow
9.23	2,974.94	0.02631	5.3566	Channel Flow
4.84	334.47	0.00121	1.1467	Channel Flow
51.38	**12,114.63**	**Total**	**Lag Time = 30.83 minutes**	





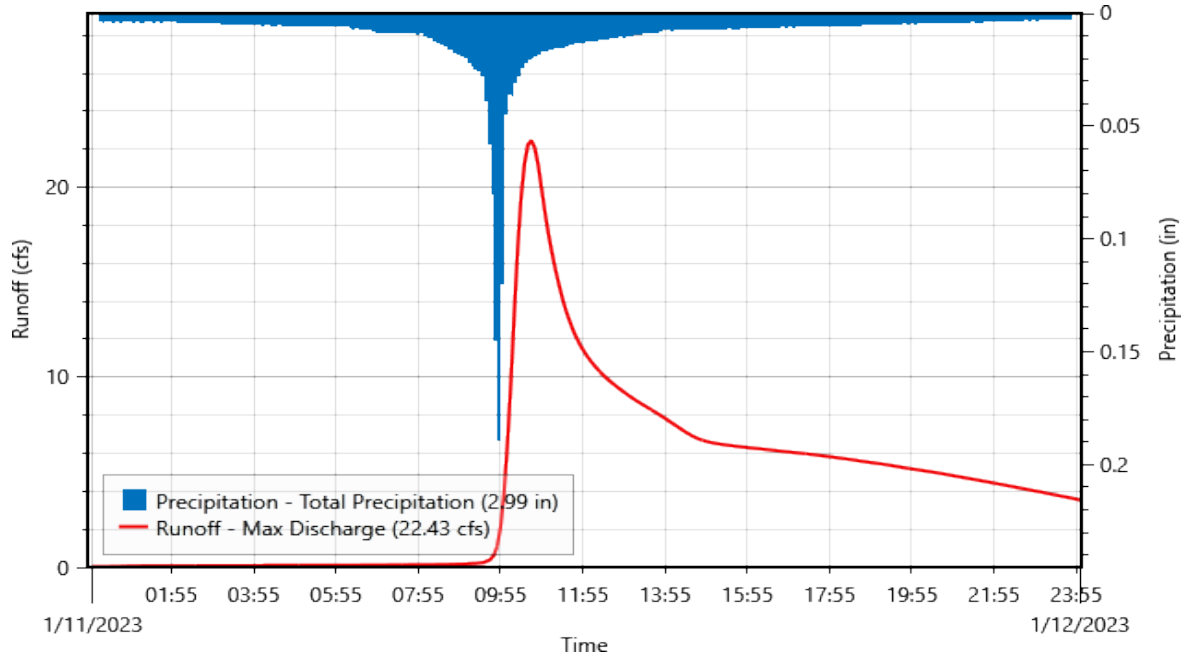
Subbasin ID:	Sub-21			
Scenario:	Existing Conditions 100yr		Depth	Volume
Peak discharge:	22.43 cfs	**Time of peak:**	11 Jan 2023, 10:40	
Drainage area:	140.608 acres	**Total rainfall:**	2.99 in	35.03483 ac-ft
Initial abstraction:	0.83 in	**Losses:**	2.23 in	26.18362 ac-ft
Curve Number:	70.73	**Precip excess:**	0.76 in	8.85121 ac-ft
Impervious surface:	0.65%	**Direct runoff:**	0.74 in	8.62 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	37.22 minutes	**Total runoff:**	0.74 in	8.62 ac-ft

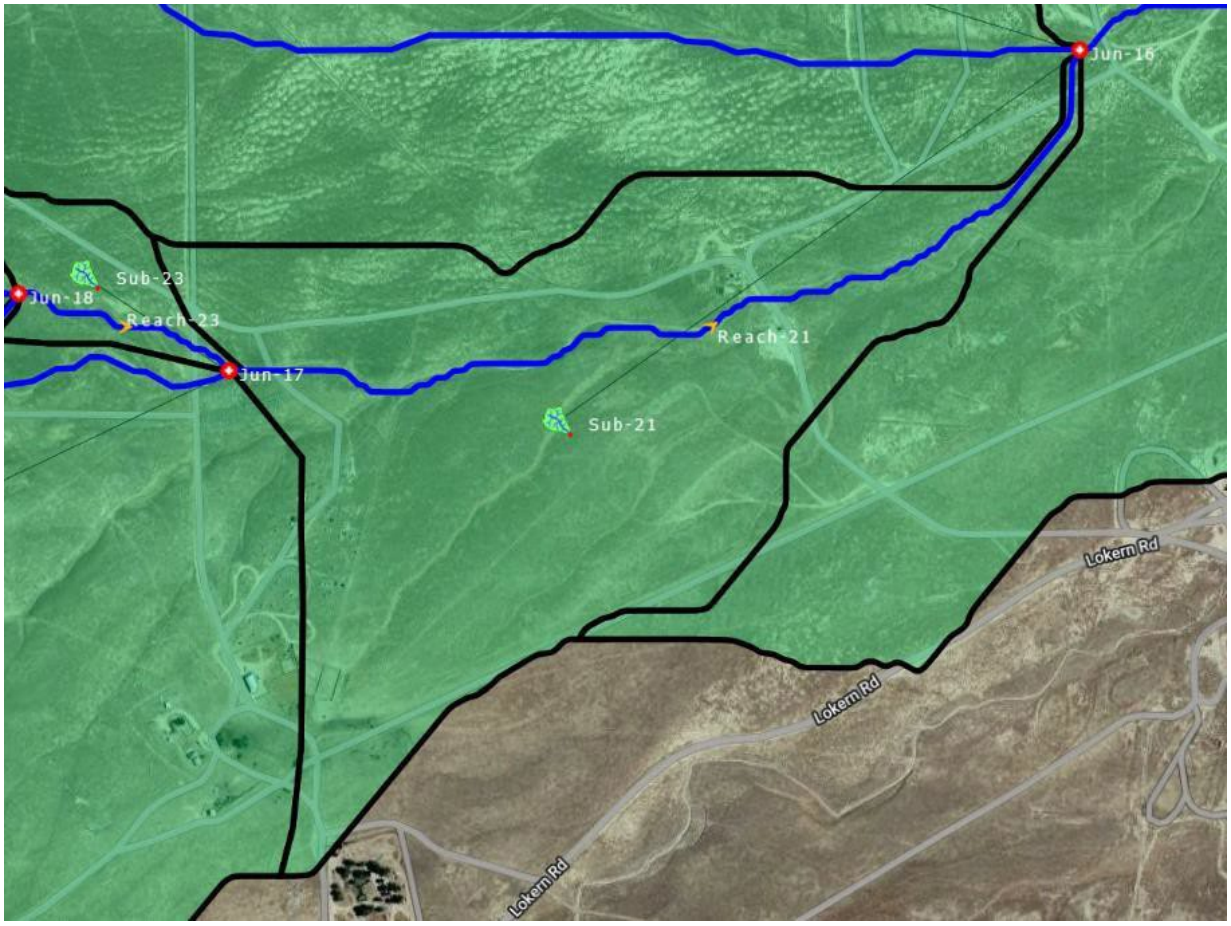
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
0.048	0.03	73.00	Undeveloped, Shrub/Scrub
23.066	16.40	70.83	Developed, Open Space
117.494	83.56	70.70	Undeveloped, Grassland
140.608	**100.00**	**70.73**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
34.47	100.00	0.02738	0.6147	Sheet Flow
19.66	3,615.01	0.03610	6.2745	Shallow Concentrated Flow
5.94	1,258.40	0.01138	3.5222	Channel Flow
1.95	736.77	0.03618	6.2812	Channel Flow
62.02	**5,710.18**	**Total**	**Lag Time = 37.22 minutes**	




Jun-16
Sub-23
Jun-18
Reach-23
Reach-21
Jun-17
Sub-21
Lokern Rd
Lokern Rd
Lokern Rd

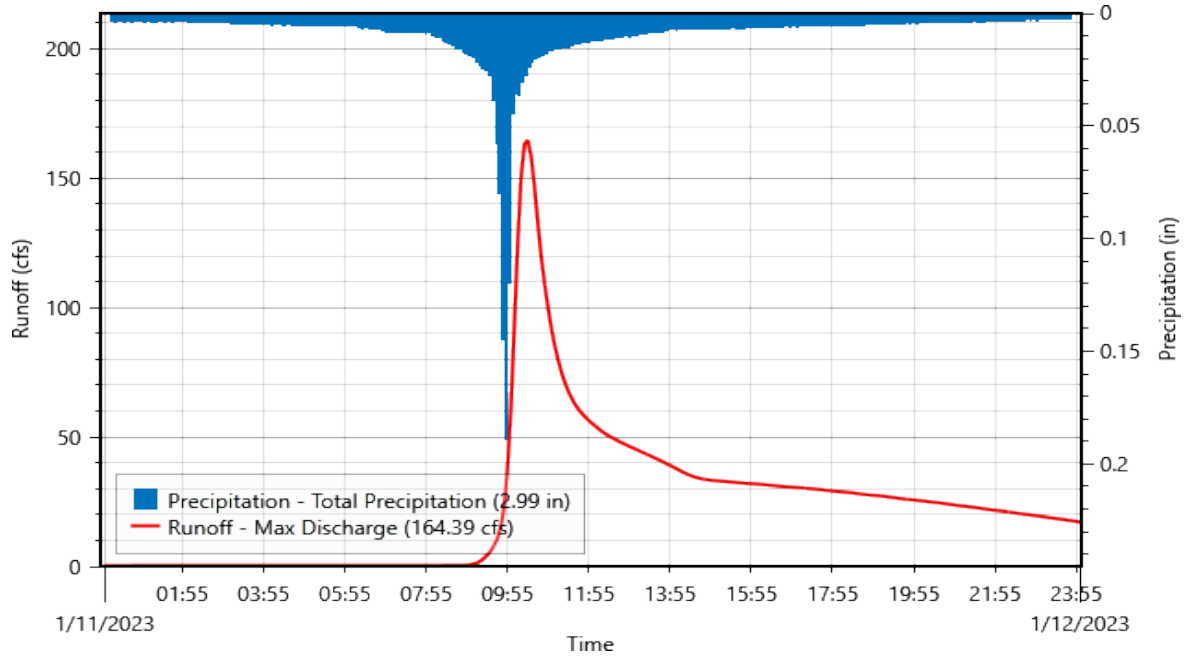
Subbasin ID:	Sub-22			
Scenario:	Existing Conditions 100yr		Depth	Volume
Peak discharge:	164.39 cfs	**Time of peak:**	11 Jan 2023, 10:25	
Drainage area:	624.791 acres	**Total rainfall:**	2.99 in	155.67135 ac-ft
Initial abstraction:	0.70 in	**Losses:**	2.08 in	108.15140 ac-ft
Curve Number:	74.21	**Precip excess:**	0.91 in	47.51995 ac-ft
Impervious surface:	0.15%	**Direct runoff:**	0.90 in	46.72 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	26.62 minutes	**Total runoff:**	0.90 in	46.72 ac-ft

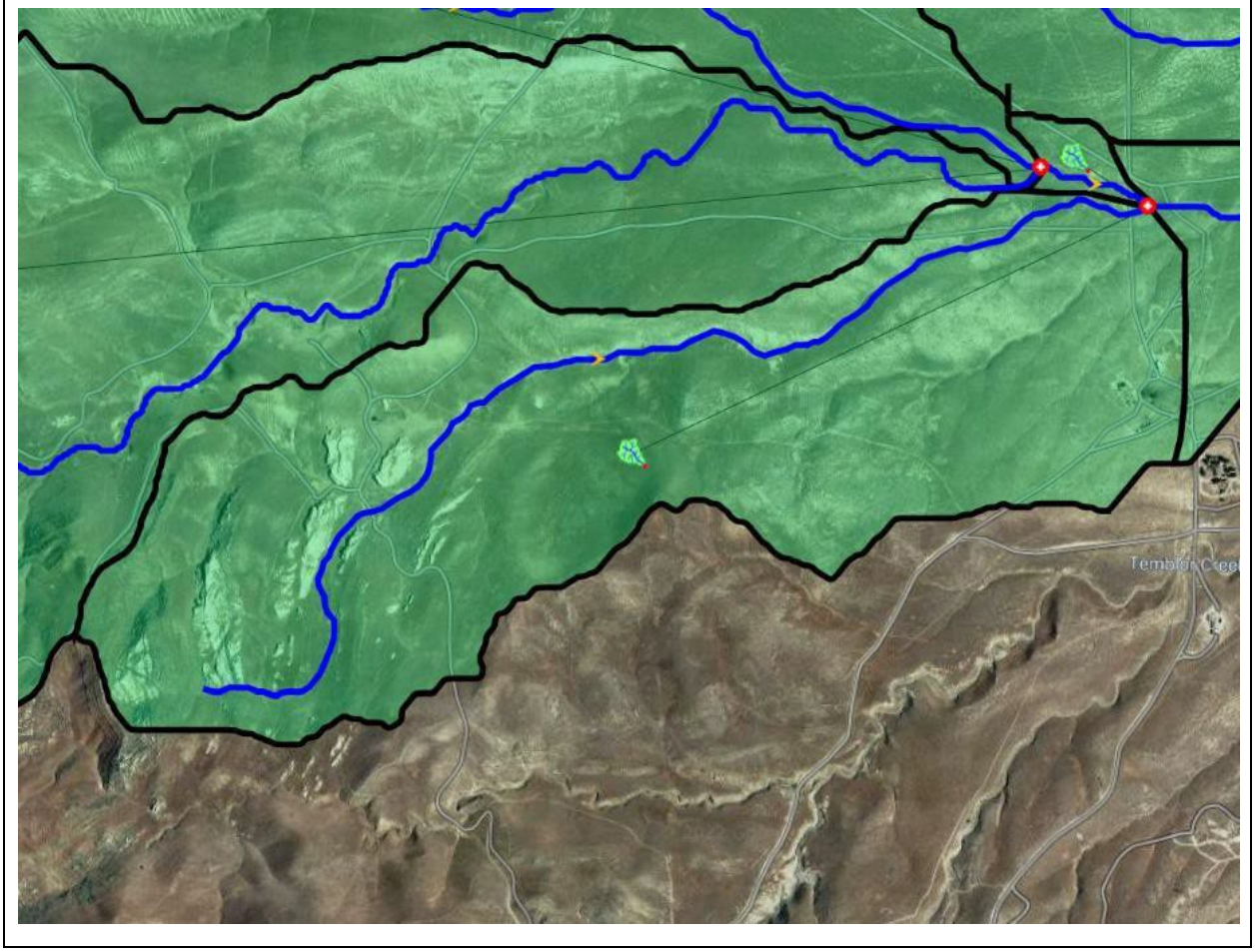
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
15.298	2.45	65.31	Undeveloped, Shrub/Scrub
44.349	7.10	81.50	Developed, Open Space
565.143	90.45	73.87	Undeveloped, Grassland
624.791	**100.00**	**74.21**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
14.10	100.00	0.25569	1.8785	Sheet Flow
1.03	658.49	0.44023	21.9101	Shallow Concentrated Flow
0.57	222.33	0.16461	13.3980	Shallow Concentrated Flow
5.54	2,803.60	0.06494	8.4151	Channel Flow
23.12	8,603.50	0.03510	6.1869	Channel Flow
44.36	**12,387.92**	**Total**	**Lag Time = 26.62 minutes**	





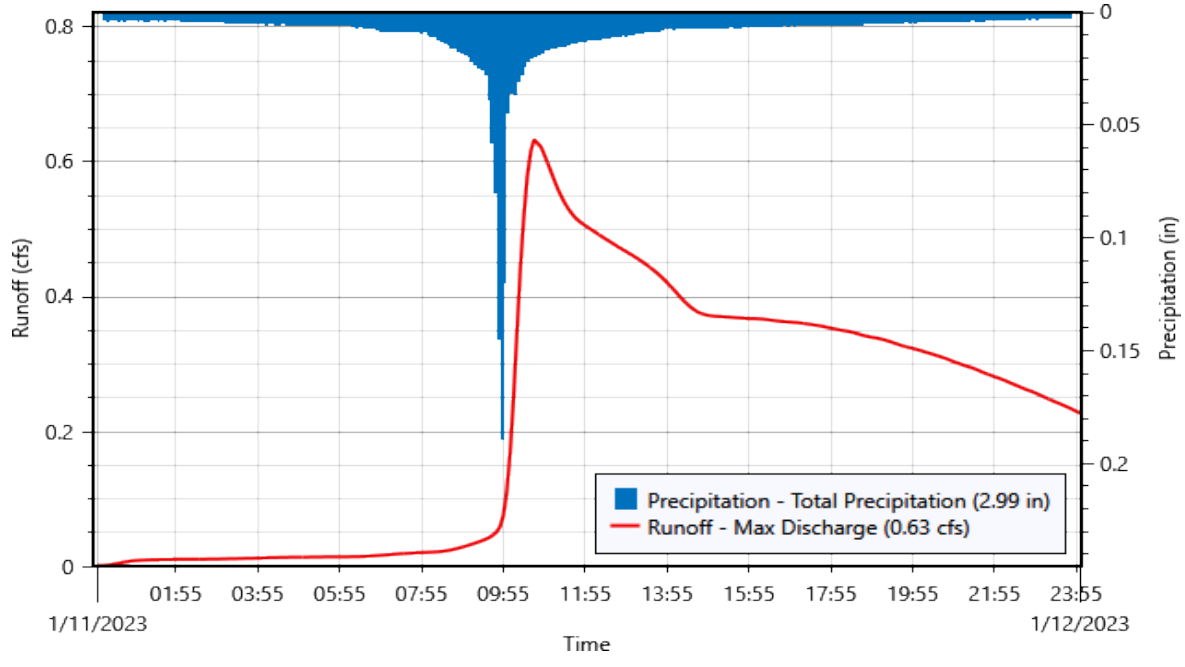
Subbasin ID:	Sub-23			
Scenario:	Existing Conditions 100yr		Depth	Volume
Peak discharge:	0.63 cfs	**Time of peak:**	11 Jan 2023, 10:45	
Drainage area:	13.631 acres	**Total rainfall:**	2.99 in	3.39664 ac-ft
Initial abstraction:	1.27 in	**Losses:**	2.59 in	2.94180 ac-ft
Curve Number:	61.18	**Precip excess:**	0.40 in	0.45484 ac-ft
Impervious surface:	1.28%	**Direct runoff:**	0.39 in	0.44 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	30.66 minutes	**Total runoff:**	0.39 in	0.44 ac-ft

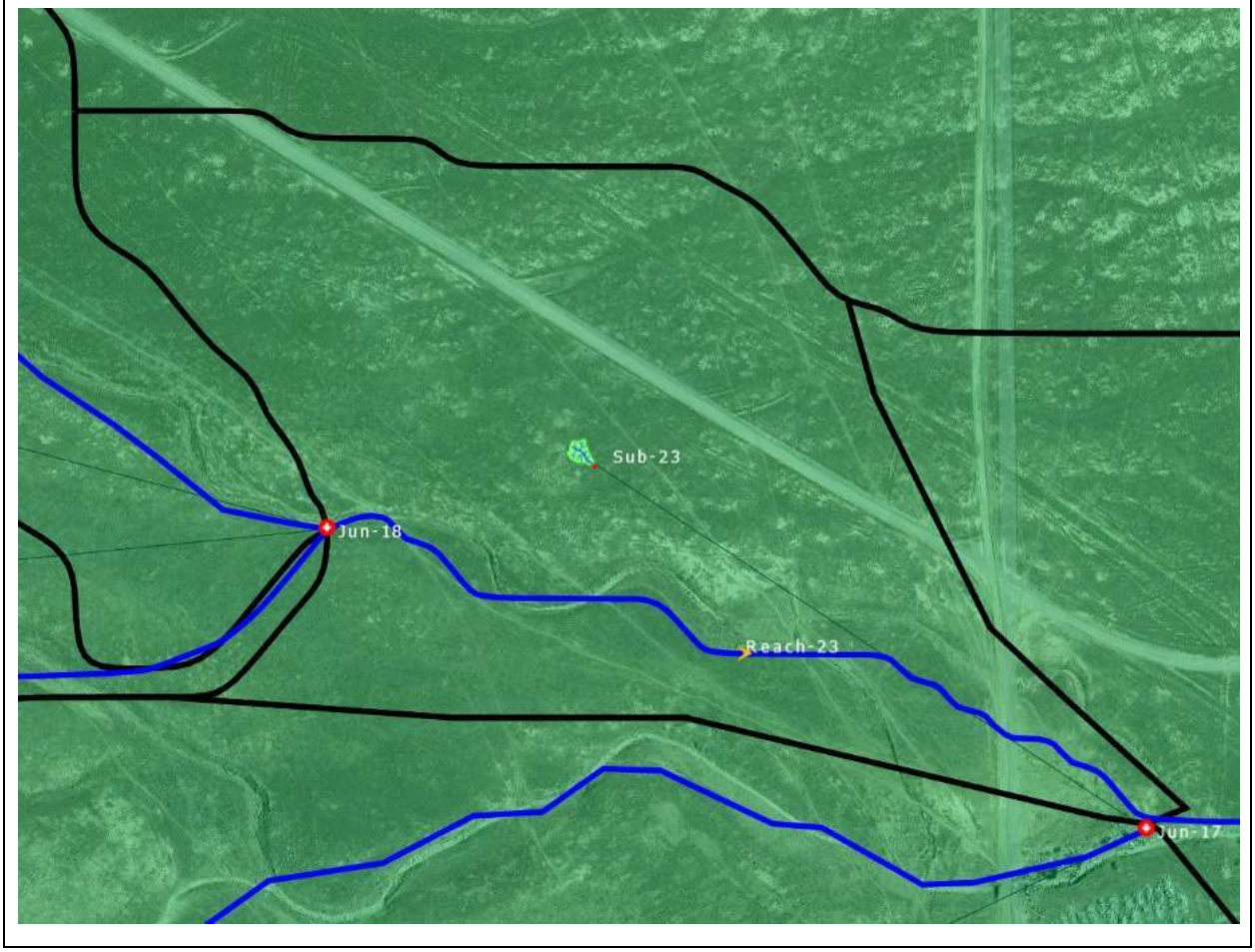
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
3.902	28.63	69.00	Developed, Open Space
9.729	71.37	58.05	Undeveloped, Grassland
13.631	**100.00**	**61.18**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
44.71	100.00	0.01429	0.4440	Sheet Flow
1.98	295.62	0.02383	5.0982	Shallow Concentrated Flow
0.56	163.06	0.09046	9.9322	Shallow Concentrated Flow
0.38	151.74	0.16695	13.4926	Shallow Concentrated Flow
0.27	66.19	0.06214	8.2320	Shallow Concentrated Flow
3.19	963.56	0.02314	5.0234	Channel Flow
51.09	**1,740.17**	**Total**	**Lag Time = 30.66 minutes**	




Sub-23
Jun-18
Reach-23
Jun-17

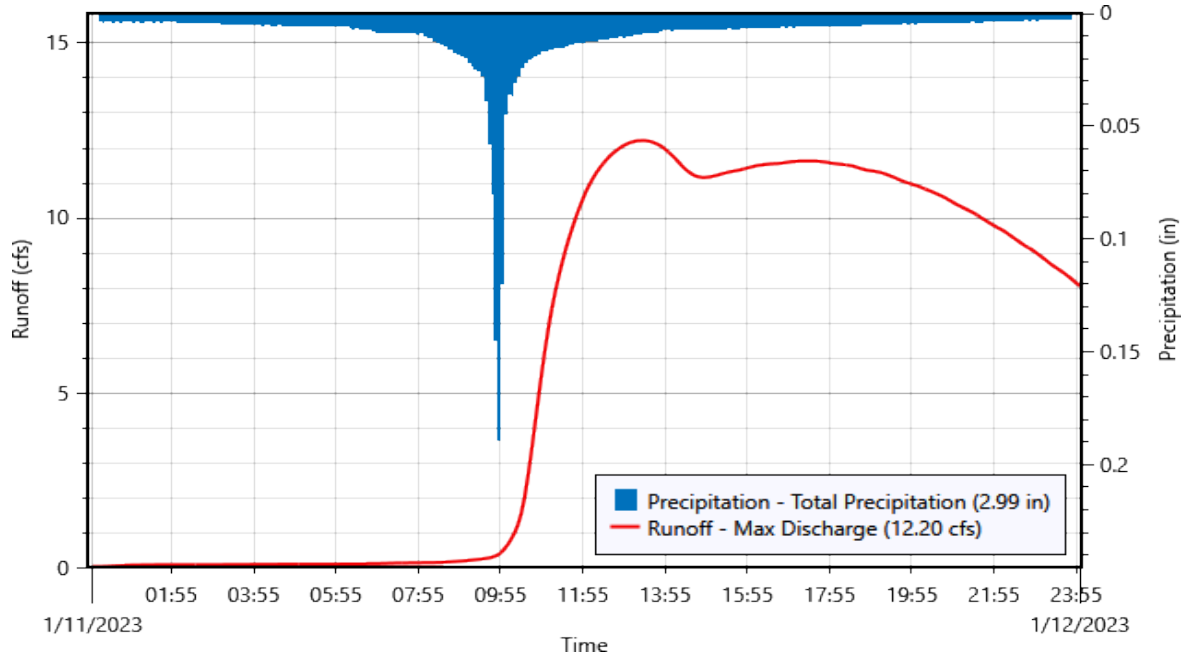
Subbasin ID:	Sub-24			
Scenario:	Existing Conditions 100yr		Depth	Volume
Peak discharge:	12.20 cfs	**Time of peak:**	11 Jan 2023, 01:20	
Drainage area:	662.076 acres	**Total rainfall:**	2.99 in	164.96826 ac-ft
Initial abstraction:	1.57 in	**Losses:**	2.77 in	152.70970 ac-ft
Curve Number:	56.09	**Precip excess:**	0.22 in	12.25856 ac-ft
Impervious surface:	0.15%	**Direct runoff:**	0.21 in	11.81 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	31.77 minutes	**Total runoff:**	0.21 in	11.81 ac-ft

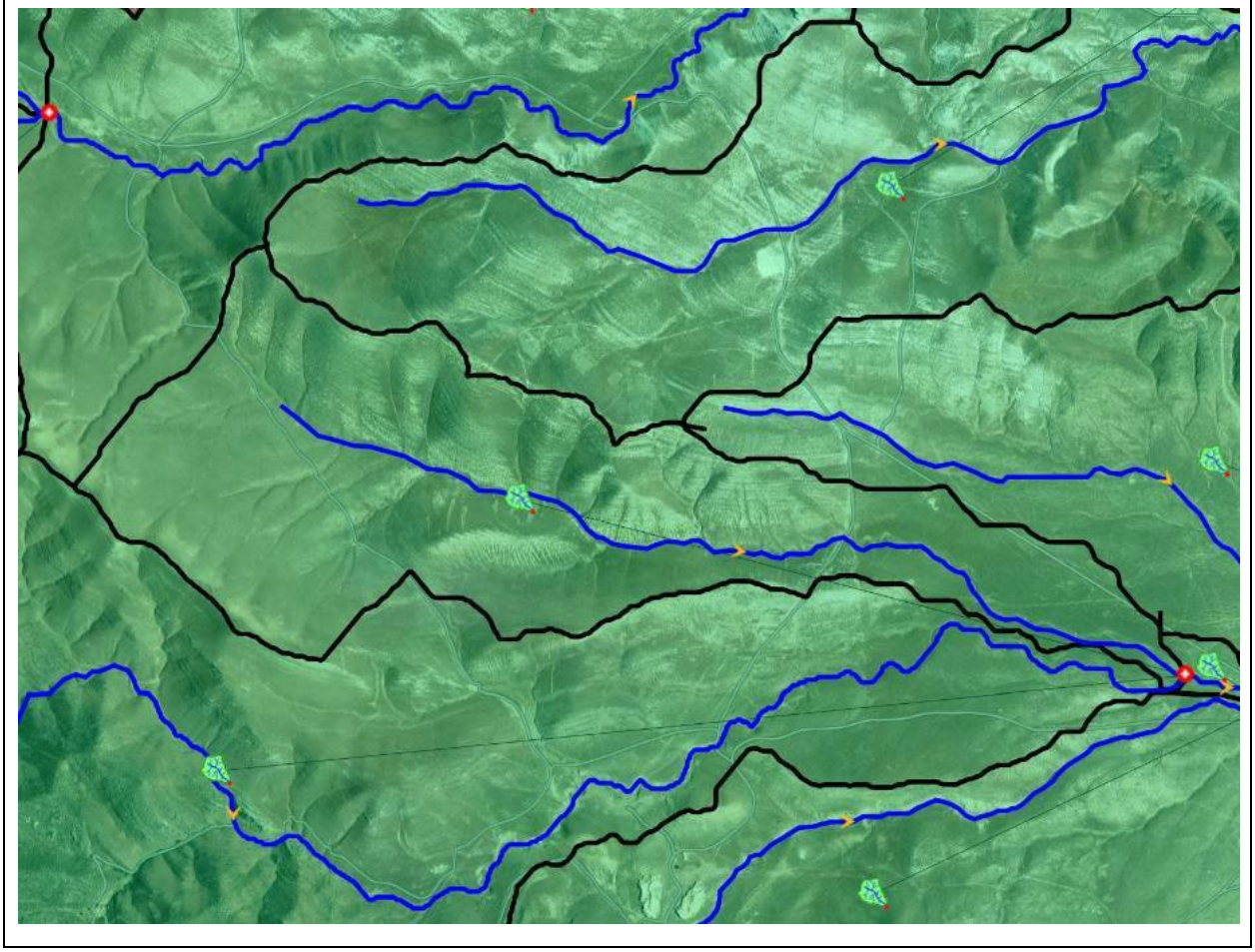
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
0.098	0.01	30.00	Undeveloped, Shrub/Scrub
37.733	5.70	67.01	Developed, Open Space
624.245	94.29	55.43	Undeveloped, Grassland
662.076	**100.00**	**56.09**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
14.40	100.00	0.24257	1.8297	Sheet Flow
1.26	869.08	0.51033	23.5902	Shallow Concentrated Flow
1.44	665.78	0.22832	15.7788	Shallow Concentrated Flow
3.67	1,184.85	0.11132	11.0178	Shallow Concentrated Flow
18.74	7,536.85	0.04100	6.6863	Channel Flow
13.43	4,799.21	0.03234	5.9389	Channel Flow
52.94	**15,155.77**	**Total**	**Lag Time = 31.77 minutes**	





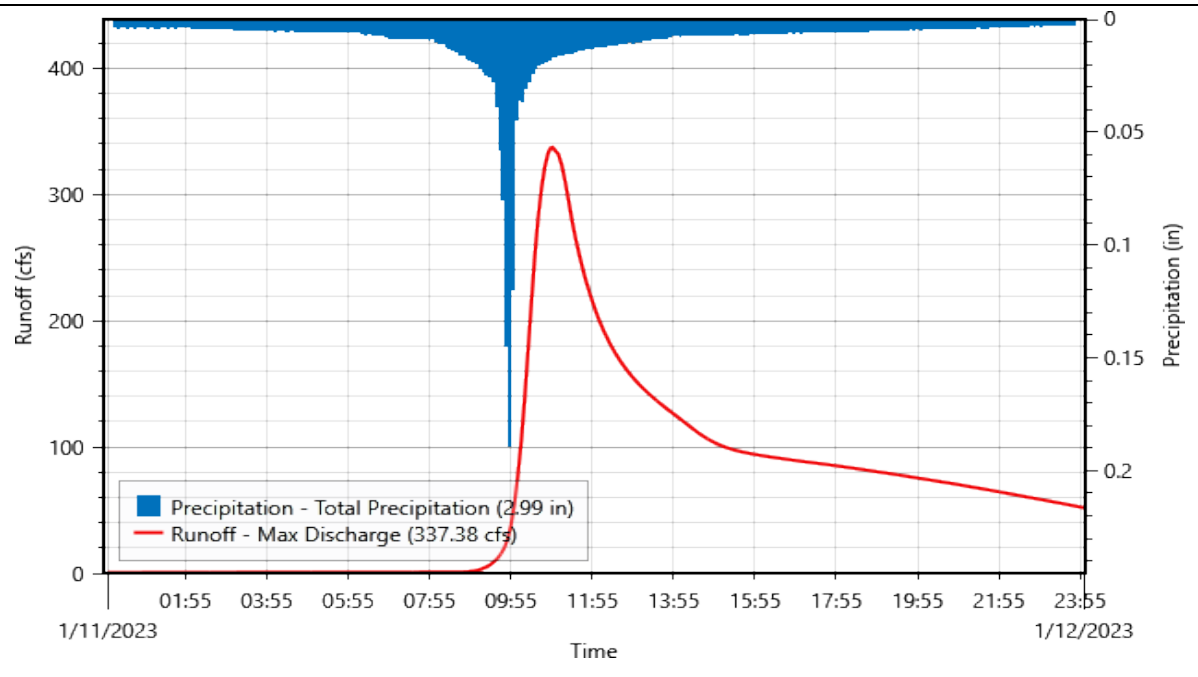
Subbasin ID:	Sub-25			
Scenario:	Existing Conditions 100yr		Depth	Volume
Peak discharge:	337.38 cfs	**Time of peak:**	11 Jan 2023, 10:55	
Drainage area:	1,694.320 acres	**Total rainfall:**	2.99 in	422.17204 ac-ft
Initial abstraction:	0.65 in	**Losses:**	2.01 in	283.42430 ac-ft
Curve Number:	75.41	**Precip excess:**	0.98 in	138.74773 ac-ft
Impervious surface:	0.25%	**Direct runoff:**	0.95 in	134.03 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	53.90 minutes	**Total runoff:**	0.95 in	134.03 ac-ft

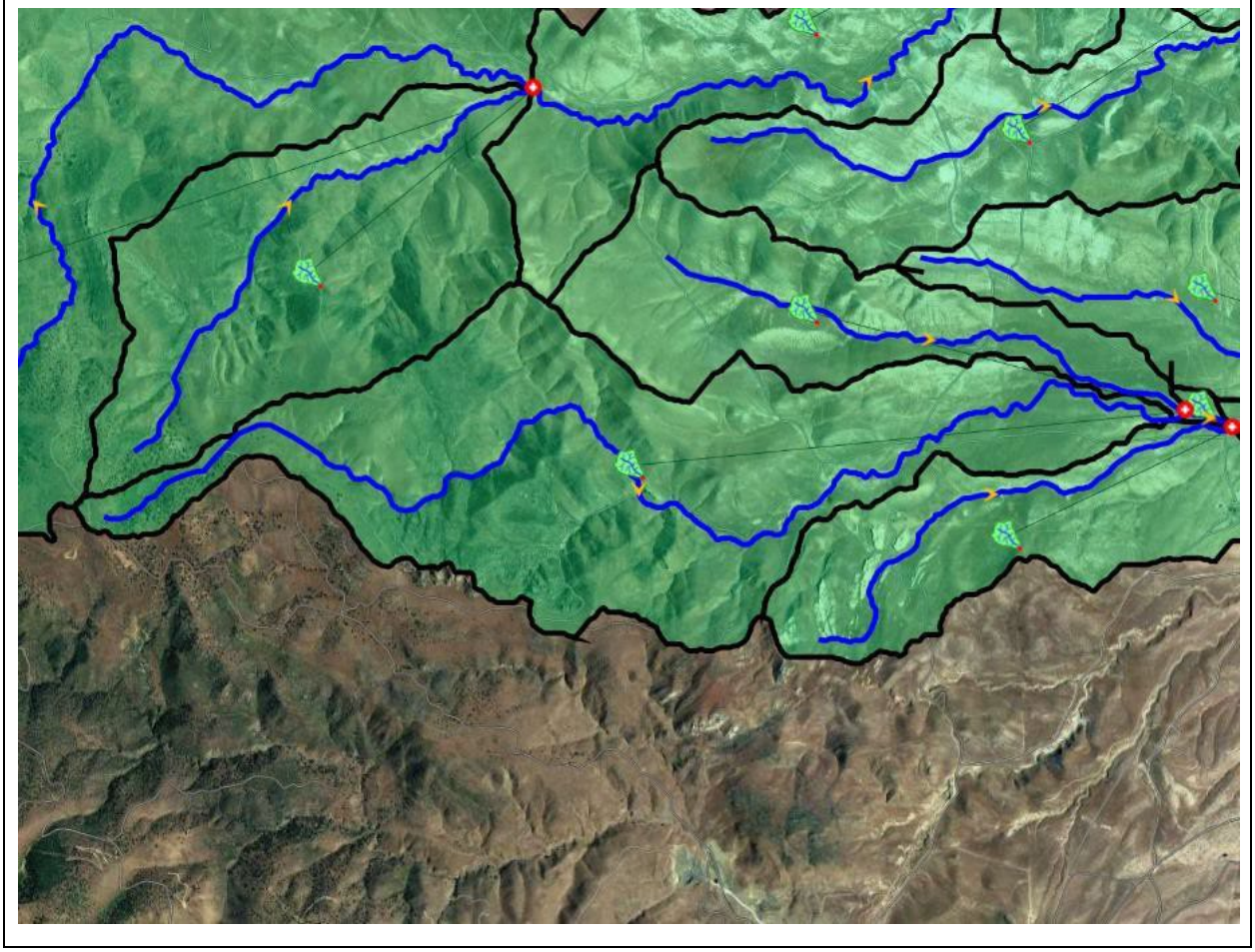
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
0.589	0.03	91.09	Developed, Medium Density
343.072	20.25	72.37	Undeveloped, Shrub/Scrub
1.038	0.06	86.45	Developed, Low Density
128.369	7.58	82.02	Developed, Open Space
1,221.252	72.08	75.55	Undeveloped, Grassland
1,694.320	**100.00**	**75.41**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
23.14	100.00	0.07413	1.0115	Sheet Flow
2.26	773.43	0.12489	11.6701	Shallow Concentrated Flow
2.16	1,933.44	0.20208	14.8446	Channel Flow
10.49	5,320.75	0.06516	8.4296	Channel Flow
3.64	2,816.87	0.15175	12.8636	Channel Flow
20.32	9,127.19	0.05113	7.4670	Channel Flow
27.81	10,228.78	0.03427	6.1135	Channel Flow
89.82	**30,300.46**	**Total**	**Lag Time = 53.90 minutes**	





Nodes

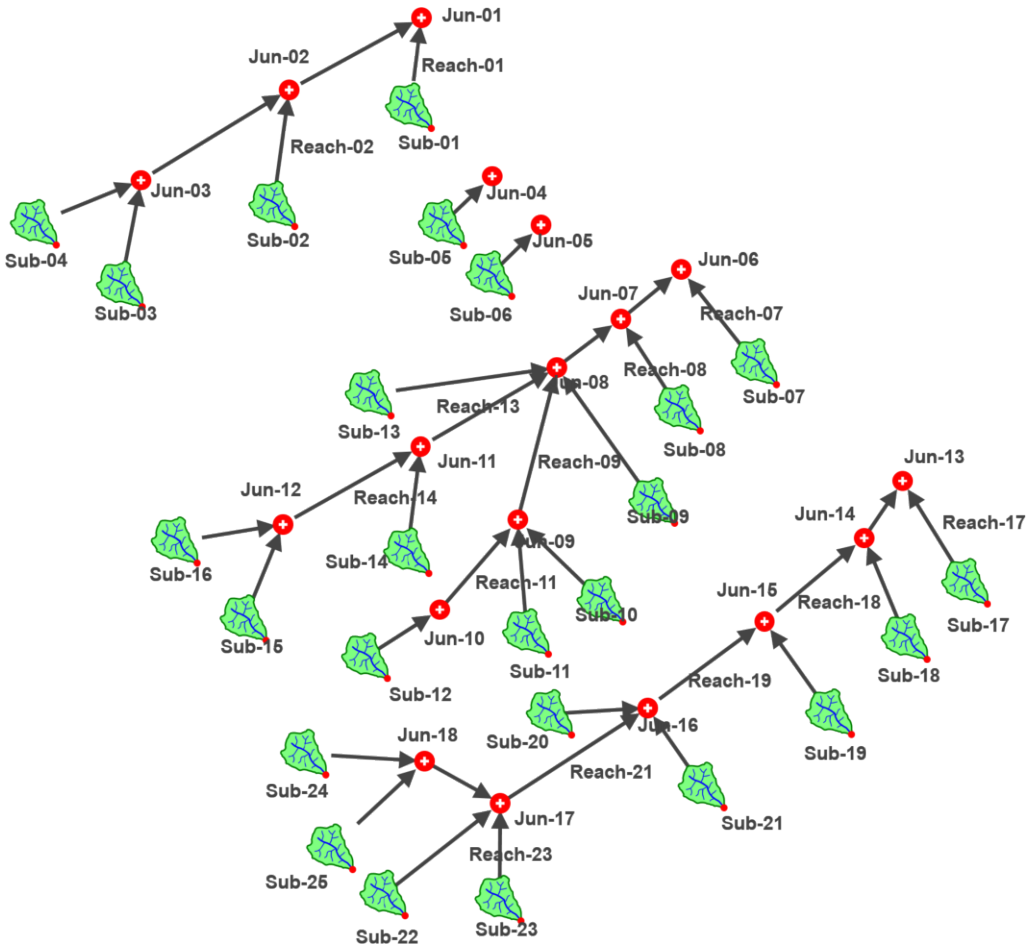
Element ID	Element Type	Peak Inflow (cfs)	Peak Outflow (cfs)	Peak Diverted Flow (cfs)
Jun-01	Junction	253.84	253.84	
Jun-02	Junction	221.03	221.03	
Jun-03	Junction	221.43	221.43	
Jun-04	Junction	13.71	13.71	
Jun-05	Junction	19.22	19.22	
Jun-06	Junction	688.43	688.43	
Jun-07	Junction	667.66	667.66	
Jun-08	Junction	668.08	668.08	
Jun-09	Junction	12.99	12.99	
Jun-10	Junction	4.46	4.46	
Jun-11	Junction	653.18	653.18	
Jun-12	Junction	652.10	652.10	
Jun-13	Junction	522.24	522.24	
Jun-14	Junction	496.28	496.28	
Jun-15	Junction	465.69	465.69	
Jun-16	Junction	461.08	461.08	
Jun-17	Junction	442.06	442.06	
Jun-18	Junction	342.92	342.92	

Routing Reaches

Reach ID	Peak Inflow (cfs)	Peak Outflow (cfs)	Attenuated Flow (cfs)
Reach-01	221.03	208.01	13.02
Reach-02	221.43	220.83	0.60
Reach-03	0.00	0.00	0.00
Reach-04	0.00	0.00	0.00
Reach-05	0.00	0.00	0.00
Reach-06	0.00	0.00	0.00
Reach-07	667.66	667.04	0.62
Reach-08	668.08	662.55	5.53
Reach-09	12.99	12.98	0.01
Reach-10	0.00	0.00	0.00
Reach-11	4.46	3.15	1.31
Reach-12	0.00	0.00	0.00
Reach-13	653.18	652.47	0.71
Reach-14	652.10	652.04	0.06
Reach-15	0.00	0.00	0.00
Reach-16	0.00	0.00	0.00
Reach-17	496.28	495.71	0.57
Reach-18	465.69	455.51	10.18
Reach-19	461.08	459.78	1.30
Reach-20	0.00	0.00	0.00
Reach-21	442.06	440.76	1.30
Reach-22	0.00	0.00	0.00
Reach-23	342.92	342.77	0.15
Reach-24	0.00	0.00	0.00
Reach-25	0.00	0.00	0.00

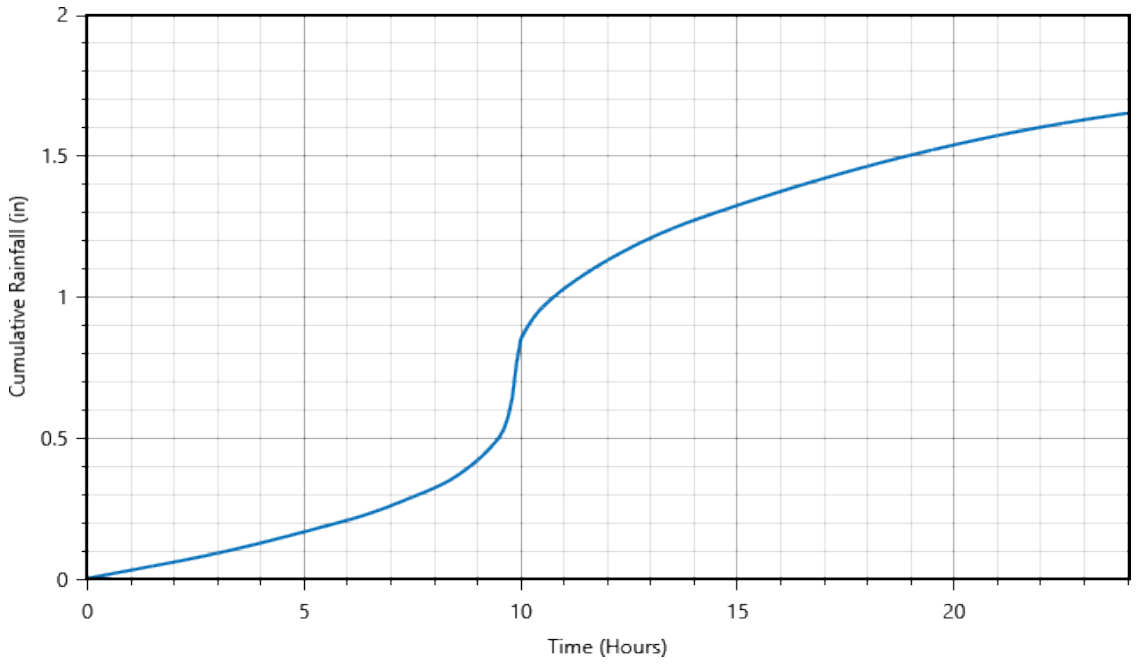
Existing Conditions 10yr

Watershed Routing Diagram



Design Storm

Precipitation type: SCS Storm
SCS storm distribution: Type I
Rainfall depth: 1.65 in



Watershed Summary

Subbasin ID	Drainage Area (acres)	Initial Abstraction (in)	Curve Number	Impervious Surface (%)	Lag Time (minutes)	Peak Discharge (cfs)
Sub-01	1,269.566	1.23	61.84	1.10	107.15	4.46
Sub-02	337.798	2.28	46.74	0.15	50.54	0.20
Sub-03	169.707	2.61	43.39	0.12	32.39	0.10
Sub-04	1,961.124	0.86	70.00	0.09	58.02	19.93
Sub-05	685.814	1.94	50.82	4.68	125.36	7.56
Sub-06	856.439	1.86	51.75	6.67	198.99	10.23
Sub-07	269.771	1.05	65.60	10.71	98.48	7.85
Sub-08	503.505	1.48	57.53	8.38	395.42	4.98
Sub-09	1,130.587	2.84	41.33	0.94	67.09	3.62
Sub-10	1,153.361	1.94	50.79	1.30	55.92	5.66
Sub-11	161.318	4.26	31.97	1.51	40.10	1.11
Sub-12	952.517	3.33	37.51	0.52	34.22	2.46
Sub-13	1,426.690	3.40	37.06	2.54	649.32	3.12
Sub-14	1,158.859	2.01	49.91	0.23	43.12	1.17
Sub-15	1,054.808	0.70	74.04	0.23	30.66	23.28
Sub-16	3,426.802	0.76	72.40	0.26	59.76	51.16
Sub-17	337.184	0.97	67.43	10.46	80.39	10.83
Sub-18	1,474.591	1.47	57.69	3.55	96.69	14.37
Sub-19	787.670	2.86	41.19	1.53	66.54	4.12
Sub-20	714.148	2.82	41.47	0.54	30.83	2.02
Sub-21	140.608	0.83	70.73	0.65	37.22	1.69
Sub-22	624.791	0.70	74.21	0.15	26.62	14.26
Sub-23	13.631	1.27	61.18	1.28	30.66	0.09
Sub-24	662.076	1.57	56.09	0.15	31.77	0.51
Sub-25	1,694.320	0.65	75.41	0.25	53.90	43.47

Subbasins

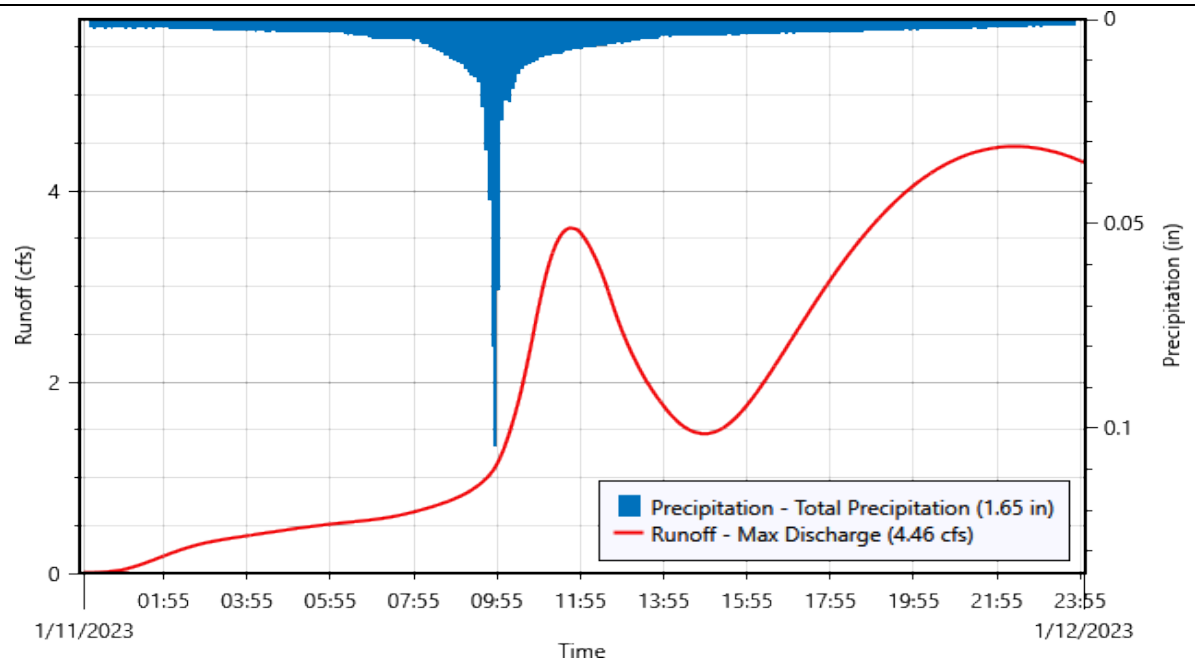
Subbasin ID:	Sub-01			
Scenario:	**Existing Conditions 10yr**		**Depth**	**Volume**
Peak discharge:	4.46 cfs	**Time of peak:**	11 Jan 2023, 10:20	
Drainage area:	1,269.566 acres	**Total rainfall:**	1.65 in	174.56559 ac-ft
Initial abstraction:	1.23 in	**Losses:**	1.61 in	169.84488 ac-ft
Curve Number:	61.84	**Precip excess:**	0.04 in	4.72071 ac-ft
Impervious surface:	1.10%	**Direct runoff:**	0.04 in	3.94 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	107.15 minutes	**Total runoff:**	0.04 in	3.94 ac-ft

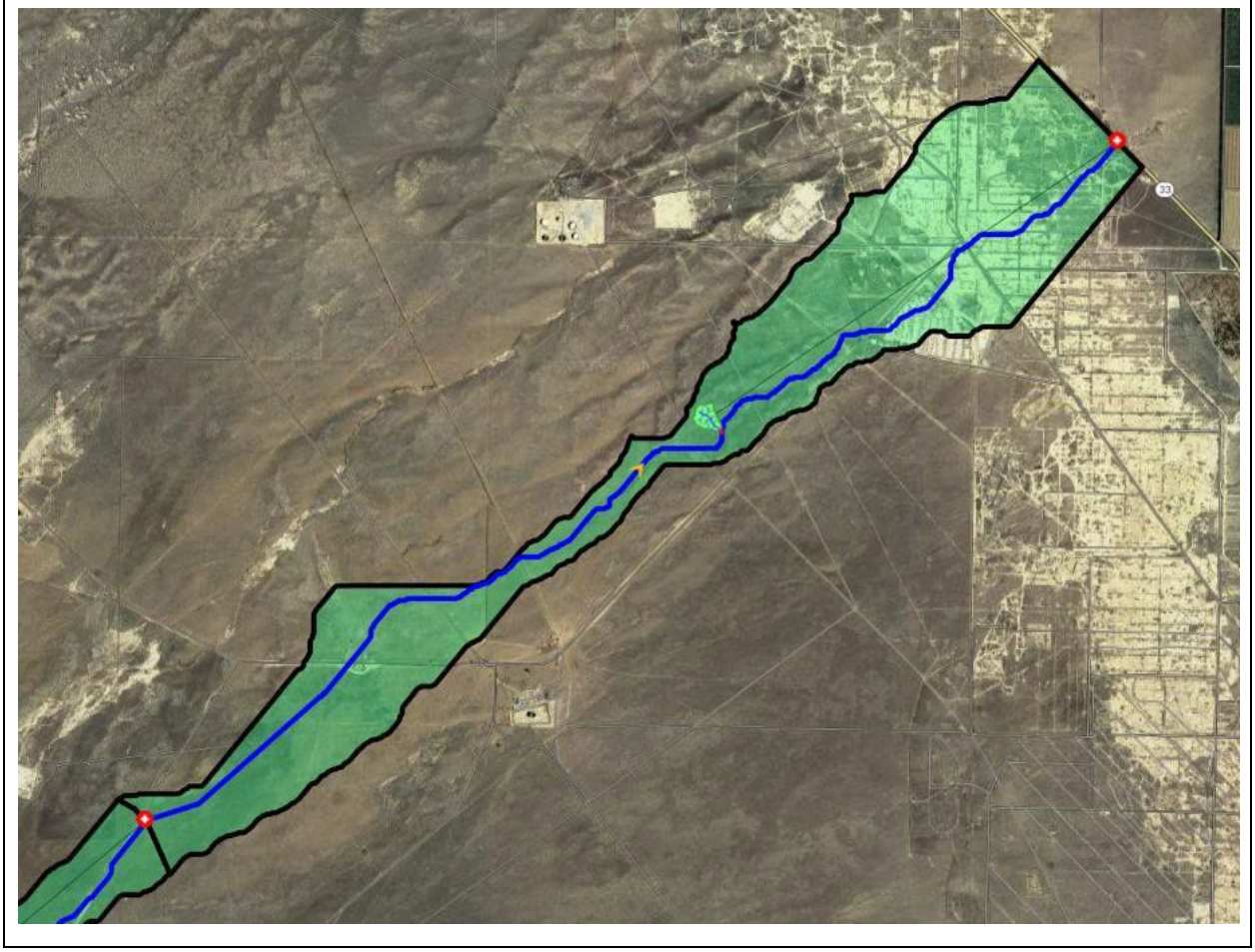
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
2.200	0.17	77.00	Developed, Medium Density
72.954	5.75	73.69	Agricultural, Cultivated Crops
12.818	1.01	73.61	Developed, Low Density
248.559	19.58	68.81	Developed, Open Space
2.419	0.19	77.00	Undeveloped, Barren Land
930.614	73.30	58.81	Undeveloped, Grassland
1,269.566	**100.00**	**61.84**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
45.65	99.01	0.01330	0.4284	Sheet Flow
13.66	1,732.24	0.01717	4.3269	Shallow Concentrated Flow
119.26	26,180.93	0.01221	3.6493	Channel Flow
178.57	**28,012.18**	**Total**	**Lag Time = 107.15 minutes**	





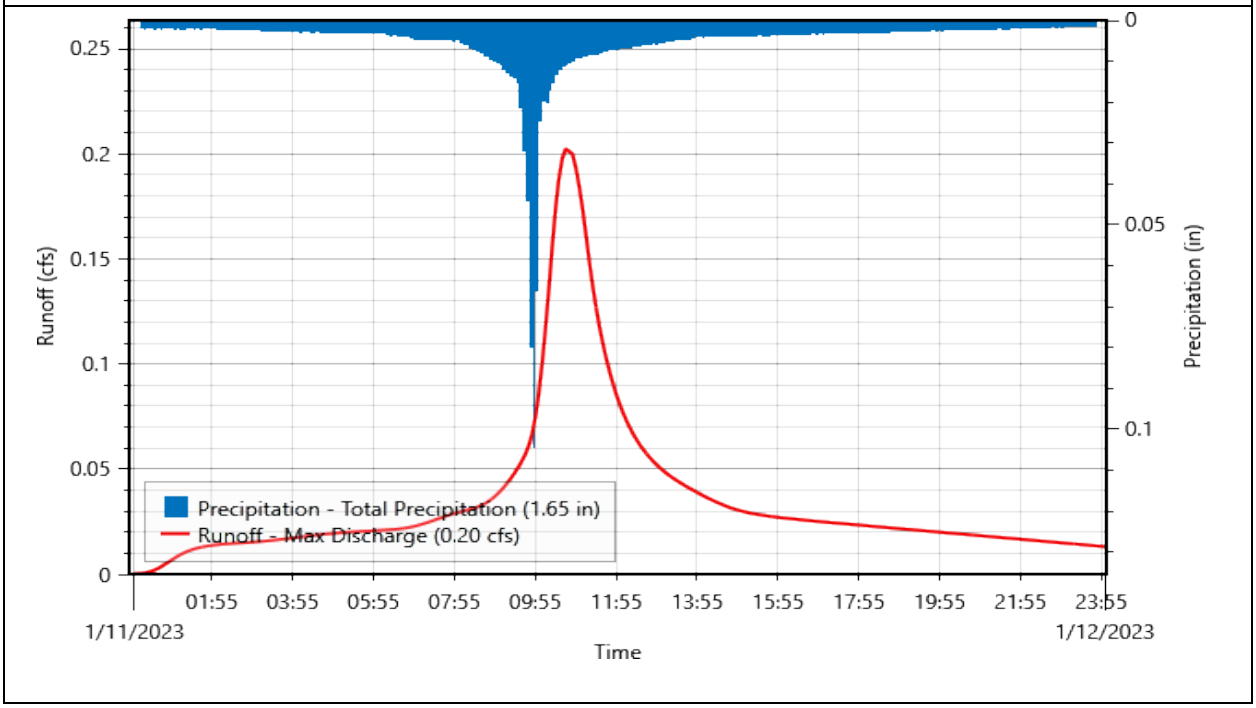
Subbasin ID:	Sub-02			
Scenario:	**Existing Conditions 10yr**		**Depth**	**Volume**
Peak discharge:	0.20 cfs	**Time of peak:**	11 Jan 2023, 10:45	
Drainage area:	337.798 acres	**Total rainfall:**	1.65 in	46.44640 ac-ft
Initial abstraction:	2.28 in	**Losses:**	1.65 in	46.37673 ac-ft
Curve Number:	46.74	**Precip excess:**	0.00 in	0.06967 ac-ft
Impervious surface:	0.15%	**Direct runoff:**	0.00 in	0.07 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	50.54 minutes	**Total runoff:**	0.00 in	0.07 ac-ft

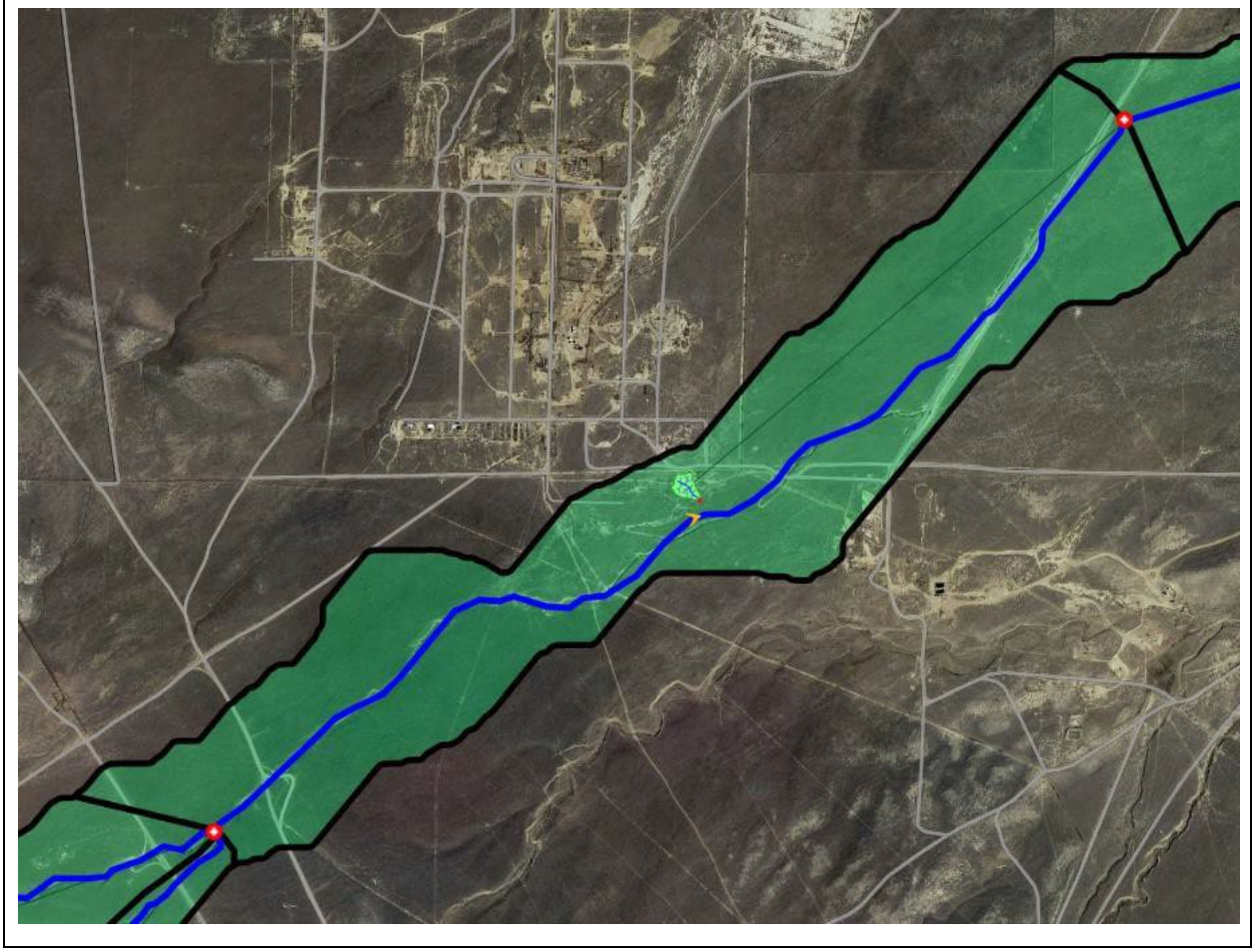
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
29.531	8.74	54.73	Developed, Open Space
308.267	91.26	45.97	Undeveloped, Grassland
337.798	**100.00**	**46.74**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
30.41	100.00	0.03745	0.7190	Sheet Flow
14.64	1,422.09	0.02620	5.3456	Shallow Concentrated Flow
39.18	10,516.23	0.01825	4.4614	Channel Flow
84.23	**12,038.32**	**Total**	**Lag Time = 50.54 minutes**	





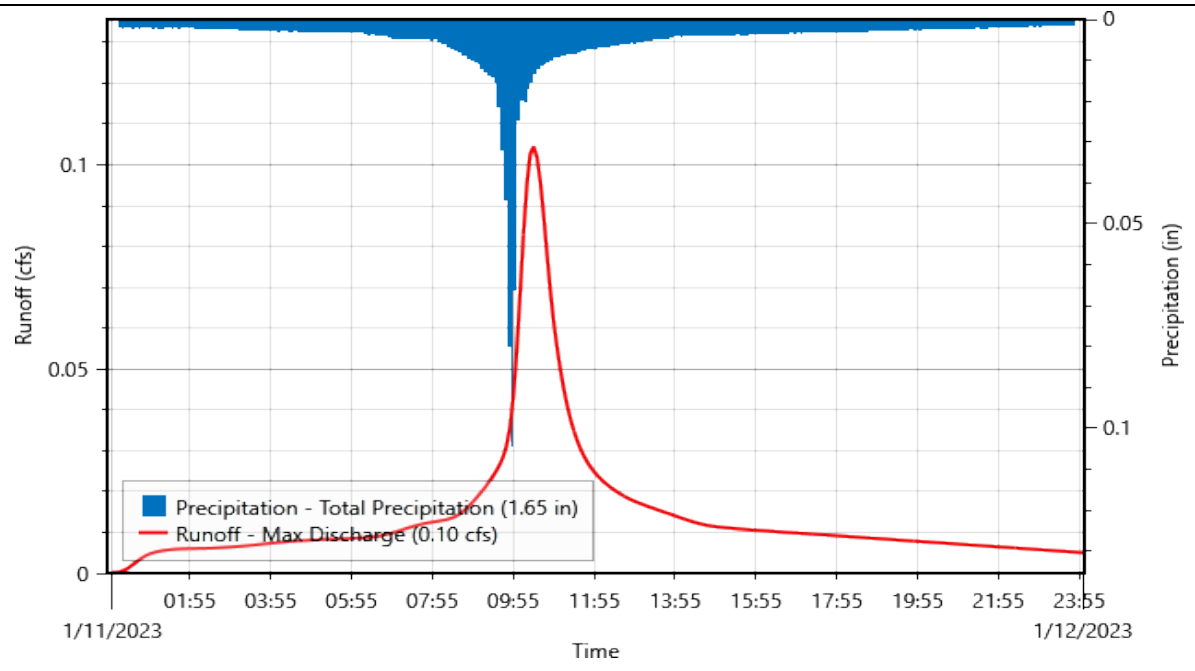
Subbasin ID:	Sub-03			
Scenario:	**Existing Conditions 10yr**		**Depth**	**Volume**
Peak discharge:	0.10 cfs	**Time of peak:**	11 Jan 2023, 10:25	
Drainage area:	169.707 acres	**Total rainfall:**	1.65 in	23.33760 ac-ft
Initial abstraction:	2.61 in	**Losses:**	1.65 in	23.30959 ac-ft
Curve Number:	43.39	**Precip excess:**	0.00 in	0.02801 ac-ft
Impervious surface:	0.12%	**Direct runoff:**	0.00 in	0.03 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	32.39 minutes	**Total runoff:**	0.00 in	0.03 ac-ft

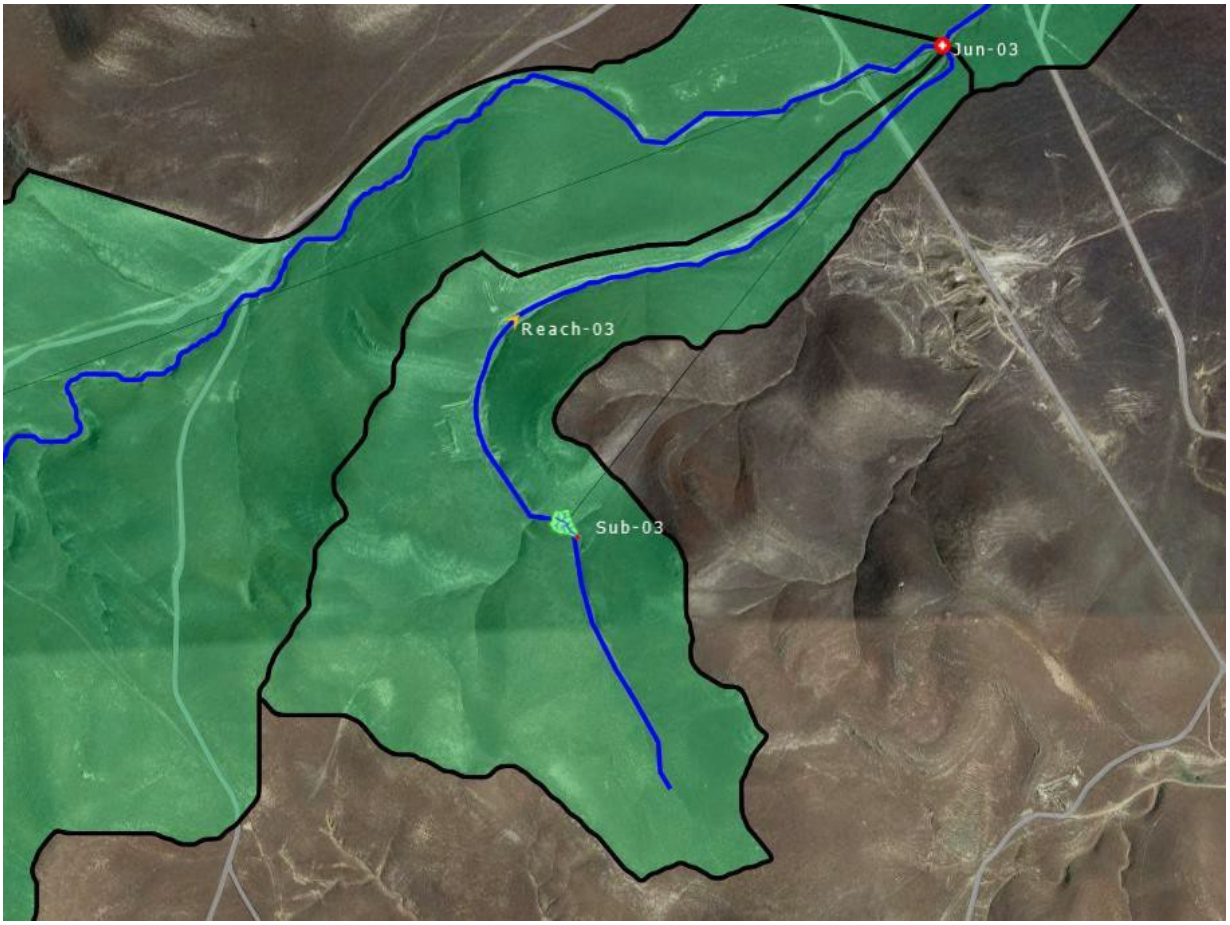
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
1.174	0.69	79.00	Developed, Open Space
168.533	99.31	43.14	Undeveloped, Grassland
169.707	**100.00**	**43.39**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
33.11	110.46	0.03693	0.7140	Sheet Flow
3.55	740.31	0.12053	11.4645	Shallow Concentrated Flow
17.32	6,423.63	0.03486	6.1655	Channel Flow
53.98	**7,274.40**	**Total**	**Lag Time = 32.39 minutes**	




Jun-03
Reach-03
Sub-03

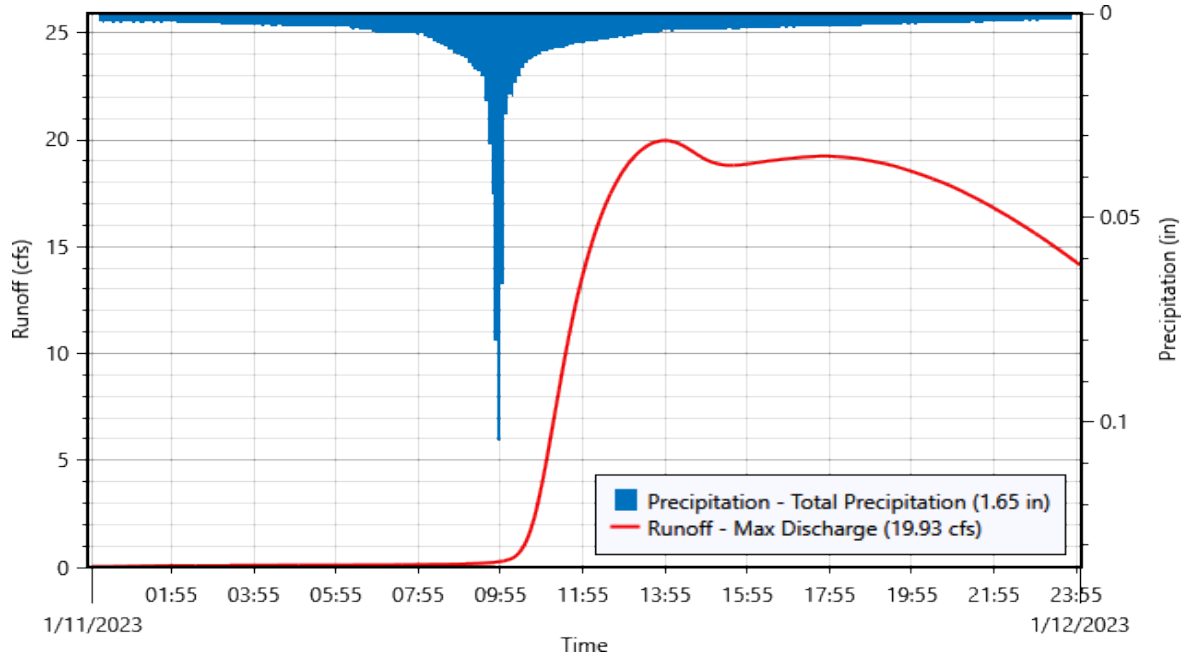
Subbasin ID:	Sub-04			
Scenario:	Existing Conditions 10yr		Depth	Volume
Peak discharge:	19.93 cfs	**Time of peak:**	11 Jan 2023, 01:55	
Drainage area:	1,961.124 acres	**Total rainfall:**	1.65 in	269.65839 ac-ft
Initial abstraction:	0.86 in	**Losses:**	1.53 in	249.33883 ac-ft
Curve Number:	70.00	**Precip excess:**	0.12 in	20.31956 ac-ft
Impervious surface:	0.09%	**Direct runoff:**	0.12 in	18.92 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	58.02 minutes	**Total runoff:**	0.12 in	18.92 ac-ft

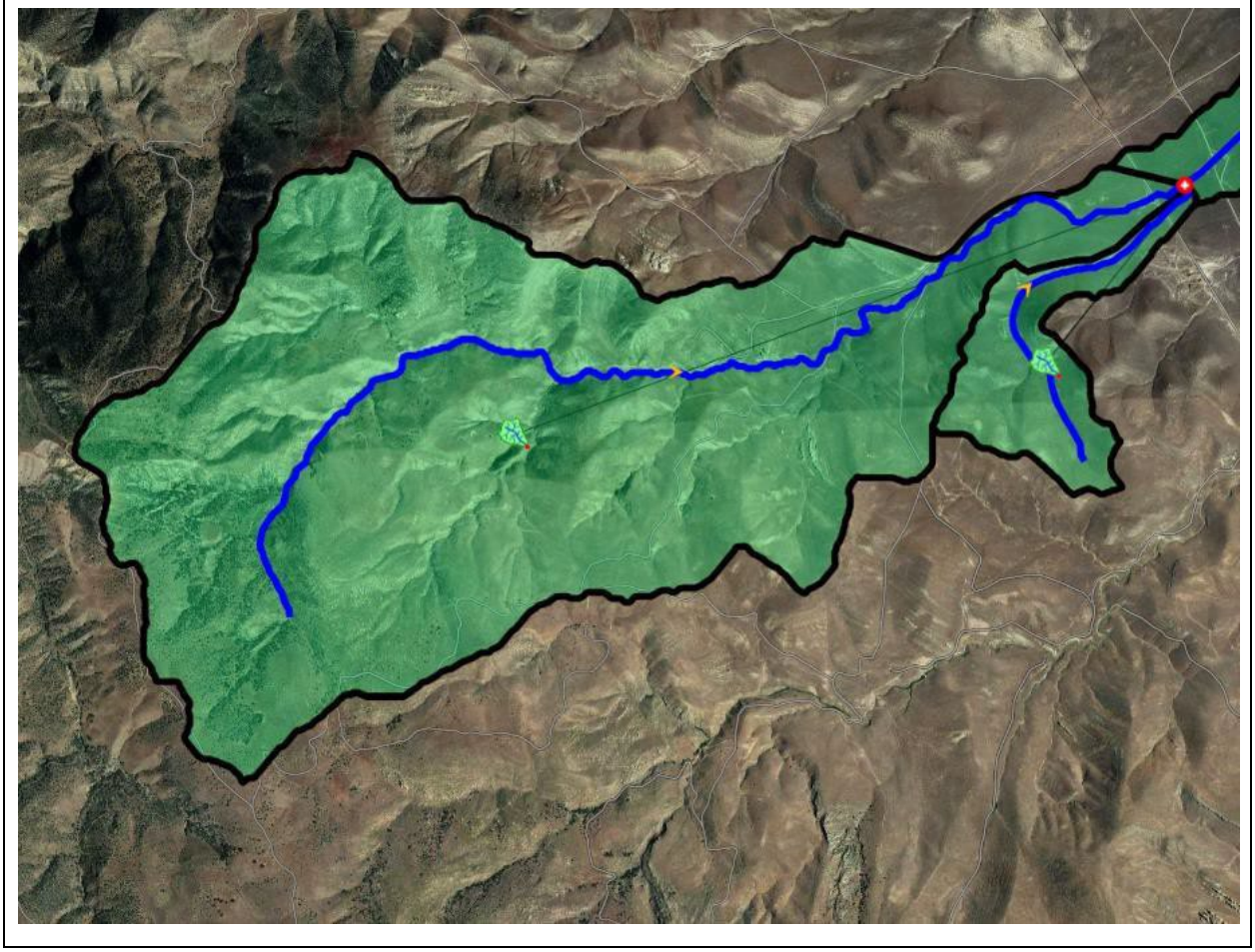
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
0.431	0.02	91.30	Developed, Medium Density
150.381	7.67	71.94	Undeveloped, Shrub/Scrub
0.305	0.02	74.40	Developed, Low Density
75.153	3.83	71.78	Developed, Open Space
1.186	0.06	88.55	Undeveloped, Barren Land
1,733.667	88.40	69.74	Undeveloped, Grassland
1,961.124	**100.00**	**70.00**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
30.90	112.95	0.04590	0.7959	Sheet Flow
13.24	3,235.61	0.16593	13.4514	Shallow Concentrated Flow
5.71	4,473.99	0.15548	13.0208	Channel Flow
46.85	15,930.03	0.02929	5.6514	Channel Flow
96.70	**23,752.58**	**Total**	**Lag Time = 58.02 minutes**	





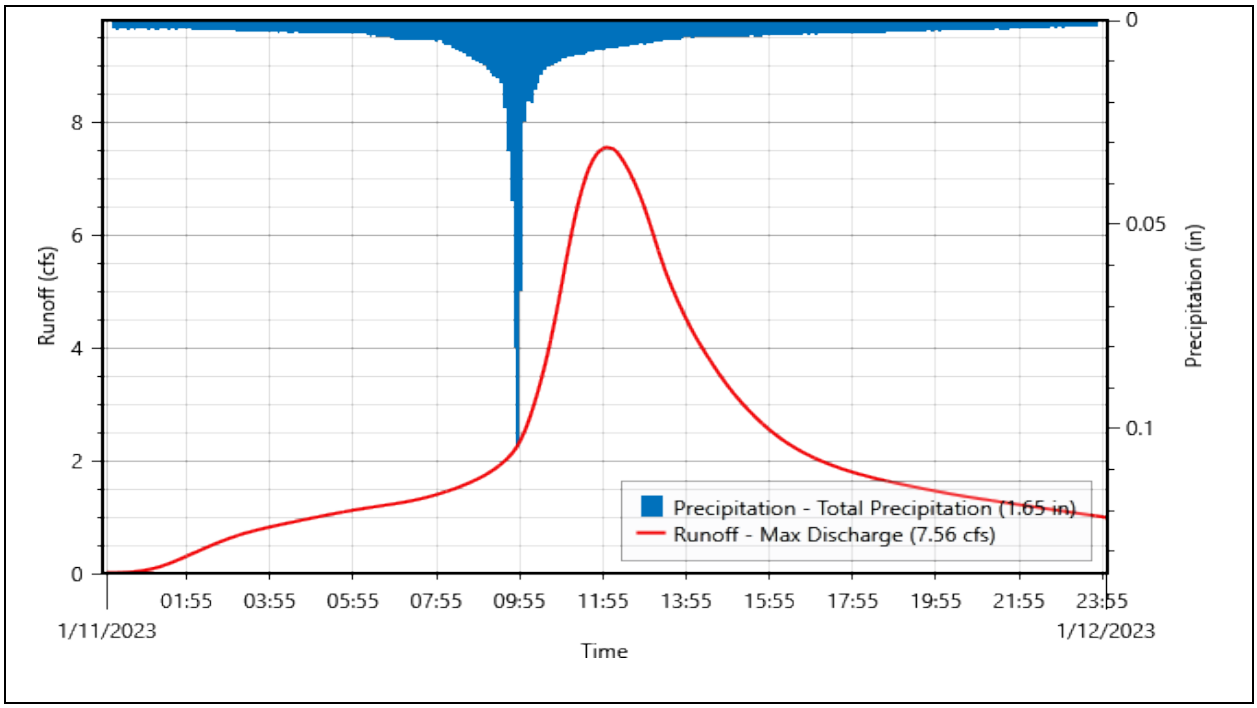
Subbasin ID:	Sub-05			
Scenario:	Existing Conditions 10yr		Depth	Volume
Peak discharge:	7.56 cfs	**Time of peak:**	11 Jan 2023, 12:05	
Drainage area:	685.814 acres	**Total rainfall:**	1.65 in	94.30080 ac-ft
Initial abstraction:	1.94 in	**Losses:**	1.57 in	89.88752 ac-ft
Curve Number:	50.82	**Precip excess:**	0.08 in	4.41328 ac-ft
Impervious surface:	4.68%	**Direct runoff:**	0.07 in	4.22 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	125.36 minutes	**Total runoff:**	0.07 in	4.22 ac-ft

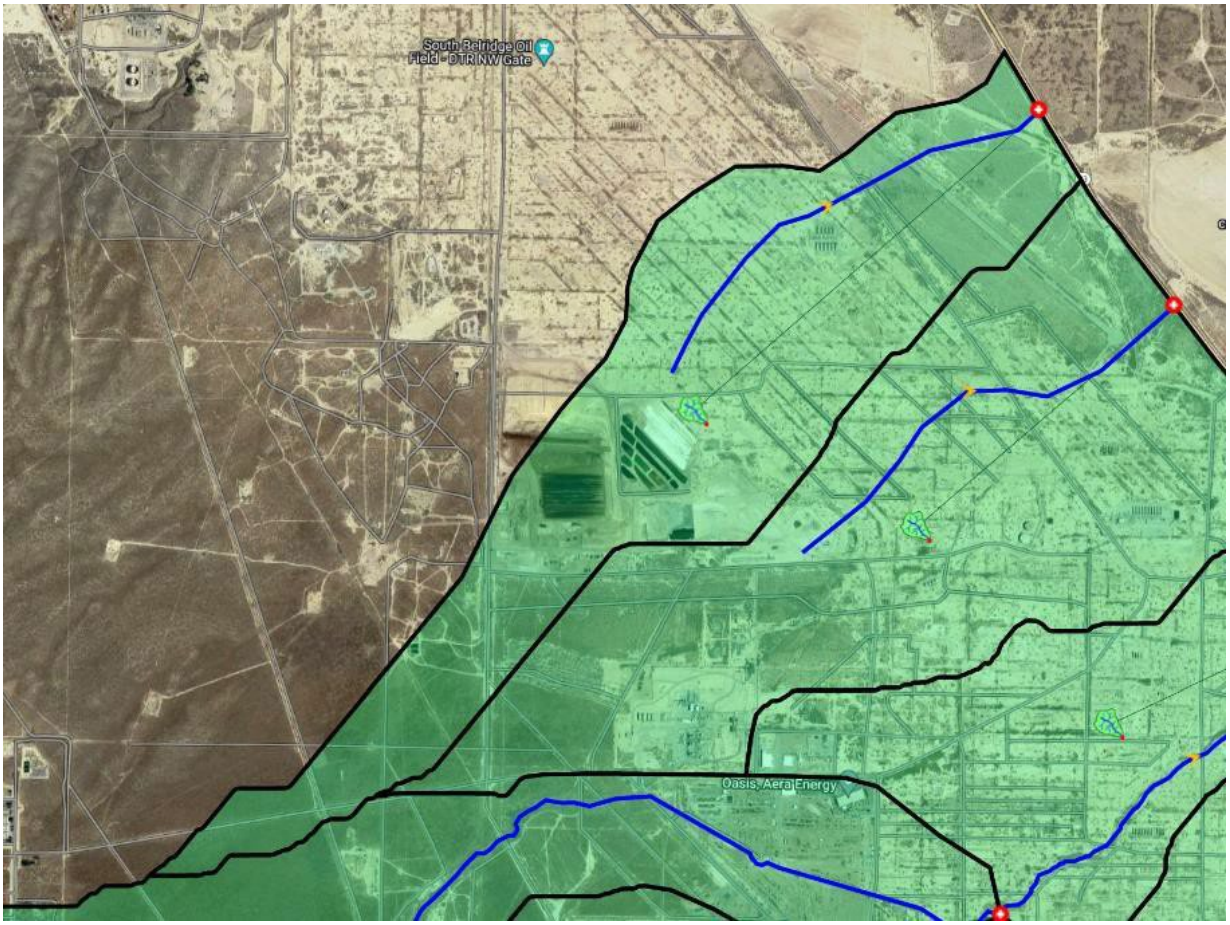
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
68.817	10.03	67.00	Agricultural, Cultivated Crops
17.830	2.60	77.74	Developed, Medium Density
42.537	6.20	78.26	Undeveloped, Barren Land
32.828	4.79	63.81	Developed, Low Density
201.828	29.43	57.17	Developed, Open Space
3.731	0.54	30.00	Undeveloped, Shrub/Scrub
0.288	0.04	100.00	Open Water
11.792	1.72	89.57	Developed, High Density
306.163	44.64	34.93	Undeveloped, Grassland
685.814	**100.00**	**50.82**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
51.04	100.00	0.01026	0.3762	Sheet Flow
84.98	9,730.86	0.01400	3.9073	Shallow Concentrated Flow
10.33	2,732.44	0.01773	4.3971	Channel Flow
62.57	3,381.56	0.00074	0.8982	Channel Flow
208.92	**15,944.86**	**Total**	**Lag Time = 125.36 minutes**	


Runoff (cfs)
Precipitation (in)
Time
1/11/2023
1/12/2023
01:55
03:55
05:55
07:55
09:55
11:55
13:55
15:55
17:55
19:55
21:55
23:55
0
2
4
6
8
0
0.05
0.1
Precipitation - Total Precipitation (1.65 in)
Runoff - Max Discharge (7.56 cfs)


South Belridge Oil Field - DTR NW Gate
Oasis, Aera Energy

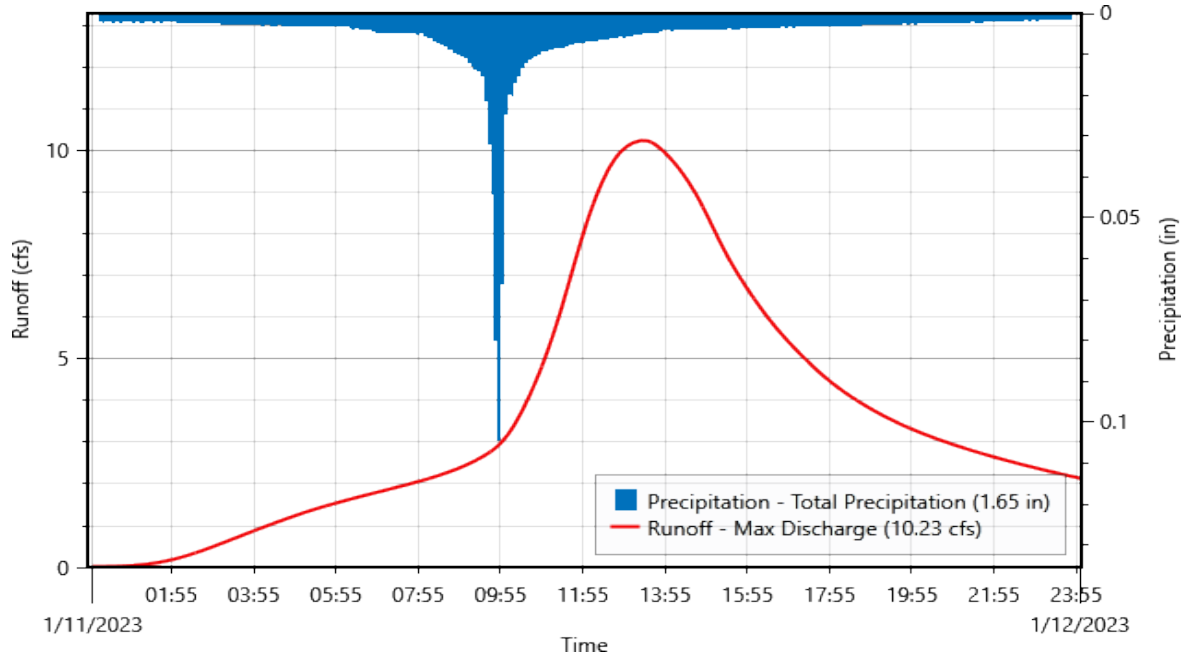
Subbasin ID:	Sub-06			
Scenario:	**Existing Conditions 10yr**		**Depth**	**Volume**
Peak discharge:	10.23 cfs	**Time of peak:**	11 Jan 2023, 01:25	
Drainage area:	856.439 acres	**Total rainfall:**	1.65 in	117.76160 ac-ft
Initial abstraction:	1.86 in	**Losses:**	1.54 in	109.90690 ac-ft
Curve Number:	51.75	**Precip excess:**	0.11 in	7.85470 ac-ft
Impervious surface:	6.67%	**Direct runoff:**	0.10 in	7.22 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	198.99 minutes	**Total runoff:**	0.10 in	7.22 ac-ft

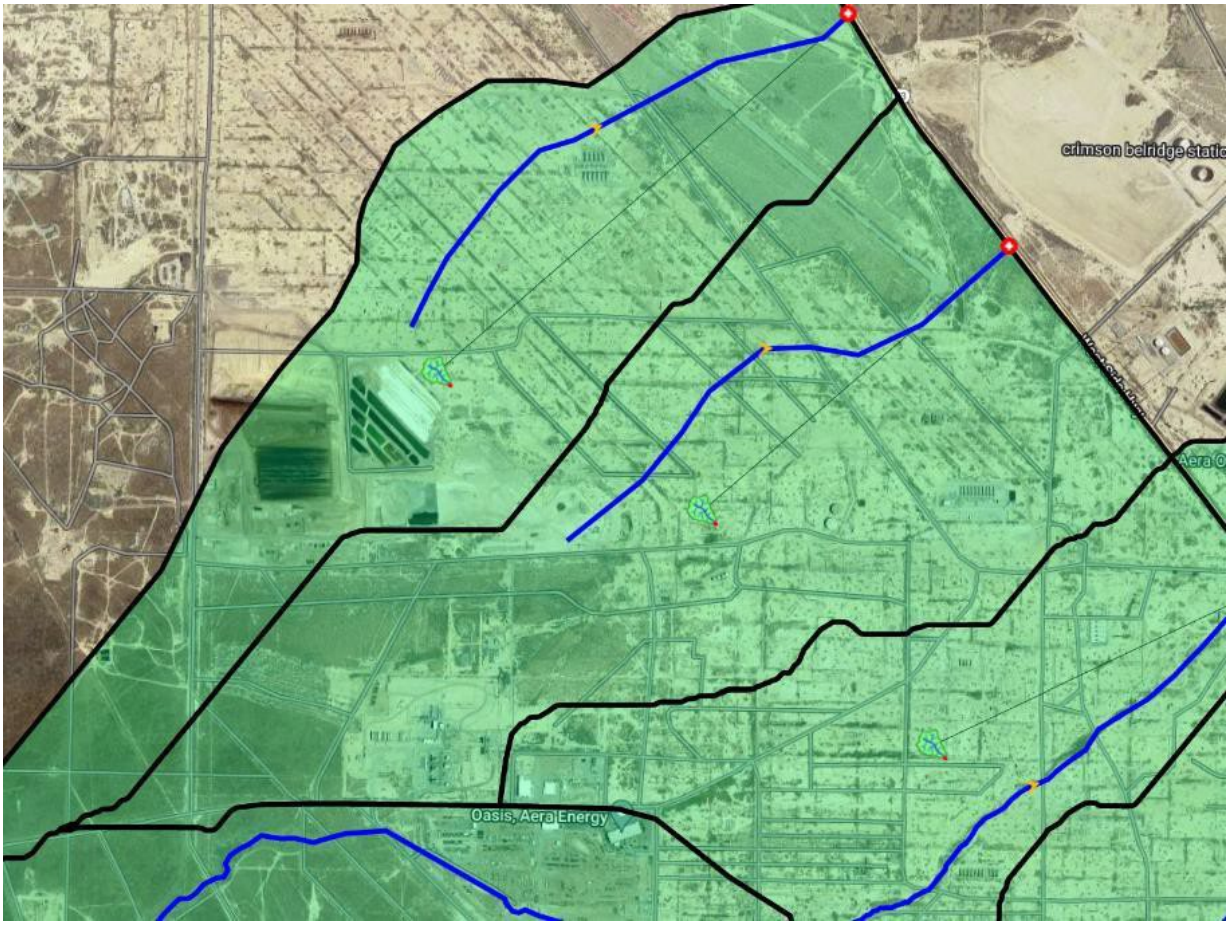
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
18.520	2.16	78.52	Developed, Medium Density
40.292	4.70	67.00	Agricultural, Cultivated Crops
0.191	0.02	30.00	Undeveloped, Shrub/Scrub
68.504	8.00	66.60	Developed, Low Density
7.679	0.90	89.48	Developed, High Density
305.373	35.66	61.82	Developed, Open Space
32.256	3.77	78.97	Undeveloped, Barren Land
383.625	44.79	35.15	Undeveloped, Grassland
856.439	**100.00**	**51.75**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
42.34	100.00	0.01637	0.4753	Sheet Flow
56.02	6,131.50	0.01279	3.7342	Shallow Concentrated Flow
2.24	757.49	0.12183	11.5262	Shallow Concentrated Flow
231.04	6,158.14	0.00018	0.4458	Channel Flow
331.64	**13,147.13**	**Total**	**Lag Time = 198.99 minutes**	




Oasis, Aera Energy

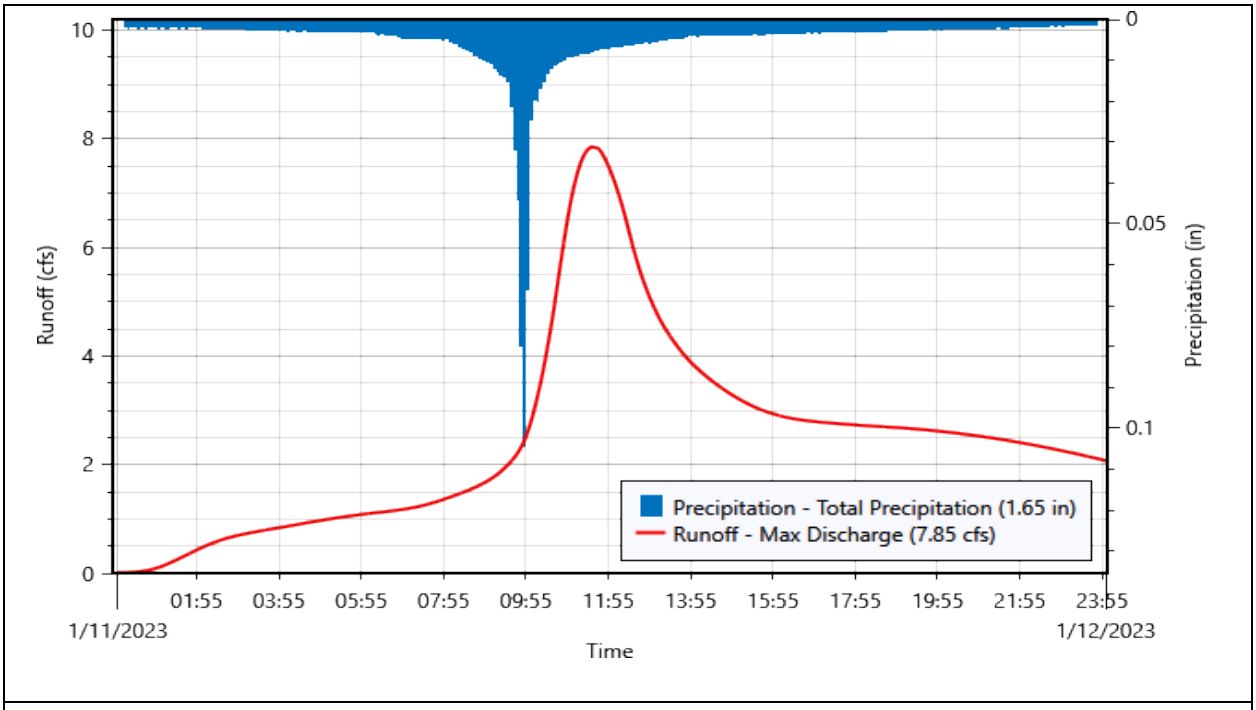
Subbasin ID:	Sub-07			
Scenario:	Existing Conditions 10yr		Depth	Volume
Peak discharge:	7.85 cfs	**Time of peak:**	11 Jan 2023, 11:35	
Drainage area:	269.771 acres	**Total rainfall:**	1.65 in	37.09200 ac-ft
Initial abstraction:	1.05 in	**Losses:**	1.42 in	31.88293 ac-ft
Curve Number:	65.60	**Precip excess:**	0.23 in	5.20907 ac-ft
Impervious surface:	10.71%	**Direct runoff:**	0.22 in	4.87 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	98.48 minutes	**Total runoff:**	0.22 in	4.87 ac-ft

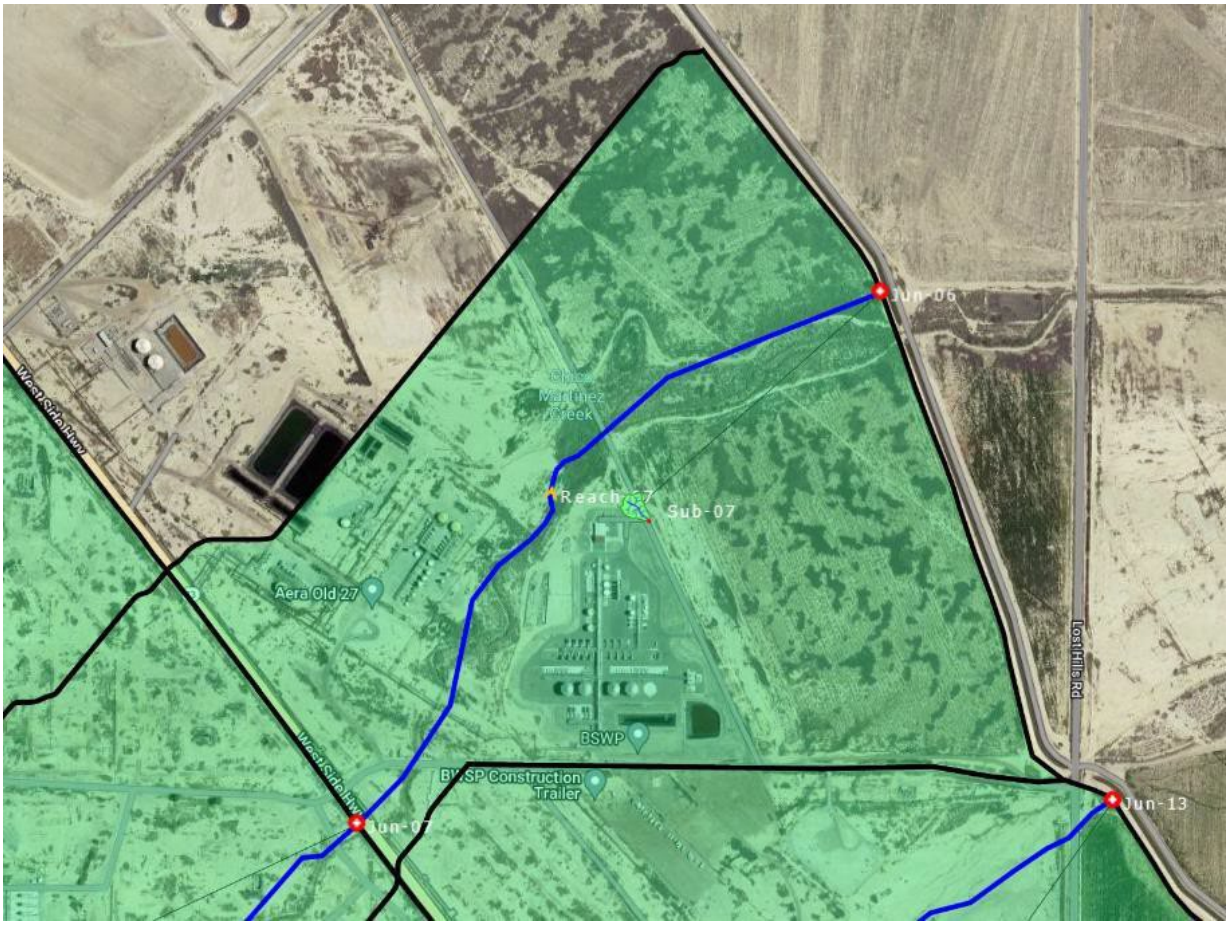
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
9.365	3.47	78.39	Developed, Medium Density
7.664	2.84	30.00	Undeveloped, Shrub/Scrub
17.372	6.44	67.37	Developed, Low Density
12.494	4.63	89.14	Developed, High Density
43.223	16.02	56.26	Developed, Open Space
5.238	1.94	77.67	Undeveloped, Barren Land
29.711	11.01	41.49	Undeveloped, Grassland
144.704	53.64	71.71	Agricultural, Cultivated Crops
269.771	**100.00**	**65.60**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
62.62	95.81	0.00565	0.2792	Sheet Flow
1.69	168.18	0.01057	3.3952	Shallow Concentrated Flow
0.84	253.65	0.09785	10.3295	Shallow Concentrated Flow
33.38	2,278.13	0.00118	1.1339	Channel Flow
1.39	551.42	0.03999	6.6036	Channel Flow
64.20	1,275.51	0.00010	0.3284	Channel Flow
164.12	**4,622.70**	**Total**	**Lag Time = 98.48 minutes**	


Runoff (cfs)
Precipitation (in)
Time
1/11/2023
1/12/2023
Precipitation - Total Precipitation (1.65 in)
Runoff - Max Discharge (7.85 cfs)


Jun-06
Reach-7
Sub-07
Aera Old 27
BSWP
Jun-07
Jun-13
Lost Hills Rd

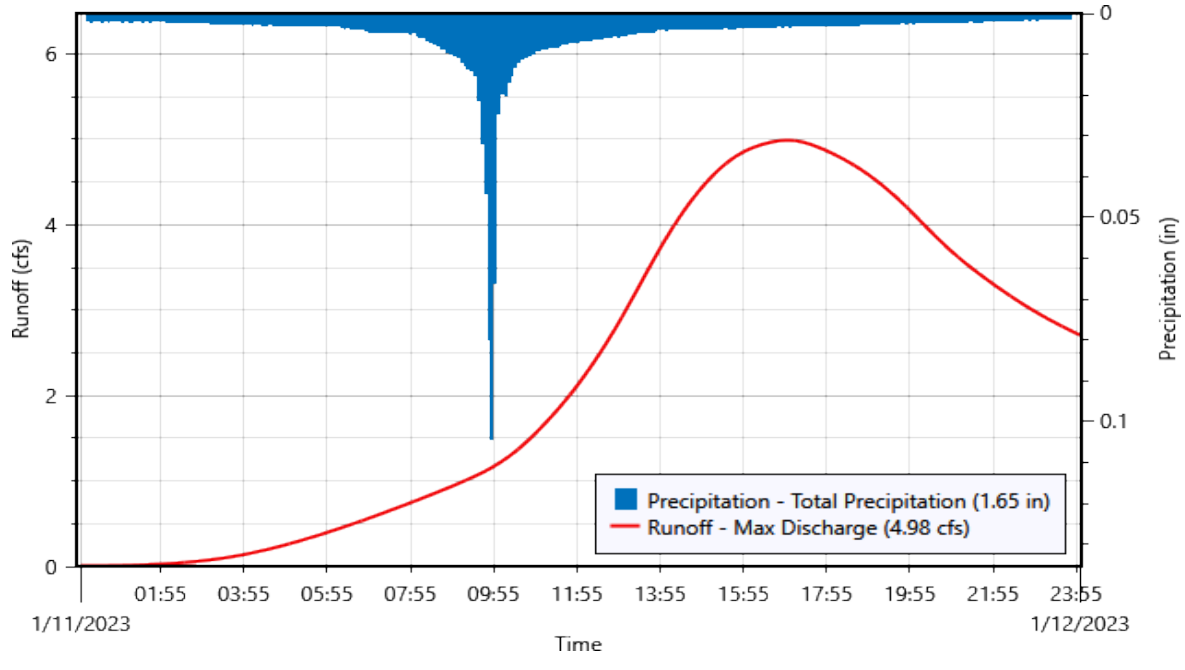
Subbasin ID:	Sub-08			
Scenario:	**Existing Conditions 10yr**		**Depth**	**Volume**
Peak discharge:	4.98 cfs	**Time of peak:**	11 Jan 2023, 05:00	
Drainage area:	503.505 acres	**Total rainfall:**	1.65 in	69.22960 ac-ft
Initial abstraction:	1.48 in	**Losses:**	1.51 in	63.28105 ac-ft
Curve Number:	57.53	**Precip excess:**	0.14 in	5.94854 ac-ft
Impervious surface:	8.38%	**Direct runoff:**	0.11 in	4.45 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	395.42 minutes	**Total runoff:**	0.11 in	4.45 ac-ft

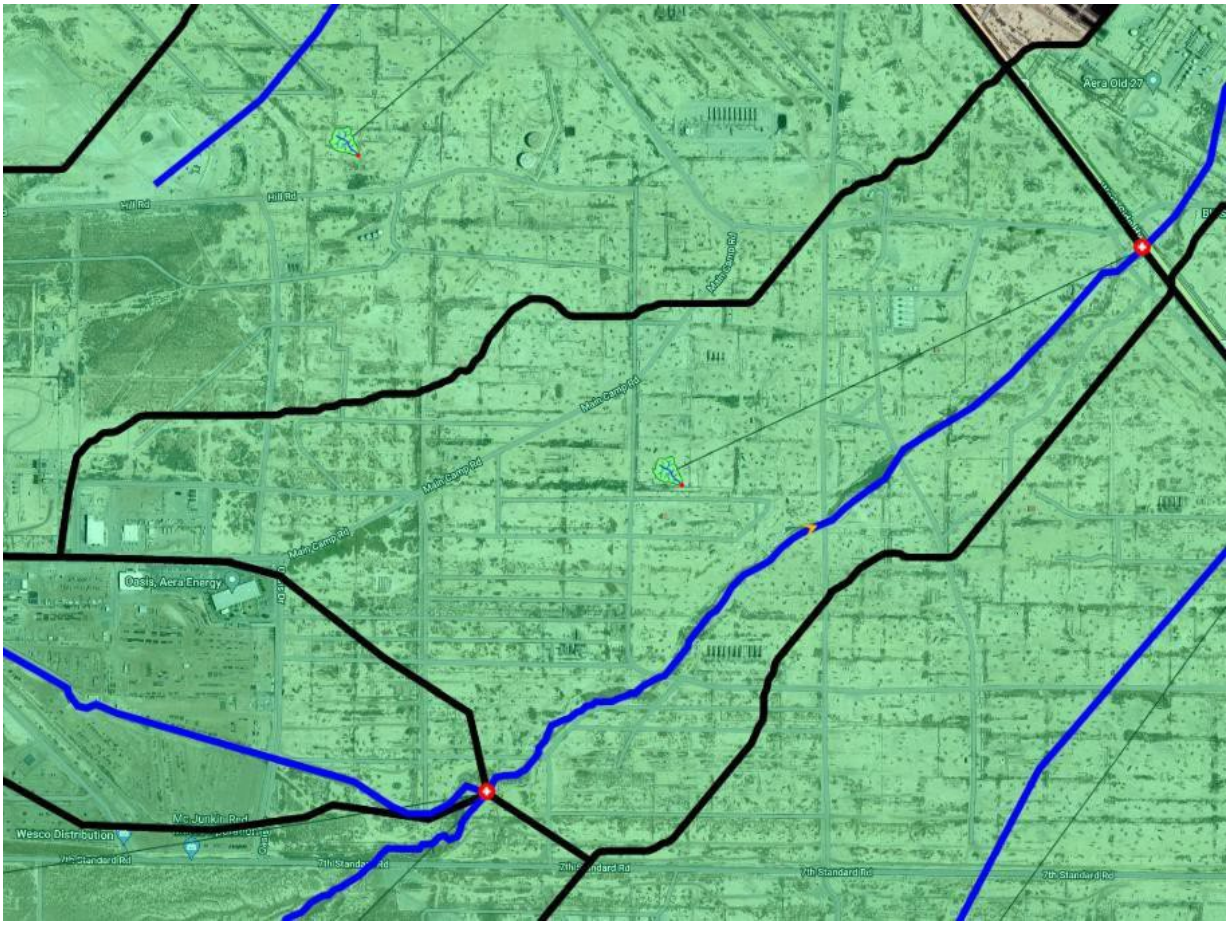
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
9.083	1.80	80.87	Developed, Medium Density
32.953	6.54	70.08	Developed, Low Density
4.702	0.93	89.23	Developed, High Density
9.827	1.95	87.02	Undeveloped, Barren Land
151.885	30.17	41.68	Undeveloped, Grassland
295.055	58.60	62.08	Developed, Open Space
503.505	**100.00**	**57.53**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
52.03	100.00	0.00978	0.3674	Sheet Flow
49.64	4,709.72	0.00961	3.2380	Shallow Concentrated Flow
2.39	661.27	0.08149	9.4267	Shallow Concentrated Flow
9.76	489.72	0.00269	1.7139	Shallow Concentrated Flow
545.21	3,425.21	0.00001	0.1271	Channel Flow
659.03	**9,385.92**	**Total**	**Lag Time = 395.42 minutes**	




Aera Old 27
Hill Rd
Main Camp Rd
Oasis, Aera Energy
Wesco Distribution
7th Standard Rd

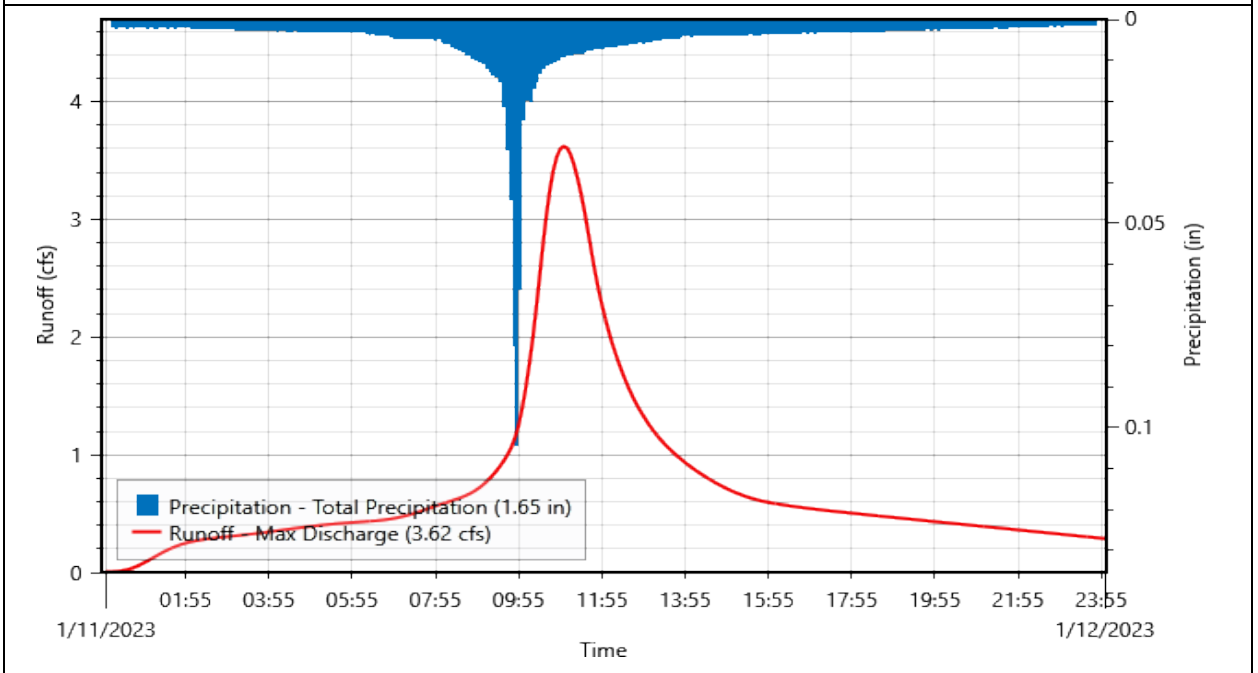
Subbasin ID:	Sub-09			
Scenario:	**Existing Conditions 10yr**		**Depth**	**Volume**
Peak discharge:	3.62 cfs	**Time of peak:**	11 Jan 2023, 11:00	
Drainage area:	1,130.587 acres	**Total rainfall:**	1.65 in	155.45199 ac-ft
Initial abstraction:	2.84 in	**Losses:**	1.63 in	153.99074 ac-ft
Curve Number:	41.33	**Precip excess:**	0.02 in	1.46125 ac-ft
Impervious surface:	0.94%	**Direct runoff:**	0.02 in	1.43 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	67.09 minutes	**Total runoff:**	0.02 in	1.43 ac-ft

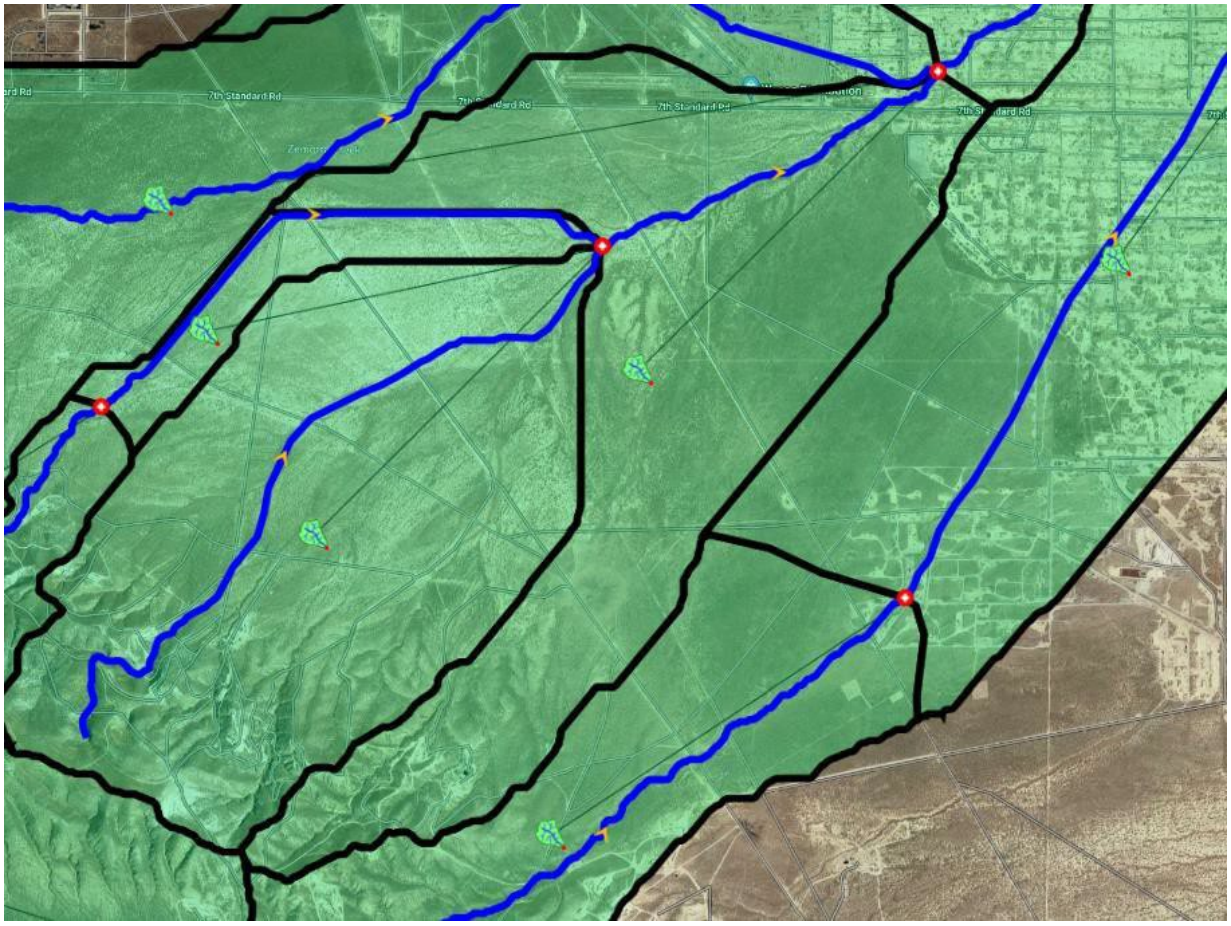
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
1.638	0.14	82.99	Developed, Medium Density
49.357	4.37	35.62	Undeveloped, Shrub/Scrub
4.469	0.40	61.00	Developed, Low Density
0.293	0.03	89.00	Developed, High Density
80.882	7.15	53.22	Developed, Open Space
3.542	0.31	77.00	Undeveloped, Barren Land
990.407	87.60	40.34	Undeveloped, Grassland
1,130.587	**100.00**	**41.33**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
16.78	99.98	0.16549	1.5113	Sheet Flow
0.86	365.47	0.19372	14.5341	Shallow Concentrated Flow
8.54	4,728.14	0.04703	9.2075	Channel Flow
60.10	7,738.83	0.01770	4.3931	Shallow Concentrated Flow
25.53	5,047.31	0.00990	3.2859	Channel Flow
111.81	**17,979.73**	**Total**	**Lag Time = 67.09 minutes**	




7th Standard Rd
7th Standard Rd
7th Standard Rd

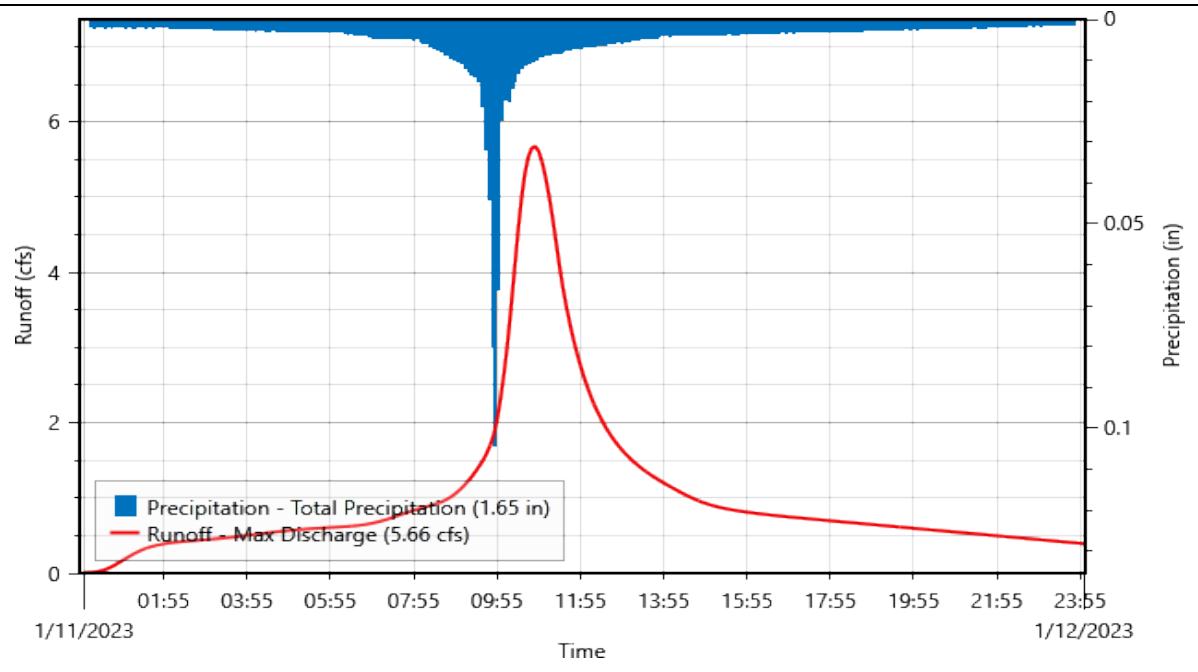
Subbasin ID:	Sub-10			
Scenario:	Existing Conditions 10yr		Depth	Volume
Peak discharge:	5.66 cfs	**Time of peak:**	11 Jan 2023, 10:50	
Drainage area:	1,153.361 acres	**Total rainfall:**	1.65 in	158.58479 ac-ft
Initial abstraction:	1.94 in	**Losses:**	1.63 in	156.52319 ac-ft
Curve Number:	50.79	**Precip excess:**	0.02 in	2.06160 ac-ft
Impervious surface:	1.30%	**Direct runoff:**	0.02 in	2.03 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	55.92 minutes	**Total runoff:**	0.02 in	2.03 ac-ft

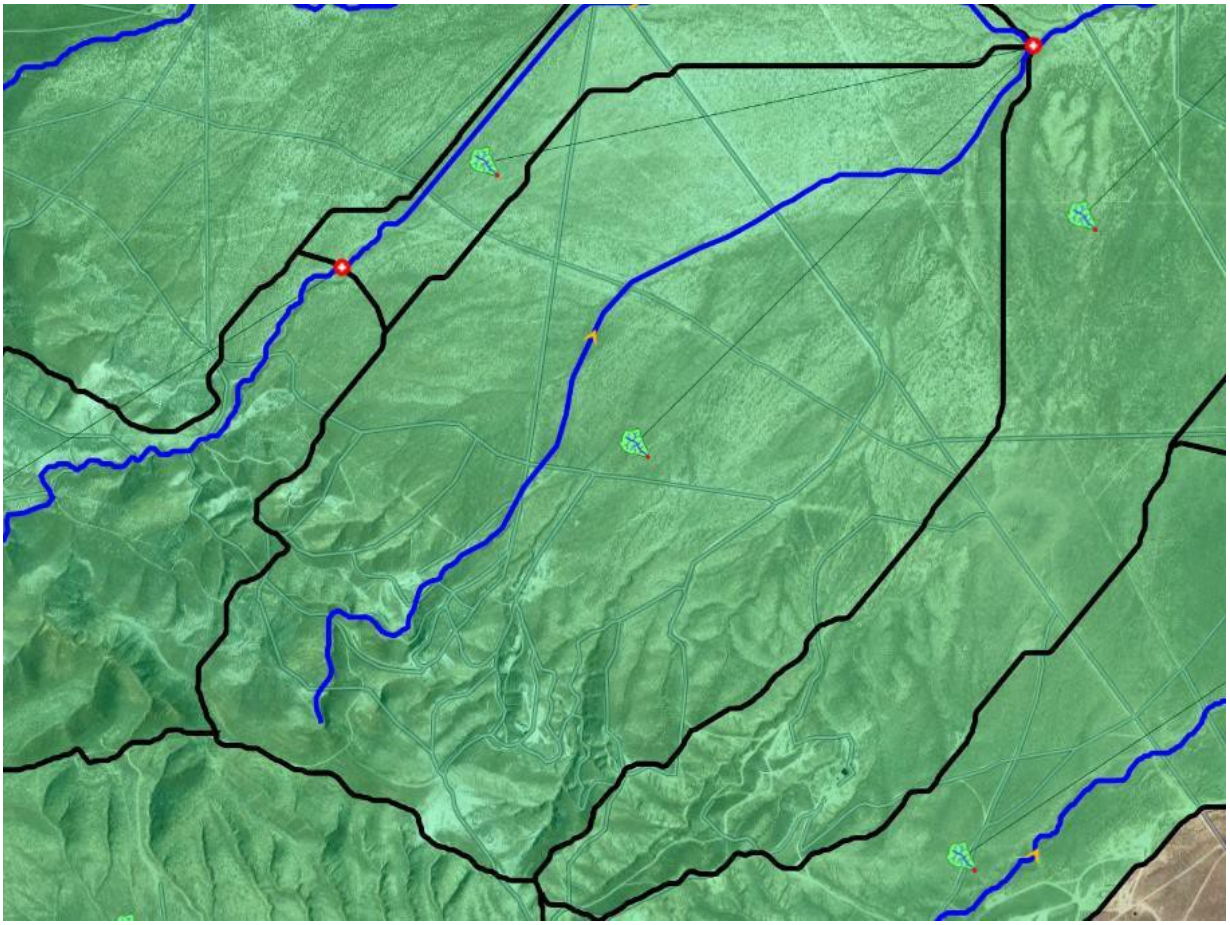
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
10.397	0.90	79.49	Developed, Medium Density
59.382	5.15	50.07	Undeveloped, Shrub/Scrub
3.103	0.27	80.28	Developed, Low Density
151.032	13.09	67.65	Developed, Open Space
2.360	0.20	91.00	Undeveloped, Barren Land
927.088	80.38	47.56	Undeveloped, Grassland
1,153.361	**100.00**	**50.79**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
21.17	100.00	0.09259	1.1304	Sheet Flow
2.60	1,127.24	0.20010	14.7716	Shallow Concentrated Flow
9.39	4,900.89	0.06895	8.6712	Channel Flow
0.40	386.93	0.23496	16.0068	Channel Flow
42.25	2,796.45	0.00111	1.0981	Channel Flow
17.39	4,299.00	0.01549	4.1093	Channel Flow
93.20	**13,610.51**	**Total**	**Lag Time = 55.92 minutes**	





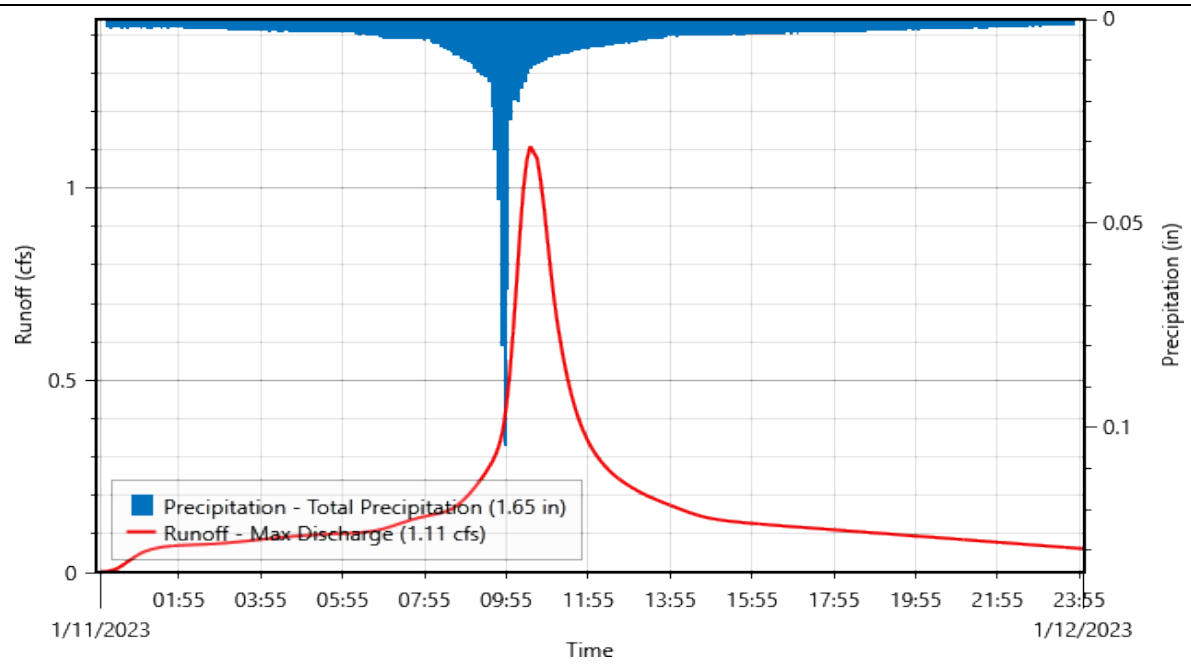
Subbasin ID:	Sub-11			
Scenario:	Existing Conditions 10yr		Depth	Volume
Peak discharge:	1.11 cfs	**Time of peak:**	11 Jan 2023, 10:30	
Drainage area:	161.318 acres	**Total rainfall:**	1.65 in	22.18480 ac-ft
Initial abstraction:	4.26 in	**Losses:**	1.63 in	21.84981 ac-ft
Curve Number:	31.97	**Precip excess:**	0.02 in	0.33499 ac-ft
Impervious surface:	1.51%	**Direct runoff:**	0.02 in	0.33 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	40.10 minutes	**Total runoff:**	0.02 in	0.33 ac-ft

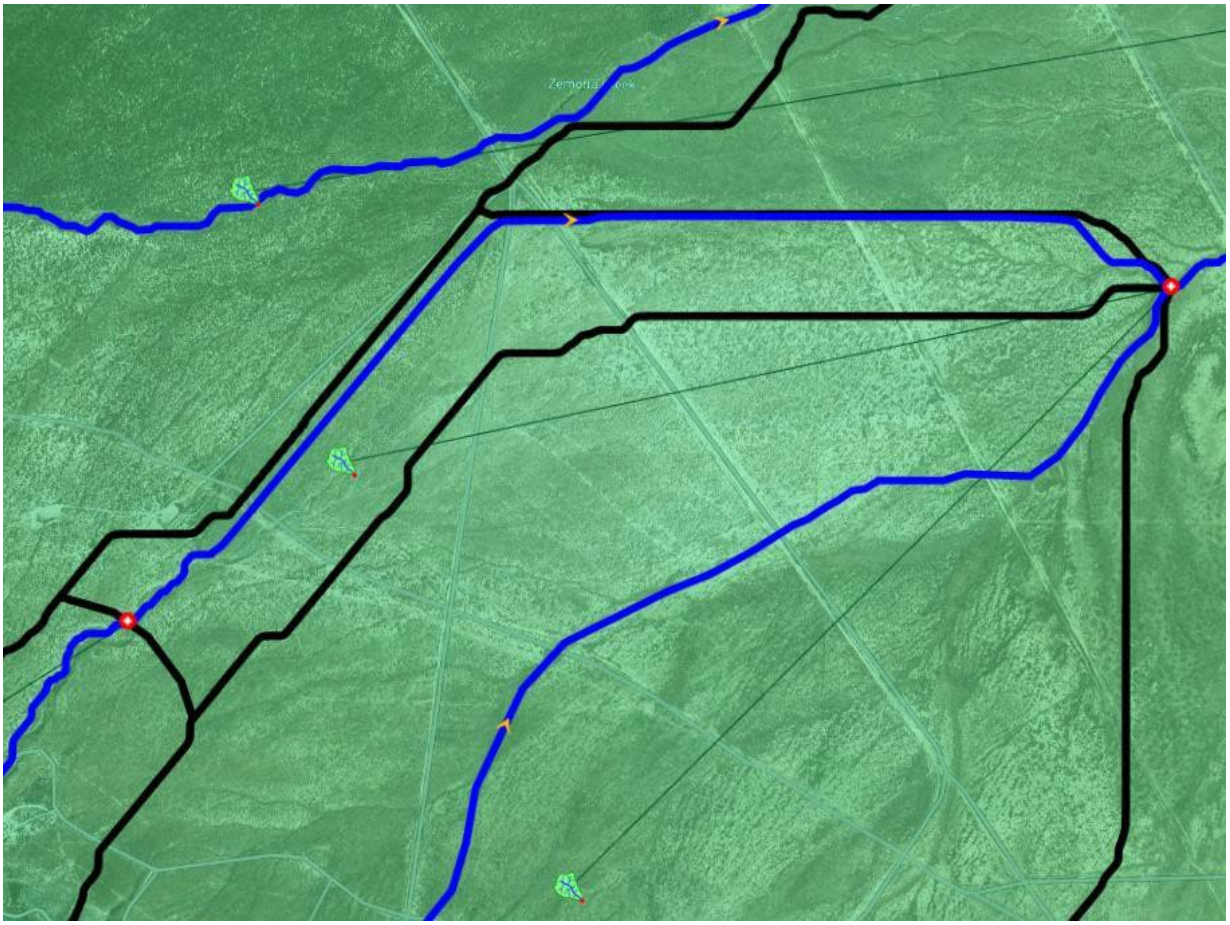
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
4.560	2.83	77.00	Developed, Medium Density
4.792	2.97	49.00	Developed, Open Space
151.966	94.20	30.08	Undeveloped, Grassland
161.318	**100.00**	**31.97**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
28.76	100.00	0.04304	0.7707	Sheet Flow
6.52	1,112.40	0.03107	5.8206	Shallow Concentrated Flow
31.55	8,418.65	0.01804	4.4358	Channel Flow
66.83	**9,631.05**	**Total**	**Lag Time = 40.10 minutes**	





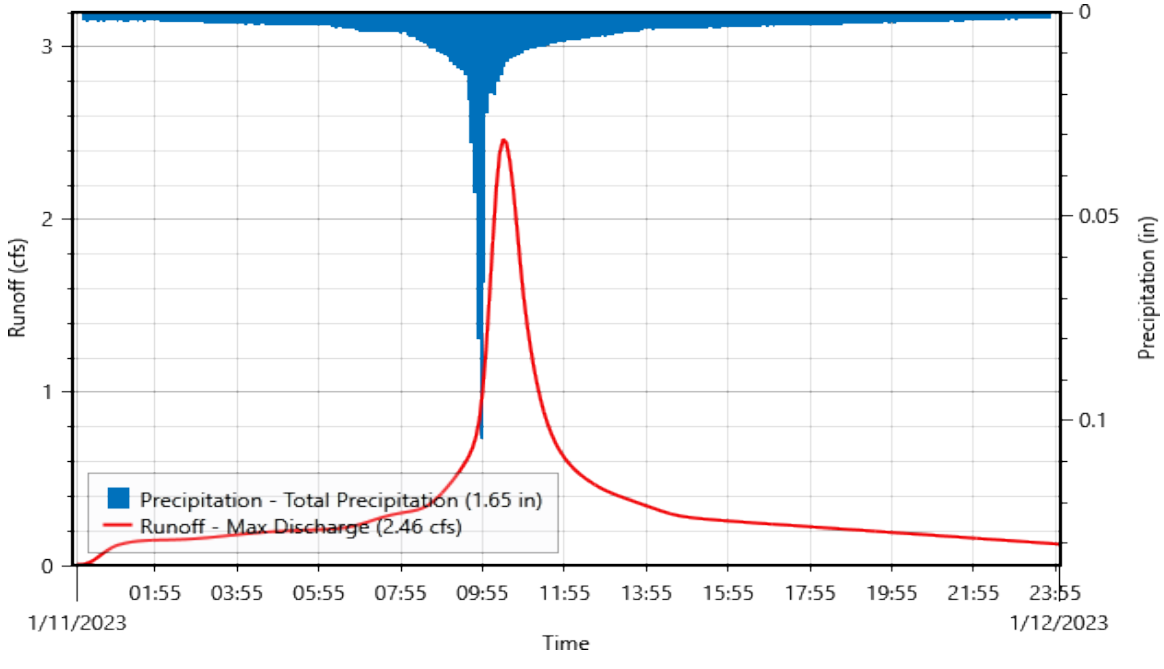
Subbasin ID:	Sub-12			
Scenario:	Existing Conditions 10yr		Depth	Volume
Peak discharge:	2.46 cfs	**Time of peak:**	11 Jan 2023, 10:25	
Drainage area:	952.517 acres	**Total rainfall:**	1.65 in	130.97039 ac-ft
Initial abstraction:	3.33 in	**Losses:**	1.64 in	130.28935 ac-ft
Curve Number:	37.51	**Precip excess:**	0.01 in	0.68105 ac-ft
Impervious surface:	0.52%	**Direct runoff:**	0.01 in	0.67 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	34.22 minutes	**Total runoff:**	0.01 in	0.67 ac-ft

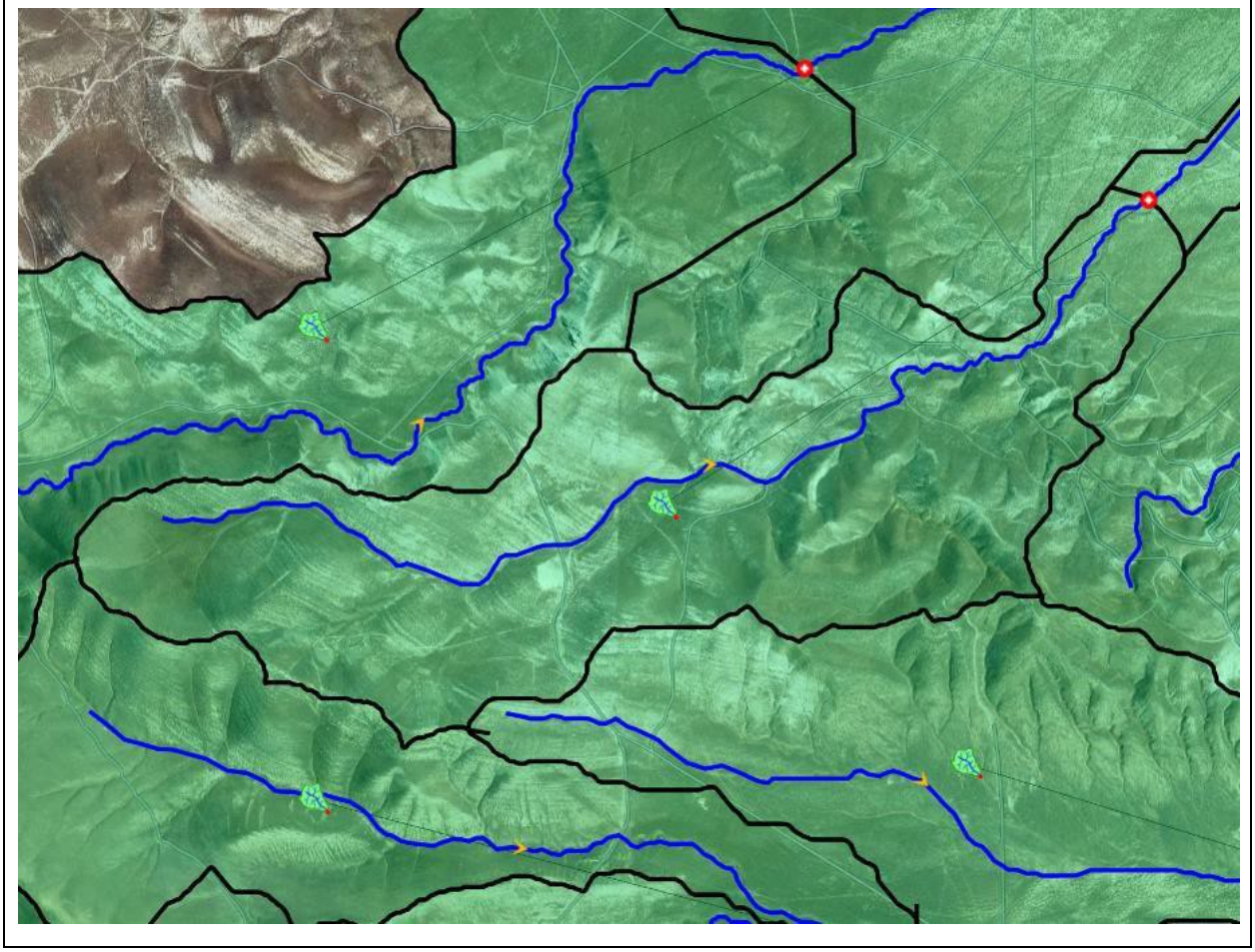
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
2.973	0.31	80.98	Developed, Medium Density
103.318	10.85	38.00	Undeveloped, Shrub/Scrub
0.143	0.02	75.00	Developed, Low Density
0.294	0.03	92.00	Developed, High Density
75.514	7.93	56.10	Developed, Open Space
770.275	80.87	35.42	Undeveloped, Grassland
952.517	**100.00**	**37.51**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
11.42	100.00	0.43323	2.4452	Sheet Flow
1.09	682.84	0.41878	21.3698	Shallow Concentrated Flow
1.93	655.49	0.12346	11.6028	Shallow Concentrated Flow
3.76	2,062.80	0.07622	9.1166	Channel Flow
38.83	14,034.51	0.03310	6.0076	Channel Flow
57.03	**17,535.64**	**Total**	**Lag Time = 34.22 minutes**	





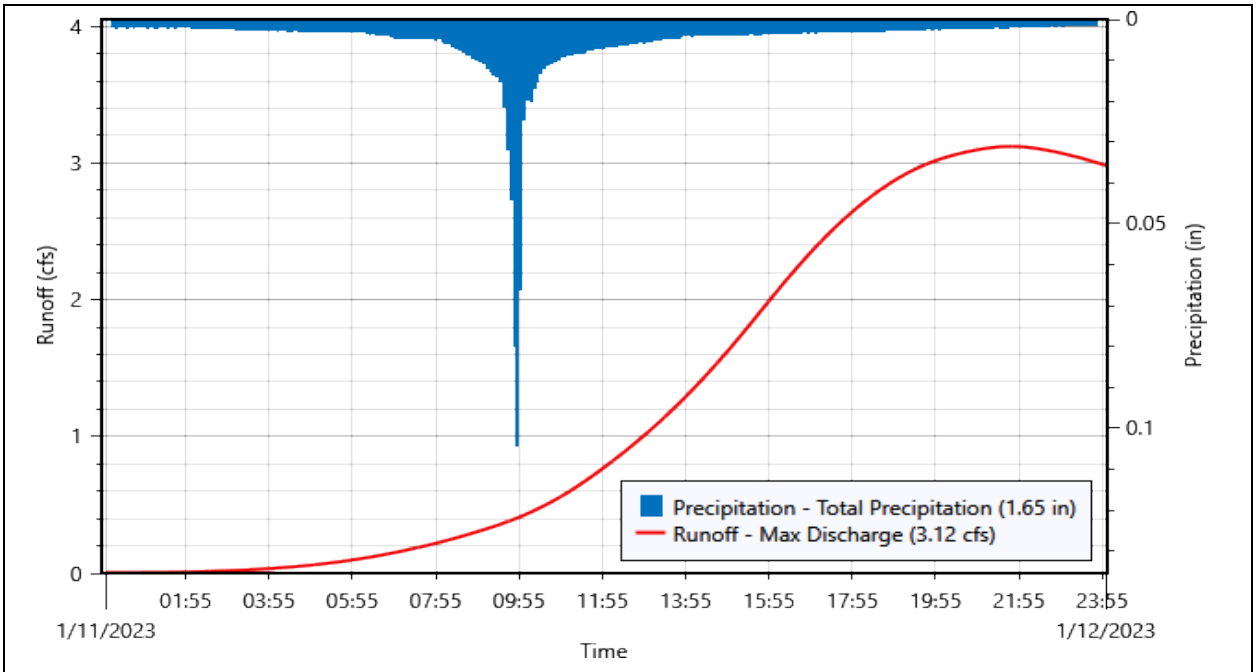
Subbasin ID:	Sub-13			
Scenario:	**Existing Conditions 10yr**		**Depth**	**Volume**
Peak discharge:	3.12 cfs	**Time of peak:**	11 Jan 2023, 09:45	
Drainage area:	1,426.690 acres	**Total rainfall:**	1.65 in	196.16959 ac-ft
Initial abstraction:	3.40 in	**Losses:**	1.61 in	191.18688 ac-ft
Curve Number:	37.06	**Precip excess:**	0.04 in	4.98271 ac-ft
Impervious surface:	2.54%	**Direct runoff:**	0.02 in	2.51 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	649.32 minutes	**Total runoff:**	0.02 in	2.51 ac-ft

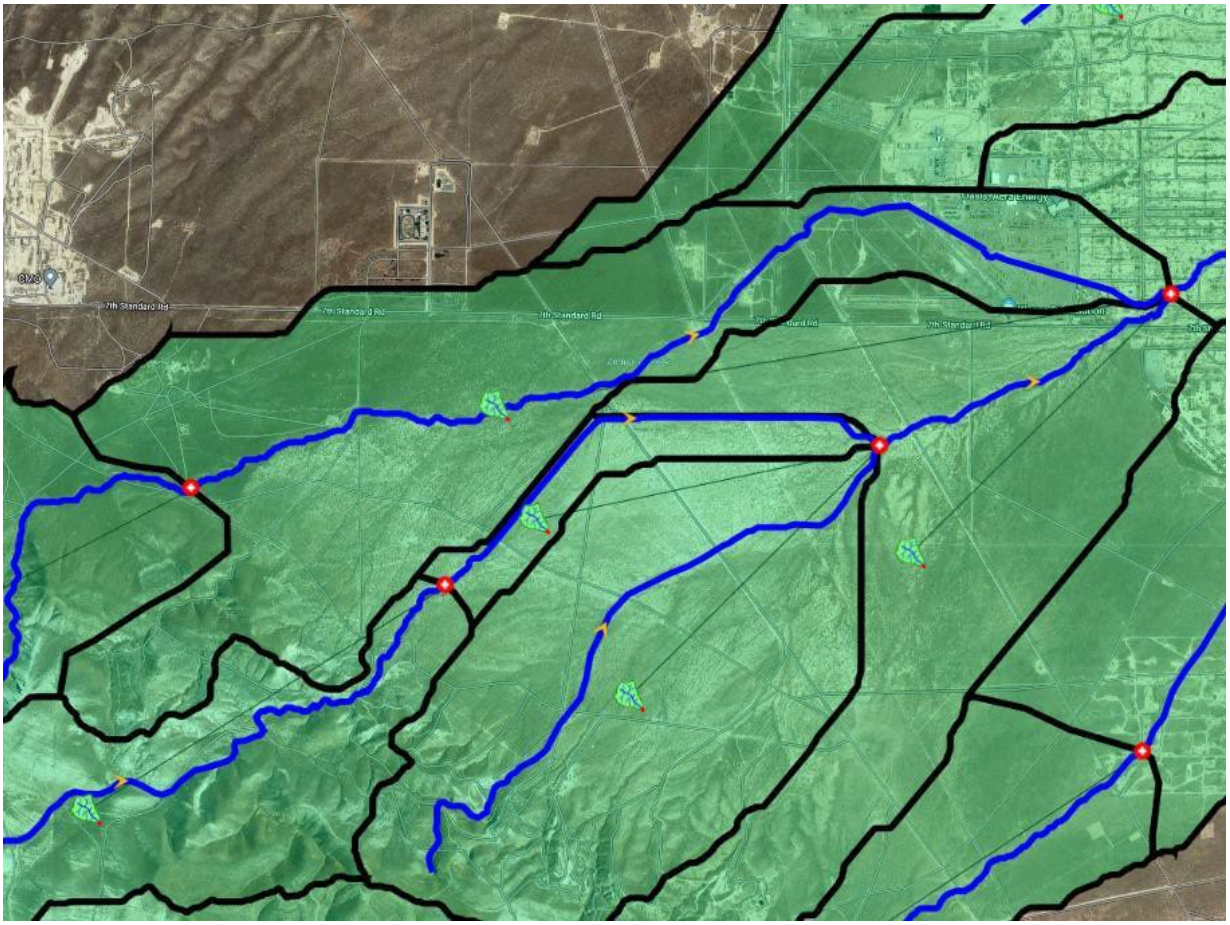
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
17.729	1.24	77.00	Developed, Medium Density
3.229	0.23	67.00	Agricultural, Cultivated Crops
80.460	5.64	37.13	Undeveloped, Shrub/Scrub
17.221	1.21	61.00	Developed, Low Density
15.586	1.09	89.00	Developed, High Density
152.768	10.71	52.06	Developed, Open Space
3.509	0.25	77.00	Undeveloped, Barren Land
1,136.188	79.64	33.14	Undeveloped, Grassland
1,426.690	**100.00**	**37.06**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
20.36	100.00	0.10212	1.1872	Sheet Flow
0.80	390.34	0.25255	16.5951	Shallow Concentrated Flow
8.53	4,253.88	0.06305	8.2916	Channel Flow
15.47	2,983.05	0.03970	6.5798	Shallow Concentrated Flow
43.39	10,314.70	0.01432	3.9513	Channel Flow
0.39	285.53	0.13608	12.1816	Channel Flow
993.25	6,239.98	0.00001	0.1044	Channel Flow
1,082.19	**24,567.48**	**Total**	**Lag Time = 649.32 minutes**	


Runoff (cfs)
Precipitation (in)
Time
1/11/2023
1/12/2023
01:55
03:55
05:55
07:55
09:55
11:55
13:55
15:55
17:55
19:55
21:55
23:55
Precipitation - Total Precipitation (1.65 in)
Runoff - Max Discharge (3.12 cfs)



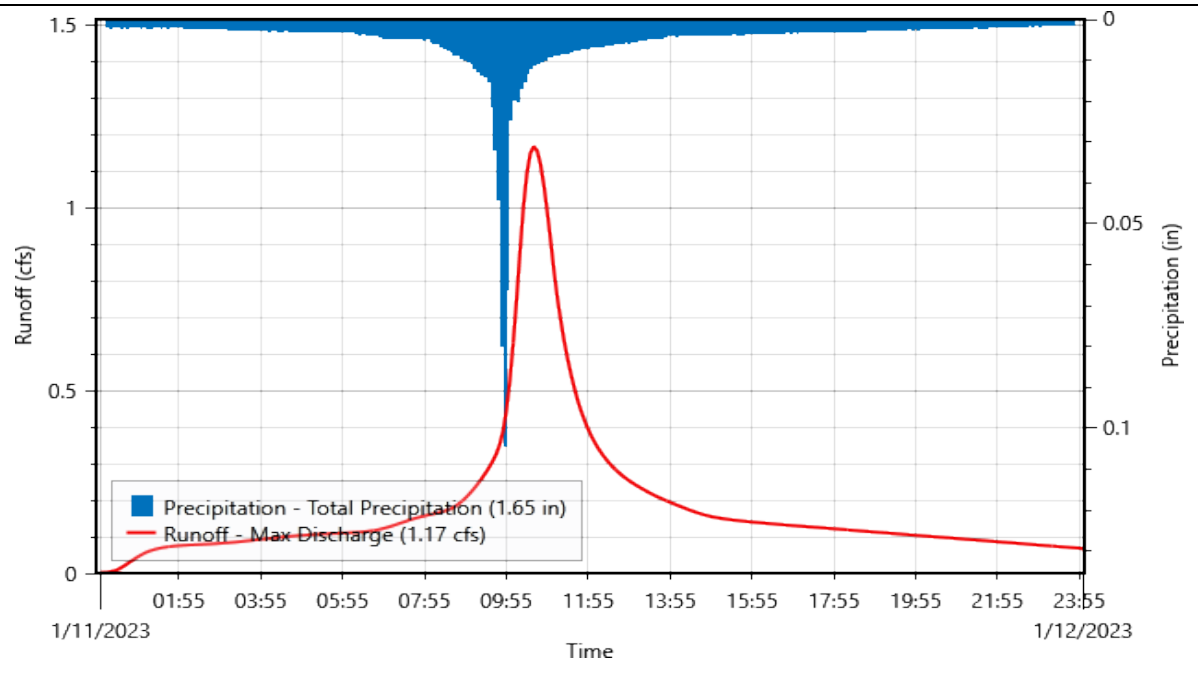
Subbasin ID:	Sub-14			
Scenario:	Existing Conditions 10yr		Depth	Volume
Peak discharge:	1.17 cfs	**Time of peak:**	11 Jan 2023, 10:35	
Drainage area:	1,158.859 acres	**Total rainfall:**	1.65 in	159.34159 ac-ft
Initial abstraction:	2.01 in	**Losses:**	1.65 in	158.97511 ac-ft
Curve Number:	49.91	**Precip excess:**	0.00 in	0.36649 ac-ft
Impervious surface:	0.23%	**Direct runoff:**	0.00 in	0.36 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	43.12 minutes	**Total runoff:**	0.00 in	0.36 ac-ft

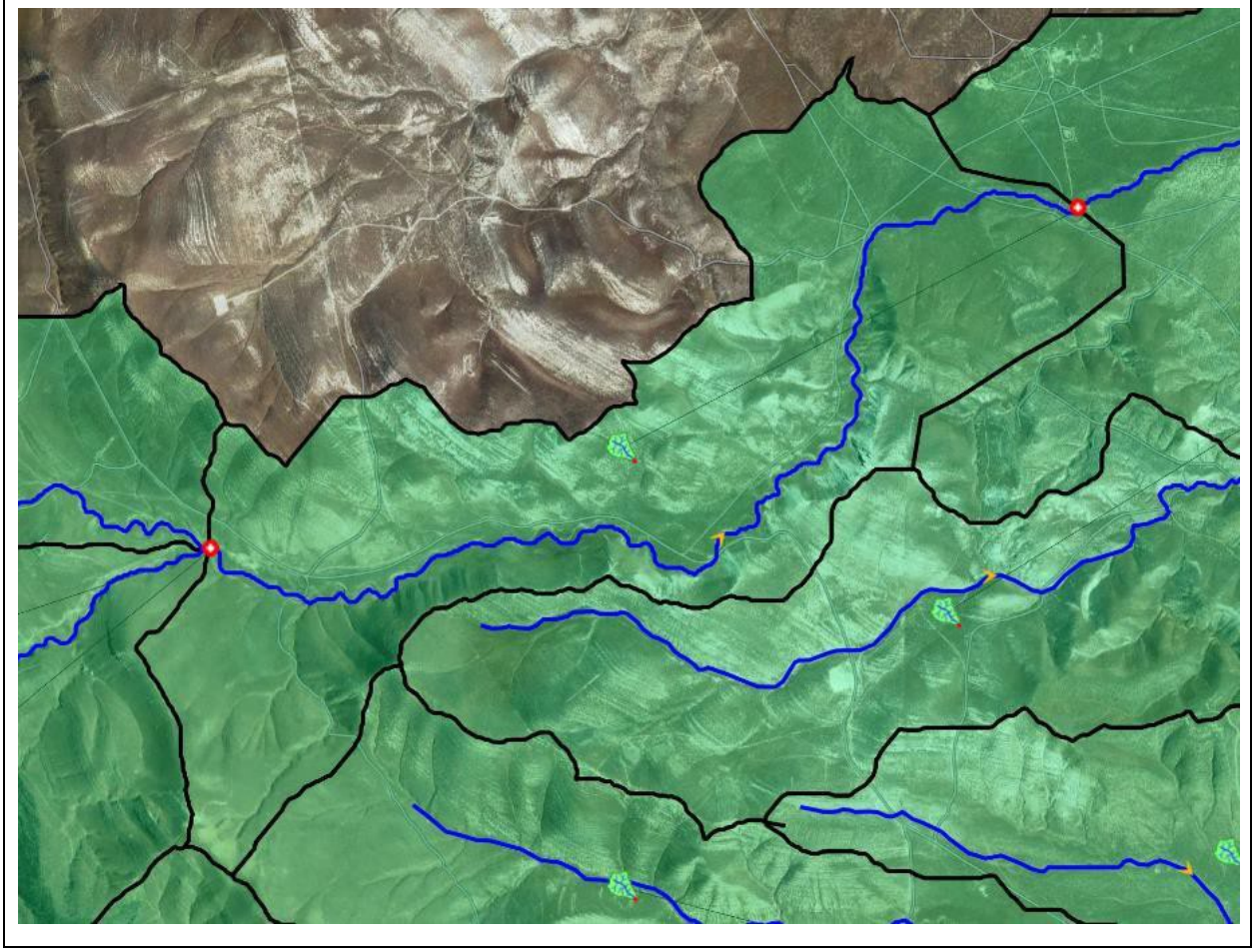
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
128.595	11.10	40.16	Undeveloped, Shrub/Scrub
0.289	0.02	61.00	Developed, Low Density
89.373	7.71	62.75	Developed, Open Space
940.602	81.17	50.02	Undeveloped, Grassland
1,158.859	**100.00**	**49.91**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
15.07	100.00	0.21650	1.7286	Sheet Flow
1.46	911.67	0.41691	21.3220	Shallow Concentrated Flow
2.49	2,157.30	0.19089	14.4277	Channel Flow
2.91	1,629.56	0.07940	9.3053	Channel Flow
49.93	15,884.87	0.02564	5.2879	Channel Flow
71.86	**20,683.40**	**Total**	**Lag Time = 43.12 minutes**	





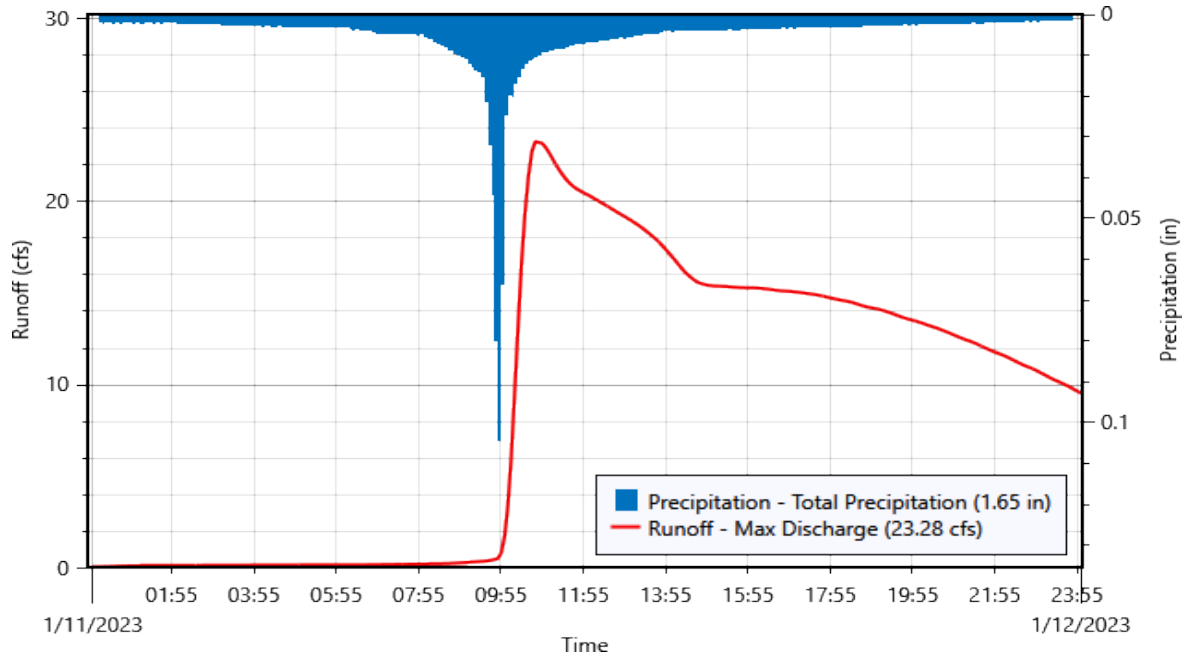
Subbasin ID:	Sub-15			
Scenario:	Existing Conditions 10yr		Depth	Volume
Peak discharge:	23.28 cfs	**Time of peak:**	11 Jan 2023, 10:50	
Drainage area:	1,054.808 acres	**Total rainfall:**	1.65 in	145.03279 ac-ft
Initial abstraction:	0.70 in	**Losses:**	1.44 in	126.93838 ac-ft
Curve Number:	74.04	**Precip excess:**	0.21 in	18.09442 ac-ft
Impervious surface:	0.23%	**Direct runoff:**	0.20 in	17.58 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	30.66 minutes	**Total runoff:**	0.20 in	17.58 ac-ft

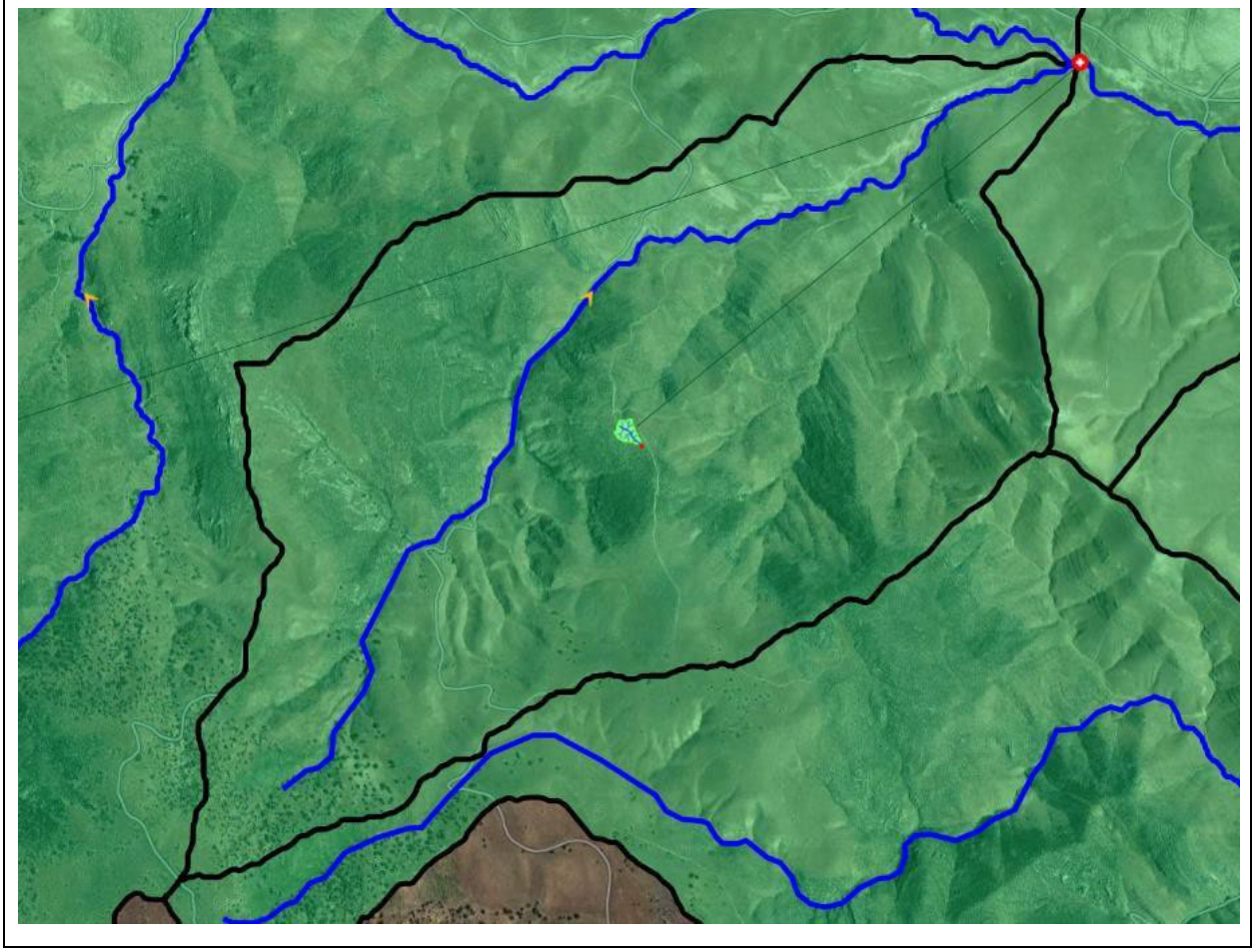
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
0.440	0.04	90.67	Developed, Medium Density
314.541	29.82	70.23	Undeveloped, Shrub/Scrub
3.839	0.36	84.20	Developed, Low Density
56.493	5.36	82.98	Developed, Open Space
679.496	64.42	74.98	Undeveloped, Grassland
1,054.808	**100.00**	**74.04**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
25.00	100.00	0.06109	0.9182	Sheet Flow
2.53	1,452.21	0.35050	19.5503	Shallow Concentrated Flow
1.74	1,776.43	0.26336	16.9464	Channel Flow
21.82	11,269.67	0.06761	8.5864	Channel Flow
51.09	**14,598.31**	**Total**	**Lag Time = 30.66 minutes**	





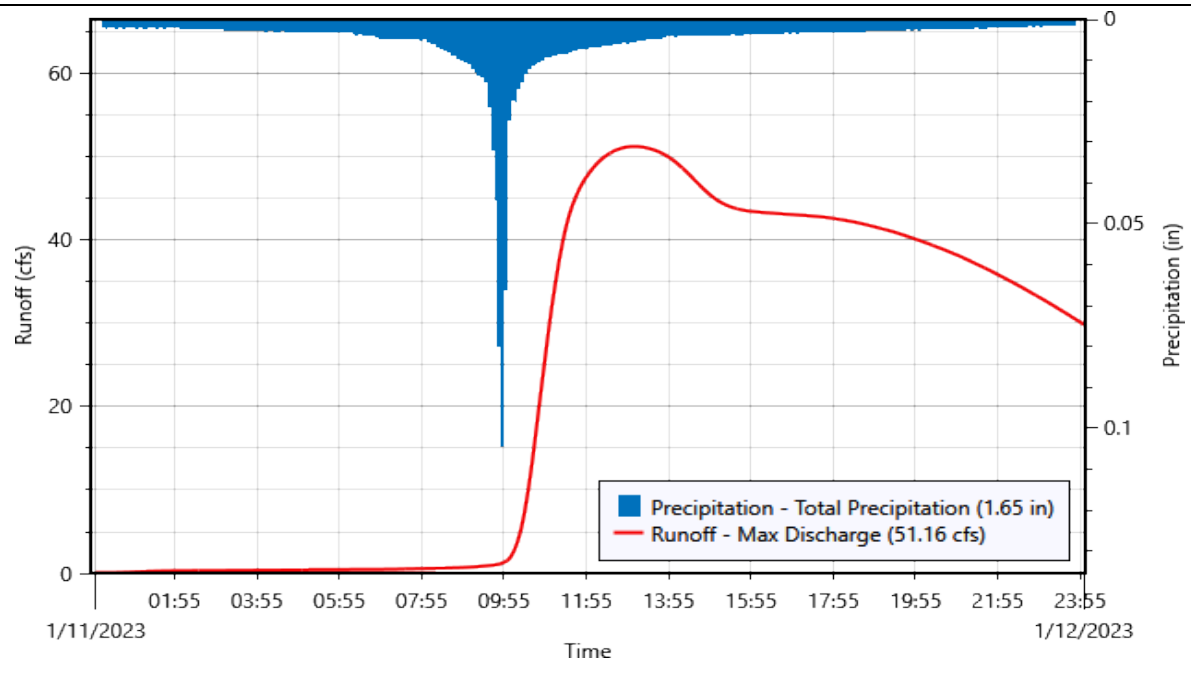
Subbasin ID:	Sub-16			
Scenario:	Existing Conditions 10yr		Depth	Volume
Peak discharge:	51.16 cfs	**Time of peak:**	11 Jan 2023, 01:05	
Drainage area:	3,426.802 acres	**Total rainfall:**	1.65 in	471.18718 ac-ft
Initial abstraction:	0.76 in	**Losses:**	1.48 in	421.98190 ac-ft
Curve Number:	72.40	**Precip excess:**	0.17 in	49.20528 ac-ft
Impervious surface:	0.26%	**Direct runoff:**	0.16 in	46.17 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	59.76 minutes	**Total runoff:**	0.16 in	46.17 ac-ft

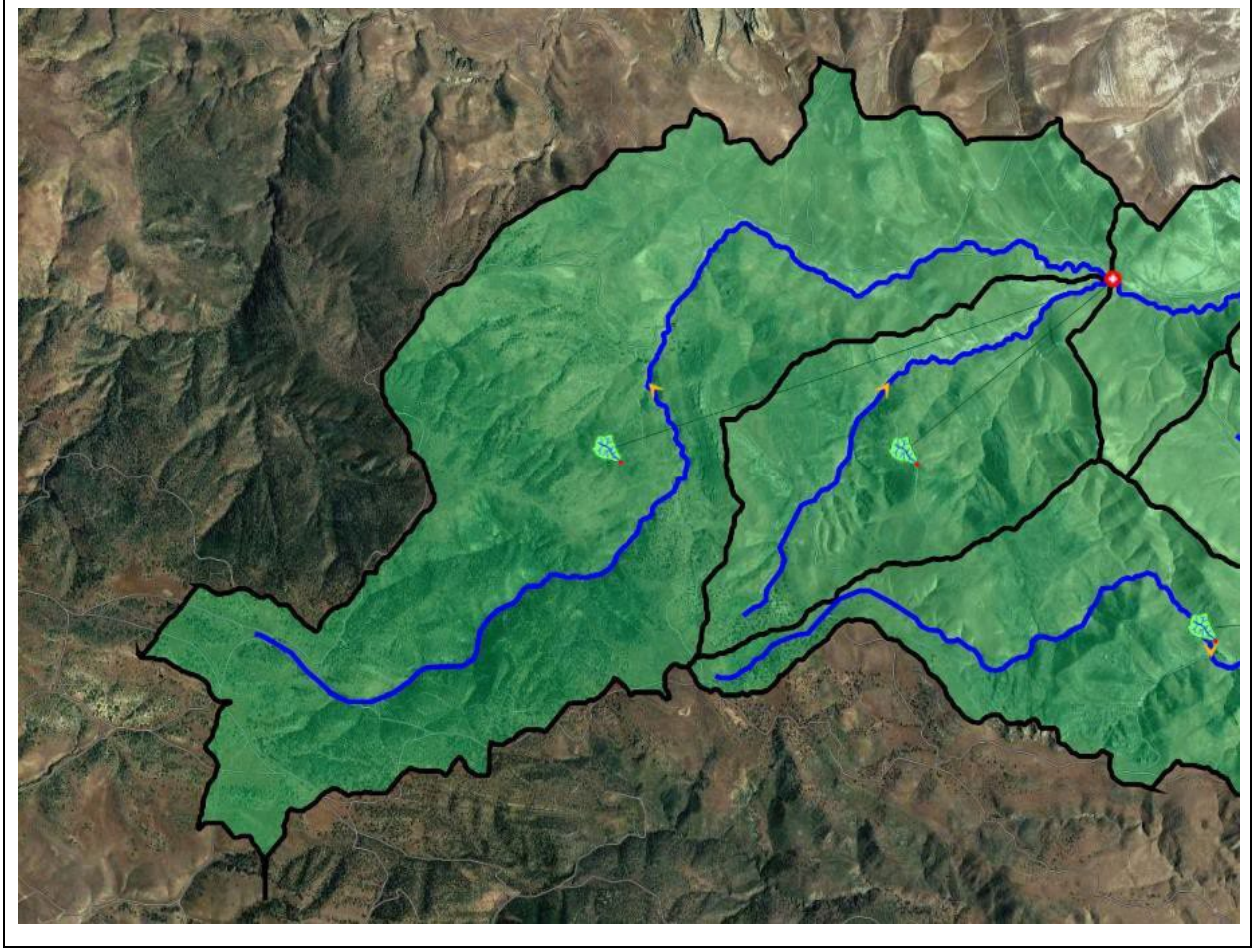
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
1.435	0.04	90.36	Developed, Medium Density
1,371.868	40.03	69.50	Undeveloped, Shrub/Scrub
7.071	0.21	85.60	Developed, Low Density
212.323	6.20	80.36	Developed, Open Space
1,834.106	53.52	73.58	Undeveloped, Grassland
3,426.802	**100.00**	**72.40**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
19.42	100.00	0.11493	1.2594	Sheet Flow
1.56	667.95	0.19509	14.5854	Shallow Concentrated Flow
13.71	2,461.83	0.03444	6.1282	Shallow Concentrated Flow
8.43	4,539.75	0.07343	8.9483	Channel Flow
9.74	7,174.45	0.13760	12.2496	Channel Flow
46.74	18,531.20	0.03983	6.5902	Channel Flow
99.60	**33,475.18**	**Total**	**Lag Time = 59.76 minutes**	





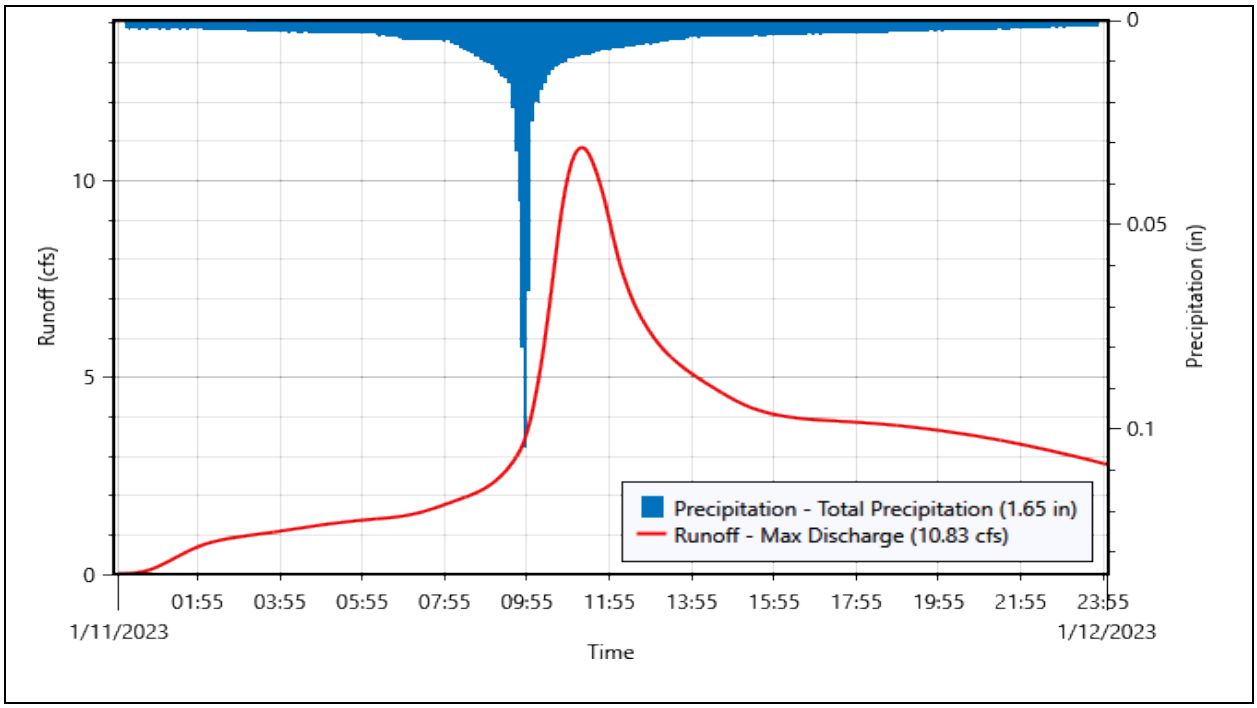
Subbasin ID:	Sub-17			
Scenario:	Existing Conditions 10yr		Depth	Volume
Peak discharge:	10.83 cfs	**Time of peak:**	11 Jan 2023, 11:15	
Drainage area:	337.184 acres	**Total rainfall:**	1.65 in	46.35840 ac-ft
Initial abstraction:	0.97 in	**Losses:**	1.40 in	39.39819 ac-ft
Curve Number:	67.43	**Precip excess:**	0.25 in	6.96021 ac-ft
Impervious surface:	10.46%	**Direct runoff:**	0.23 in	6.59 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	80.39 minutes	**Total runoff:**	0.23 in	6.59 ac-ft

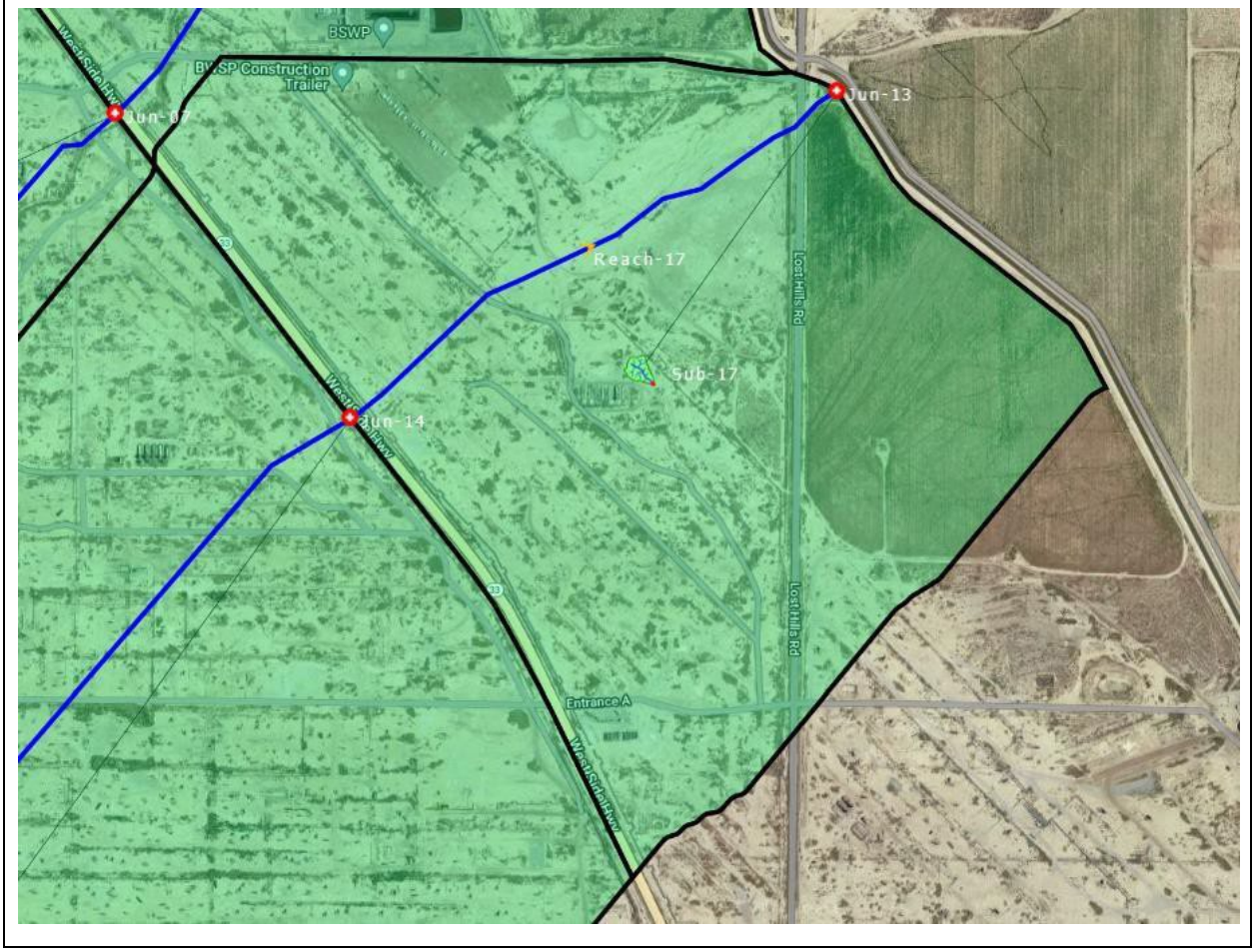
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
11.293	3.35	79.56	Developed, Medium Density
11.056	3.28	57.09	Undeveloped, Shrub/Scrub
67.566	20.04	78.79	Agricultural, Cultivated Crops
47.927	14.21	72.20	Developed, Low Density
0.803	0.24	90.30	Developed, High Density
1.132	0.34	86.00	Undeveloped, Barren Land
45.684	13.55	49.39	Undeveloped, Grassland
151.725	45.00	65.89	Developed, Open Space
337.184	**100.00**	**67.43**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
51.35	100.00	0.01011	0.3736	Sheet Flow
17.31	2,002.38	0.01428	3.9466	Shallow Concentrated Flow
0.33	116.98	0.13224	12.0085	Shallow Concentrated Flow
61.55	2,055.00	0.00119	1.1398	Shallow Concentrated Flow
3.43	792.13	0.01352	3.8394	Channel Flow
133.97	**5,066.49**	**Total**	**Lag Time = 80.39 minutes**	


Runoff (cfs)
10
5
0
0
0.05
0.1
Precipitation (in)
Precipitation - Total Precipitation (1.65 in)
Runoff - Max Discharge (10.83 cfs)
01:55
03:55
05:55
07:55
09:55
11:55
13:55
15:55
17:55
19:55
21:55
23:55
1/11/2023
1/12/2023
Time


BSWP
BWSP Construction Trailer
Jun-13
Reach-17
Lost Hills Rd
Sub-17
Jun-14
Entrance A

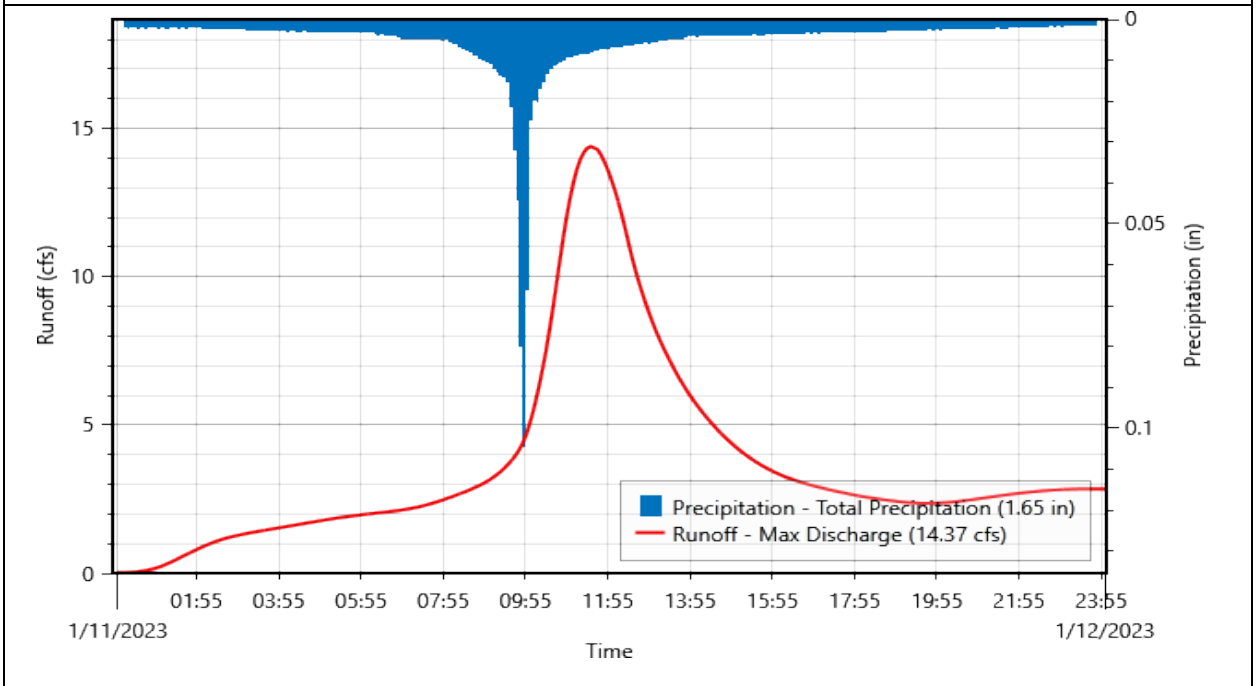
Subbasin ID:	Sub-18			
Scenario:	**Existing Conditions 10yr**		**Depth**	**Volume**
Peak discharge:	14.37 cfs	**Time of peak:**	11 Jan 2023, 11:30	
Drainage area:	1,474.591 acres	**Total rainfall:**	1.65 in	202.75199 ac-ft
Initial abstraction:	1.47 in	**Losses:**	1.59 in	195.04325 ac-ft
Curve Number:	57.69	**Precip excess:**	0.06 in	7.70874 ac-ft
Impervious surface:	3.55%	**Direct runoff:**	0.06 in	7.23 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	96.69 minutes	**Total runoff:**	0.06 in	7.23 ac-ft

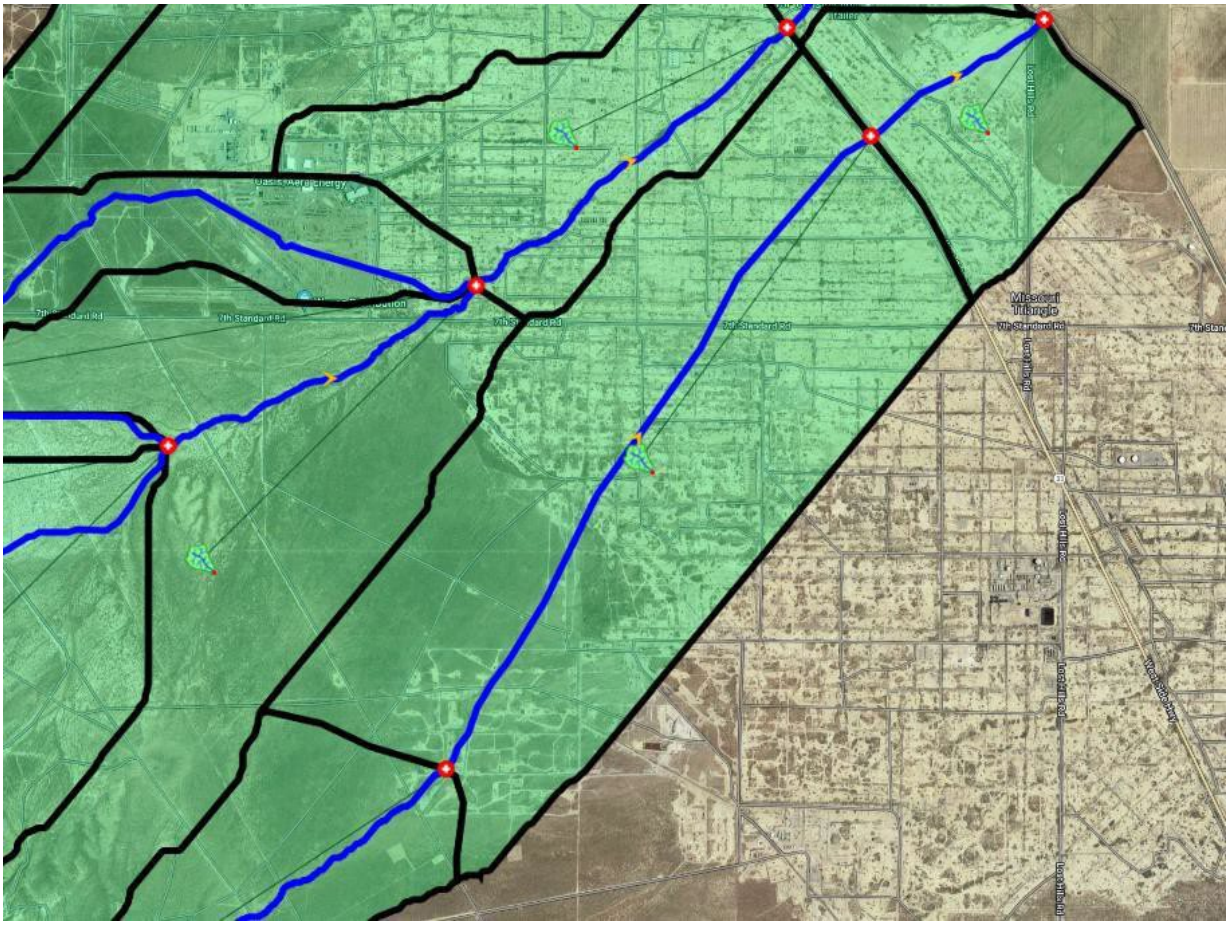
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
3.985	0.27	88.87	Developed, Medium Density
5.873	0.40	43.83	Undeveloped, Shrub/Scrub
60.728	4.12	78.75	Developed, Low Density
0.093	0.01	92.00	Developed, High Density
624.729	42.37	71.04	Developed, Open Space
3.600	0.24	89.56	Undeveloped, Barren Land
775.583	52.60	45.08	Undeveloped, Grassland
1,474.591	**100.00**	**57.69**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
47.88	100.00	0.01204	0.4077	Sheet Flow
16.47	2,024.74	0.01613	4.1935	Shallow Concentrated Flow
47.40	10,905.83	0.01341	3.8241	Channel Flow
49.39	438.84	0.00002	0.1541	Channel Flow
161.14	**13,469.41**	**Total**	**Lag Time = 96.69 minutes**	




7th Standard Rd
Loop 11 Rd
Missouri Triangle

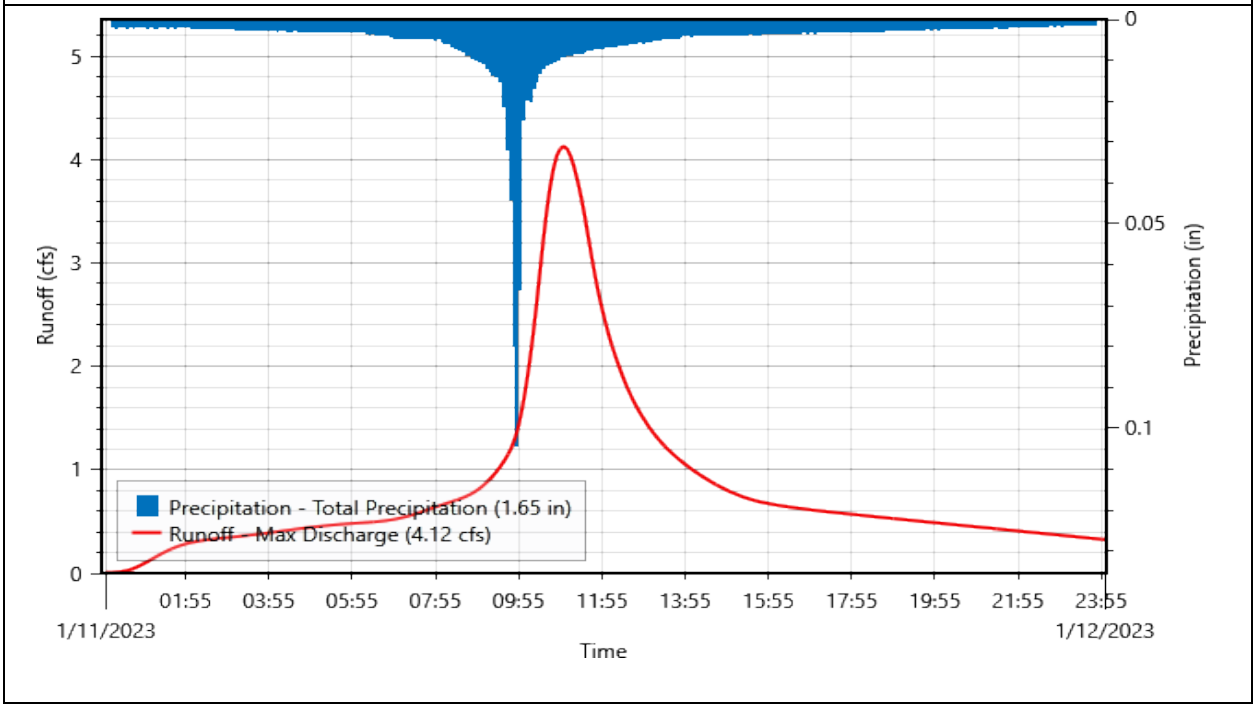
Subbasin ID:	Sub-19			
Scenario:	**Existing Conditions 10yr**		**Depth**	**Volume**
Peak discharge:	4.12 cfs	**Time of peak:**	11 Jan 2023, 11:00	
Drainage area:	787.670 acres	**Total rainfall:**	1.65 in	108.30160 ac-ft
Initial abstraction:	2.86 in	**Losses:**	1.62 in	106.64458 ac-ft
Curve Number:	41.19	**Precip excess:**	0.03 in	1.65701 ac-ft
Impervious surface:	1.53%	**Direct runoff:**	0.02 in	1.62 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	66.54 minutes	**Total runoff:**	0.02 in	1.62 ac-ft

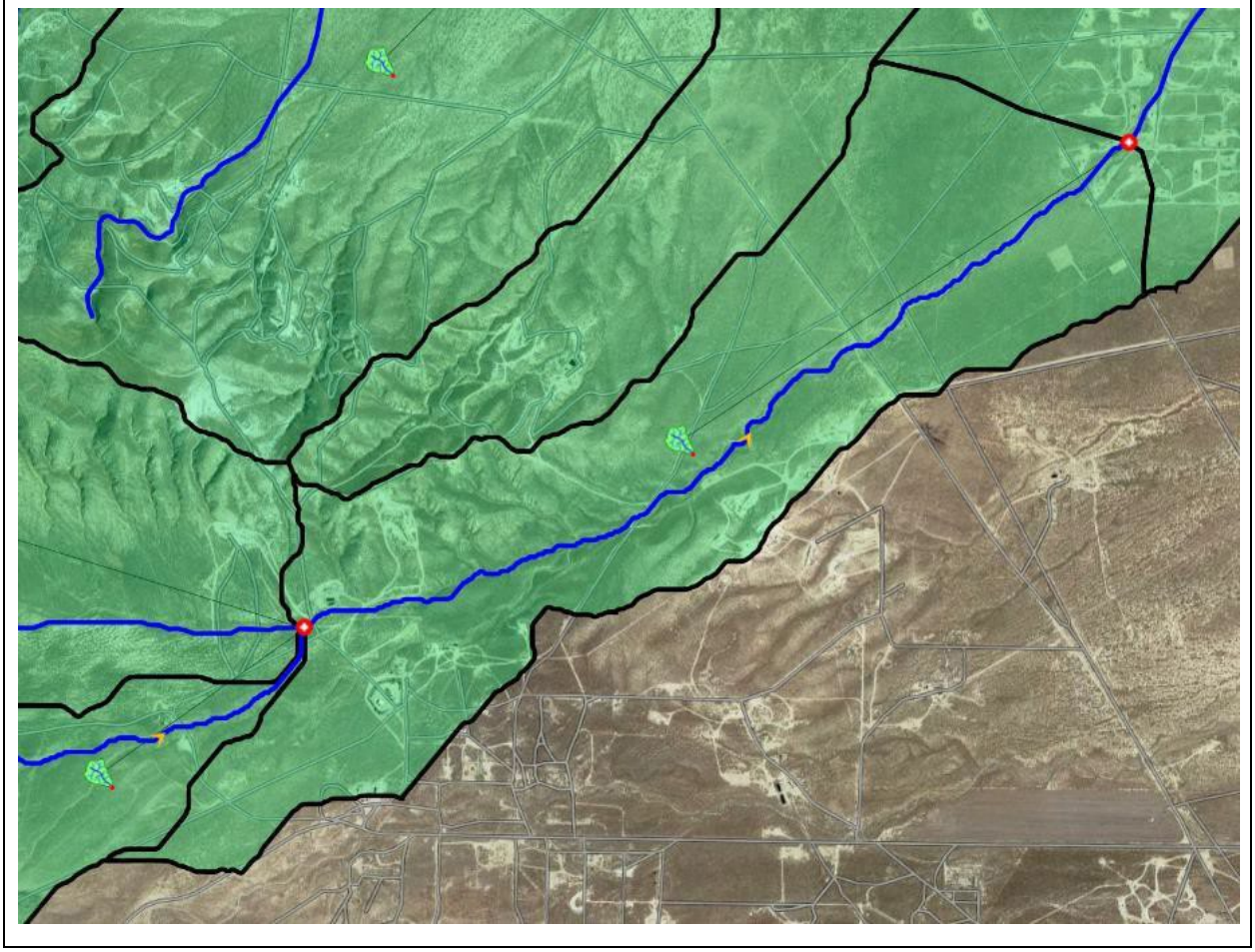
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
1.108	0.14	85.00	Developed, Medium Density
3.612	0.46	36.54	Undeveloped, Shrub/Scrub
0.954	0.12	61.03	Developed, Low Density
92.294	11.72	56.80	Developed, Open Space
0.138	0.02	77.00	Undeveloped, Barren Land
689.564	87.54	39.02	Undeveloped, Grassland
787.670	**100.00**	**41.19**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
29.59	100.00	0.04010	0.7440	Sheet Flow
29.99	4,469.59	0.02372	5.0858	Shallow Concentrated Flow
13.10	1,472.11	0.00320	1.8666	Channel Flow
38.21	10,337.14	0.01854	4.4965	Channel Flow
110.89	**16,378.84**	**Total**	**Lag Time = 66.54 minutes**	





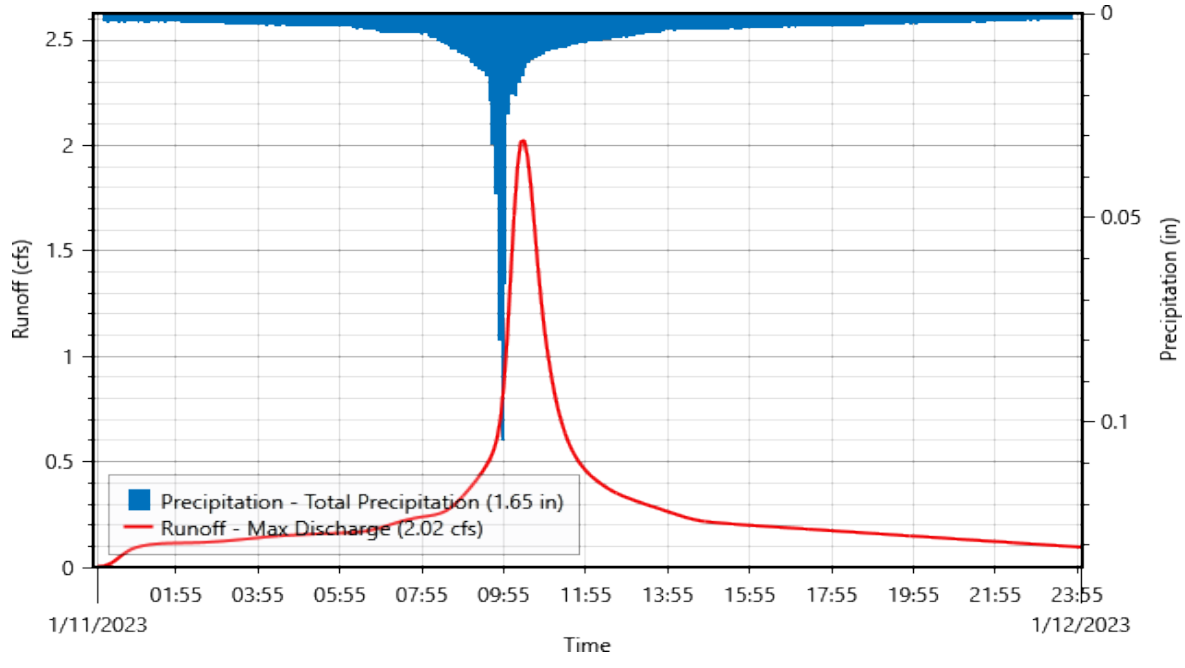
Subbasin ID:	Sub-20			
Scenario:	**Existing Conditions 10yr**		**Depth**	**Volume**
Peak discharge:	2.02 cfs	**Time of peak:**	11 Jan 2023, 10:25	
Drainage area:	714.148 acres	**Total rainfall:**	1.65 in	98.19920 ac-ft
Initial abstraction:	2.82 in	**Losses:**	1.64 in	97.66892 ac-ft
Curve Number:	41.47	**Precip excess:**	0.01 in	0.53028 ac-ft
Impervious surface:	0.54%	**Direct runoff:**	0.01 in	0.53 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	30.83 minutes	**Total runoff:**	0.01 in	0.53 ac-ft

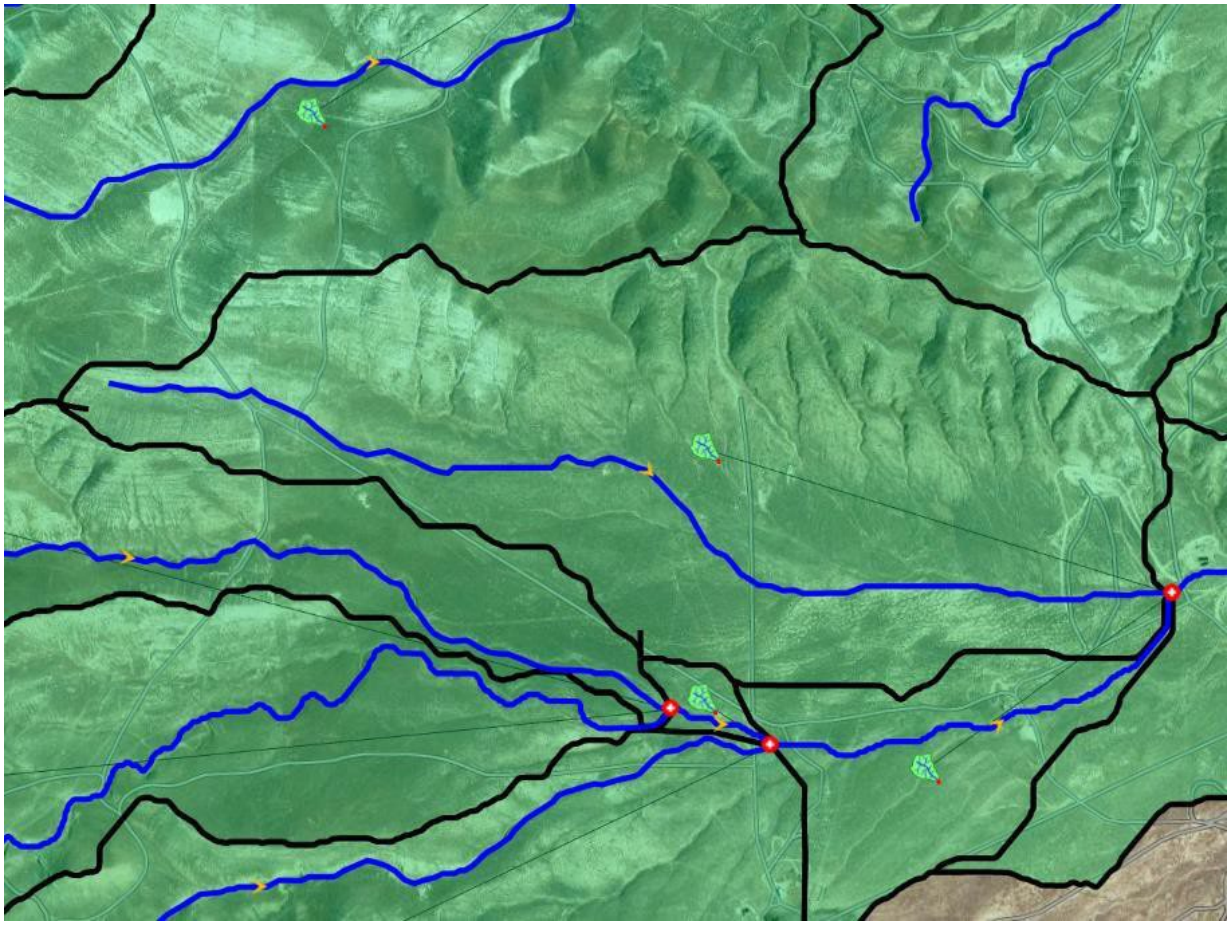
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
1.599	0.22	79.30	Developed, Medium Density
24.804	3.47	30.65	Undeveloped, Shrub/Scrub
0.430	0.06	61.00	Developed, Low Density
60.511	8.47	56.19	Developed, Open Space
626.805	87.77	40.37	Undeveloped, Grassland
714.148	**100.00**	**41.47**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
16.55	100.00	0.17144	1.5382	Sheet Flow
1.01	456.12	0.21931	15.4645	Shallow Concentrated Flow
0.89	623.85	0.12498	11.6744	Channel Flow
18.86	7,625.25	0.04142	6.7210	Channel Flow
9.23	2,974.94	0.02631	5.3566	Channel Flow
4.84	334.47	0.00121	1.1467	Channel Flow
51.38	**12,114.63**	**Total**	**Lag Time = 30.83 minutes**	





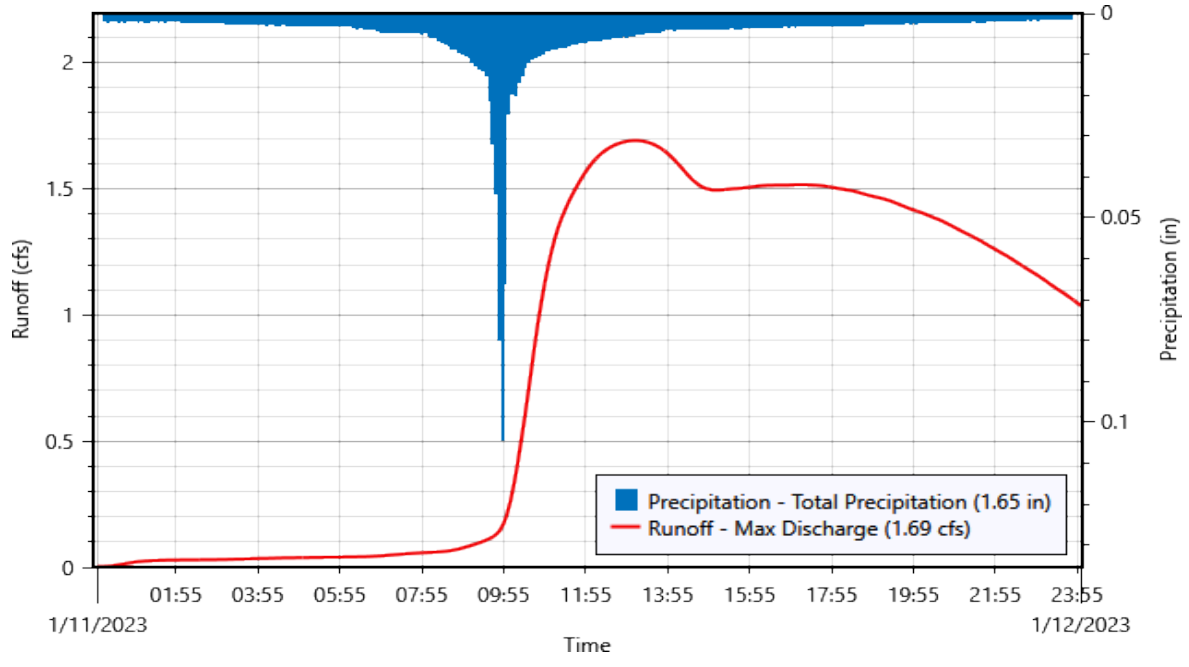
Subbasin ID:	Sub-21			
Scenario:	Existing Conditions 10yr		Depth	Volume
Peak discharge:	1.69 cfs	**Time of peak:**	11 Jan 2023, 01:05	
Drainage area:	140.608 acres	**Total rainfall:**	1.65 in	19.33360 ac-ft
Initial abstraction:	0.83 in	**Losses:**	1.50 in	17.62925 ac-ft
Curve Number:	70.73	**Precip excess:**	0.15 in	1.70435 ac-ft
Impervious surface:	0.65%	**Direct runoff:**	0.14 in	1.64 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	37.22 minutes	**Total runoff:**	0.14 in	1.64 ac-ft

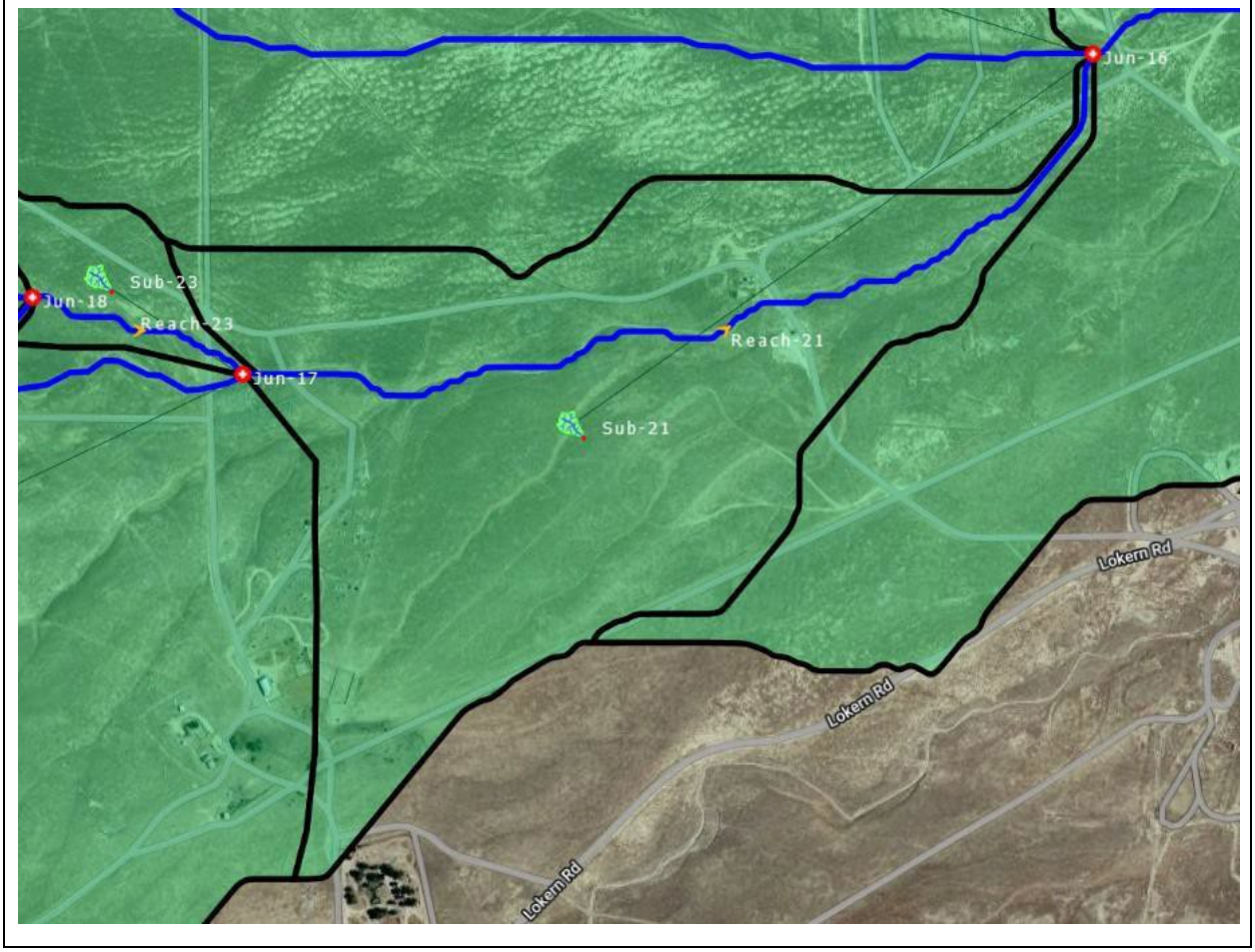
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
0.048	0.03	73.00	Undeveloped, Shrub/Scrub
23.066	16.40	70.83	Developed, Open Space
117.494	83.56	70.70	Undeveloped, Grassland
140.608	**100.00**	**70.73**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
34.47	100.00	0.02738	0.6147	Sheet Flow
19.66	3,615.01	0.03610	6.2745	Shallow Concentrated Flow
5.94	1,258.40	0.01138	3.5222	Channel Flow
1.95	736.77	0.03618	6.2812	Channel Flow
62.02	**5,710.18**	**Total**	**Lag Time = 37.22 minutes**	




Jun-16
Sub-23
Jun-18
Reach-23
Reach-21
Jun-17
Sub-21
Lokern Rd
Lokern Rd
Lokern Rd

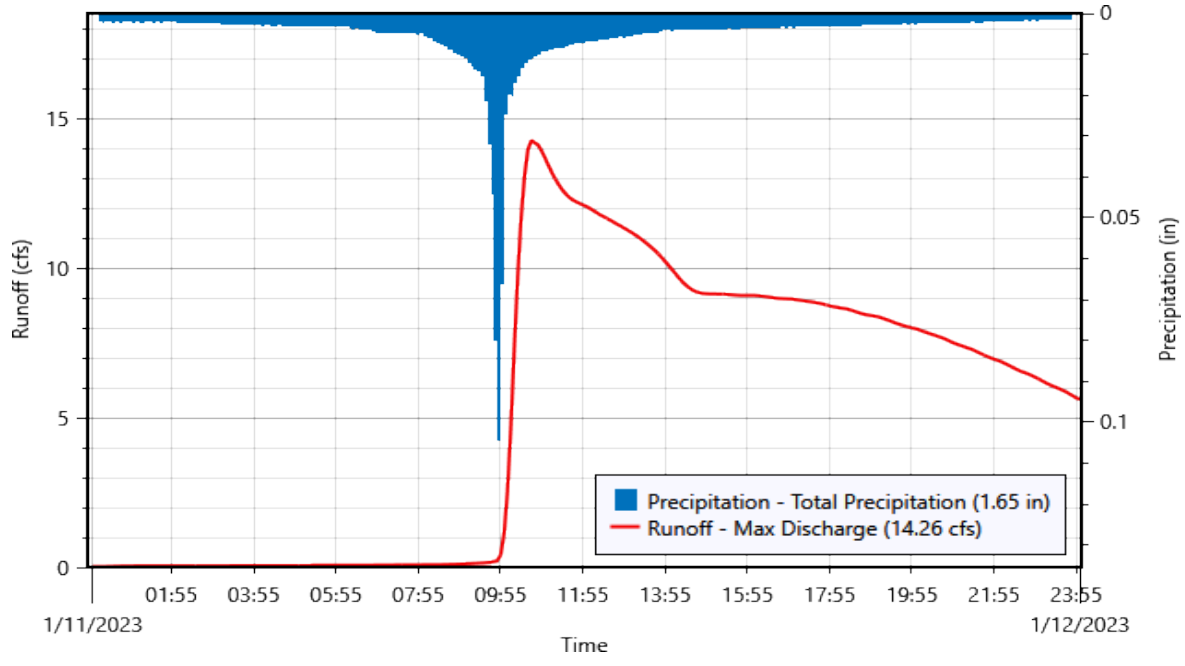
Subbasin ID:	Sub-22			
Scenario:	Existing Conditions 10yr		Depth	Volume
Peak discharge:	14.26 cfs	**Time of peak:**	11 Jan 2023, 10:40	
Drainage area:	624.791 acres	**Total rainfall:**	1.65 in	85.90560 ac-ft
Initial abstraction:	0.70 in	**Losses:**	1.44 in	75.17462 ac-ft
Curve Number:	74.21	**Precip excess:**	0.21 in	10.73098 ac-ft
Impervious surface:	0.15%	**Direct runoff:**	0.20 in	10.47 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	26.62 minutes	**Total runoff:**	0.20 in	10.47 ac-ft

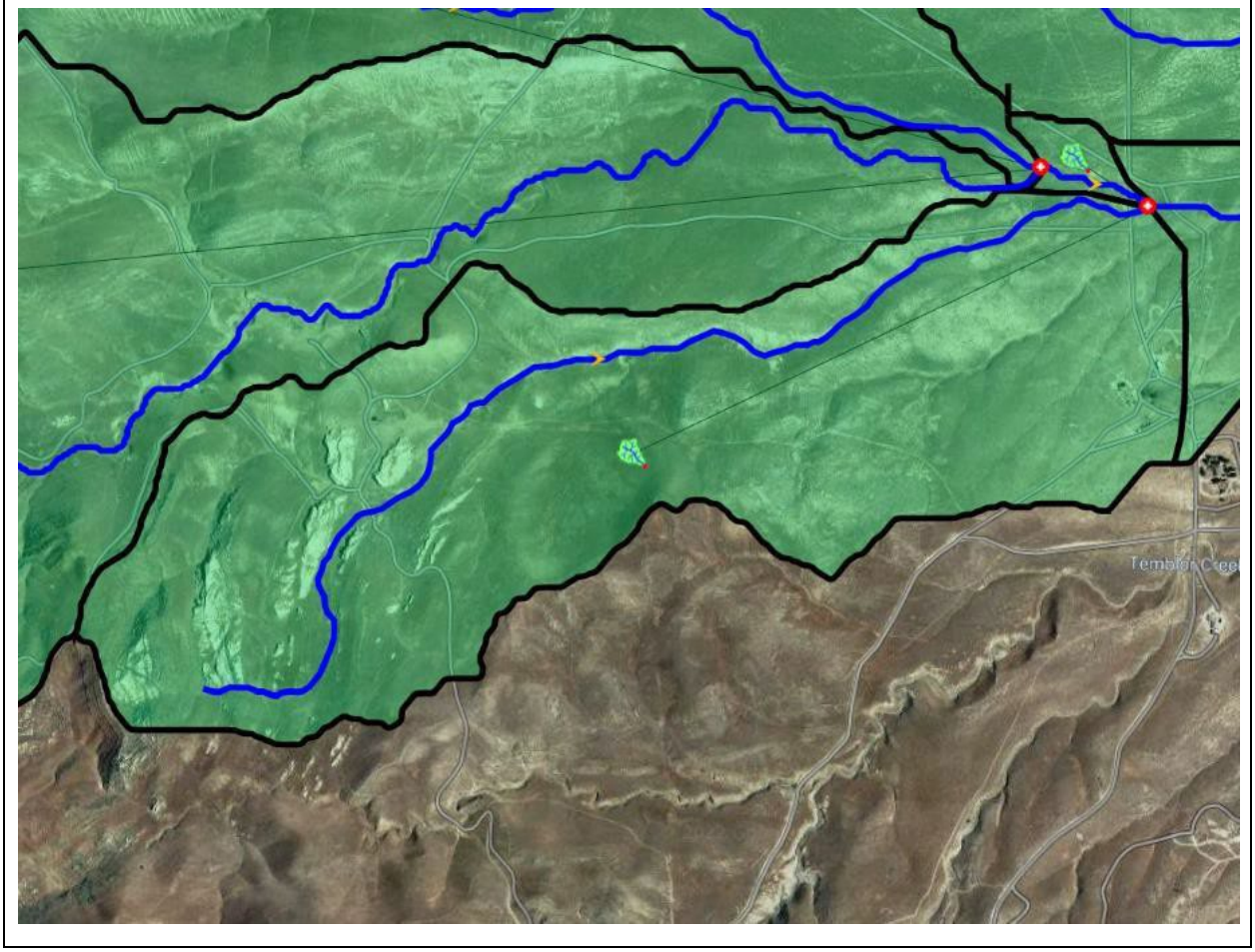
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
15.298	2.45	65.31	Undeveloped, Shrub/Scrub
44.349	7.10	81.50	Developed, Open Space
565.143	90.45	73.87	Undeveloped, Grassland
624.791	**100.00**	**74.21**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
14.10	100.00	0.25569	1.8785	Sheet Flow
1.03	658.49	0.44023	21.9101	Shallow Concentrated Flow
0.57	222.33	0.16461	13.3980	Shallow Concentrated Flow
5.54	2,803.60	0.06494	8.4151	Channel Flow
23.12	8,603.50	0.03510	6.1869	Channel Flow
44.36	**12,387.92**	**Total**	**Lag Time = 26.62 minutes**	





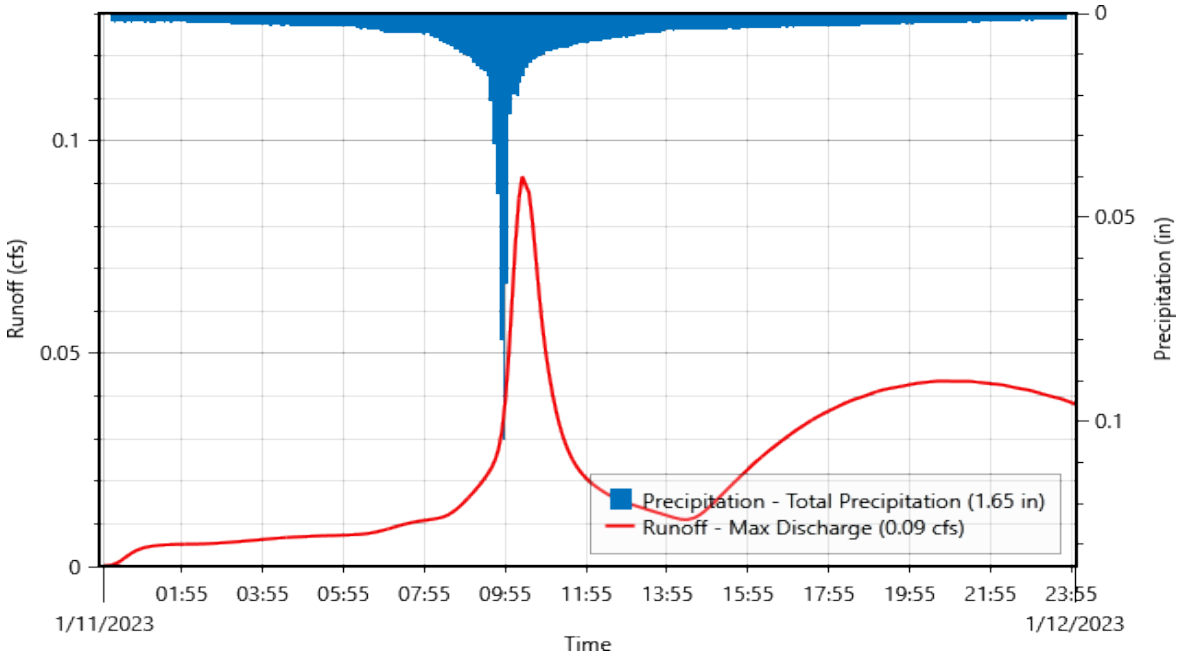
Subbasin ID:	Sub-23			
Scenario:	Existing Conditions 10yr		Depth	Volume
Peak discharge:	0.09 cfs	**Time of peak:**	11 Jan 2023, 10:25	
Drainage area:	13.631 acres	**Total rainfall:**	1.65 in	1.87440 ac-ft
Initial abstraction:	1.27 in	**Losses:**	1.61 in	1.82633 ac-ft
Curve Number:	61.18	**Precip excess:**	0.04 in	0.04807 ac-ft
Impervious surface:	1.28%	**Direct runoff:**	0.04 in	0.05 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	30.66 minutes	**Total runoff:**	0.04 in	0.05 ac-ft

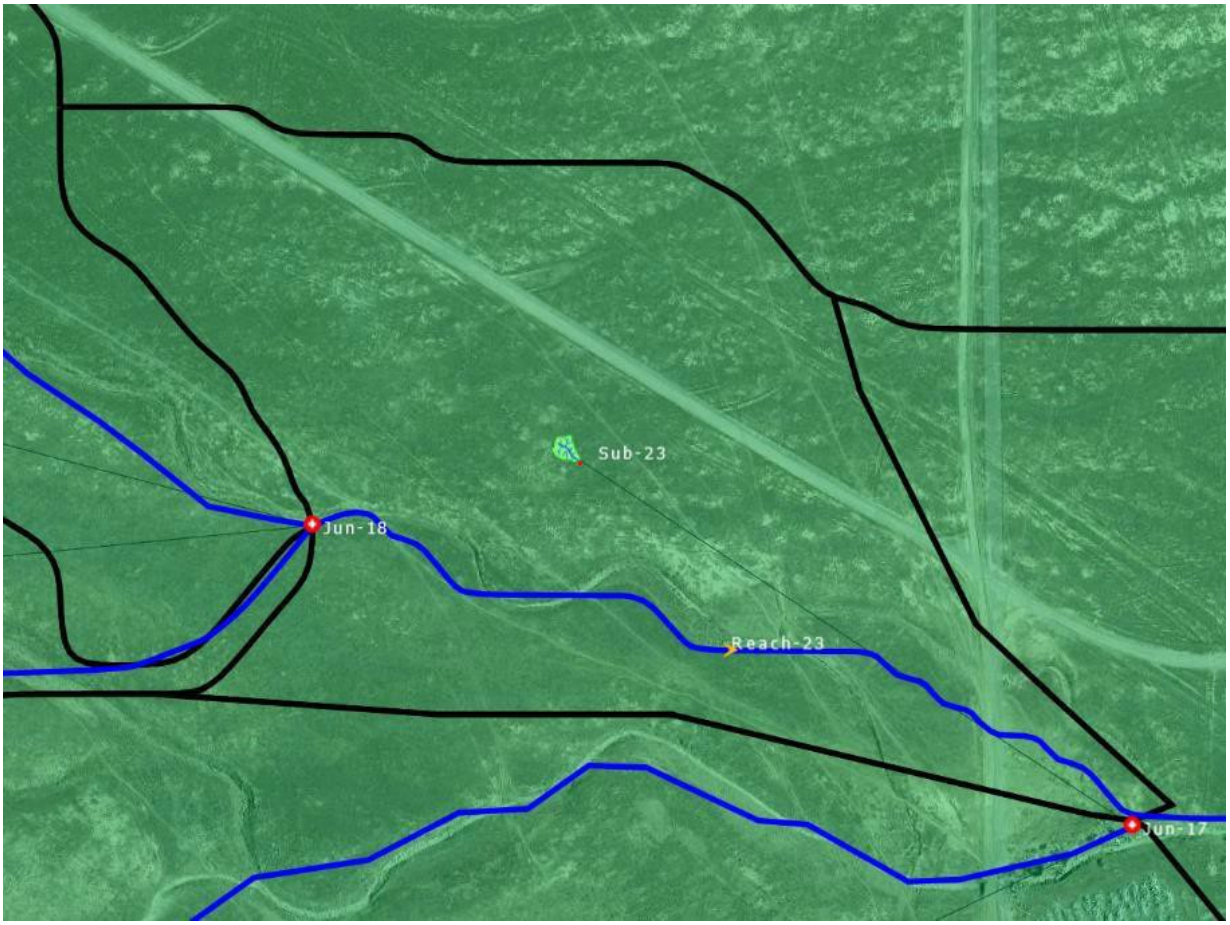
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
3.902	28.63	69.00	Developed, Open Space
9.729	71.37	58.05	Undeveloped, Grassland
13.631	**100.00**	**61.18**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
44.71	100.00	0.01429	0.4440	Sheet Flow
1.98	295.62	0.02383	5.0982	Shallow Concentrated Flow
0.56	163.06	0.09046	9.9322	Shallow Concentrated Flow
0.38	151.74	0.16695	13.4926	Shallow Concentrated Flow
0.27	66.19	0.06214	8.2320	Shallow Concentrated Flow
3.19	963.56	0.02314	5.0234	Channel Flow
51.09	**1,740.17**	**Total**	**Lag Time = 30.66 minutes**	




Sub-23
Jun-18
Reach-23
Jun-17

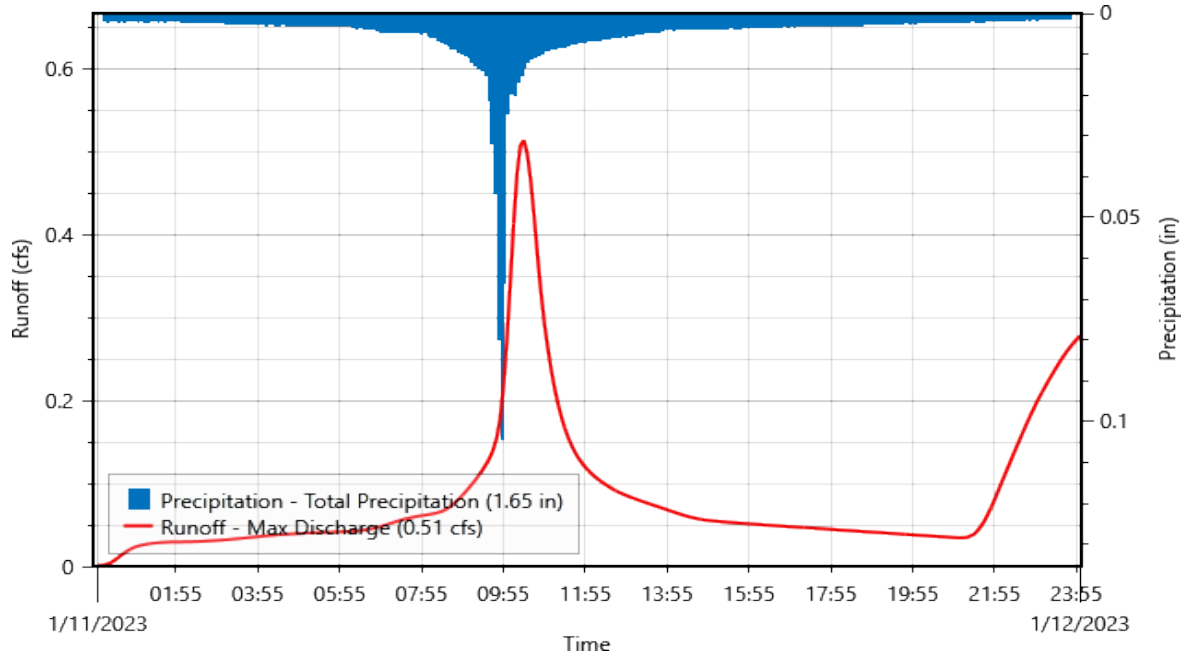
Subbasin ID:	Sub-24			
Scenario:	Existing Conditions 10yr		Depth	Volume
Peak discharge:	0.51 cfs	**Time of peak:**	11 Jan 2023, 10:25	
Drainage area:	662.076 acres	**Total rainfall:**	1.65 in	91.03600 ac-ft
Initial abstraction:	1.57 in	**Losses:**	1.65 in	90.85486 ac-ft
Curve Number:	56.09	**Precip excess:**	0.00 in	0.18114 ac-ft
Impervious surface:	0.15%	**Direct runoff:**	0.00 in	0.16 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	31.77 minutes	**Total runoff:**	0.00 in	0.16 ac-ft

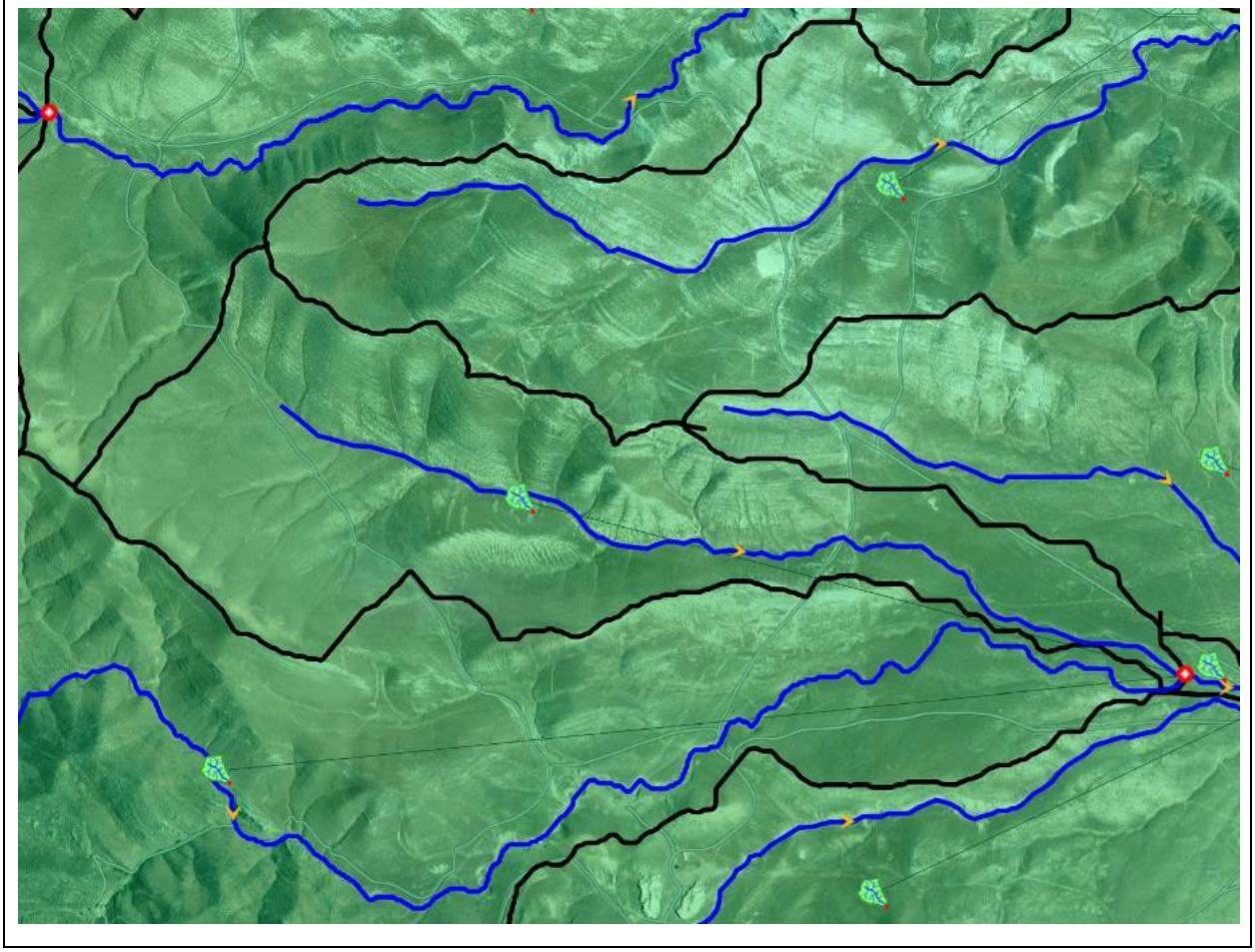
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
0.098	0.01	30.00	Undeveloped, Shrub/Scrub
37.733	5.70	67.01	Developed, Open Space
624.245	94.29	55.43	Undeveloped, Grassland
662.076	**100.00**	**56.09**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
14.40	100.00	0.24257	1.8297	Sheet Flow
1.26	869.08	0.51033	23.5902	Shallow Concentrated Flow
1.44	665.78	0.22832	15.7788	Shallow Concentrated Flow
3.67	1,184.85	0.11132	11.0178	Shallow Concentrated Flow
18.74	7,536.85	0.04100	6.6863	Channel Flow
13.43	4,799.21	0.03234	5.9389	Channel Flow
52.94	**15,155.77**	**Total**	**Lag Time = 31.77 minutes**	





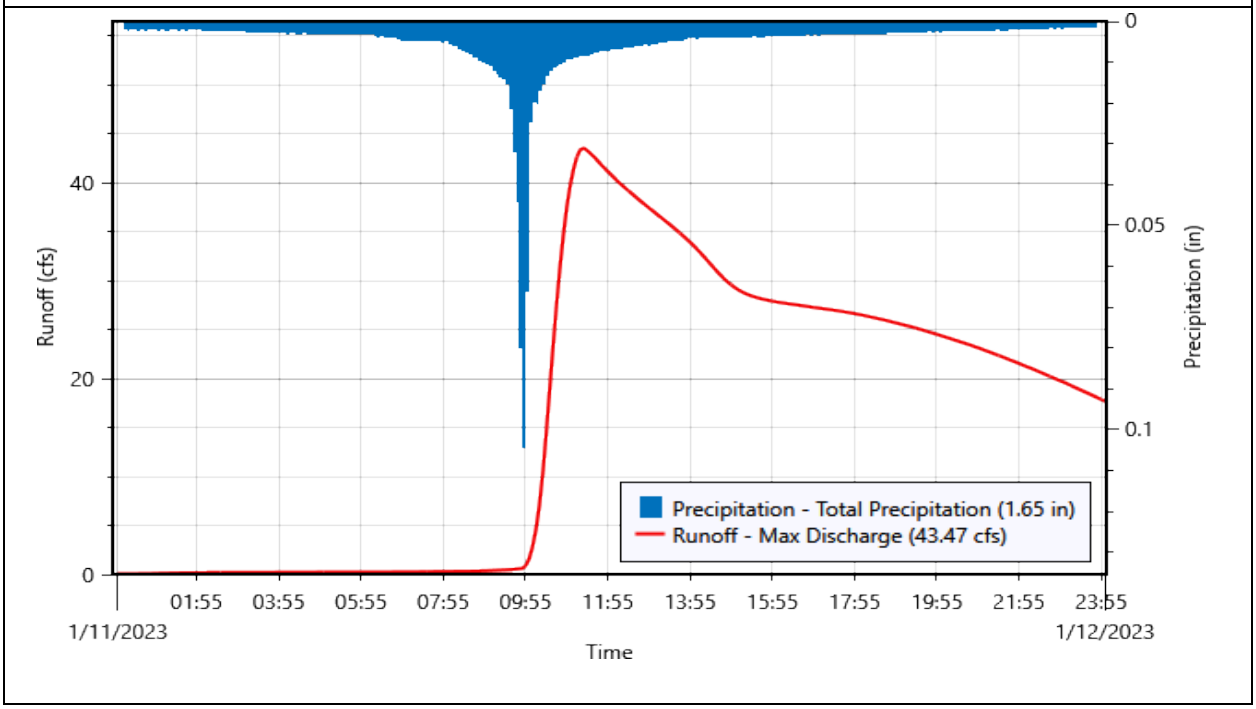
Subbasin ID:	Sub-25			
Scenario:	**Existing Conditions 10yr**		**Depth**	**Volume**
Peak discharge:	43.47 cfs	**Time of peak:**	11 Jan 2023, 11:20	
Drainage area:	1,694.320 acres	**Total rainfall:**	1.65 in	232.97119 ac-ft
Initial abstraction:	0.65 in	**Losses:**	1.41 in	199.33386 ac-ft
Curve Number:	75.41	**Precip excess:**	0.24 in	33.63733 ac-ft
Impervious surface:	0.25%	**Direct runoff:**	0.23 in	32.01 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	53.90 minutes	**Total runoff:**	0.23 in	32.01 ac-ft

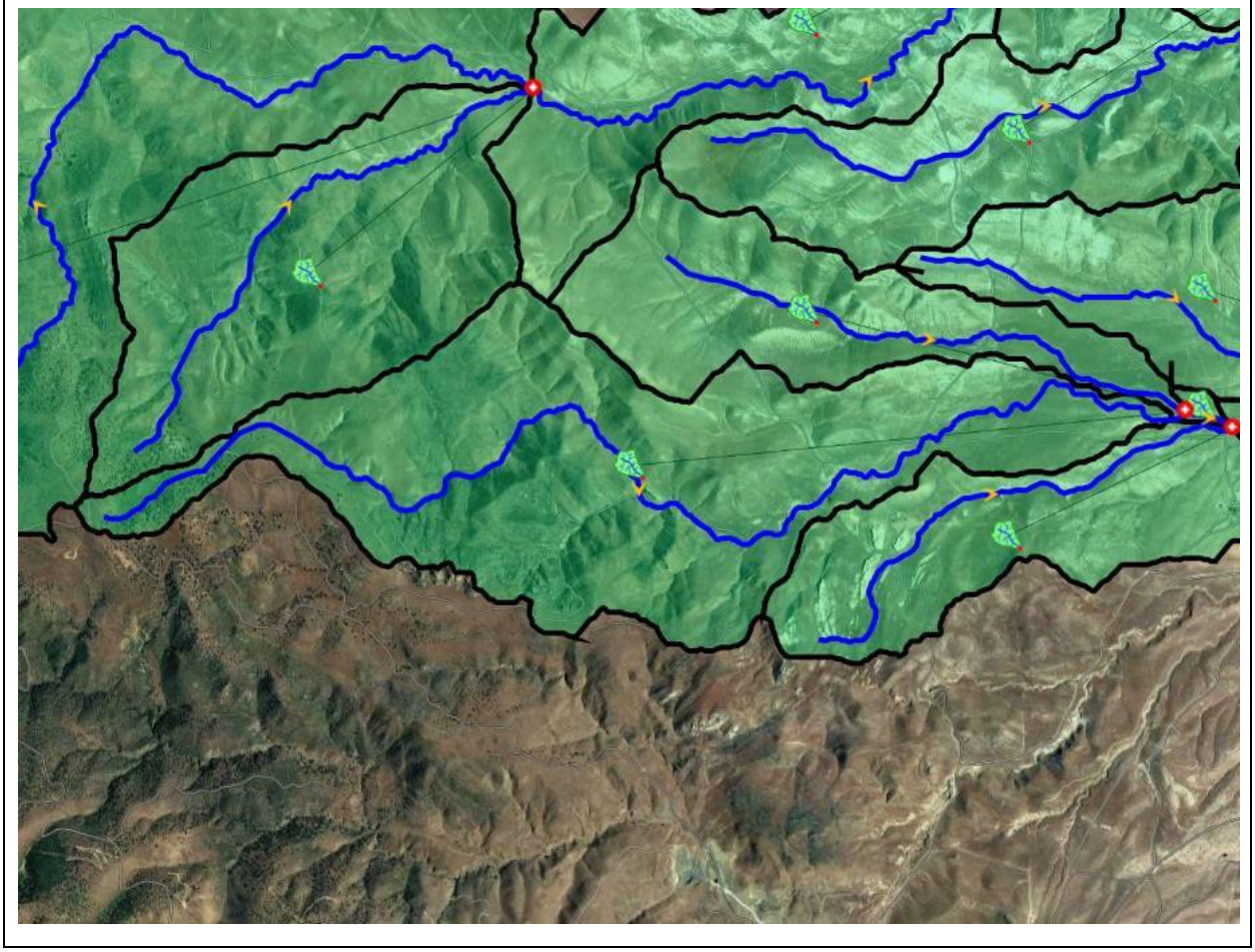
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
0.589	0.03	91.09	Developed, Medium Density
343.072	20.25	72.37	Undeveloped, Shrub/Scrub
1.038	0.06	86.45	Developed, Low Density
128.369	7.58	82.02	Developed, Open Space
1,221.252	72.08	75.55	Undeveloped, Grassland
1,694.320	**100.00**	**75.41**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
23.14	100.00	0.07413	1.0115	Sheet Flow
2.26	773.43	0.12489	11.6701	Shallow Concentrated Flow
2.16	1,933.44	0.20208	14.8446	Channel Flow
10.49	5,320.75	0.06516	8.4296	Channel Flow
3.64	2,816.87	0.15175	12.8636	Channel Flow
20.32	9,127.19	0.05113	7.4670	Channel Flow
27.81	10,228.78	0.03427	6.1135	Channel Flow
89.82	**30,300.46**	**Total**	**Lag Time = 53.90 minutes**	





Nodes

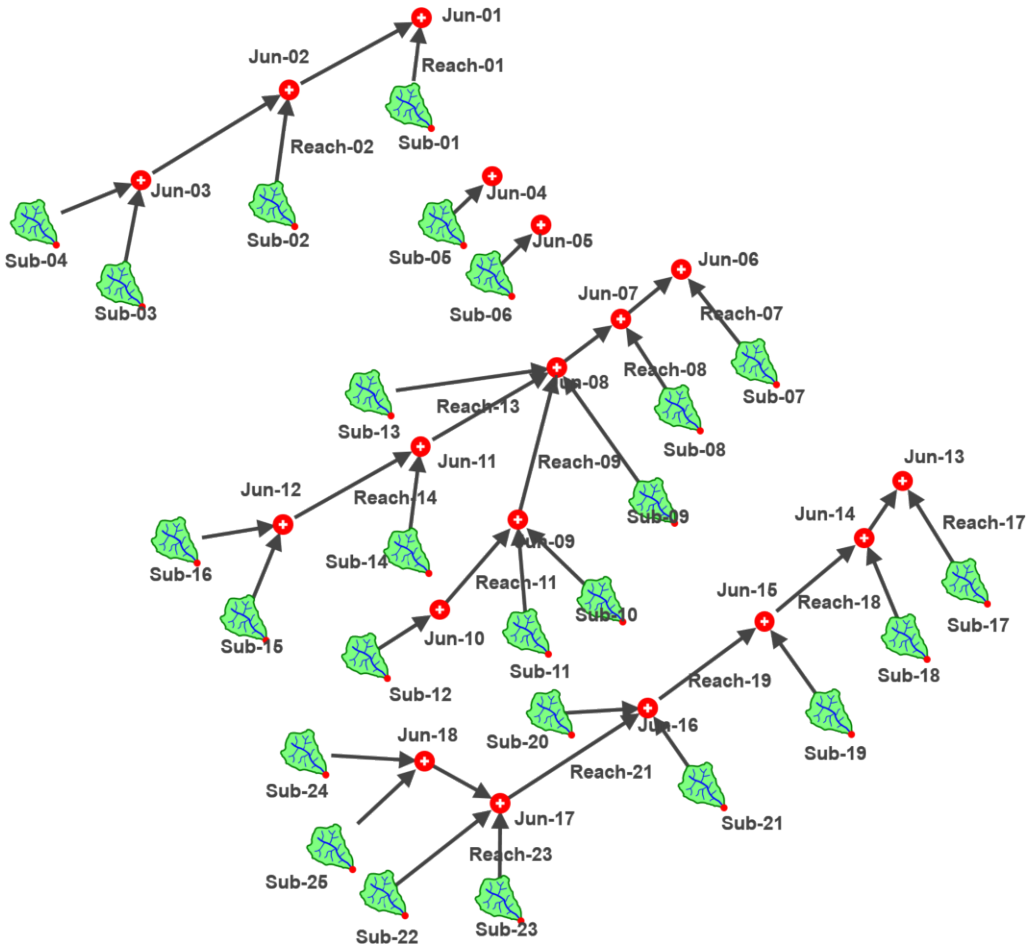
Element ID	Element Type	Peak Inflow (cfs)	Peak Outflow (cfs)	Peak Diverted Flow (cfs)
Jun-01	Junction	23.65	23.65	
Jun-02	Junction	19.94	19.94	
Jun-03	Junction	19.95	19.95	
Jun-04	Junction	7.56	7.56	
Jun-05	Junction	10.23	10.23	
Jun-06	Junction	82.75	82.75	
Jun-07	Junction	79.89	79.89	
Jun-08	Junction	75.09	75.09	
Jun-09	Junction	7.00	7.00	
Jun-10	Junction	2.46	2.46	
Jun-11	Junction	70.51	70.51	
Jun-12	Junction	70.31	70.31	
Jun-13	Junction	65.72	65.72	
Jun-14	Junction	61.52	61.52	
Jun-15	Junction	59.52	59.52	
Jun-16	Junction	58.07	58.07	
Jun-17	Junction	56.37	56.37	
Jun-18	Junction	43.65	43.65	

Routing Reaches

Reach ID	Peak Inflow (cfs)	Peak Outflow (cfs)	Attenuated Flow (cfs)
Reach-01	19.94	19.73	0.21
Reach-02	19.95	19.91	0.04
Reach-03	0.00	0.00	0.00
Reach-04	0.00	0.00	0.00
Reach-05	0.00	0.00	0.00
Reach-06	0.00	0.00	0.00
Reach-07	79.89	79.89	0.00
Reach-08	75.09	75.08	0.01
Reach-09	7.00	6.24	0.76
Reach-10	0.00	0.00	0.00
Reach-11	2.46	1.58	0.88
Reach-12	0.00	0.00	0.00
Reach-13	70.51	70.47	0.04
Reach-14	70.31	70.30	0.01
Reach-15	0.00	0.00	0.00
Reach-16	0.00	0.00	0.00
Reach-17	61.52	61.52	0.00
Reach-18	59.52	57.51	2.01
Reach-19	58.07	57.83	0.24
Reach-20	0.00	0.00	0.00
Reach-21	56.37	56.05	0.32
Reach-22	0.00	0.00	0.00
Reach-23	43.65	43.56	0.09
Reach-24	0.00	0.00	0.00
Reach-25	0.00	0.00	0.00

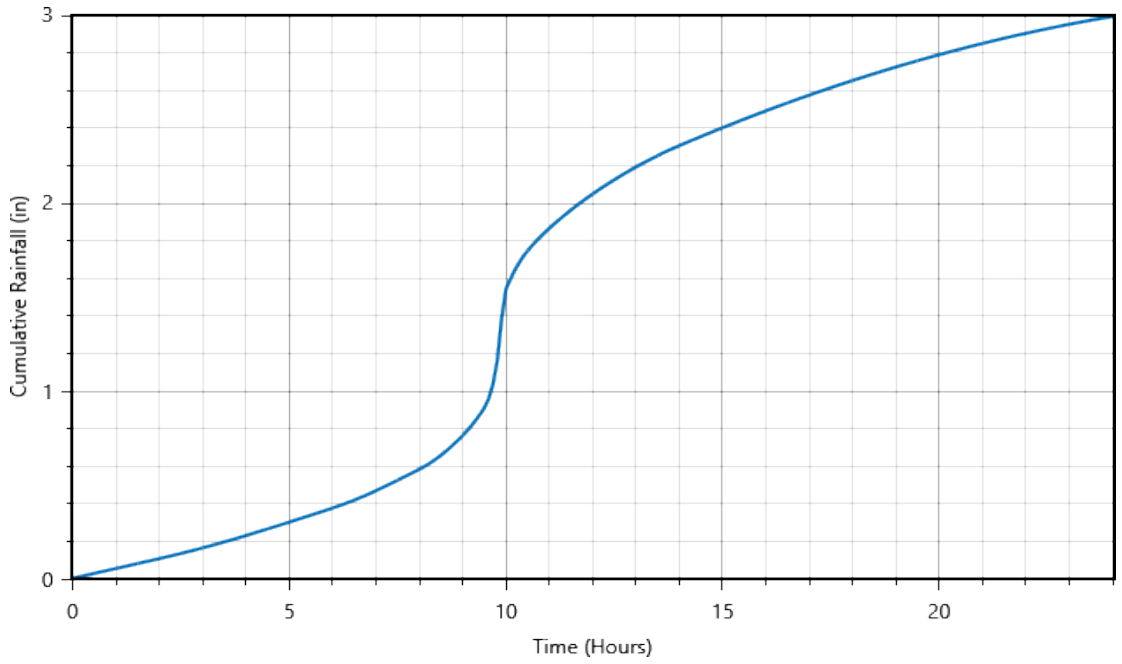
Proposed Development 100yr

Watershed Routing Diagram



Design Storm

Precipitation type: SCS Storm
SCS storm distribution: Type I
Rainfall depth: 2.99 in



Watershed Summary

Subbasin ID	Drainage Area (acres)	Initial Abstraction (in)	Curve Number	Impervious Surface (%)	Lag Time (minutes)	Peak Discharge (cfs)
Sub-01	1,269.566	1.23	61.84	1.18	107.15	46.48
Sub-02	337.798	2.28	46.74	0.15	50.54	1.81
Sub-03	169.707	2.61	43.39	0.12	32.39	0.39
Sub-04	1,961.124	0.86	70.00	0.09	58.02	221.35
Sub-05	685.814	1.94	50.82	9.03	125.36	26.44
Sub-06	856.439	1.86	51.75	9.59	198.99	27.28
Sub-07	269.771	1.05	65.60	10.71	98.48	25.53
Sub-08	503.505	1.48	57.53	8.38	395.42	14.19
Sub-09	1,130.587	2.84	41.33	0.94	67.09	6.55
Sub-10	1,153.361	1.94	50.79	1.30	55.92	12.39
Sub-11	161.318	4.26	31.97	1.51	40.10	2.01
Sub-12	952.517	3.33	37.51	0.52	34.22	4.46
Sub-13	1,426.690	3.40	37.06	2.54	649.32	5.65
Sub-14	1,158.859	2.01	49.91	0.23	43.12	10.40
Sub-15	1,054.808	0.70	74.04	0.23	30.66	256.17
Sub-16	3,426.802	0.76	72.40	0.26	59.76	492.32
Sub-17	337.184	0.97	67.43	10.46	80.39	39.46
Sub-18	1,474.591	1.47	57.69	3.55	96.69	40.88
Sub-19	787.670	2.86	41.19	1.53	66.54	7.46
Sub-20	714.148	2.82	41.47	0.54	30.83	3.66
Sub-21	140.608	0.83	70.73	0.65	37.22	22.43
Sub-22	624.791	0.70	74.21	0.15	26.62	164.39
Sub-23	13.631	1.27	61.18	1.28	30.66	0.63
Sub-24	662.076	1.57	56.09	0.15	31.77	12.20
Sub-25	1,694.320	0.65	75.41	0.25	53.90	337.38

Subbasins

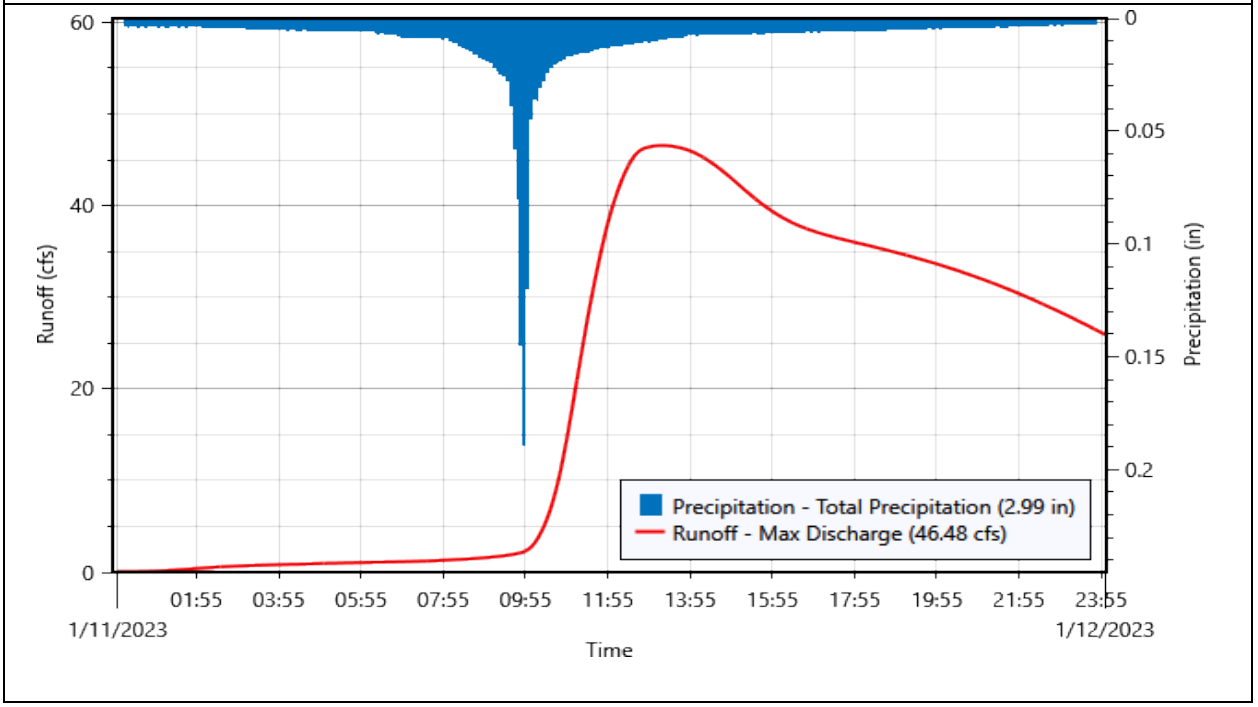
Subbasin ID:	**Sub-01**			
Scenario:	**Proposed Development 100yr**		**Depth**	**Volume**
Peak discharge:	46.48 cfs	**Time of peak:**	11 Jan 2023, 01:15	
Drainage area:	1,269.566 acres	**Total rainfall:**	2.99 in	316.33401 ac-ft
Initial abstraction:	1.23 in	**Losses:**	2.57 in	271.76652 ac-ft
Curve Number:	61.84	**Precip excess:**	0.42 in	44.56749 ac-ft
Impervious surface:	1.18%	**Direct runoff:**	0.38 in	40.01 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	107.15 minutes	**Total runoff:**	0.38 in	40.01 ac-ft

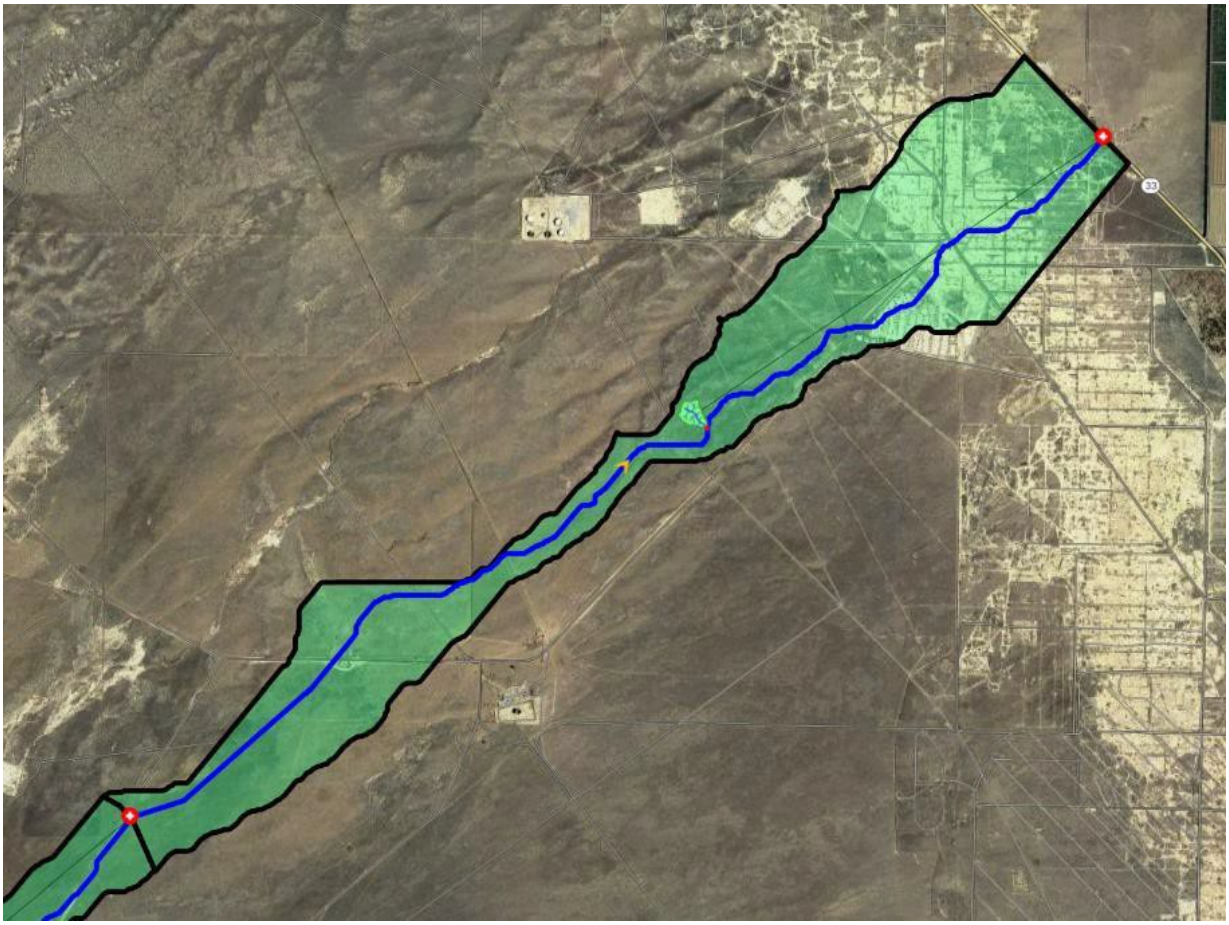
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
2.200	0.17	77.00	Developed, Medium Density
72.954	5.75	73.69	Agricultural, Cultivated Crops
12.818	1.01	73.61	Developed, Low Density
248.559	19.58	68.81	Developed, Open Space
2.419	0.19	77.00	Undeveloped, Barren Land
930.614	73.30	58.81	Undeveloped, Grassland
1,269.566	**100.00**	**61.84**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
45.65	99.01	0.01330	0.4284	Sheet Flow
13.66	1,732.24	0.01717	4.3269	Shallow Concentrated Flow
119.26	26,180.93	0.01221	3.6493	Channel Flow
178.57	**28,012.18**	**Total**	**Lag Time = 107.15 minutes**	





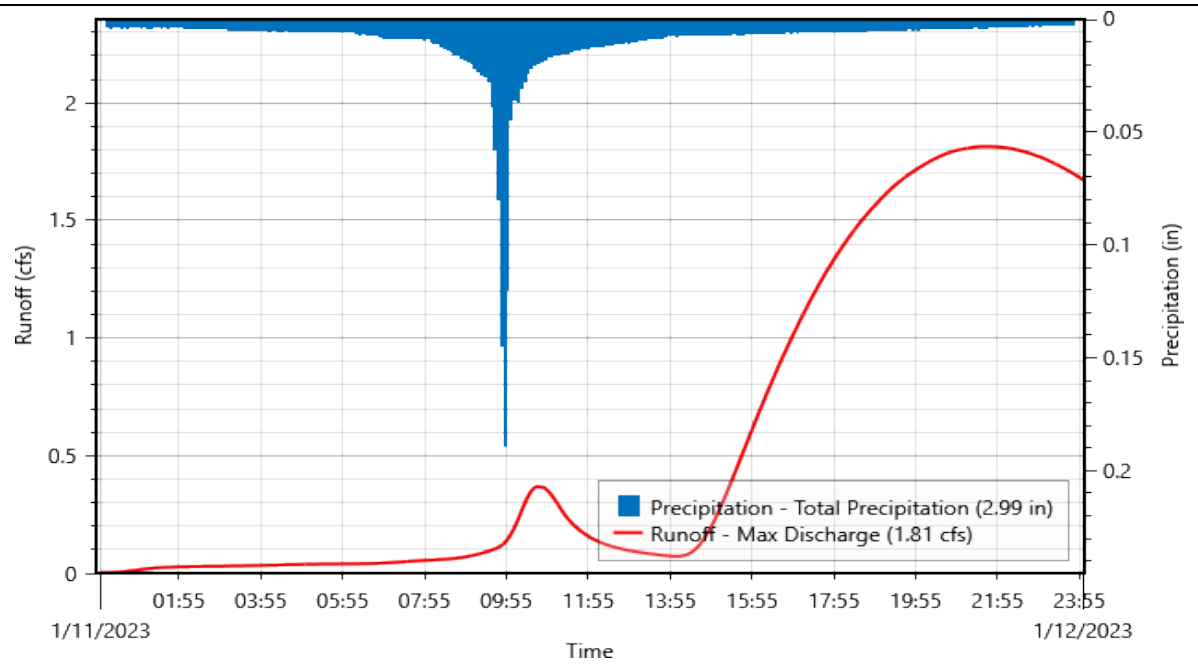
Subbasin ID:	Sub-02		Depth	Volume
Scenario:	Proposed Development 100yr			
Peak discharge:	1.81 cfs	**Time of peak:**	11 Jan 2023, 09:40	
Drainage area:	337.798 acres	**Total rainfall:**	2.99 in	84.16650 ac-ft
Initial abstraction:	2.28 in	**Losses:**	2.94 in	82.86976 ac-ft
Curve Number:	46.74	**Precip excess:**	0.05 in	1.29675 ac-ft
Impervious surface:	0.15%	**Direct runoff:**	0.04 in	1.15 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	50.54 minutes	**Total runoff:**	0.04 in	1.15 ac-ft

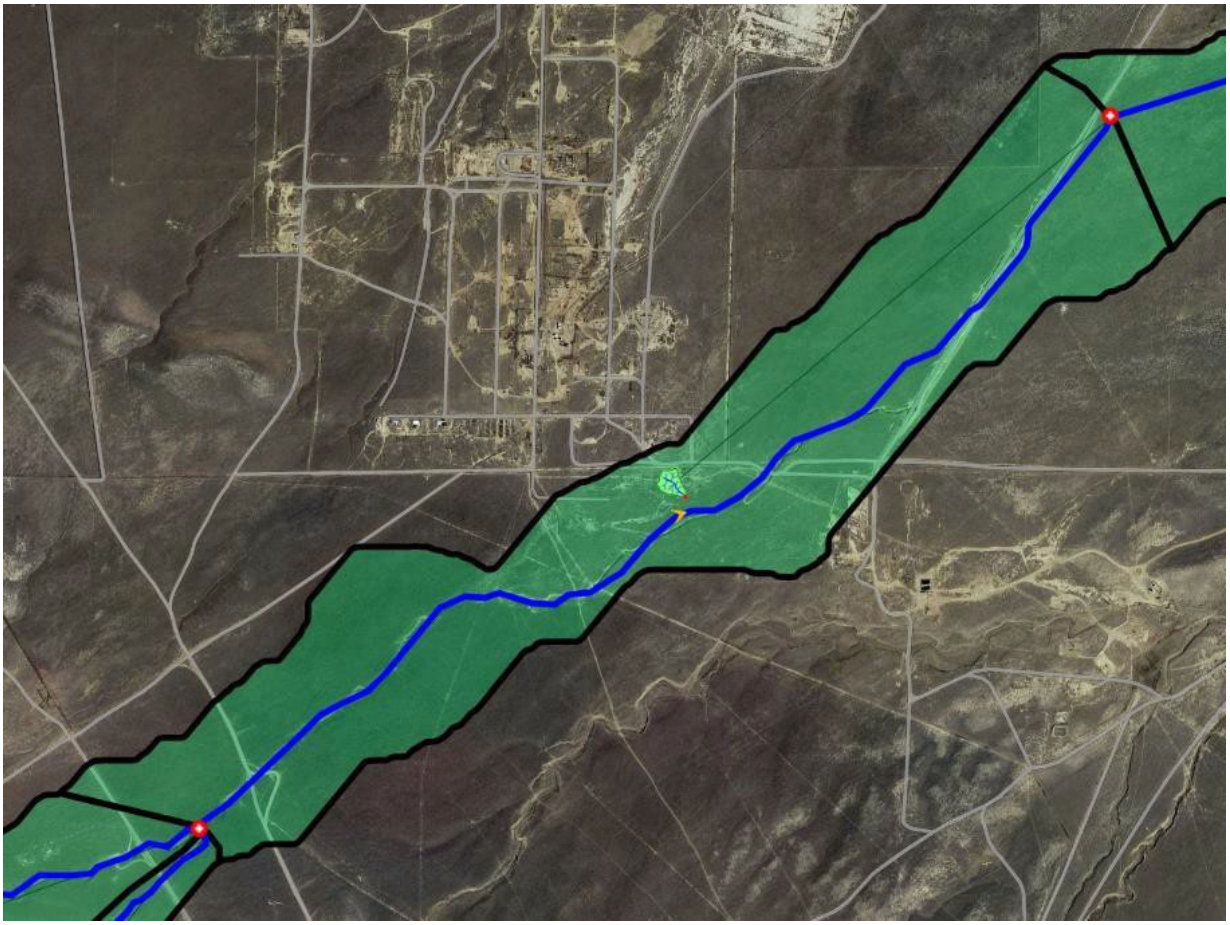
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
29.531	8.74	54.73	Developed, Open Space
308.267	91.26	45.97	Undeveloped, Grassland
337.798	**100.00**	**46.74**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
30.41	100.00	0.03745	0.7190	Sheet Flow
14.64	1,422.09	0.02620	5.3456	Shallow Concentrated Flow
39.18	10,516.23	0.01825	4.4614	Channel Flow
84.23	**12,038.32**	**Total**	**Lag Time = 50.54 minutes**	





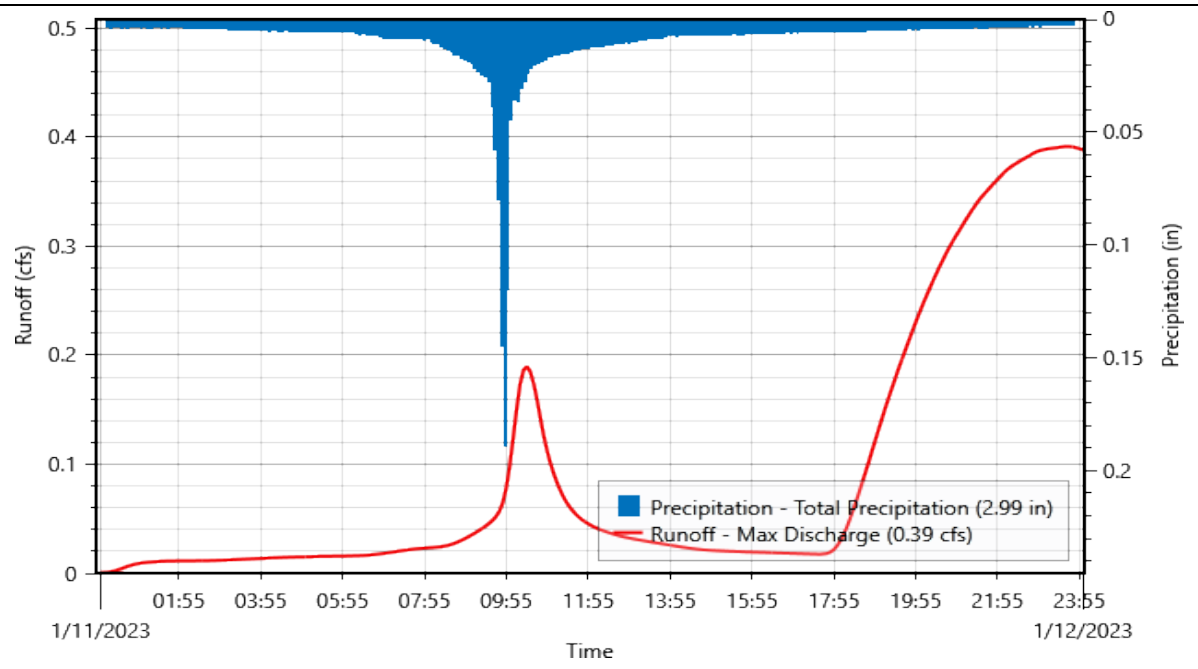
Subbasin ID:	Sub-03		Depth	Volume
Scenario:	Proposed Development 100yr			
Peak discharge:	0.39 cfs	**Time of peak:**	11 Jan 2023, 11:35	
Drainage area:	169.707 acres	**Total rainfall:**	2.99 in	42.29056 ac-ft
Initial abstraction:	2.61 in	**Losses:**	2.98 in	42.08788 ac-ft
Curve Number:	43.39	**Precip excess:**	0.01 in	0.20268 ac-ft
Impervious surface:	0.12%	**Direct runoff:**	0.01 in	0.18 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	32.39 minutes	**Total runoff:**	0.01 in	0.18 ac-ft

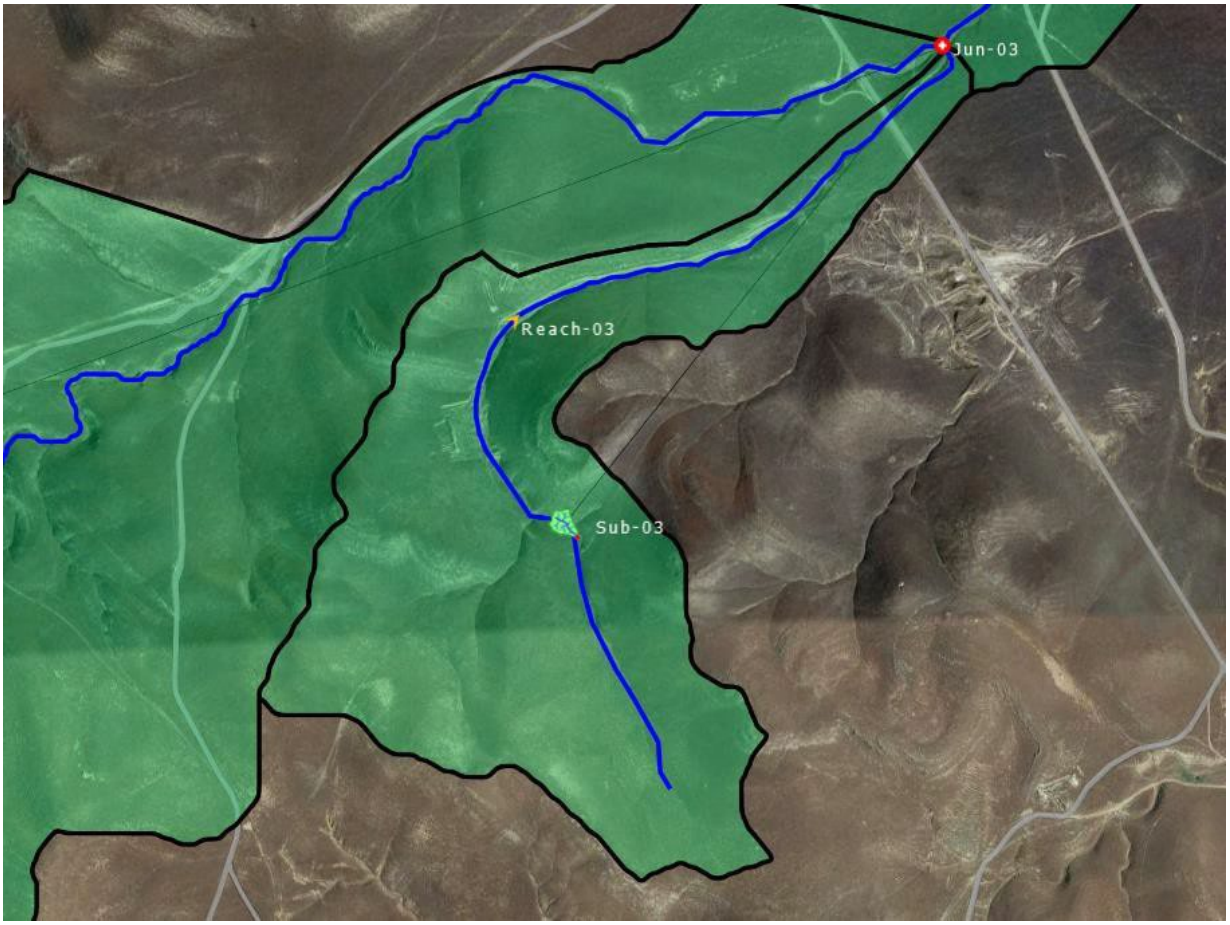
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
1.174	0.69	79.00	Developed, Open Space
168.533	99.31	43.14	Undeveloped, Grassland
169.707	**100.00**	**43.39**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
33.11	110.46	0.03693	0.7140	Sheet Flow
3.55	740.31	0.12053	11.4645	Shallow Concentrated Flow
17.32	6,423.63	0.03486	6.1655	Channel Flow
53.98	**7,274.40**	**Total**	**Lag Time = 32.39 minutes**	




Jun-03
Reach-03
Sub-03

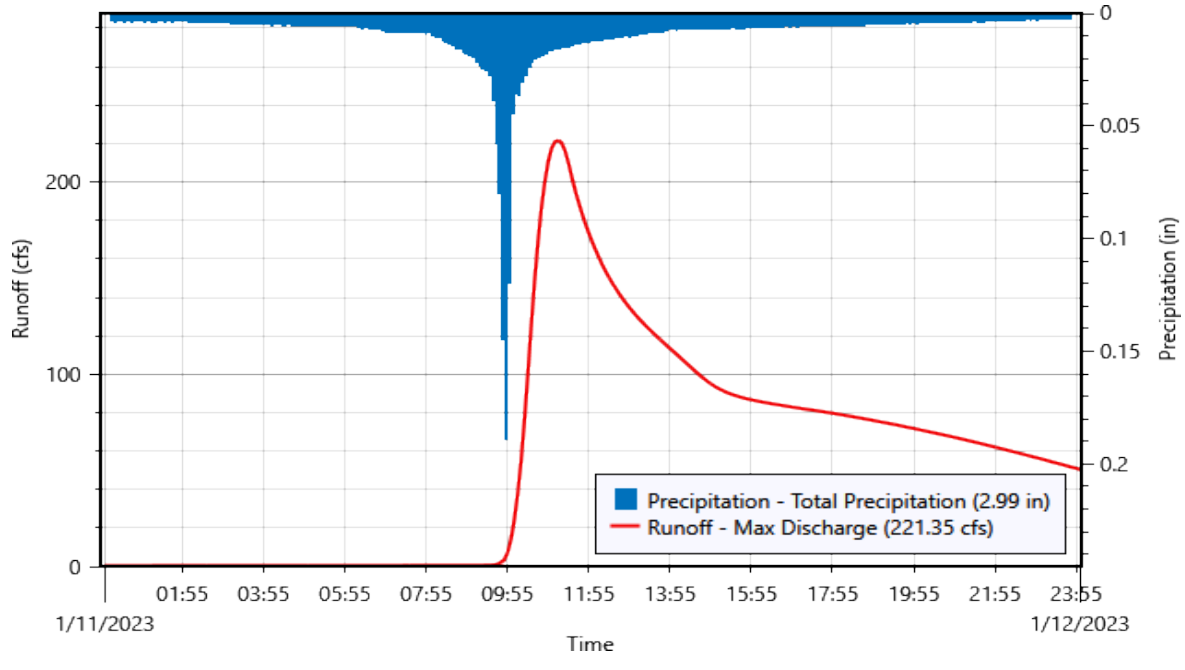
Subbasin ID:	Sub-04		Depth	Volume
Scenario:	Proposed Development 100yr			
Peak discharge:	221.35 cfs	**Time of peak:**	11 Jan 2023, 11:10	
Drainage area:	1,961.124 acres	**Total rainfall:**	2.99 in	488.65369 ac-ft
Initial abstraction:	0.86 in	**Losses:**	2.28 in	372.74816 ac-ft
Curve Number:	70.00	**Precip excess:**	0.71 in	115.90553 ac-ft
Impervious surface:	0.09%	**Direct runoff:**	0.68 in	110.97 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	58.02 minutes	**Total runoff:**	0.68 in	110.97 ac-ft

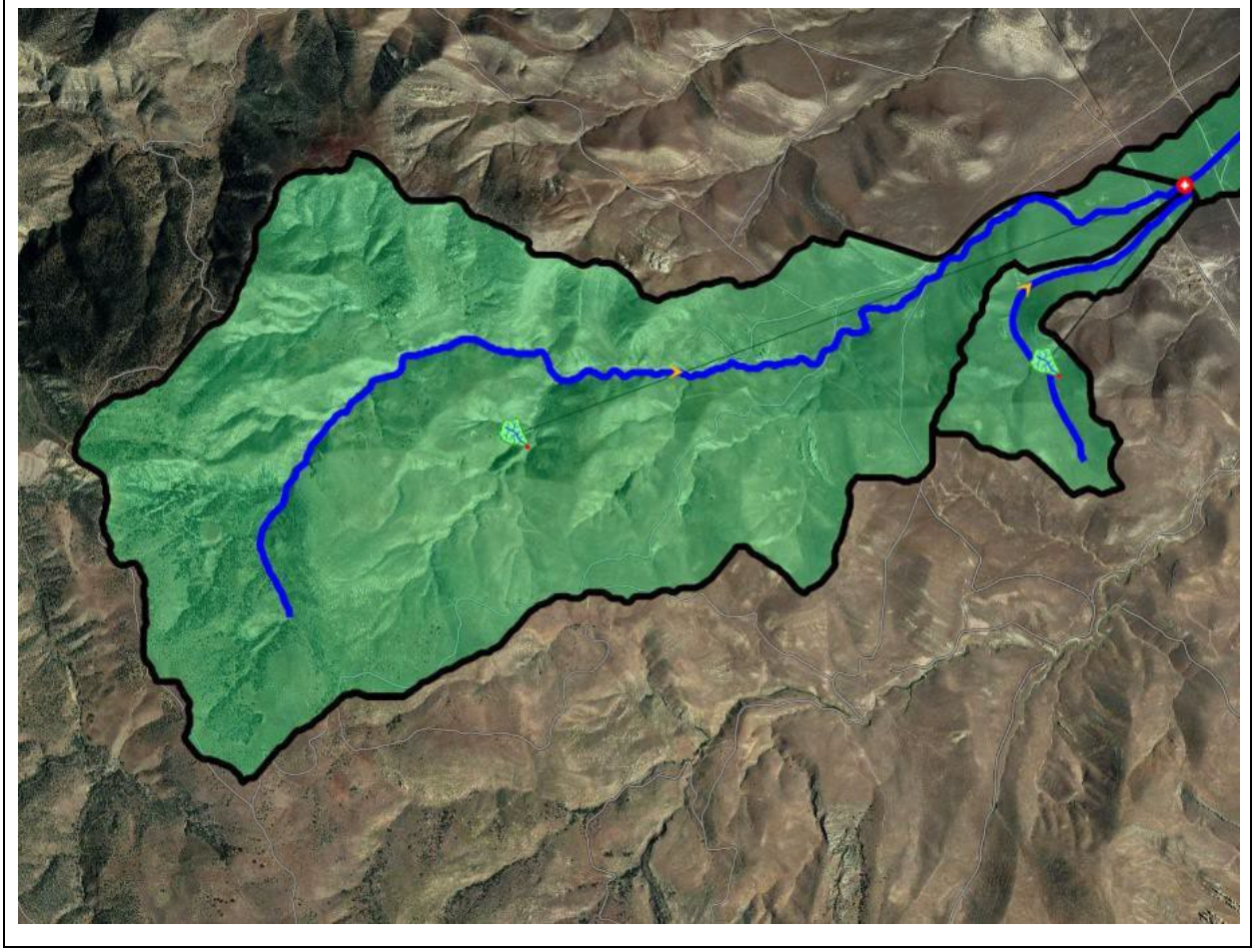
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
0.431	0.02	91.30	Developed, Medium Density
150.381	7.67	71.94	Undeveloped, Shrub/Scrub
0.305	0.02	74.40	Developed, Low Density
75.153	3.83	71.78	Developed, Open Space
1.186	0.06	88.55	Undeveloped, Barren Land
1,733.667	88.40	69.74	Undeveloped, Grassland
1,961.124	**100.00**	**70.00**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
30.90	112.95	0.04590	0.7959	Sheet Flow
13.24	3,235.61	0.16593	13.4514	Shallow Concentrated Flow
5.71	4,473.99	0.15548	13.0208	Channel Flow
46.85	15,930.03	0.02929	5.6514	Channel Flow
96.70	**23,752.58**	**Total**	**Lag Time = 58.02 minutes**	





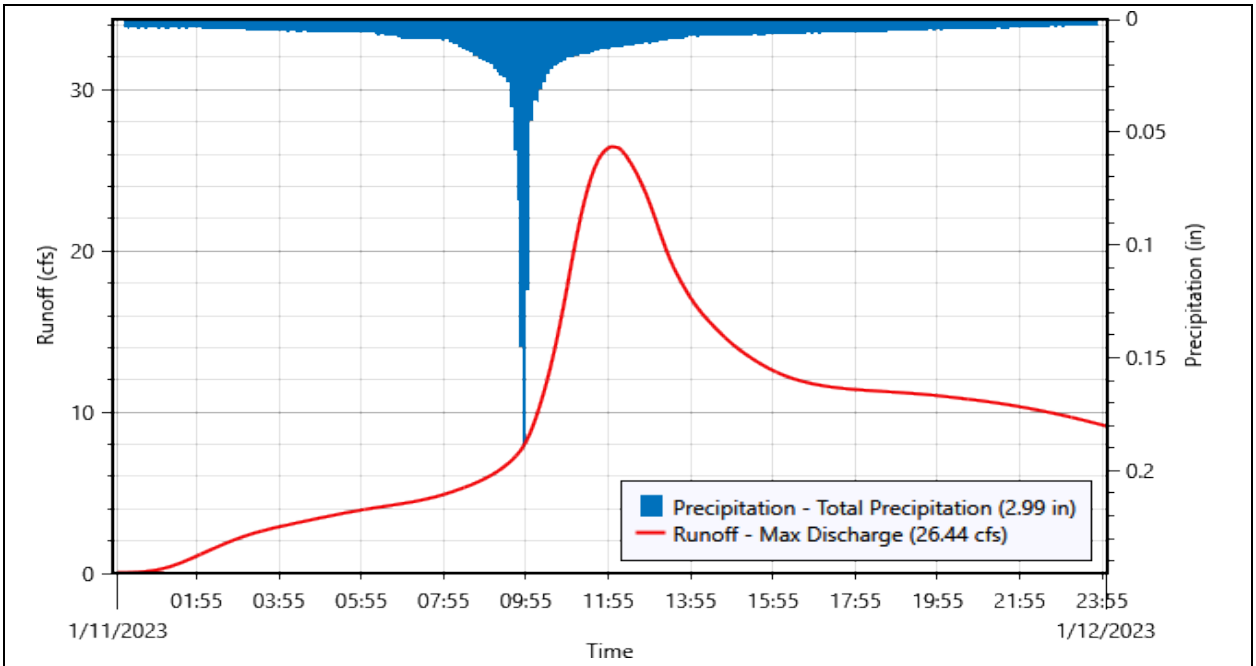
Subbasin ID:	Sub-05			
Scenario:	Proposed Development 100yr		Depth	Volume
Peak discharge:	26.44 cfs	**Time of peak:**	11 Jan 2023, 12:05	
Drainage area:	685.814 acres	**Total rainfall:**	2.99 in	170.88447 ac-ft
Initial abstraction:	1.94 in	**Losses:**	2.63 in	150.11020 ac-ft
Curve Number:	50.82	**Precip excess:**	0.36 in	20.77427 ac-ft
Impervious surface:	9.03%	**Direct runoff:**	0.33 in	18.90 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	125.36 minutes	**Total runoff:**	0.33 in	18.90 ac-ft

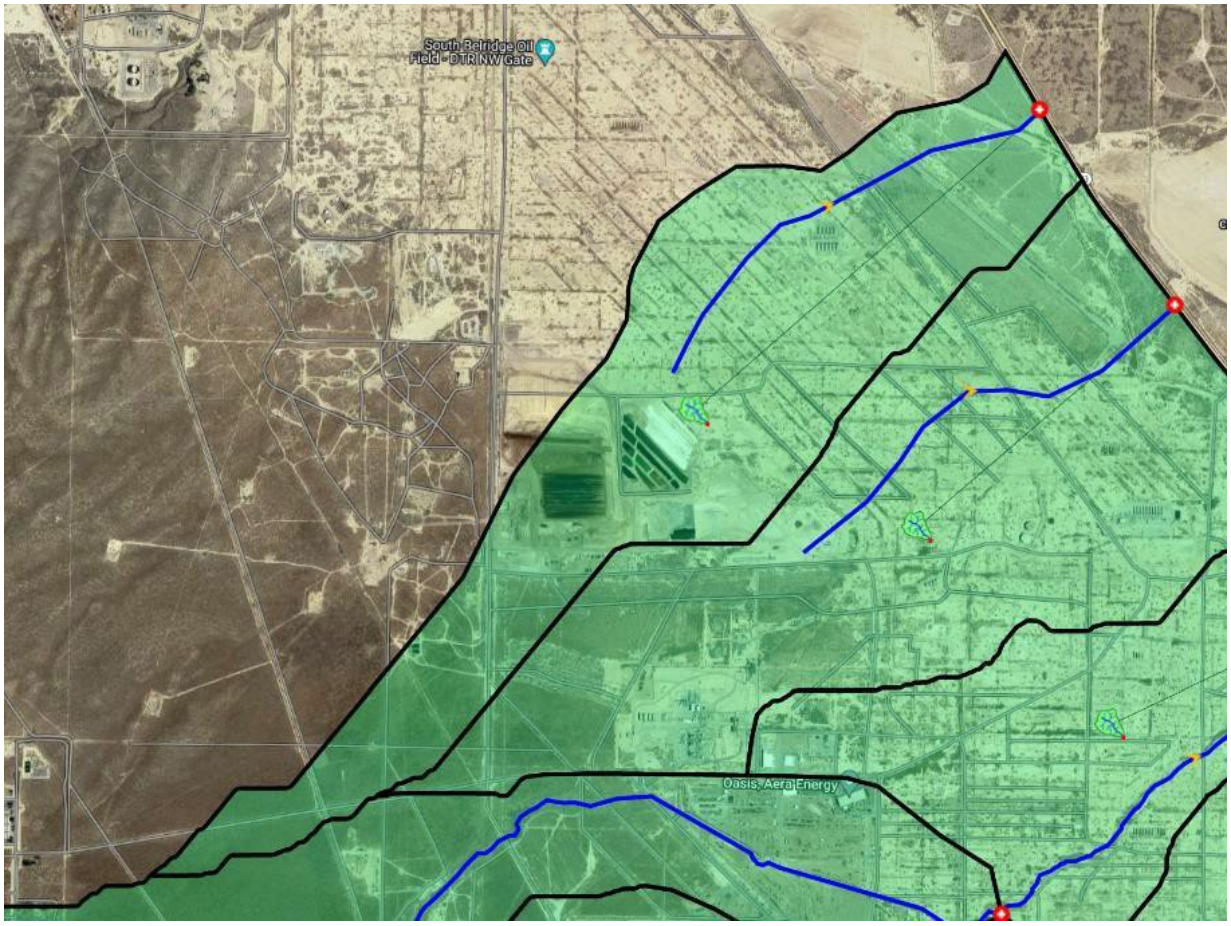
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
68.817	10.03	67.00	Agricultural, Cultivated Crops
17.830	2.60	77.74	Developed, Medium Density
42.537	6.20	78.26	Undeveloped, Barren Land
32.828	4.79	63.81	Developed, Low Density
201.828	29.43	57.17	Developed, Open Space
3.731	0.54	30.00	Undeveloped, Shrub/Scrub
0.288	0.04	100.00	Open Water
11.792	1.72	89.57	Developed, High Density
306.163	44.64	34.93	Undeveloped, Grassland
685.814	**100.00**	**50.82**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
51.04	100.00	0.01026	0.3762	Sheet Flow
84.98	9,730.86	0.01400	3.9073	Shallow Concentrated Flow
10.33	2,732.44	0.01773	4.3971	Channel Flow
62.57	3,381.56	0.00074	0.8982	Channel Flow
208.92	**15,944.86**	**Total**	**Lag Time = 125.36 minutes**	


Runoff (cfs)
30
20
10
0
Precipitation (in)
0
0.05
0.1
0.15
0.2
01:55
03:55
05:55
07:55
09:55
11:55
13:55
15:55
17:55
19:55
21:55
23:55
1/11/2023
1/12/2023
Time
Precipitation - Total Precipitation (2.99 in)
Runoff - Max Discharge (26.44 cfs)


South Belridge Oil Field - DTR NW Gate
Oasis, Aera Energy

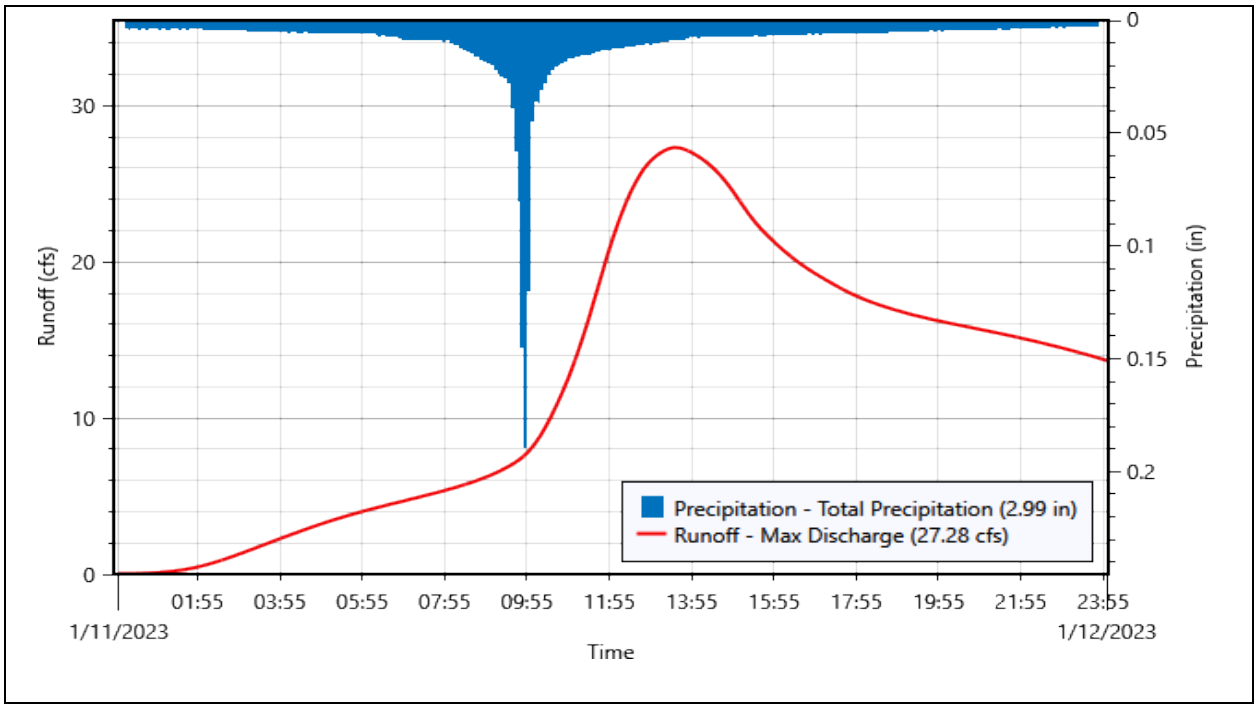
Subbasin ID:	Sub-06			
Scenario:	Proposed Development 100yr		Depth	Volume
Peak discharge:	27.28 cfs	**Time of peak:**	11 Jan 2023, 01:30	
Drainage area:	856.439 acres	**Total rainfall:**	2.99 in	213.39828 ac-ft
Initial abstraction:	1.86 in	**Losses:**	2.59 in	185.05161 ac-ft
Curve Number:	51.75	**Precip excess:**	0.40 in	28.34667 ac-ft
Impervious surface:	9.59%	**Direct runoff:**	0.34 in	24.01 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	198.99 minutes	**Total runoff:**	0.34 in	24.01 ac-ft

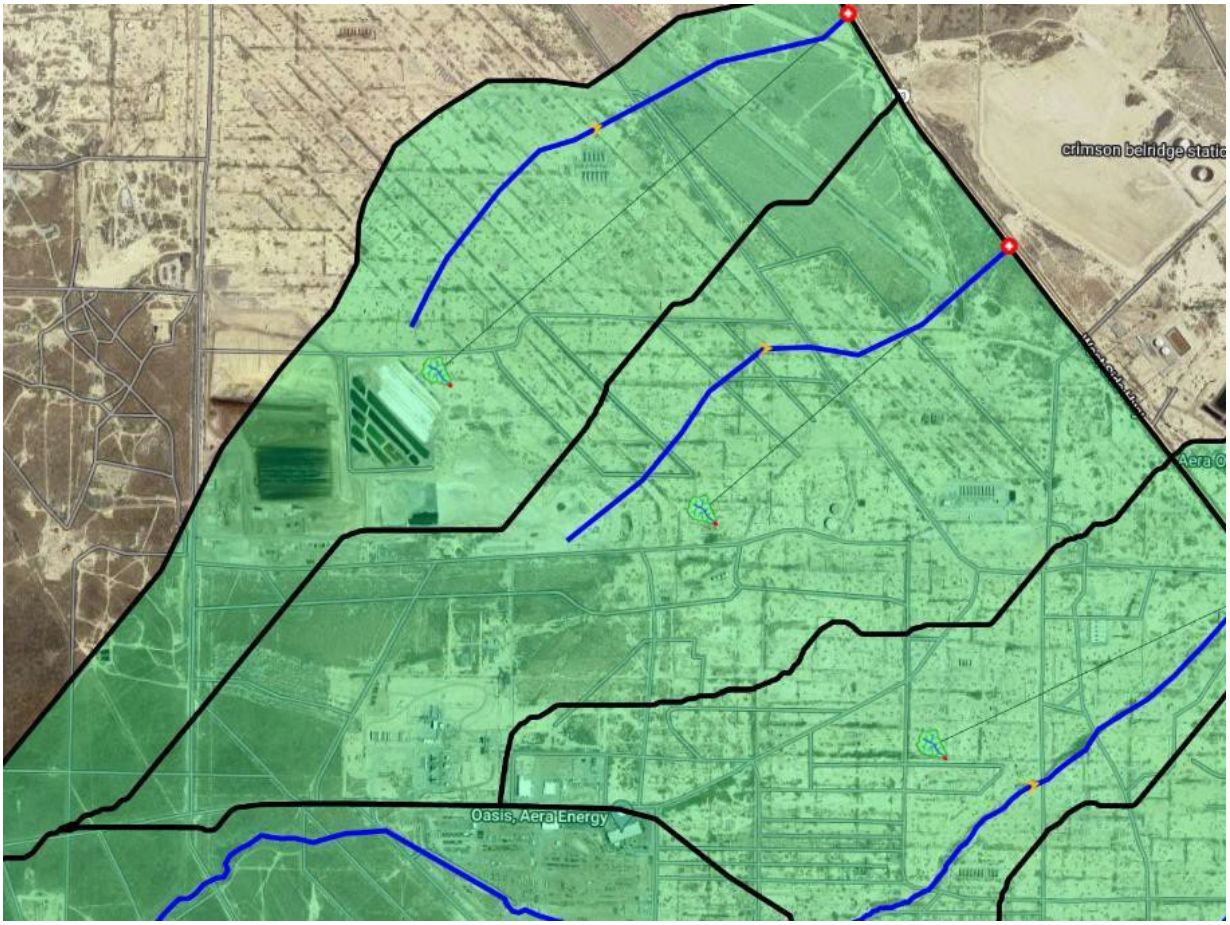
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
18.520	2.16	78.52	Developed, Medium Density
40.292	4.70	67.00	Agricultural, Cultivated Crops
0.191	0.02	30.00	Undeveloped, Shrub/Scrub
68.504	8.00	66.60	Developed, Low Density
7.679	0.90	89.48	Developed, High Density
305.373	35.66	61.82	Developed, Open Space
32.256	3.77	78.97	Undeveloped, Barren Land
383.625	44.79	35.15	Undeveloped, Grassland
856.439	**100.00**	**51.75**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
42.34	100.00	0.01637	0.4753	Sheet Flow
56.02	6,131.50	0.01279	3.7342	Shallow Concentrated Flow
2.24	757.49	0.12183	11.5262	Shallow Concentrated Flow
231.04	6,158.14	0.00018	0.4458	Channel Flow
331.64	**13,147.13**	**Total**	**Lag Time = 198.99 minutes**	


Runoff (cfs)
30
20
10
0
Precipitation (in)
0
0.05
0.1
0.15
0.2
Precipitation - Total Precipitation (2.99 in)
Runoff - Max Discharge (27.28 cfs)
01:55
03:55
05:55
07:55
09:55
11:55
13:55
15:55
17:55
19:55
21:55
23:55
1/11/2023
1/12/2023
Time


Oasis, Aera Energy

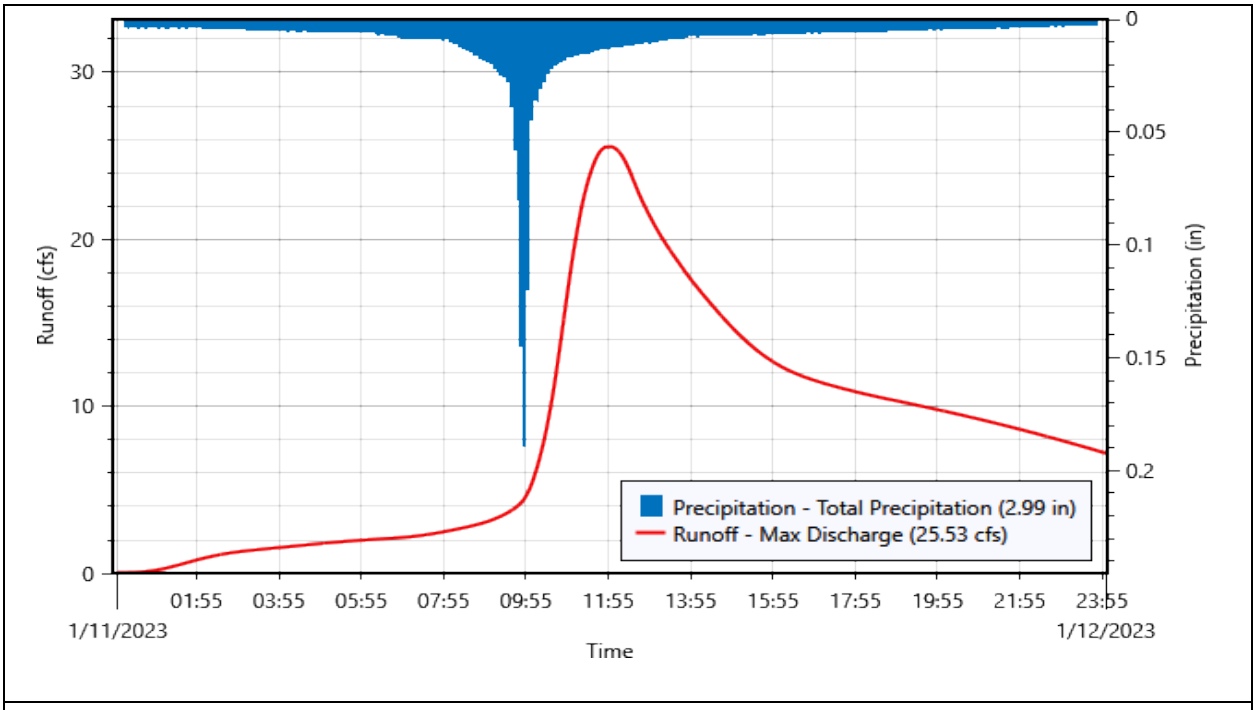
Subbasin ID:	Sub-07			
Scenario:	Proposed Development 100yr		Depth	Volume
Peak discharge:	25.53 cfs	**Time of peak:**	11 Jan 2023, 11:55	
Drainage area:	269.771 acres	**Total rainfall:**	2.99 in	67.21520 ac-ft
Initial abstraction:	1.05 in	**Losses:**	2.20 in	49.50065 ac-ft
Curve Number:	65.60	**Precip excess:**	0.79 in	17.71454 ac-ft
Impervious surface:	10.71%	**Direct runoff:**	0.74 in	16.56 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	98.48 minutes	**Total runoff:**	0.74 in	16.56 ac-ft

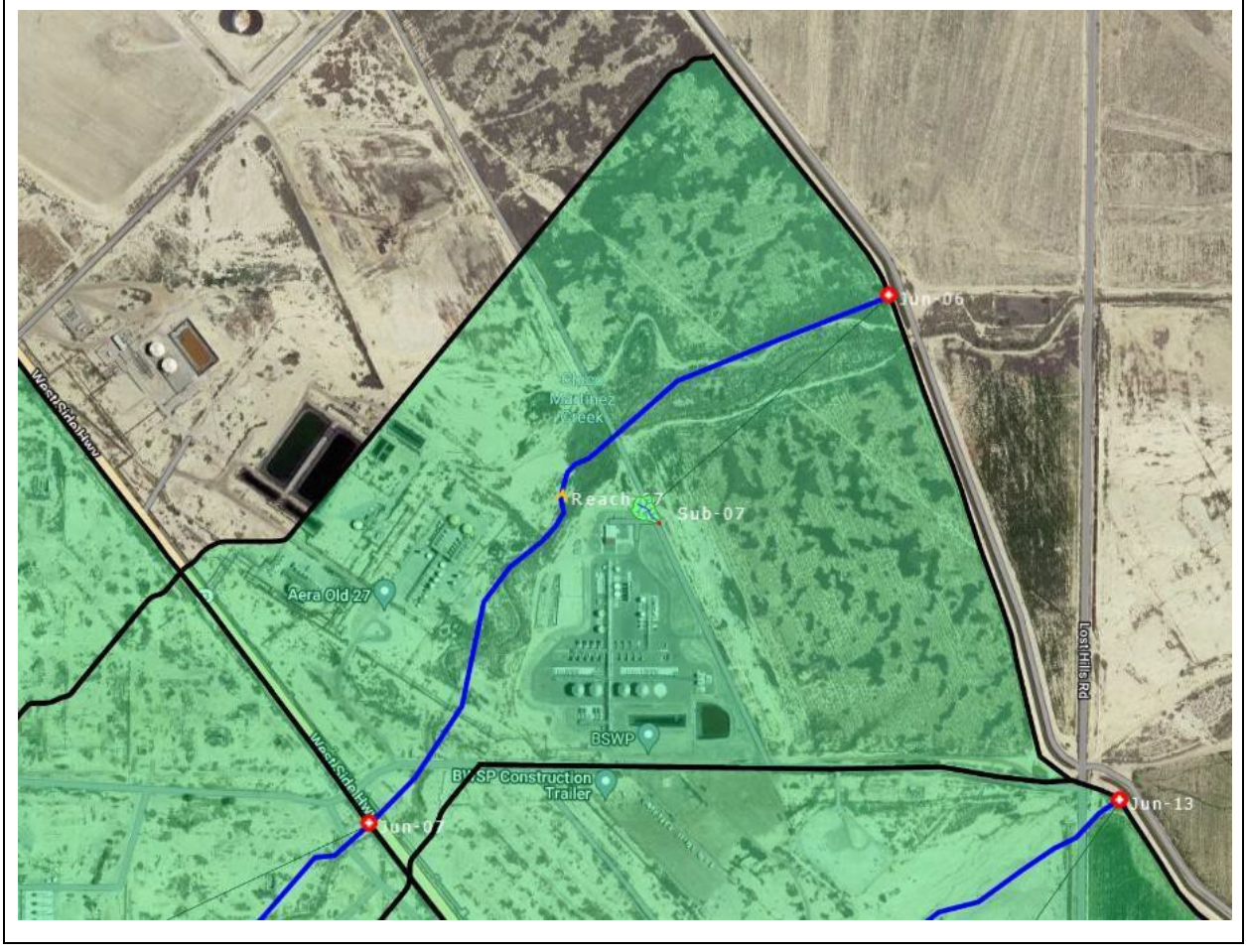
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
9.365	3.47	78.39	Developed, Medium Density
7.664	2.84	30.00	Undeveloped, Shrub/Scrub
17.372	6.44	67.37	Developed, Low Density
12.494	4.63	89.14	Developed, High Density
43.223	16.02	56.26	Developed, Open Space
5.238	1.94	77.67	Undeveloped, Barren Land
29.711	11.01	41.49	Undeveloped, Grassland
144.704	53.64	71.71	Agricultural, Cultivated Crops
269.771	**100.00**	**65.60**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
62.62	95.81	0.00565	0.2792	Sheet Flow
1.69	168.18	0.01057	3.3952	Shallow Concentrated Flow
0.84	253.65	0.09785	10.3295	Shallow Concentrated Flow
33.38	2,278.13	0.00118	1.1339	Channel Flow
1.39	551.42	0.03999	6.6036	Channel Flow
64.20	1,275.51	0.00010	0.3284	Channel Flow
164.12	**4,622.70**	**Total**	**Lag Time = 98.48 minutes**	


Runoff (cfs)
Precipitation (in)
Time
1/11/2023
1/12/2023
Precipitation - Total Precipitation (2.99 in)
Runoff - Max Discharge (25.53 cfs)


Jun-06
Reach-7
Sub-07
Aera Old 27
BSWP
Jun-07
Jun-13
Lost Hills Rd

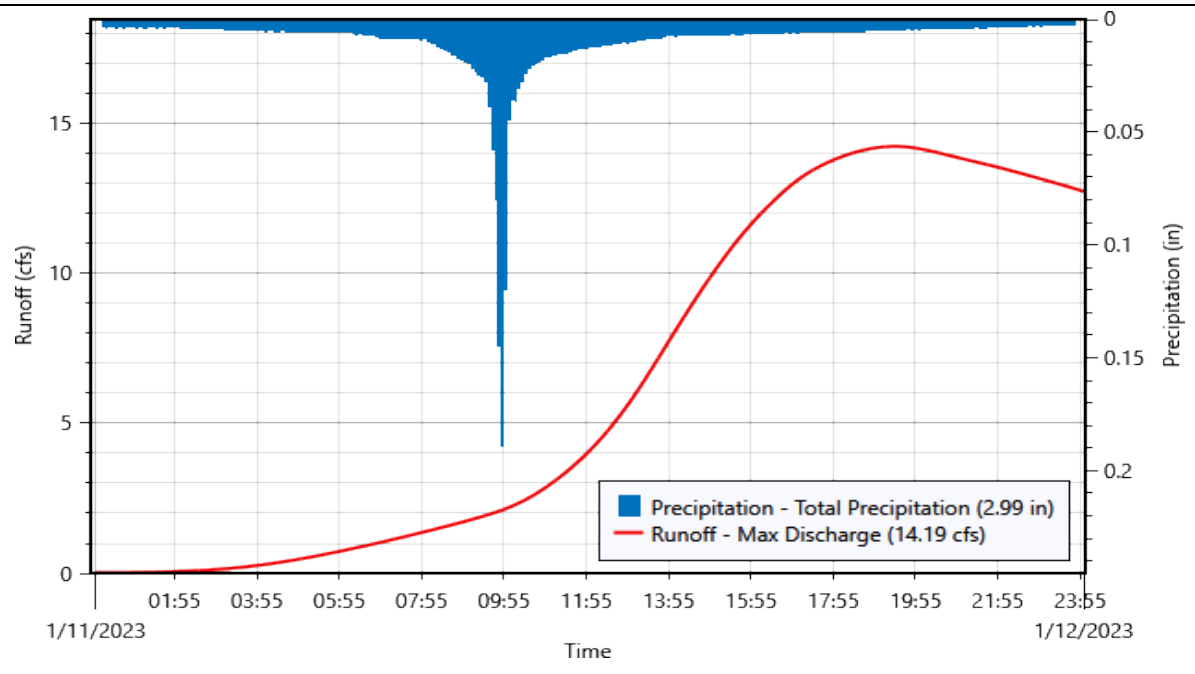
Subbasin ID:	Sub-08			
Scenario:	Proposed Development 100yr		Depth	Volume
Peak discharge:	14.19 cfs	**Time of peak:**	11 Jan 2023, 07:25	
Drainage area:	503.505 acres	**Total rainfall:**	2.99 in	125.45242 ac-ft
Initial abstraction:	1.48 in	**Losses:**	2.50 in	105.08259 ac-ft
Curve Number:	57.53	**Precip excess:**	0.49 in	20.36983 ac-ft
Impervious surface:	8.38%	**Direct runoff:**	0.30 in	12.56 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	395.42 minutes	**Total runoff:**	0.30 in	12.56 ac-ft

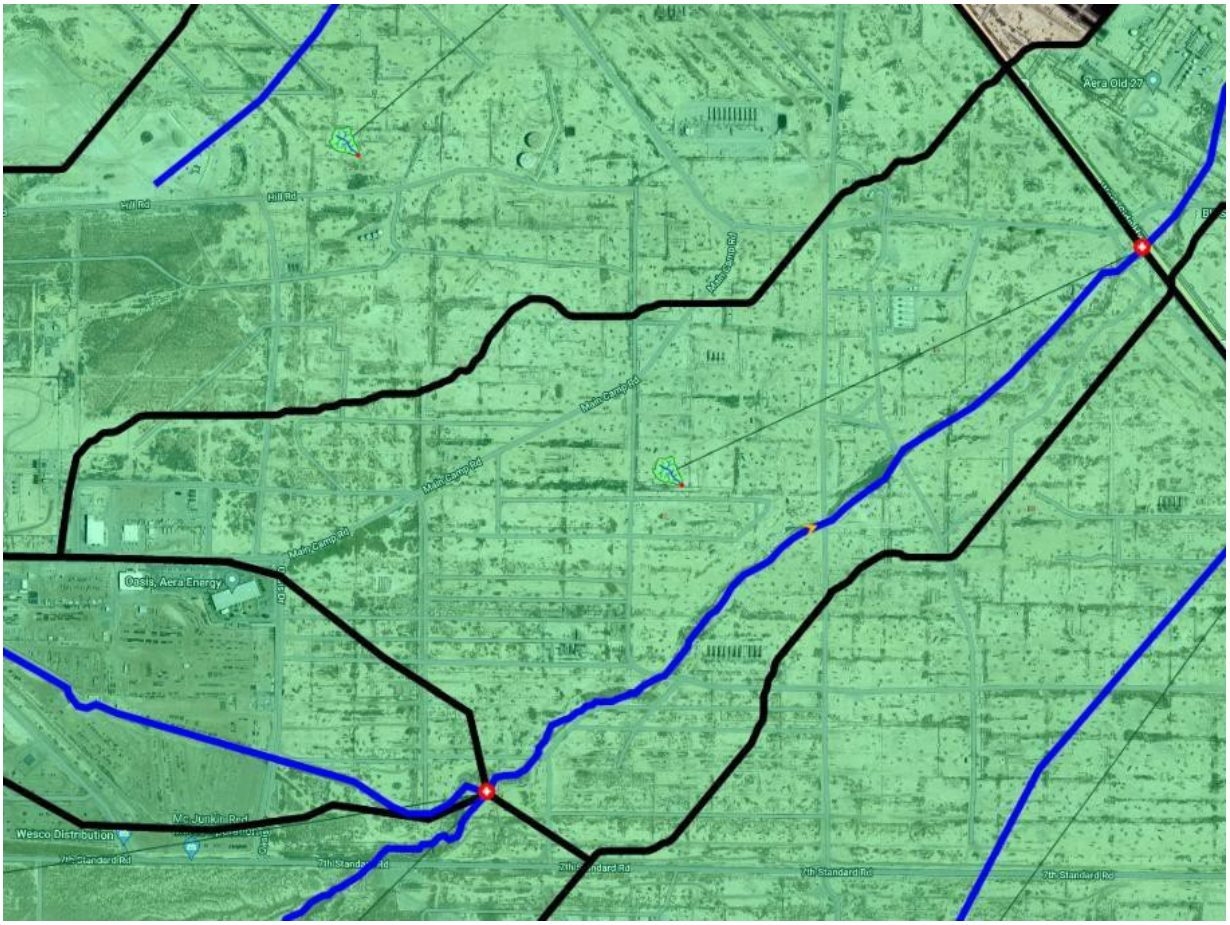
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
9.083	1.80	80.87	Developed, Medium Density
32.953	6.54	70.08	Developed, Low Density
4.702	0.93	89.23	Developed, High Density
9.827	1.95	87.02	Undeveloped, Barren Land
151.885	30.17	41.68	Undeveloped, Grassland
295.055	58.60	62.08	Developed, Open Space
503.505	**100.00**	**57.53**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
52.03	100.00	0.00978	0.3674	Sheet Flow
49.64	4,709.72	0.00961	3.2380	Shallow Concentrated Flow
2.39	661.27	0.08149	9.4267	Shallow Concentrated Flow
9.76	489.72	0.00269	1.7139	Shallow Concentrated Flow
545.21	3,425.21	0.00001	0.1271	Channel Flow
659.03	**9,385.92**	**Total**	**Lag Time = 395.42 minutes**	




Aera Old 27
Hill Rd
Main Camp Rd
Oasis, Aera Energy
Wesco Distribution
7th Standard Rd

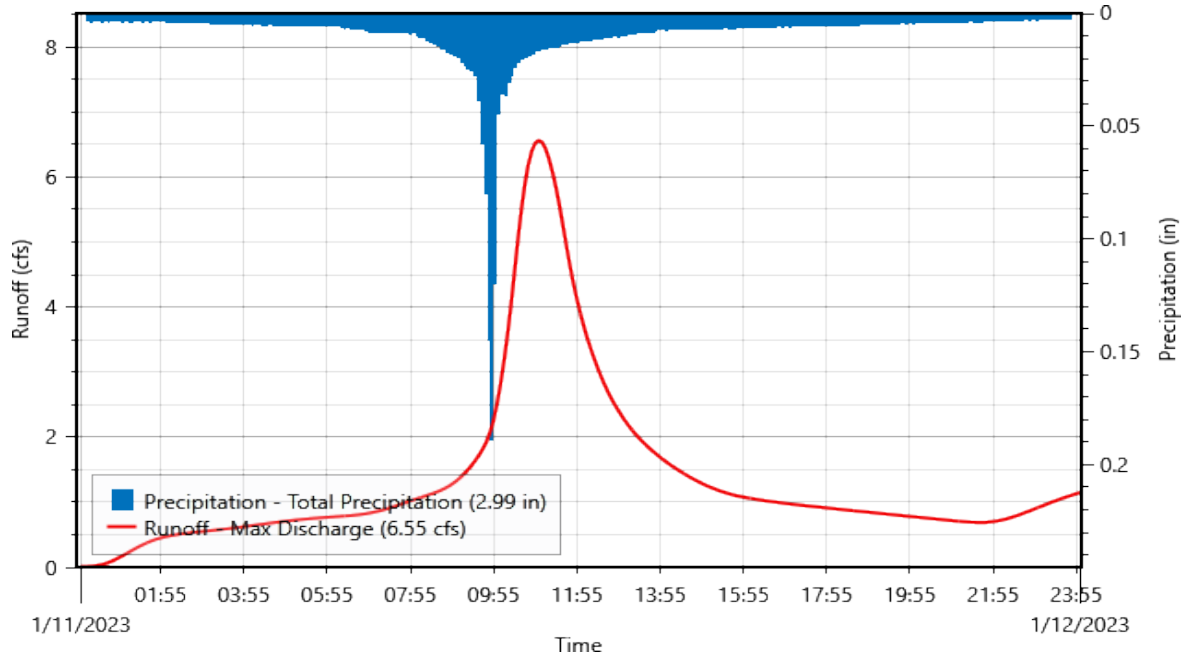
Subbasin ID:	Sub-09		Depth	Volume
Scenario:	Proposed Development 100yr			
Peak discharge:	6.55 cfs	**Time of peak:**	11 Jan 2023, 11:00	
Drainage area:	1,130.587 acres	**Total rainfall:**	2.99 in	281.69785 ac-ft
Initial abstraction:	2.84 in	**Losses:**	2.96 in	278.90352 ac-ft
Curve Number:	41.33	**Precip excess:**	0.03 in	2.79434 ac-ft
Impervious surface:	0.94%	**Direct runoff:**	0.03 in	2.65 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	67.09 minutes	**Total runoff:**	0.03 in	2.65 ac-ft

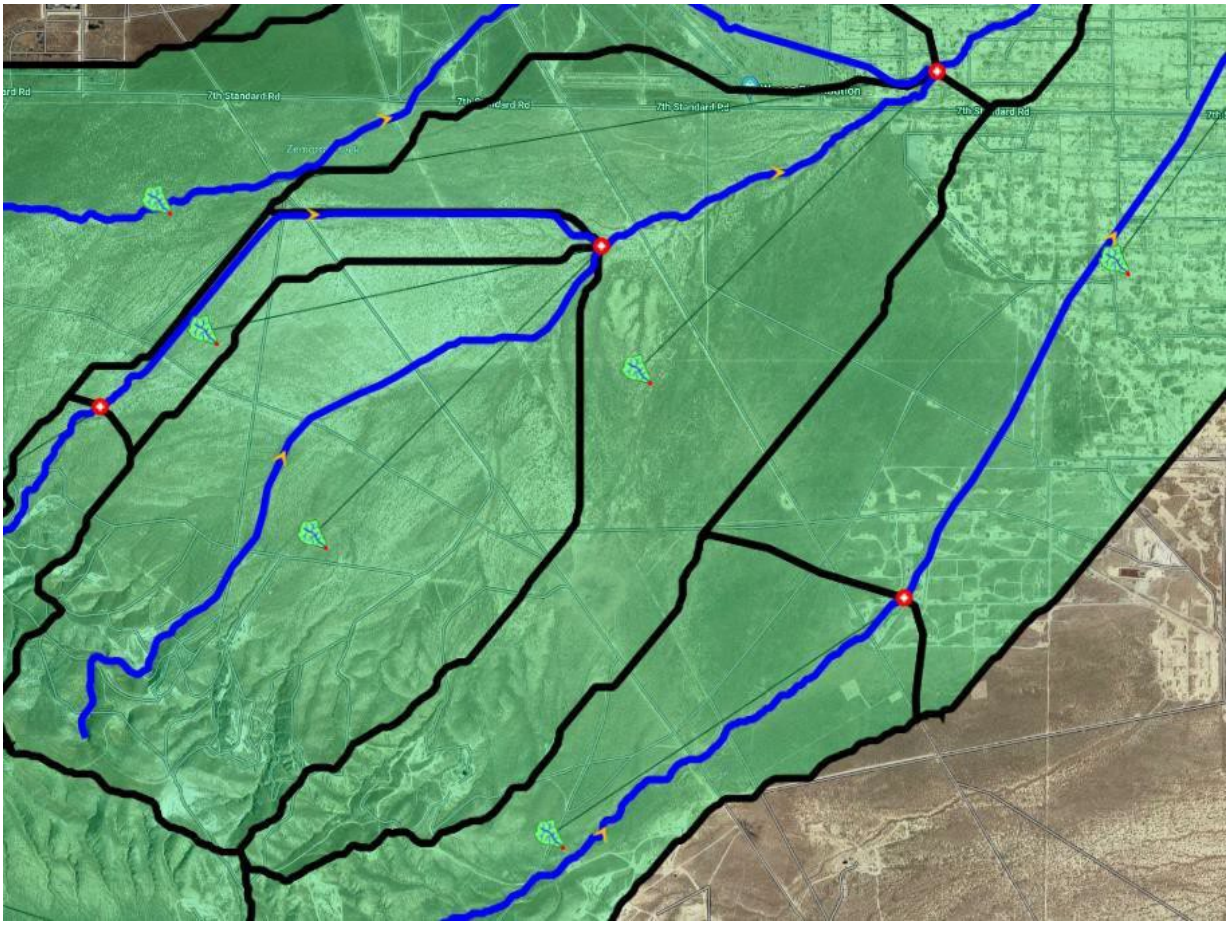
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
1.638	0.14	82.99	Developed, Medium Density
49.357	4.37	35.62	Undeveloped, Shrub/Scrub
4.469	0.40	61.00	Developed, Low Density
0.293	0.03	89.00	Developed, High Density
80.882	7.15	53.22	Developed, Open Space
3.542	0.31	77.00	Undeveloped, Barren Land
990.407	87.60	40.34	Undeveloped, Grassland
1,130.587	**100.00**	**41.33**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
16.78	99.98	0.16549	1.5113	Sheet Flow
0.86	365.47	0.19372	14.5341	Shallow Concentrated Flow
8.54	4,728.14	0.04703	9.2075	Channel Flow
60.10	7,738.83	0.01770	4.3931	Shallow Concentrated Flow
25.53	5,047.31	0.00990	3.2859	Channel Flow
111.81	**17,979.73**	**Total**	**Lag Time = 67.09 minutes**	




7th Standard Rd
7th Standard Rd
7th Standard Rd

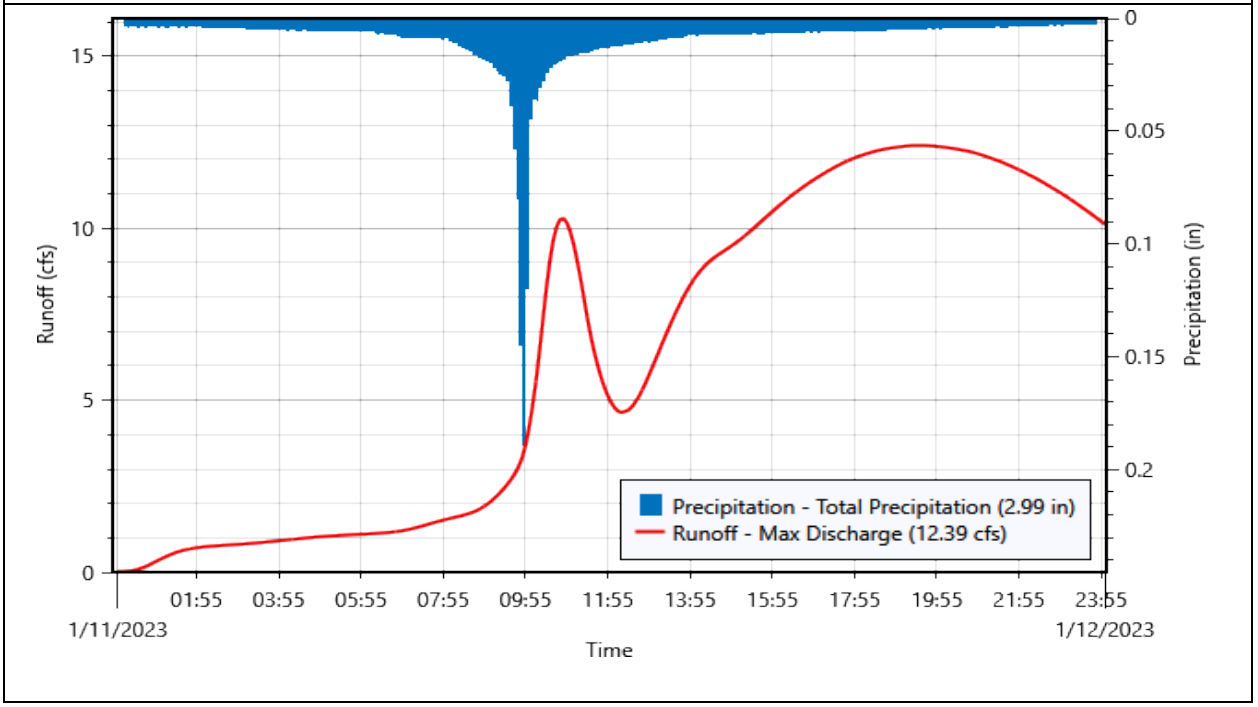
Subbasin ID:	Sub-10			
Scenario:	Proposed Development 100yr		Depth	Volume
Peak discharge:	12.39 cfs	**Time of peak:**	11 Jan 2023, 07:30	
Drainage area:	1,153.361 acres	**Total rainfall:**	2.99 in	287.37487 ac-ft
Initial abstraction:	1.94 in	**Losses:**	2.85 in	273.90003 ac-ft
Curve Number:	50.79	**Precip excess:**	0.14 in	13.47484 ac-ft
Impervious surface:	1.30%	**Direct runoff:**	0.13 in	12.50 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	55.92 minutes	**Total runoff:**	0.13 in	12.50 ac-ft

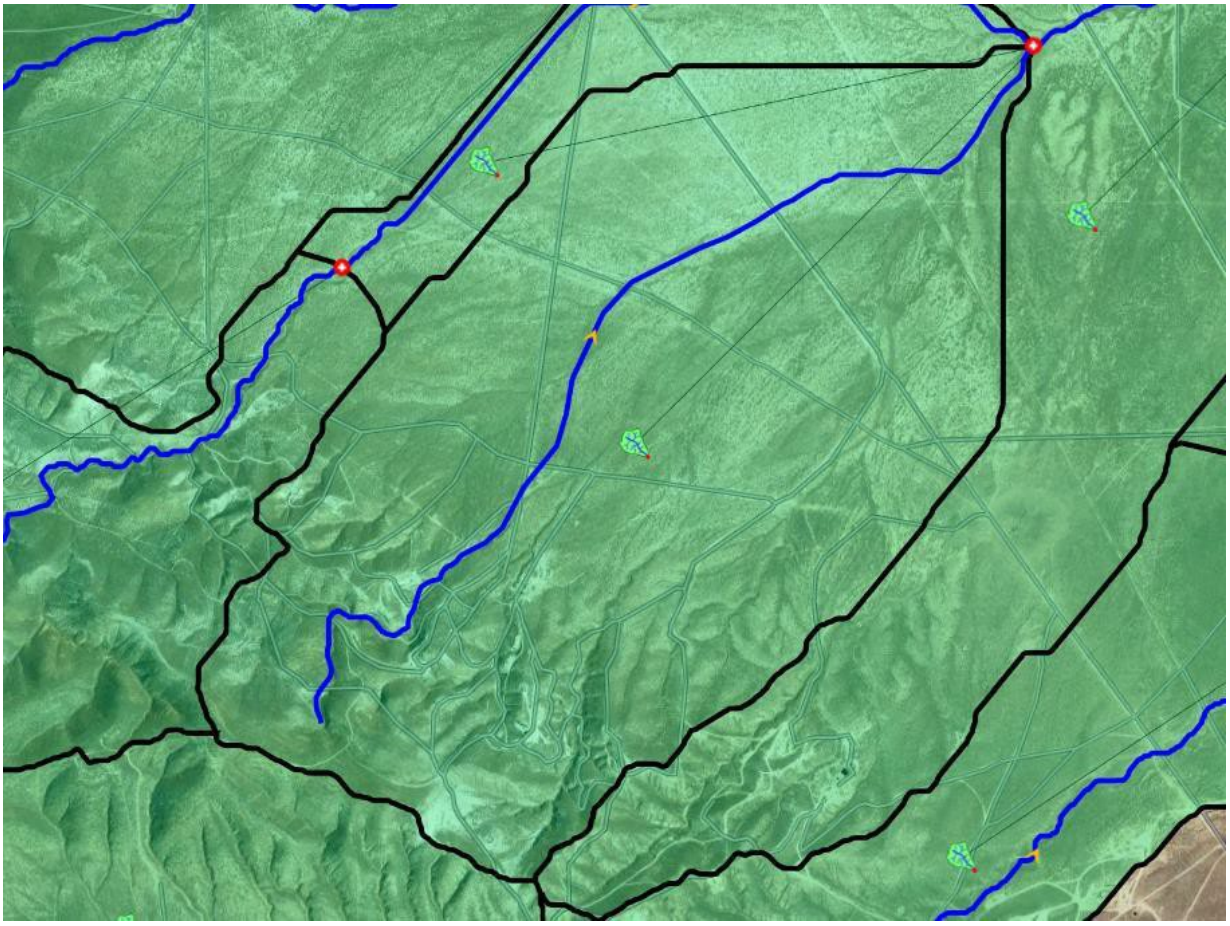
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
10.397	0.90	79.49	Developed, Medium Density
59.382	5.15	50.07	Undeveloped, Shrub/Scrub
3.103	0.27	80.28	Developed, Low Density
151.032	13.09	67.65	Developed, Open Space
2.360	0.20	91.00	Undeveloped, Barren Land
927.088	80.38	47.56	Undeveloped, Grassland
1,153.361	**100.00**	**50.79**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
21.17	100.00	0.09259	1.1304	Sheet Flow
2.60	1,127.24	0.20010	14.7716	Shallow Concentrated Flow
9.39	4,900.89	0.06895	8.6712	Channel Flow
0.40	386.93	0.23496	16.0068	Channel Flow
42.25	2,796.45	0.00111	1.0981	Channel Flow
17.39	4,299.00	0.01549	4.1093	Channel Flow
93.20	**13,610.51**	**Total**	**Lag Time = 55.92 minutes**	





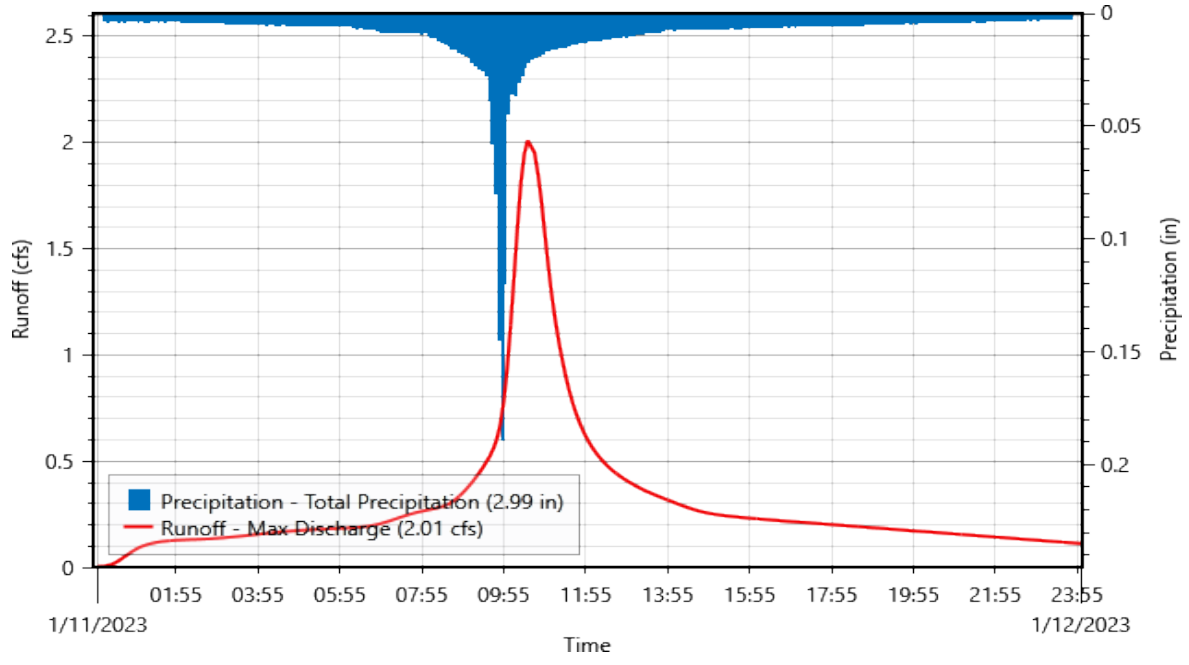
Subbasin ID:	Sub-11			
Scenario:	Proposed Development 100yr		Depth	Volume
Peak discharge:	2.01 cfs	**Time of peak:**	11 Jan 2023, 10:30	
Drainage area:	161.318 acres	**Total rainfall:**	2.99 in	40.20155 ac-ft
Initial abstraction:	4.26 in	**Losses:**	2.94 in	39.59450 ac-ft
Curve Number:	31.97	**Precip excess:**	0.05 in	0.60704 ac-ft
Impervious surface:	1.51%	**Direct runoff:**	0.04 in	0.60 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	40.10 minutes	**Total runoff:**	0.04 in	0.60 ac-ft

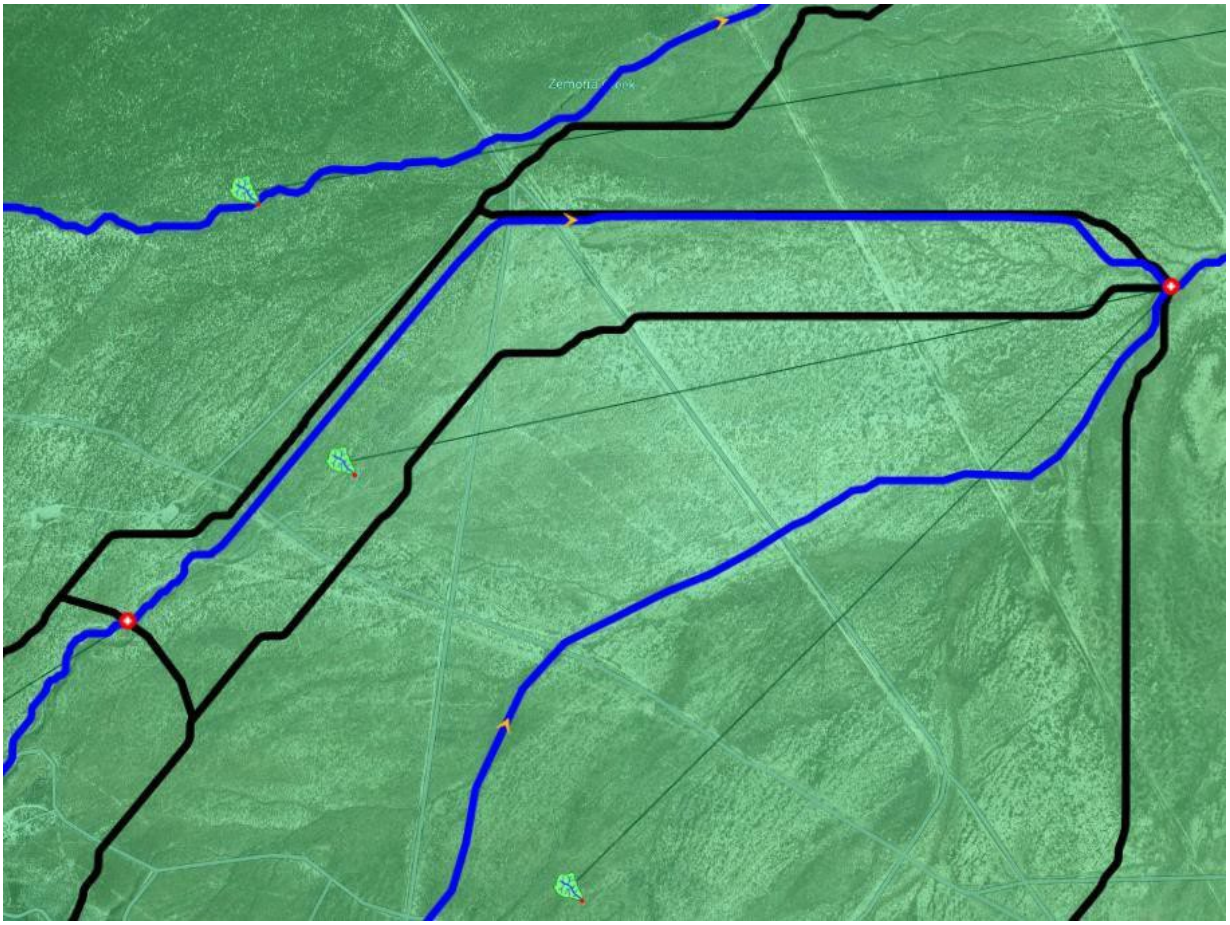
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
4.560	2.83	77.00	Developed, Medium Density
4.792	2.97	49.00	Developed, Open Space
151.966	94.20	30.08	Undeveloped, Grassland
161.318	**100.00**	**31.97**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
28.76	100.00	0.04304	0.7707	Sheet Flow
6.52	1,112.40	0.03107	5.8206	Shallow Concentrated Flow
31.55	8,418.65	0.01804	4.4358	Channel Flow
66.83	**9,631.05**	**Total**	**Lag Time = 40.10 minutes**	





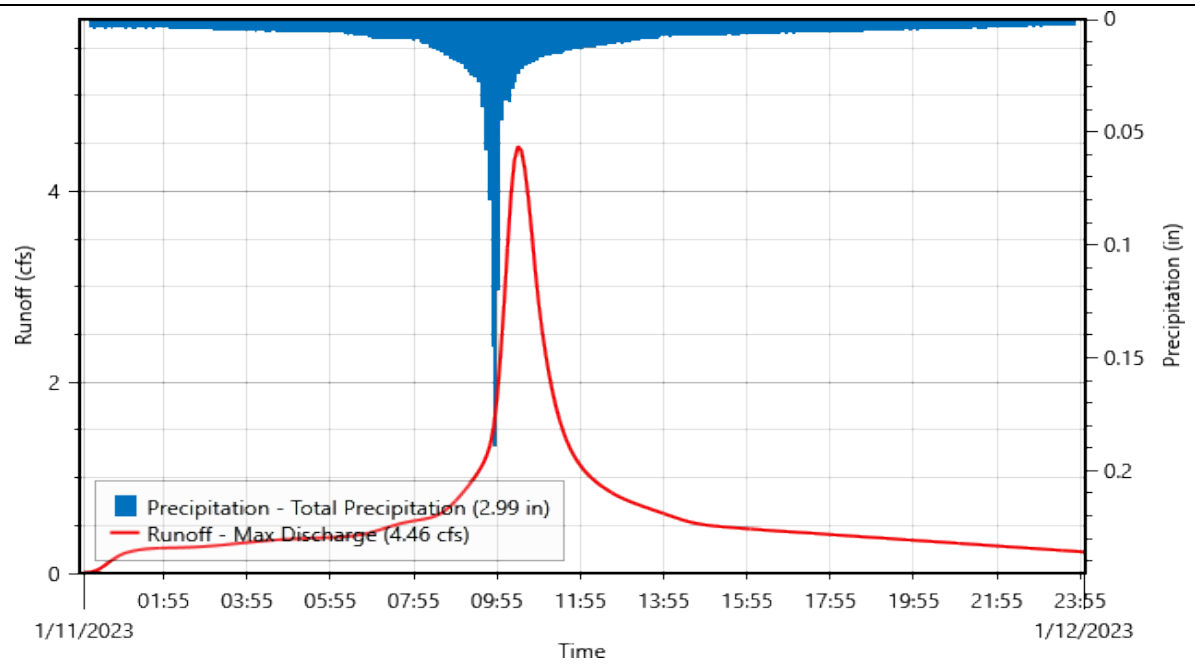
Subbasin ID:	Sub-12			
Scenario:	Proposed Development 100yr		Depth	Volume
Peak discharge:	4.46 cfs	**Time of peak:**	11 Jan 2023, 10:25	
Drainage area:	952.517 acres	**Total rainfall:**	2.99 in	237.33423 ac-ft
Initial abstraction:	3.33 in	**Losses:**	2.97 in	236.10009 ac-ft
Curve Number:	37.51	**Precip excess:**	0.02 in	1.23414 ac-ft
Impervious surface:	0.52%	**Direct runoff:**	0.02 in	1.22 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	34.22 minutes	**Total runoff:**	0.02 in	1.22 ac-ft

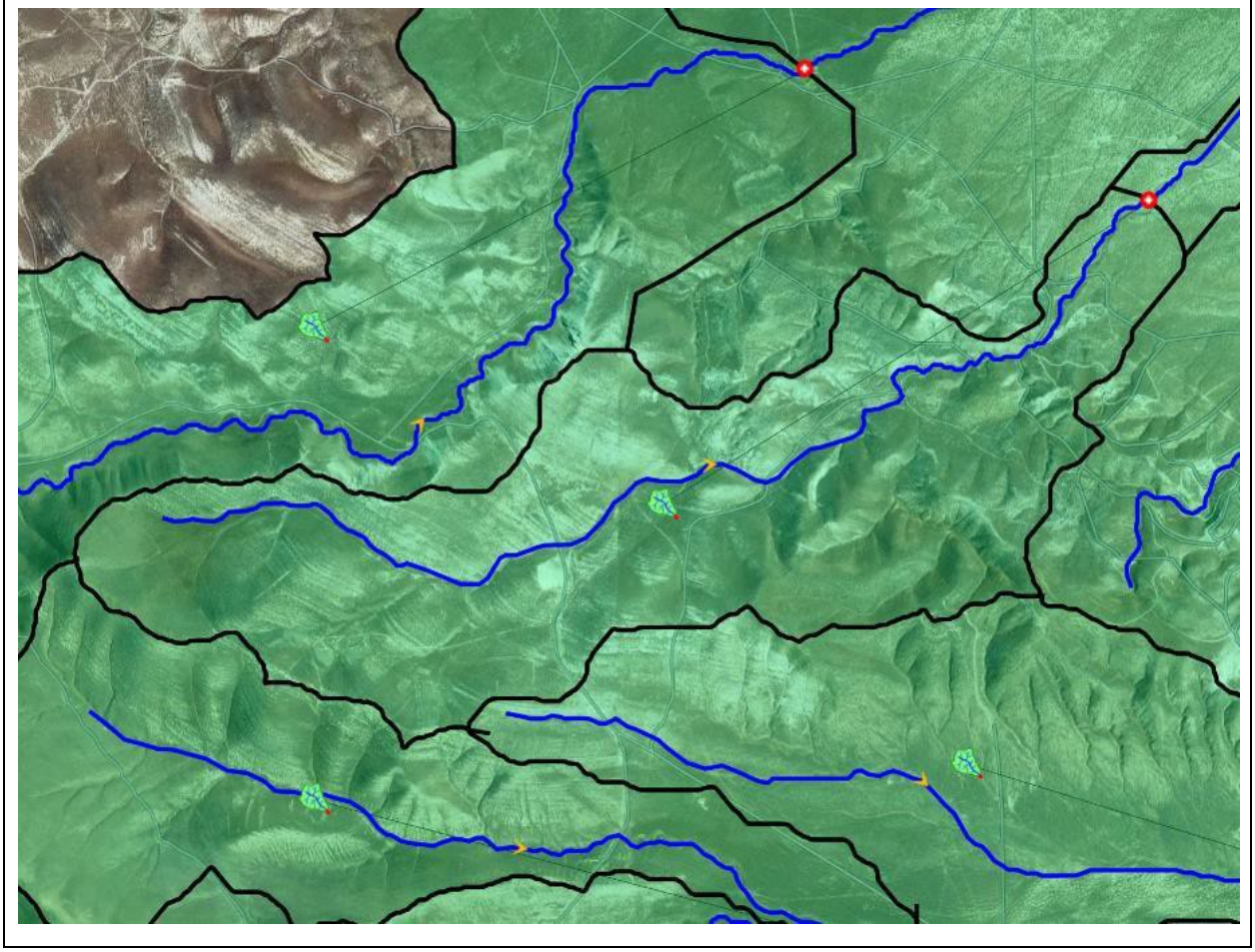
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
2.973	0.31	80.98	Developed, Medium Density
103.318	10.85	38.00	Undeveloped, Shrub/Scrub
0.143	0.02	75.00	Developed, Low Density
0.294	0.03	92.00	Developed, High Density
75.514	7.93	56.10	Developed, Open Space
770.275	80.87	35.42	Undeveloped, Grassland
952.517	**100.00**	**37.51**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
11.42	100.00	0.43323	2.4452	Sheet Flow
1.09	682.84	0.41878	21.3698	Shallow Concentrated Flow
1.93	655.49	0.12346	11.6028	Shallow Concentrated Flow
3.76	2,062.80	0.07622	9.1166	Channel Flow
38.83	14,034.51	0.03310	6.0076	Channel Flow
57.03	**17,535.64**	**Total**	**Lag Time = 34.22 minutes**	





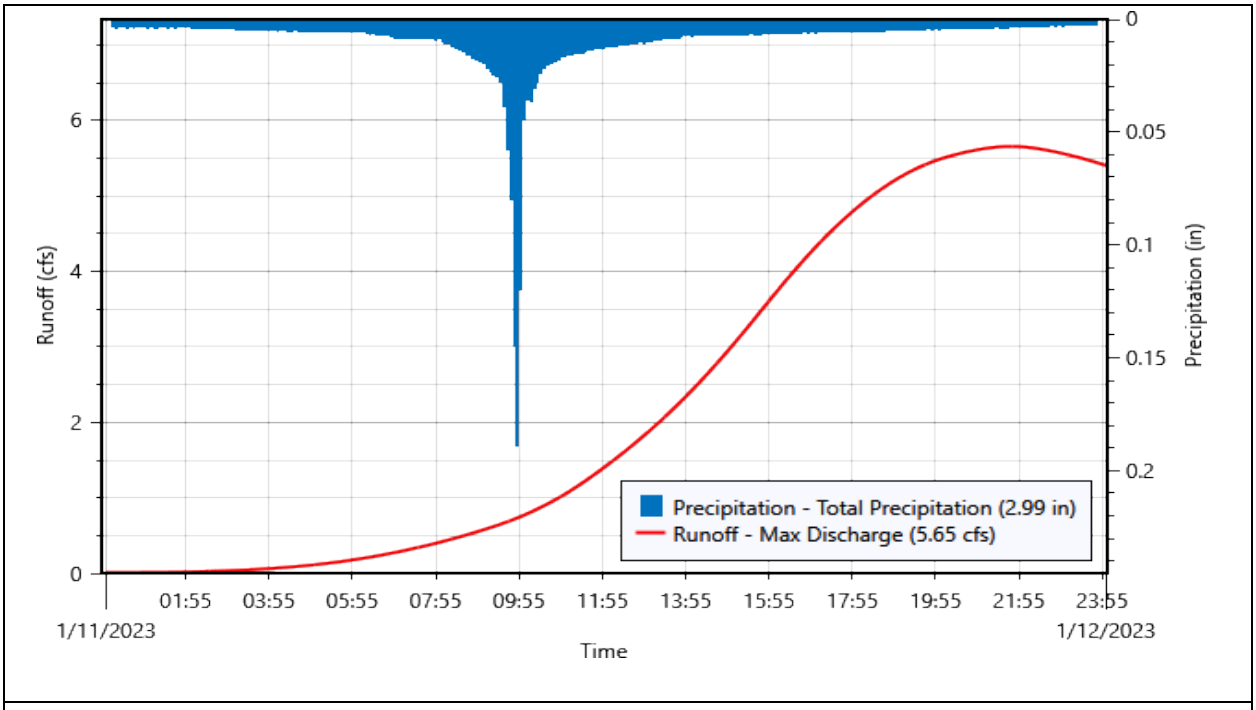
Subbasin ID:	Sub-13			
Scenario:	Proposed Development 100yr		Depth	Volume
Peak discharge:	5.65 cfs	**Time of peak:**	11 Jan 2023, 09:45	
Drainage area:	1,426.690 acres	**Total rainfall:**	2.99 in	355.48308 ac-ft
Initial abstraction:	3.40 in	**Losses:**	2.91 in	346.45381 ac-ft
Curve Number:	37.06	**Precip excess:**	0.08 in	9.02927 ac-ft
Impervious surface:	2.54%	**Direct runoff:**	0.04 in	4.54 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	649.32 minutes	**Total runoff:**	0.04 in	4.54 ac-ft

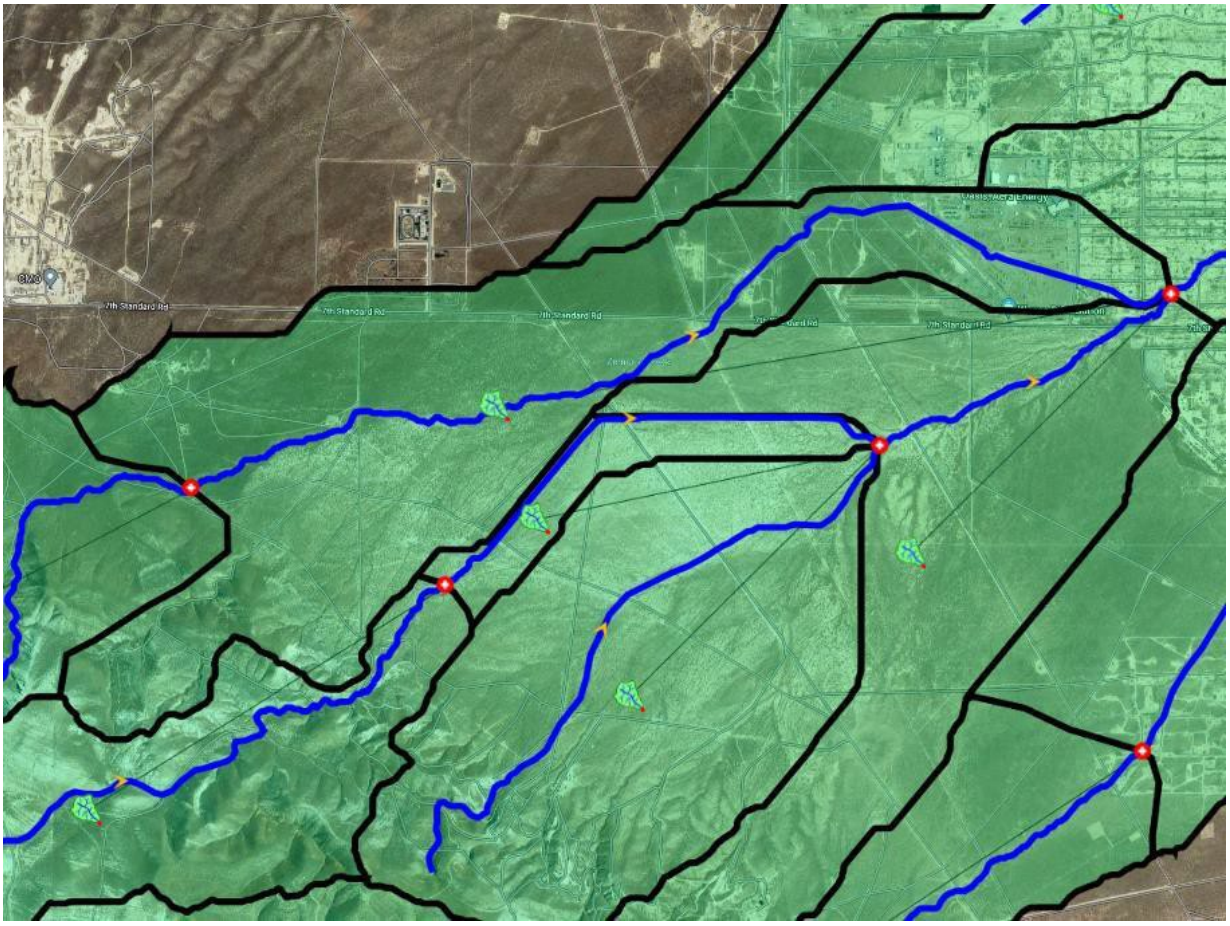
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
17.729	1.24	77.00	Developed, Medium Density
3.229	0.23	67.00	Agricultural, Cultivated Crops
80.460	5.64	37.13	Undeveloped, Shrub/Scrub
17.221	1.21	61.00	Developed, Low Density
15.586	1.09	89.00	Developed, High Density
152.768	10.71	52.06	Developed, Open Space
3.509	0.25	77.00	Undeveloped, Barren Land
1,136.188	79.64	33.14	Undeveloped, Grassland
1,426.690	**100.00**	**37.06**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
20.36	100.00	0.10212	1.1872	Sheet Flow
0.80	390.34	0.25255	16.5951	Shallow Concentrated Flow
8.53	4,253.88	0.06305	8.2916	Channel Flow
15.47	2,983.05	0.03970	6.5798	Shallow Concentrated Flow
43.39	10,314.70	0.01432	3.9513	Channel Flow
0.39	285.53	0.13608	12.1816	Channel Flow
993.25	6,239.98	0.00001	0.1044	Channel Flow
1,082.19	**24,567.48**	**Total**	**Lag Time = 649.32 minutes**	


Runoff (cfs)
Precipitation (in)
Time
1/11/2023
1/12/2023
Precipitation - Total Precipitation (2.99 in)
Runoff - Max Discharge (5.65 cfs)



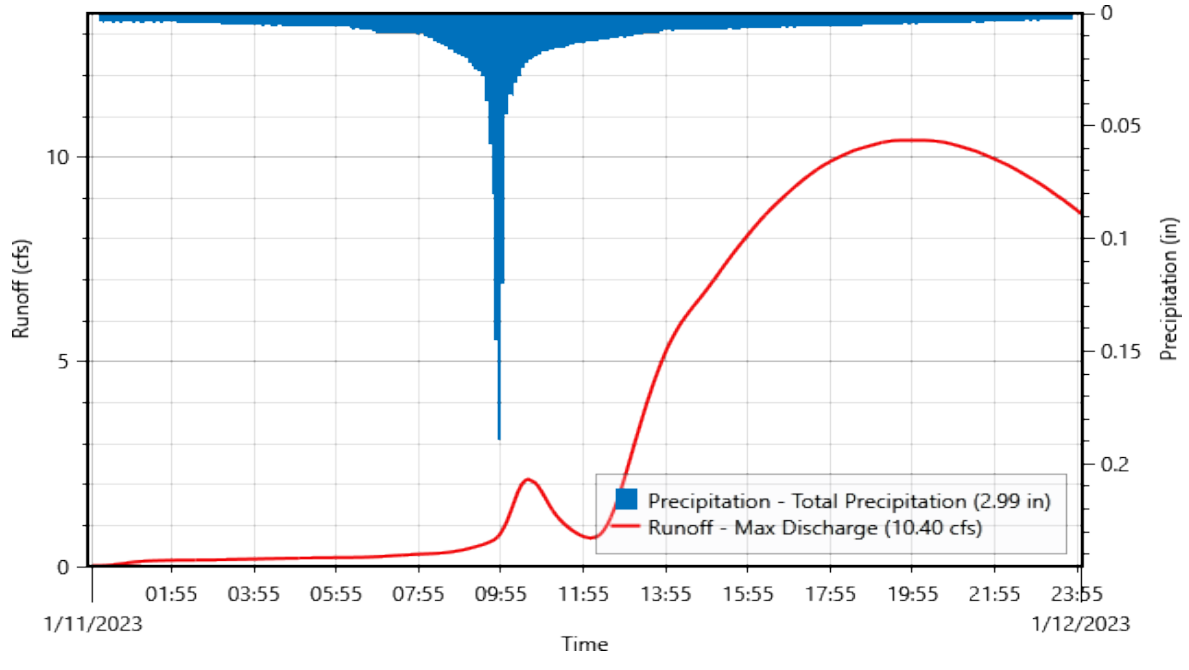
Subbasin ID:	Sub-14		Depth	Volume
Scenario:	Proposed Development 100yr			
Peak discharge:	10.40 cfs	**Time of peak:**	11 Jan 2023, 08:10	
Drainage area:	1,158.859 acres	**Total rainfall:**	2.99 in	288.74628 ac-ft
Initial abstraction:	2.01 in	**Losses:**	2.90 in	279.68233 ac-ft
Curve Number:	49.91	**Precip excess:**	0.09 in	9.06395 ac-ft
Impervious surface:	0.23%	**Direct runoff:**	0.09 in	8.42 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	43.12 minutes	**Total runoff:**	0.09 in	8.42 ac-ft

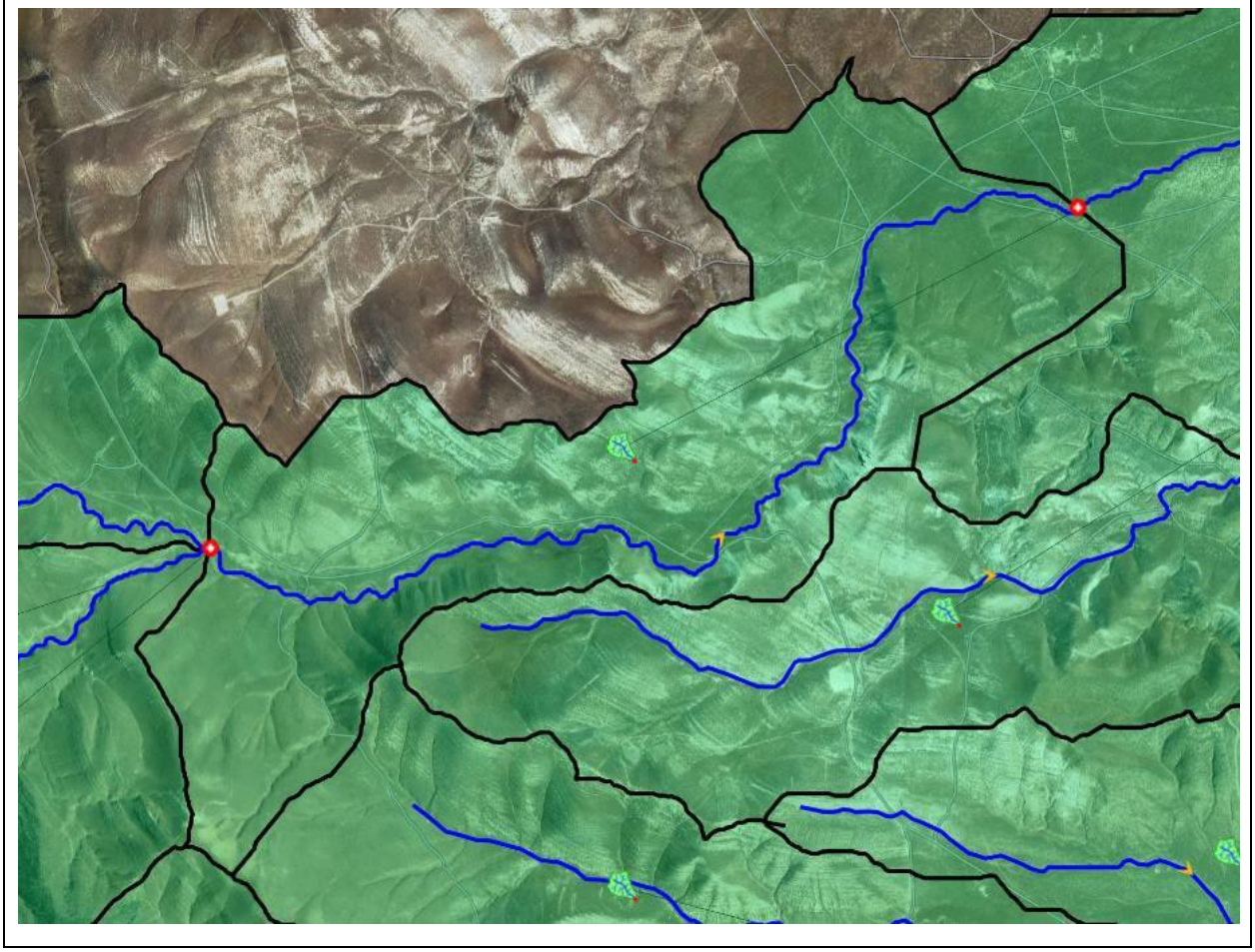
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
128.595	11.10	40.16	Undeveloped, Shrub/Scrub
0.289	0.02	61.00	Developed, Low Density
89.373	7.71	62.75	Developed, Open Space
940.602	81.17	50.02	Undeveloped, Grassland
1,158.859	**100.00**	**49.91**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
15.07	100.00	0.21650	1.7286	Sheet Flow
1.46	911.67	0.41691	21.3220	Shallow Concentrated Flow
2.49	2,157.30	0.19089	14.4277	Channel Flow
2.91	1,629.56	0.07940	9.3053	Channel Flow
49.93	15,884.87	0.02564	5.2879	Channel Flow
71.86	**20,683.40**	**Total**	**Lag Time = 43.12 minutes**	





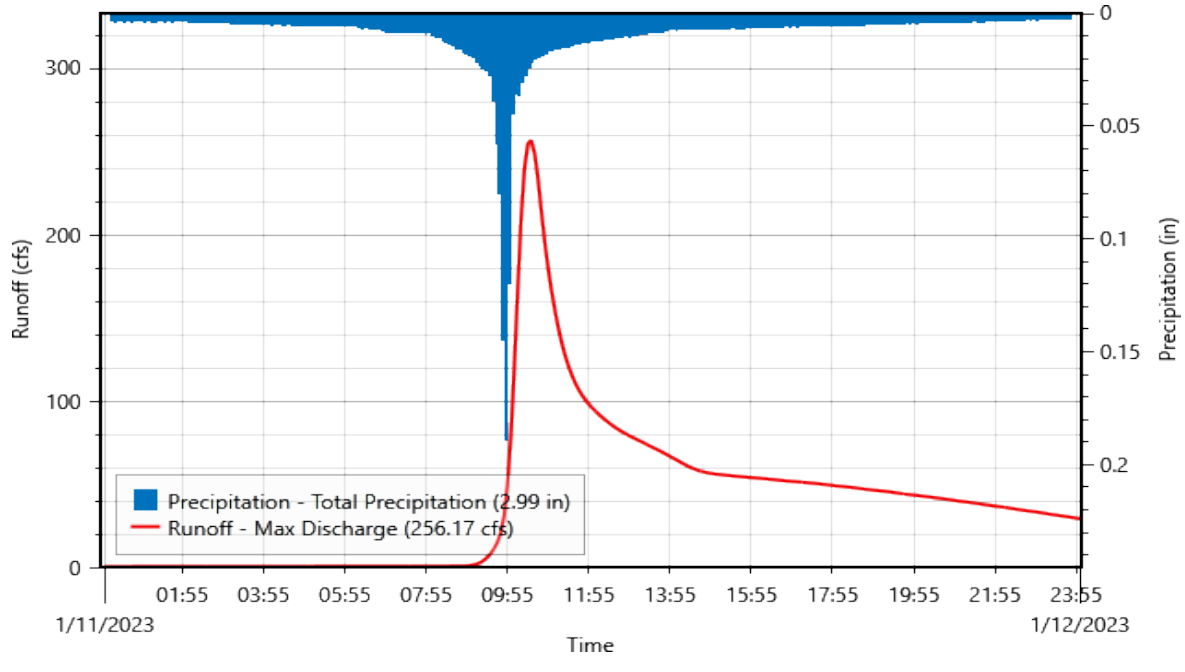
Subbasin ID:	Sub-15			
Scenario:	Proposed Development 100yr		Depth	Volume
Peak discharge:	256.17 cfs	**Time of peak:**	11 Jan 2023, 10:30	
Drainage area:	1,054.808 acres	**Total rainfall:**	2.99 in	262.81700 ac-ft
Initial abstraction:	0.70 in	**Losses:**	2.08 in	182.86948 ac-ft
Curve Number:	74.04	**Precip excess:**	0.91 in	79.94753 ac-ft
Impervious surface:	0.23%	**Direct runoff:**	0.89 in	78.40 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	30.66 minutes	**Total runoff:**	0.89 in	78.40 ac-ft

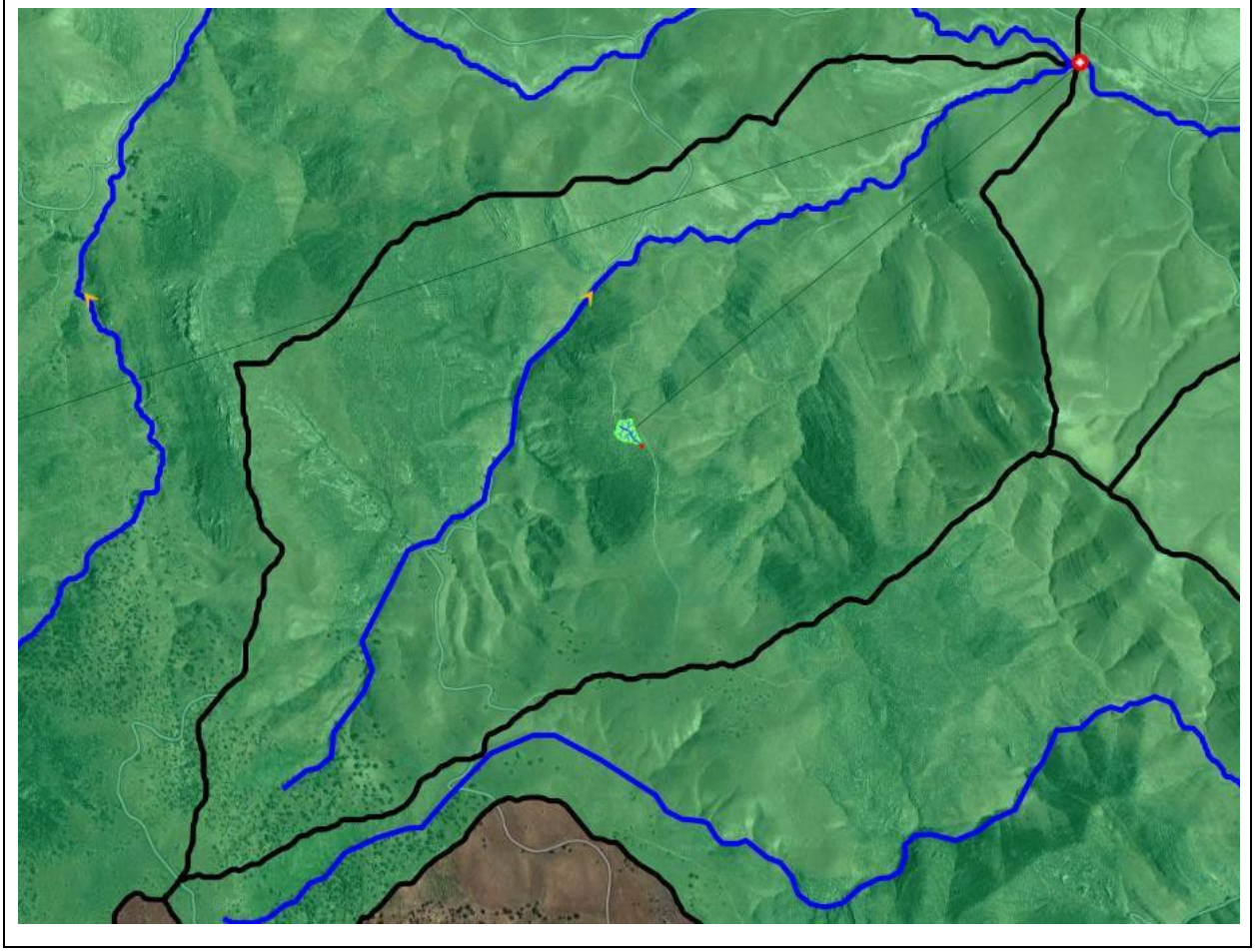
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
0.440	0.04	90.67	Developed, Medium Density
314.541	29.82	70.23	Undeveloped, Shrub/Scrub
3.839	0.36	84.20	Developed, Low Density
56.493	5.36	82.98	Developed, Open Space
679.496	64.42	74.98	Undeveloped, Grassland
1,054.808	**100.00**	**74.04**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
25.00	100.00	0.06109	0.9182	Sheet Flow
2.53	1,452.21	0.35050	19.5503	Shallow Concentrated Flow
1.74	1,776.43	0.26336	16.9464	Channel Flow
21.82	11,269.67	0.06761	8.5864	Channel Flow
51.09	**14,598.31**	**Total**	**Lag Time = 30.66 minutes**	





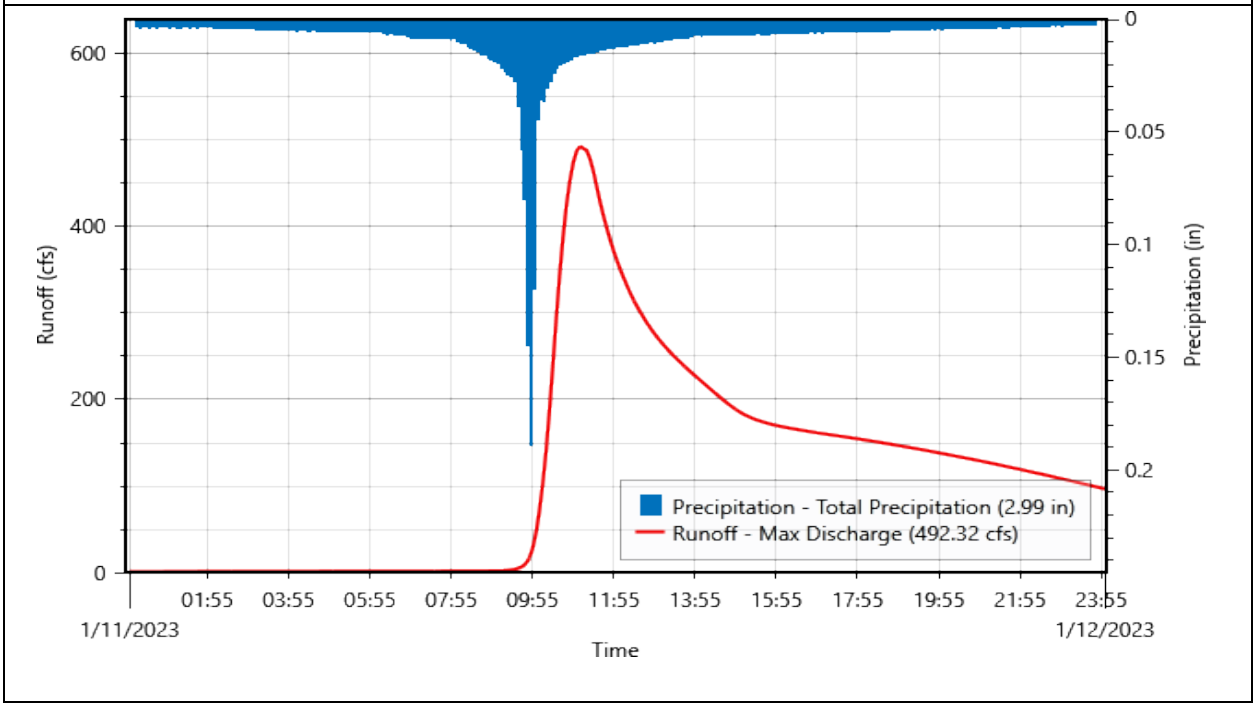
Subbasin ID:	Sub-16			
Scenario:	Proposed Development 100yr		Depth	Volume
Peak discharge:	492.32 cfs	**Time of peak:**	11 Jan 2023, 11:05	
Drainage area:	3,426.802 acres	**Total rainfall:**	2.99 in	853.84828 ac-ft
Initial abstraction:	0.76 in	**Losses:**	2.16 in	617.20714 ac-ft
Curve Number:	72.40	**Precip excess:**	0.83 in	236.64114 ac-ft
Impervious surface:	0.26%	**Direct runoff:**	0.79 in	226.93 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	59.76 minutes	**Total runoff:**	0.79 in	226.93 ac-ft

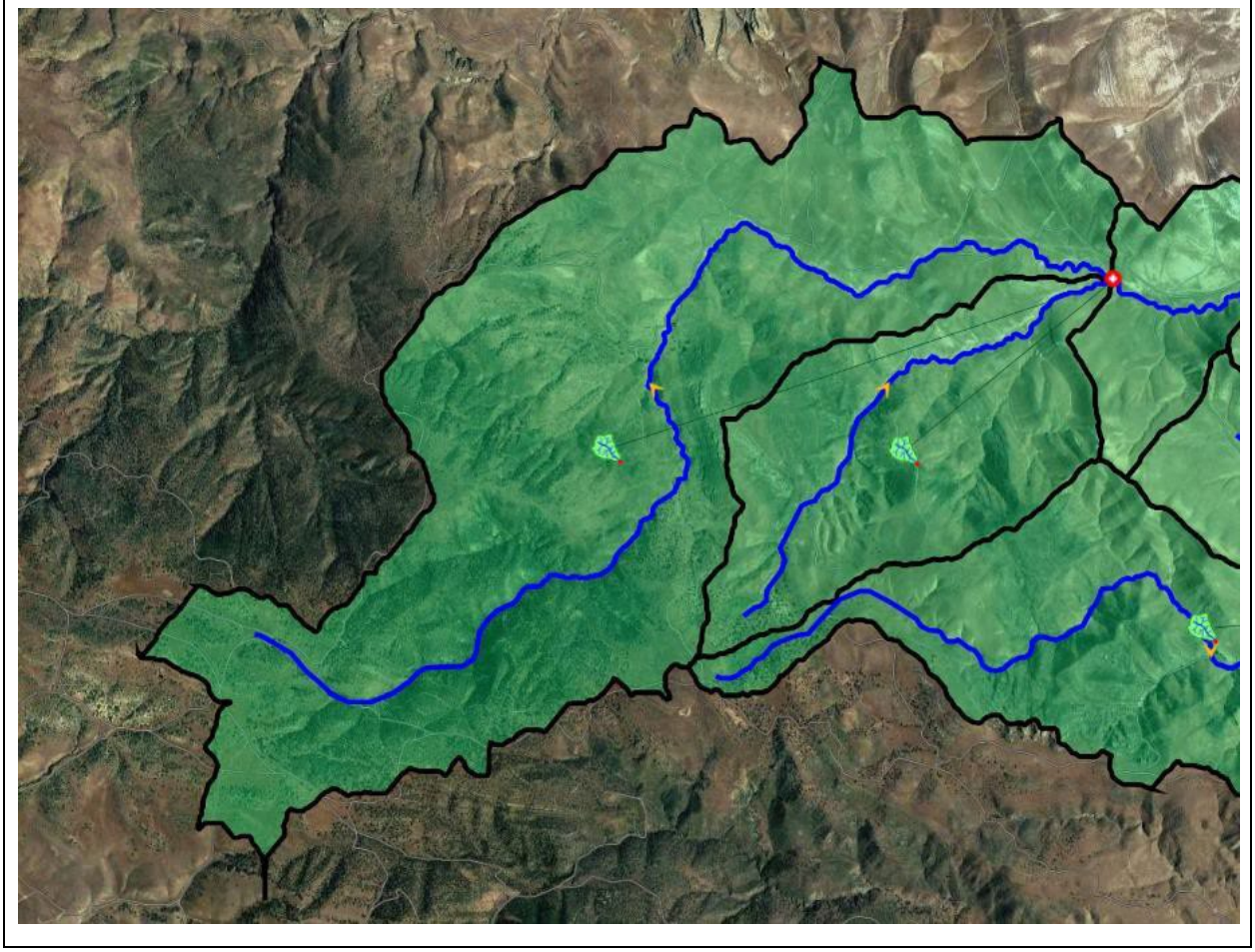
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
1.435	0.04	90.36	Developed, Medium Density
1,371.868	40.03	69.50	Undeveloped, Shrub/Scrub
7.071	0.21	85.60	Developed, Low Density
212.323	6.20	80.36	Developed, Open Space
1,834.106	53.52	73.58	Undeveloped, Grassland
3,426.802	**100.00**	**72.40**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
19.42	100.00	0.11493	1.2594	Sheet Flow
1.56	667.95	0.19509	14.5854	Shallow Concentrated Flow
13.71	2,461.83	0.03444	6.1282	Shallow Concentrated Flow
8.43	4,539.75	0.07343	8.9483	Channel Flow
9.74	7,174.45	0.13760	12.2496	Channel Flow
46.74	18,531.20	0.03983	6.5902	Channel Flow
99.60	**33,475.18**	**Total**	**Lag Time = 59.76 minutes**	





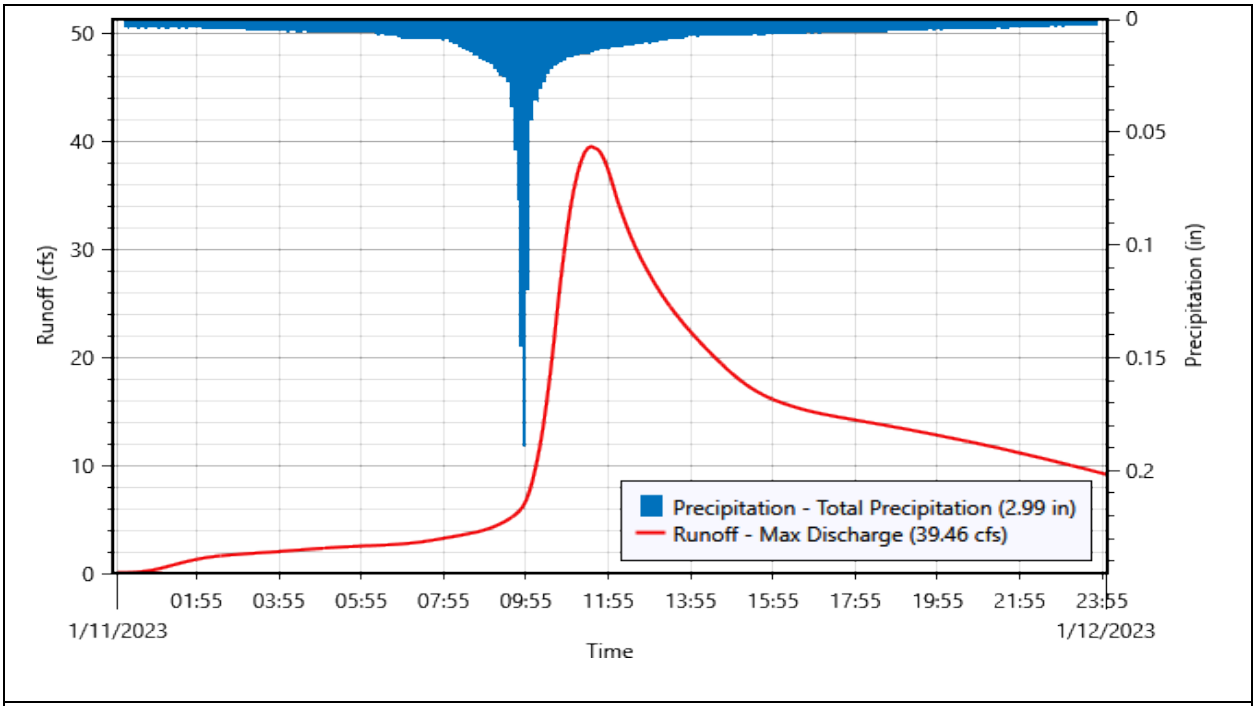
Subbasin ID:	Sub-17			
Scenario:	Proposed Development 100yr		Depth	Volume
Peak discharge:	39.46 cfs	**Time of peak:**	11 Jan 2023, 11:30	
Drainage area:	337.184 acres	**Total rainfall:**	2.99 in	84.00704 ac-ft
Initial abstraction:	0.97 in	**Losses:**	2.14 in	60.23474 ac-ft
Curve Number:	67.43	**Precip excess:**	0.85 in	23.77230 ac-ft
Impervious surface:	10.46%	**Direct runoff:**	0.80 in	22.55 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	80.39 minutes	**Total runoff:**	0.80 in	22.55 ac-ft

Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
11.293	3.35	79.56	Developed, Medium Density
11.056	3.28	57.09	Undeveloped, Shrub/Scrub
67.566	20.04	78.79	Agricultural, Cultivated Crops
47.927	14.21	72.20	Developed, Low Density
0.803	0.24	90.30	Developed, High Density
1.132	0.34	86.00	Undeveloped, Barren Land
45.684	13.55	49.39	Undeveloped, Grassland
151.725	45.00	65.89	Developed, Open Space
337.184	**100.00**	**67.43**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
51.35	100.00	0.01011	0.3736	Sheet Flow
17.31	2,002.38	0.01428	3.9466	Shallow Concentrated Flow
0.33	116.98	0.13224	12.0085	Shallow Concentrated Flow
61.55	2,055.00	0.00119	1.1398	Shallow Concentrated Flow
3.43	792.13	0.01352	3.8394	Channel Flow
133.97	**5,066.49**	**Total**	**Lag Time = 80.39 minutes**	


Runoff (cfs)
Precipitation (in)
Time
1/11/2023
1/12/2023
Precipitation - Total Precipitation (2.99 in)
Runoff - Max Discharge (39.46 cfs)


BSWP
Jun-13
Reach-17
Sub-17
Jun-14
Lost Hills Rd
Entrance A
West Side Hwy

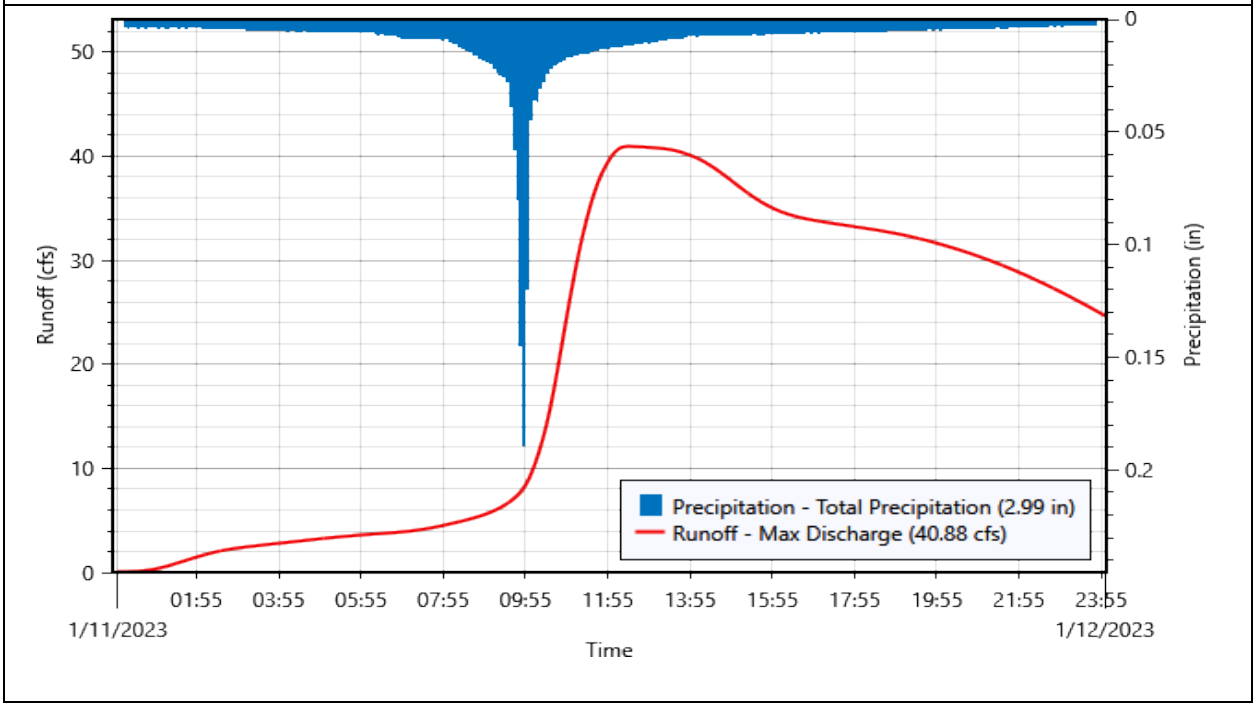
Subbasin ID:	Sub-18			
Scenario:	Proposed Development 100yr		Depth	Volume
Peak discharge:	40.88 cfs	**Time of peak:**	11 Jan 2023, 12:25	
Drainage area:	1,474.591 acres	**Total rainfall:**	2.99 in	367.41118 ac-ft
Initial abstraction:	1.47 in	**Losses:**	2.63 in	323.44166 ac-ft
Curve Number:	57.69	**Precip excess:**	0.36 in	43.96953 ac-ft
Impervious surface:	3.55%	**Direct runoff:**	0.33 in	40.02 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	96.69 minutes	**Total runoff:**	0.33 in	40.02 ac-ft

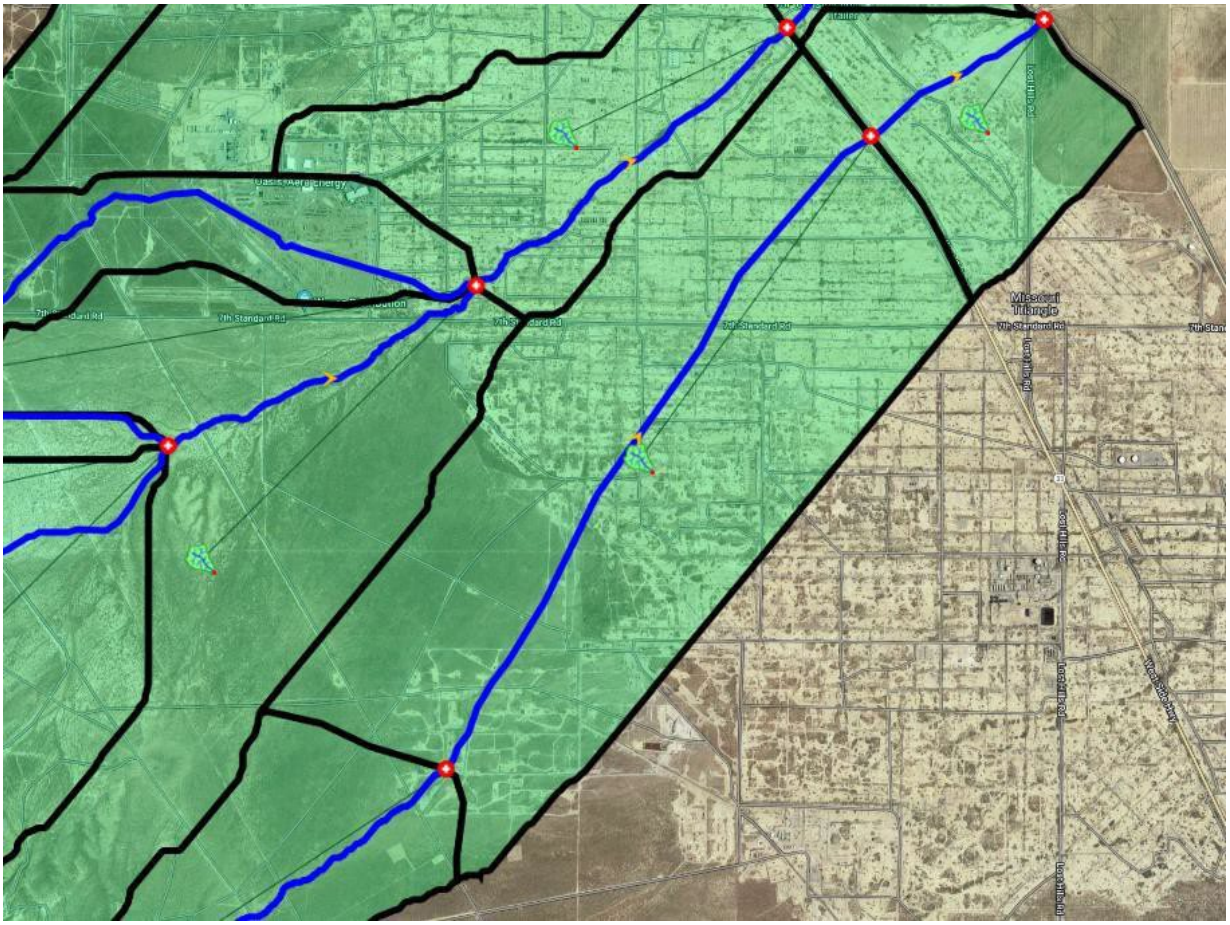
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
3.985	0.27	88.87	Developed, Medium Density
5.873	0.40	43.83	Undeveloped, Shrub/Scrub
60.728	4.12	78.75	Developed, Low Density
0.093	0.01	92.00	Developed, High Density
624.729	42.37	71.04	Developed, Open Space
3.600	0.24	89.56	Undeveloped, Barren Land
775.583	52.60	45.08	Undeveloped, Grassland
1,474.591	**100.00**	**57.69**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
47.88	100.00	0.01204	0.4077	Sheet Flow
16.47	2,024.74	0.01613	4.1935	Shallow Concentrated Flow
47.40	10,905.83	0.01341	3.8241	Channel Flow
49.39	438.84	0.00002	0.1541	Channel Flow
161.14	**13,469.41**	**Total**	**Lag Time = 96.69 minutes**	




7th Standard Rd
Missouri Triangle
Loop 289
Slide Rd
Quaker Ave

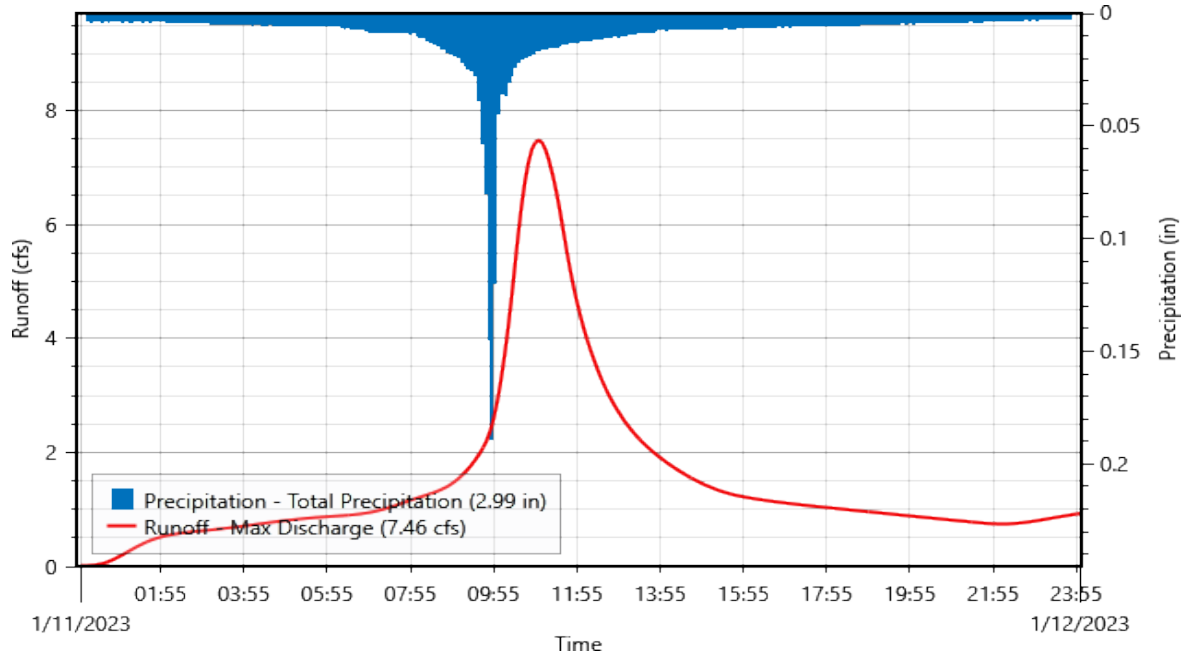
Subbasin ID:	Sub-19			
Scenario:	Proposed Development 100yr		Depth	Volume
Peak discharge:	7.46 cfs	**Time of peak:**	11 Jan 2023, 11:00	
Drainage area:	787.670 acres	**Total rainfall:**	2.99 in	196.25562 ac-ft
Initial abstraction:	2.86 in	**Losses:**	2.94 in	193.17709 ac-ft
Curve Number:	41.19	**Precip excess:**	0.05 in	3.07852 ac-ft
Impervious surface:	1.53%	**Direct runoff:**	0.05 in	2.96 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	66.54 minutes	**Total runoff:**	0.05 in	2.96 ac-ft

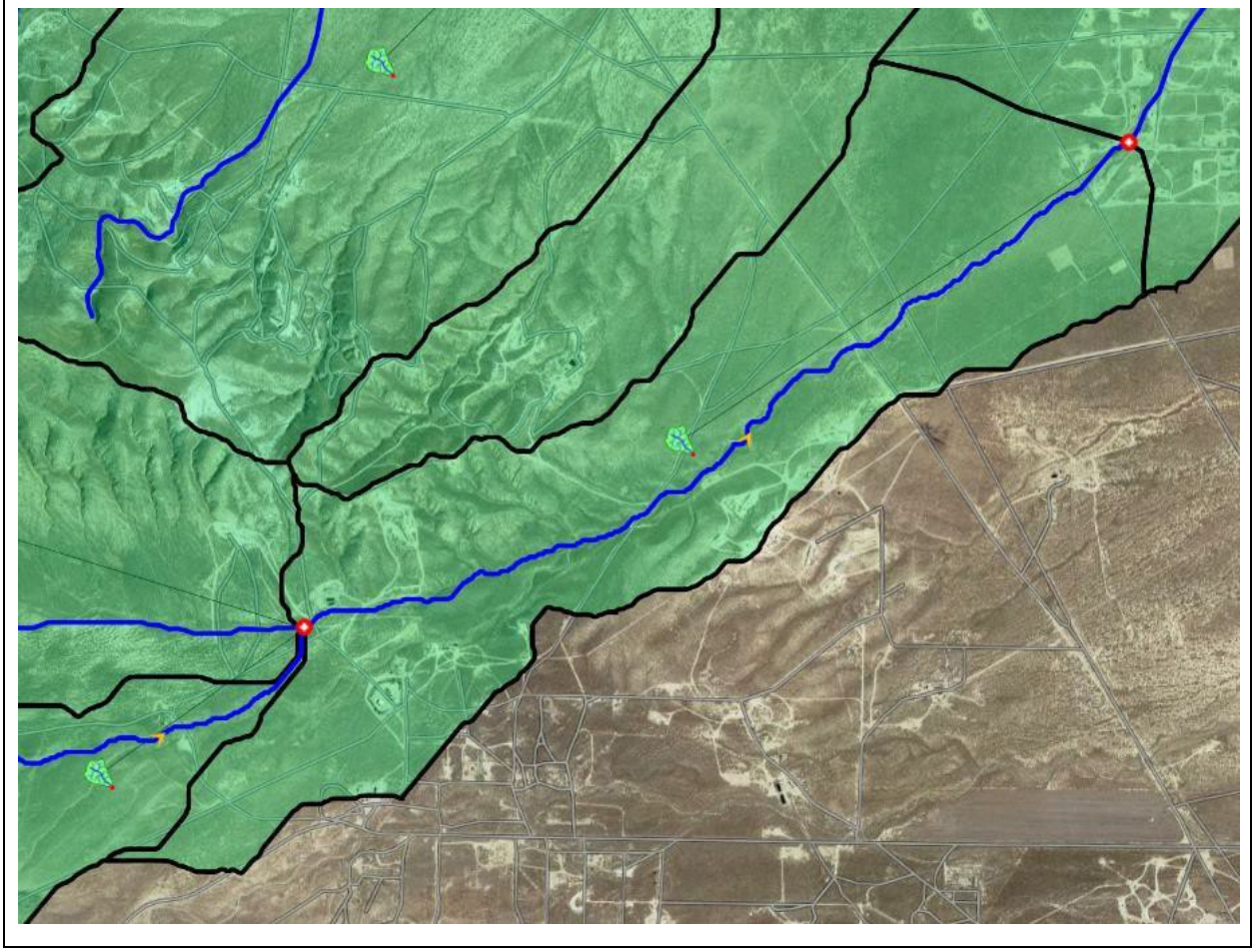
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
1.108	0.14	85.00	Developed, Medium Density
3.612	0.46	36.54	Undeveloped, Shrub/Scrub
0.954	0.12	61.03	Developed, Low Density
92.294	11.72	56.80	Developed, Open Space
0.138	0.02	77.00	Undeveloped, Barren Land
689.564	87.54	39.02	Undeveloped, Grassland
787.670	**100.00**	**41.19**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
29.59	100.00	0.04010	0.7440	Sheet Flow
29.99	4,469.59	0.02372	5.0858	Shallow Concentrated Flow
13.10	1,472.11	0.00320	1.8666	Channel Flow
38.21	10,337.14	0.01854	4.4965	Channel Flow
110.89	**16,378.84**	**Total**	**Lag Time = 66.54 minutes**	





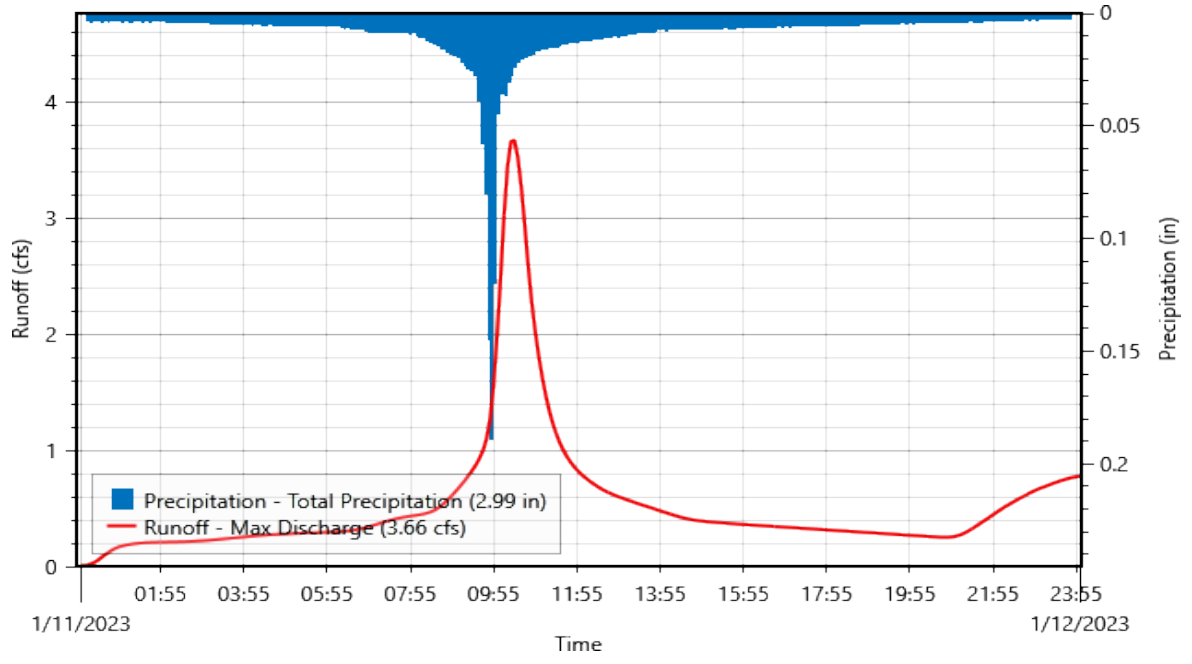
Subbasin ID:	Sub-20		Depth	Volume
Scenario:	Proposed Development 100yr			
Peak discharge:	3.66 cfs	**Time of peak:**	11 Jan 2023, 10:25	
Drainage area:	714.148 acres	**Total rainfall:**	2.99 in	177.94885 ac-ft
Initial abstraction:	2.82 in	**Losses:**	2.97 in	176.86816 ac-ft
Curve Number:	41.47	**Precip excess:**	0.02 in	1.08069 ac-ft
Impervious surface:	0.54%	**Direct runoff:**	0.02 in	1.04 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	30.83 minutes	**Total runoff:**	0.02 in	1.04 ac-ft

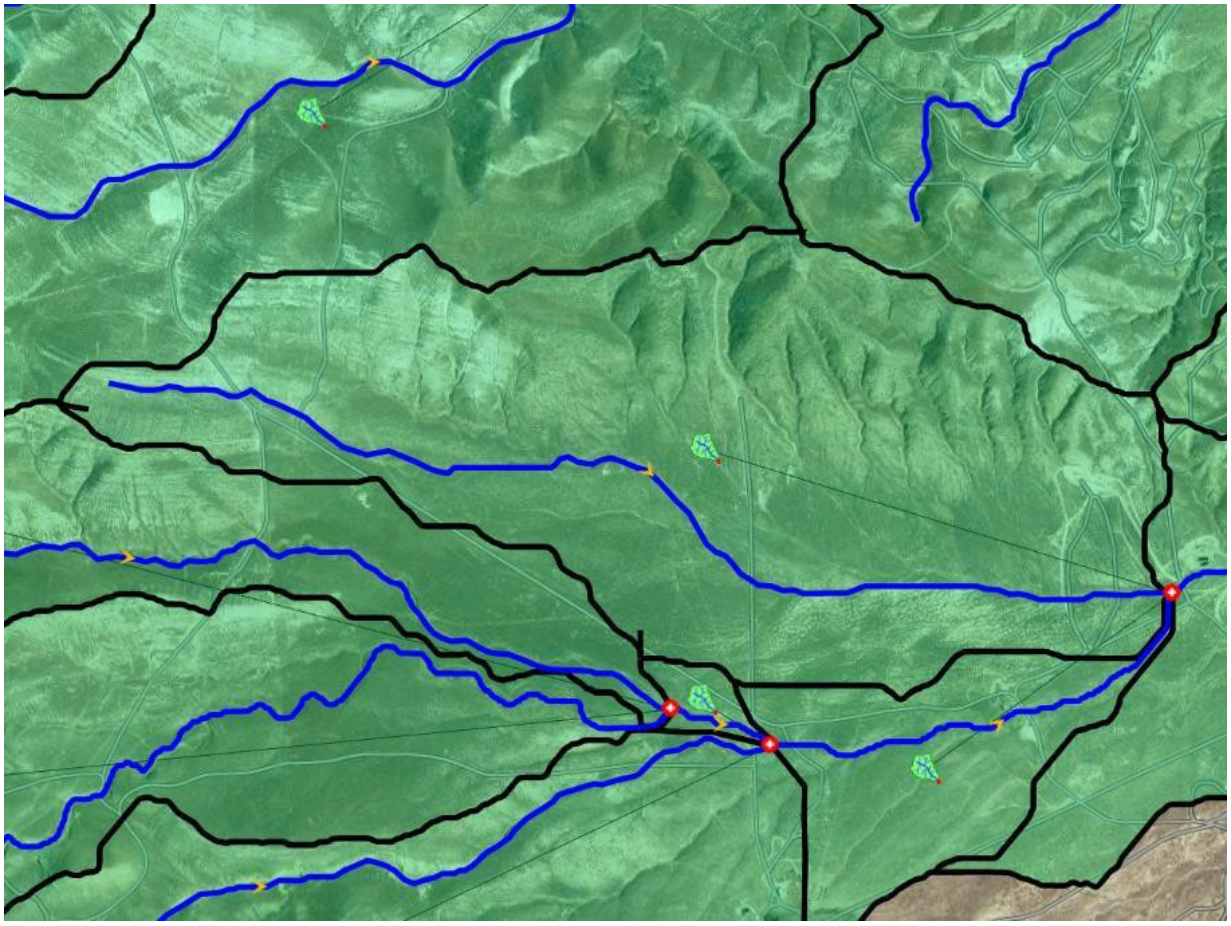
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
1.599	0.22	79.30	Developed, Medium Density
24.804	3.47	30.65	Undeveloped, Shrub/Scrub
0.430	0.06	61.00	Developed, Low Density
60.511	8.47	56.19	Developed, Open Space
626.805	87.77	40.37	Undeveloped, Grassland
714.148	**100.00**	**41.47**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
16.55	100.00	0.17144	1.5382	Sheet Flow
1.01	456.12	0.21931	15.4645	Shallow Concentrated Flow
0.89	623.85	0.12498	11.6744	Channel Flow
18.86	7,625.25	0.04142	6.7210	Channel Flow
9.23	2,974.94	0.02631	5.3566	Channel Flow
4.84	334.47	0.00121	1.1467	Channel Flow
51.38	**12,114.63**	**Total**	**Lag Time = 30.83 minutes**	





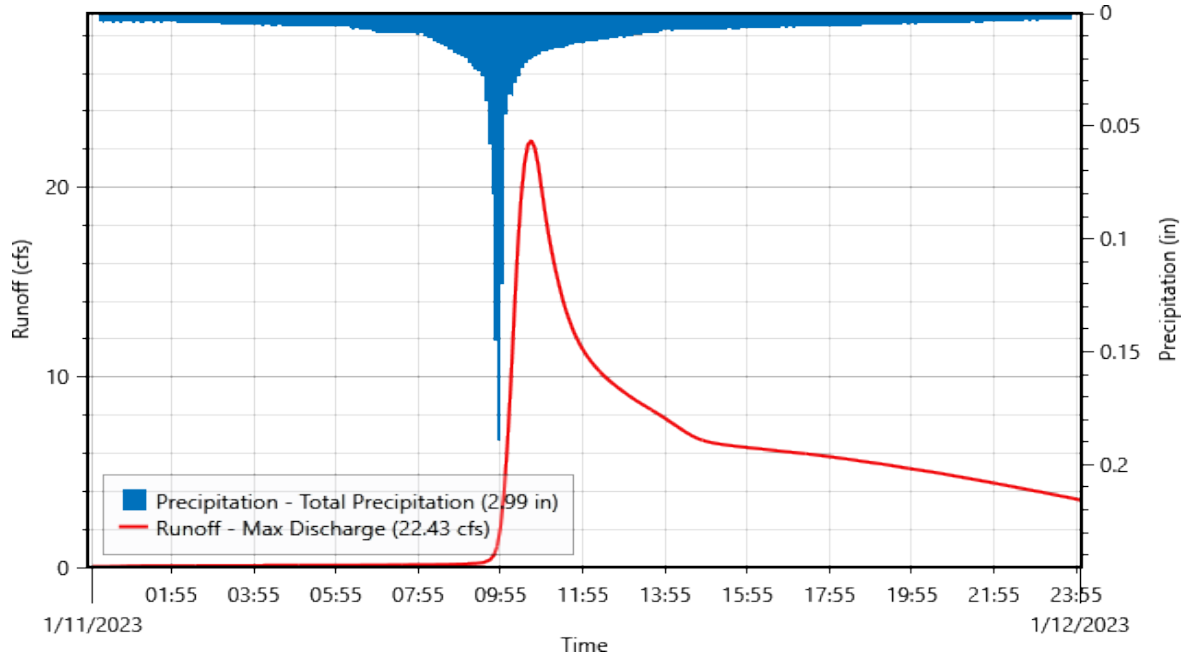
Subbasin ID:	**Sub-21**			
Scenario:	**Proposed Development 100yr**		**Depth**	**Volume**
Peak discharge:	22.43 cfs	**Time of peak:**	11 Jan 2023, 10:40	
Drainage area:	140.608 acres	**Total rainfall:**	2.99 in	35.03483 ac-ft
Initial abstraction:	0.83 in	**Losses:**	2.23 in	26.18362 ac-ft
Curve Number:	70.73	**Precip excess:**	0.76 in	8.85121 ac-ft
Impervious surface:	0.65%	**Direct runoff:**	0.74 in	8.62 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	37.22 minutes	**Total runoff:**	0.74 in	8.62 ac-ft

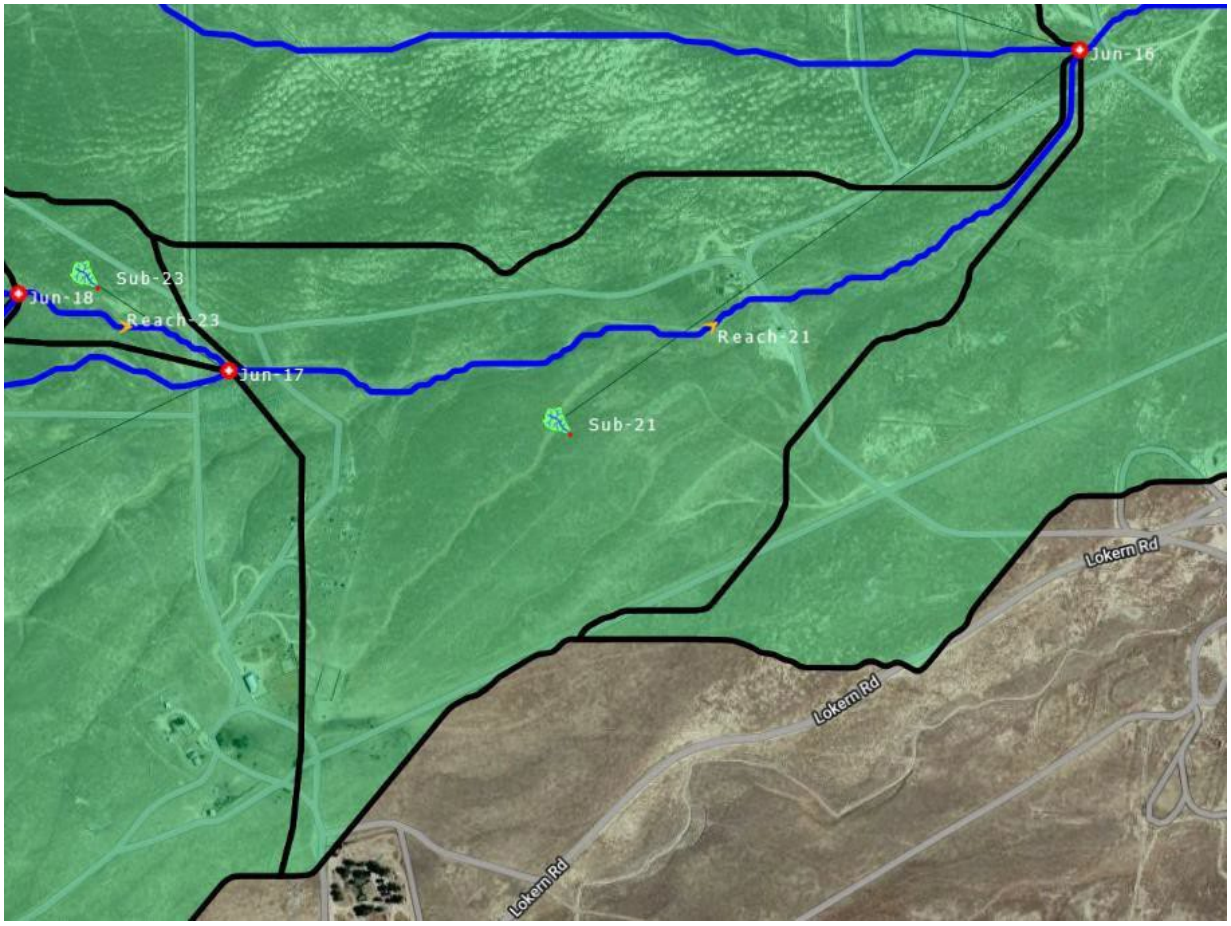
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
0.048	0.03	73.00	Undeveloped, Shrub/Scrub
23.066	16.40	70.83	Developed, Open Space
117.494	83.56	70.70	Undeveloped, Grassland
140.608	**100.00**	**70.73**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
34.47	100.00	0.02738	0.6147	Sheet Flow
19.66	3,615.01	0.03610	6.2745	Shallow Concentrated Flow
5.94	1,258.40	0.01138	3.5222	Channel Flow
1.95	736.77	0.03618	6.2812	Channel Flow
62.02	**5,710.18**	**Total**	**Lag Time = 37.22 minutes**	




Jun-16
Sub-23
Jun-18
Reach-23
Reach-21
Jun-17
Sub-21
Lokern Rd
Lokern Rd
Lokern Rd

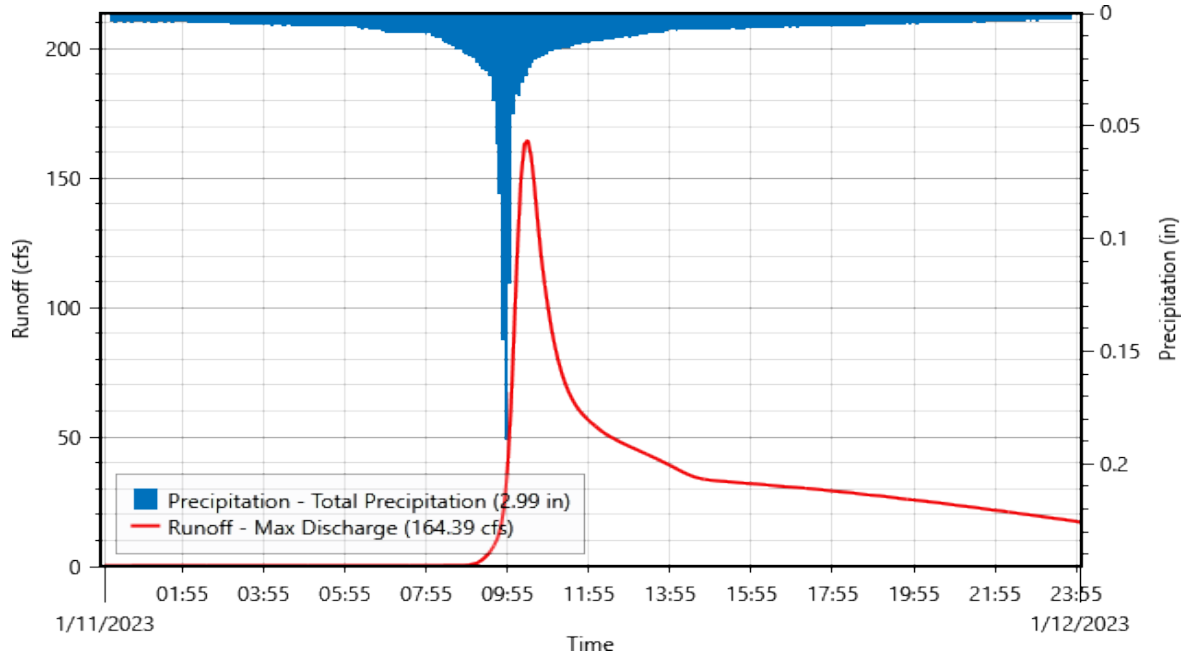
Subbasin ID:	Sub-22			
Scenario:	Proposed Development 100yr		Depth	Volume
Peak discharge:	164.39 cfs	**Time of peak:**	11 Jan 2023, 10:25	
Drainage area:	624.791 acres	**Total rainfall:**	2.99 in	155.67135 ac-ft
Initial abstraction:	0.70 in	**Losses:**	2.08 in	108.15140 ac-ft
Curve Number:	74.21	**Precip excess:**	0.91 in	47.51995 ac-ft
Impervious surface:	0.15%	**Direct runoff:**	0.90 in	46.72 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	26.62 minutes	**Total runoff:**	0.90 in	46.72 ac-ft

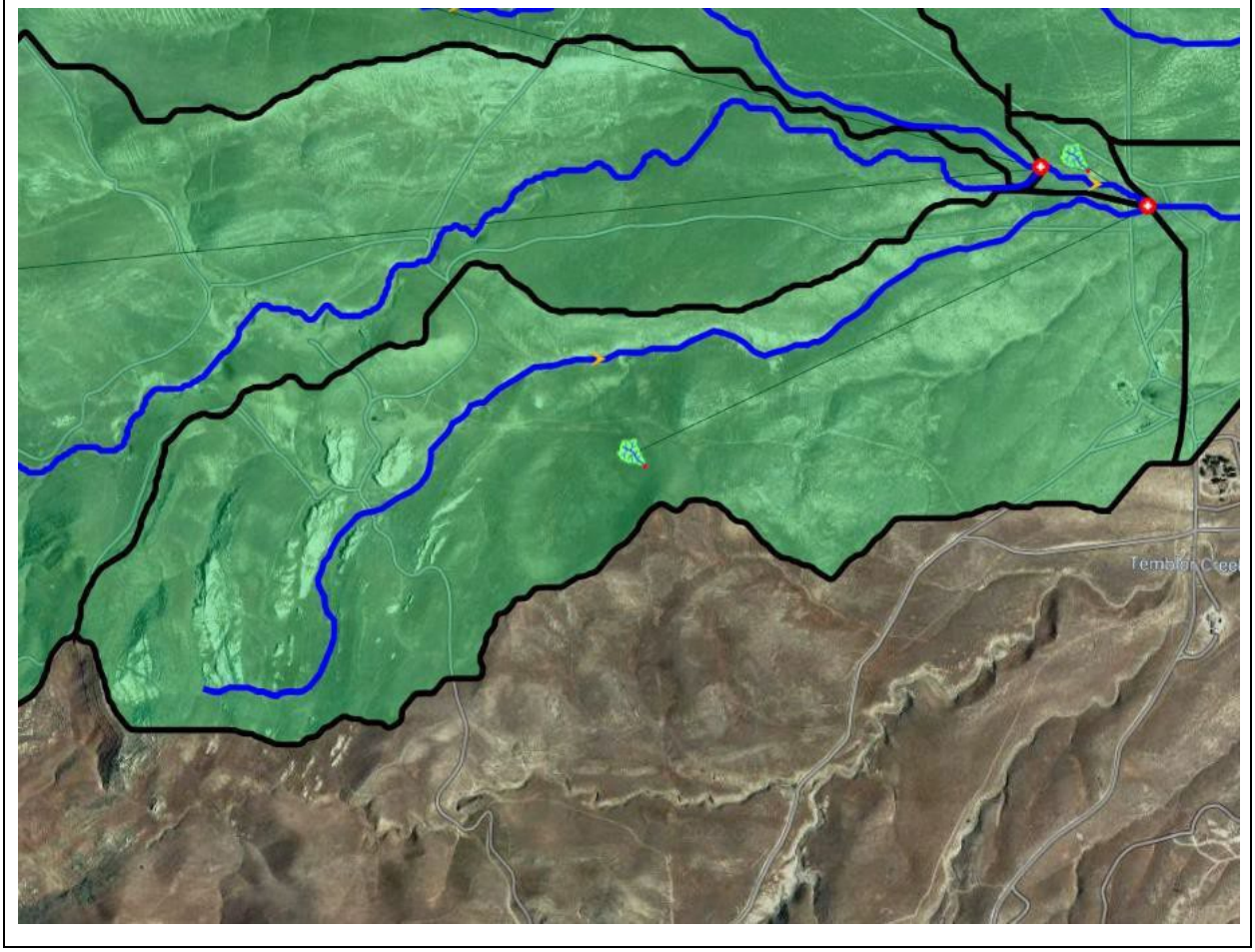
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
15.298	2.45	65.31	Undeveloped, Shrub/Scrub
44.349	7.10	81.50	Developed, Open Space
565.143	90.45	73.87	Undeveloped, Grassland
624.791	**100.00**	**74.21**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
14.10	100.00	0.25569	1.8785	Sheet Flow
1.03	658.49	0.44023	21.9101	Shallow Concentrated Flow
0.57	222.33	0.16461	13.3980	Shallow Concentrated Flow
5.54	2,803.60	0.06494	8.4151	Channel Flow
23.12	8,603.50	0.03510	6.1869	Channel Flow
44.36	**12,387.92**	**Total**	**Lag Time = 26.62 minutes**	





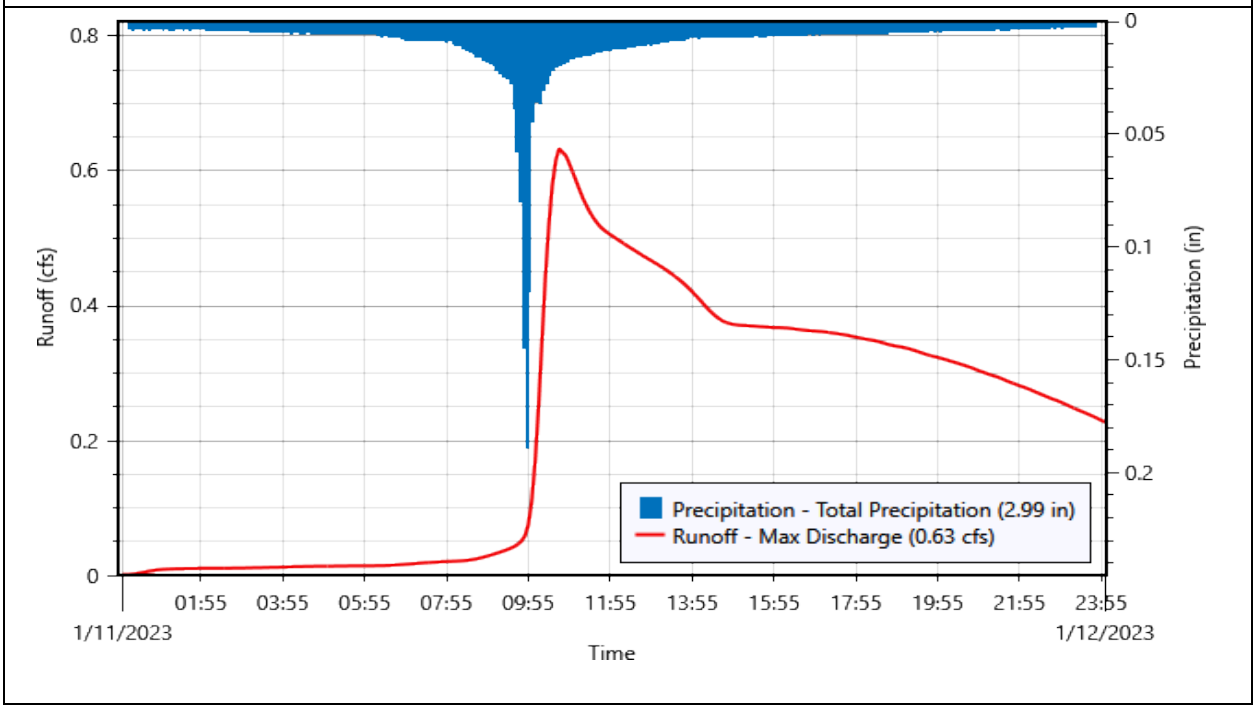
Subbasin ID:	**Sub-23**			
Scenario:	**Proposed Development 100yr**		**Depth**	**Volume**
Peak discharge:	0.63 cfs	**Time of peak:**	11 Jan 2023, 10:45	
Drainage area:	13.631 acres	**Total rainfall:**	2.99 in	3.39664 ac-ft
Initial abstraction:	1.27 in	**Losses:**	2.59 in	2.94180 ac-ft
Curve Number:	61.18	**Precip excess:**	0.40 in	0.45484 ac-ft
Impervious surface:	1.28%	**Direct runoff:**	0.39 in	0.44 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	30.66 minutes	**Total runoff:**	0.39 in	0.44 ac-ft

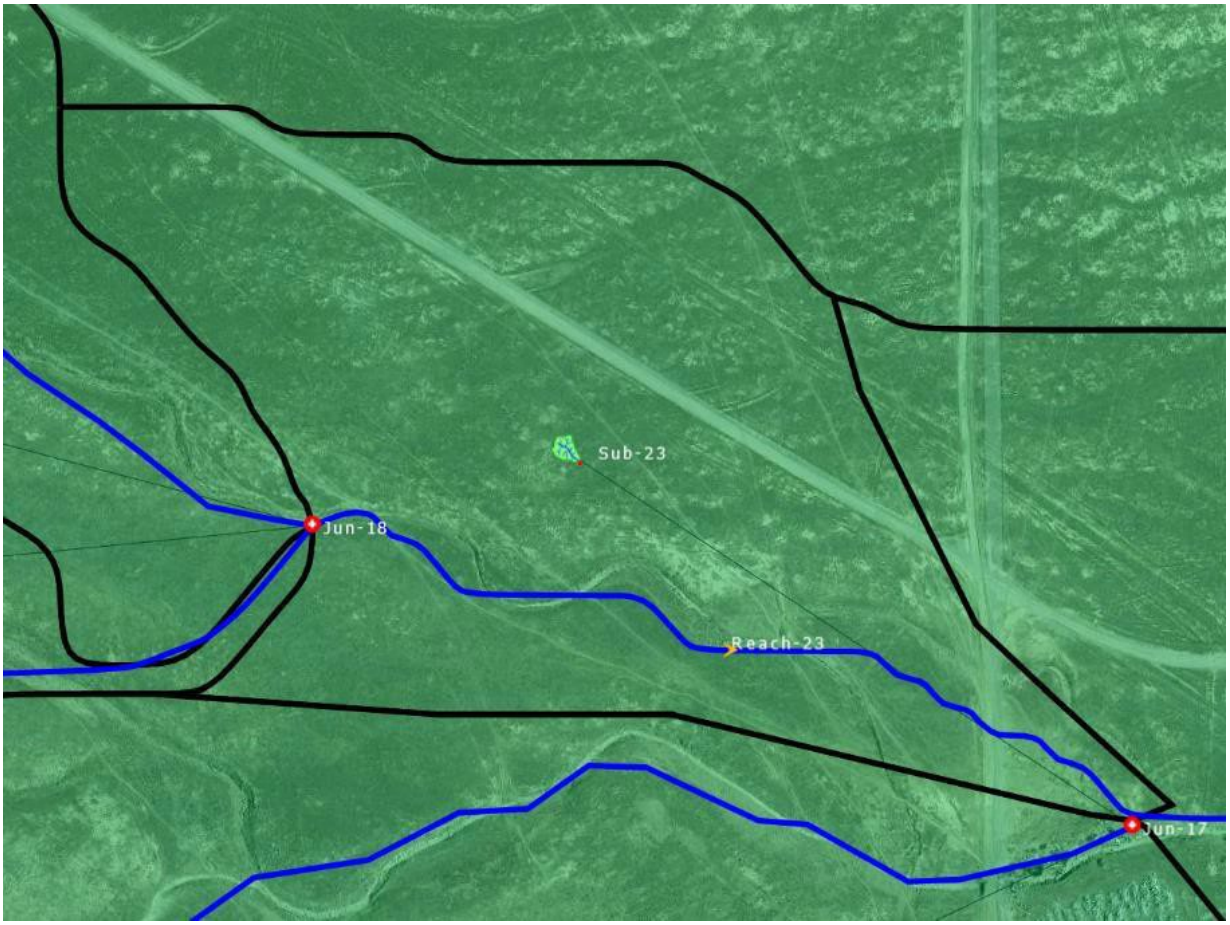
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
3.902	28.63	69.00	Developed, Open Space
9.729	71.37	58.05	Undeveloped, Grassland
13.631	**100.00**	**61.18**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
44.71	100.00	0.01429	0.4440	Sheet Flow
1.98	295.62	0.02383	5.0982	Shallow Concentrated Flow
0.56	163.06	0.09046	9.9322	Shallow Concentrated Flow
0.38	151.74	0.16695	13.4926	Shallow Concentrated Flow
0.27	66.19	0.06214	8.2320	Shallow Concentrated Flow
3.19	963.56	0.02314	5.0234	Channel Flow
51.09	**1,740.17**	**Total**	**Lag Time = 30.66 minutes**	




Sub-23
Jun-18
Reach-23
Jun-17

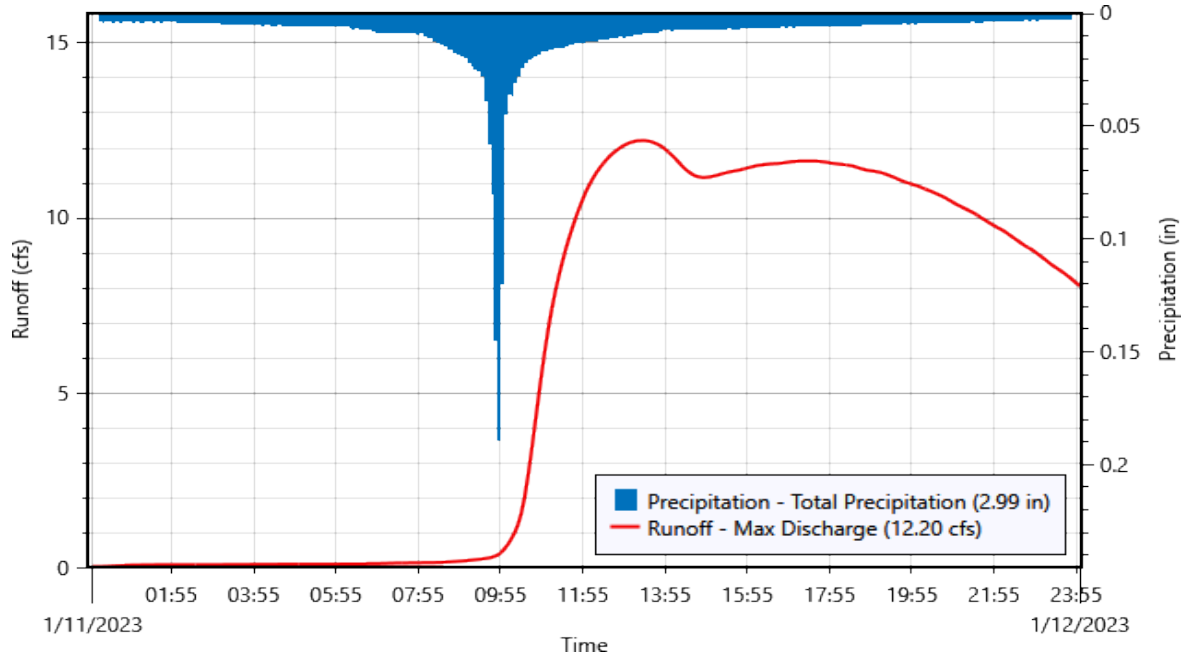
Subbasin ID:	Sub-24			
Scenario:	Proposed Development 100yr		Depth	Volume
Peak discharge:	12.20 cfs	**Time of peak:**	11 Jan 2023, 01:20	
Drainage area:	662.076 acres	**Total rainfall:**	2.99 in	164.96826 ac-ft
Initial abstraction:	1.57 in	**Losses:**	2.77 in	152.70970 ac-ft
Curve Number:	56.09	**Precip excess:**	0.22 in	12.25856 ac-ft
Impervious surface:	0.15%	**Direct runoff:**	0.21 in	11.81 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	31.77 minutes	**Total runoff:**	0.21 in	11.81 ac-ft

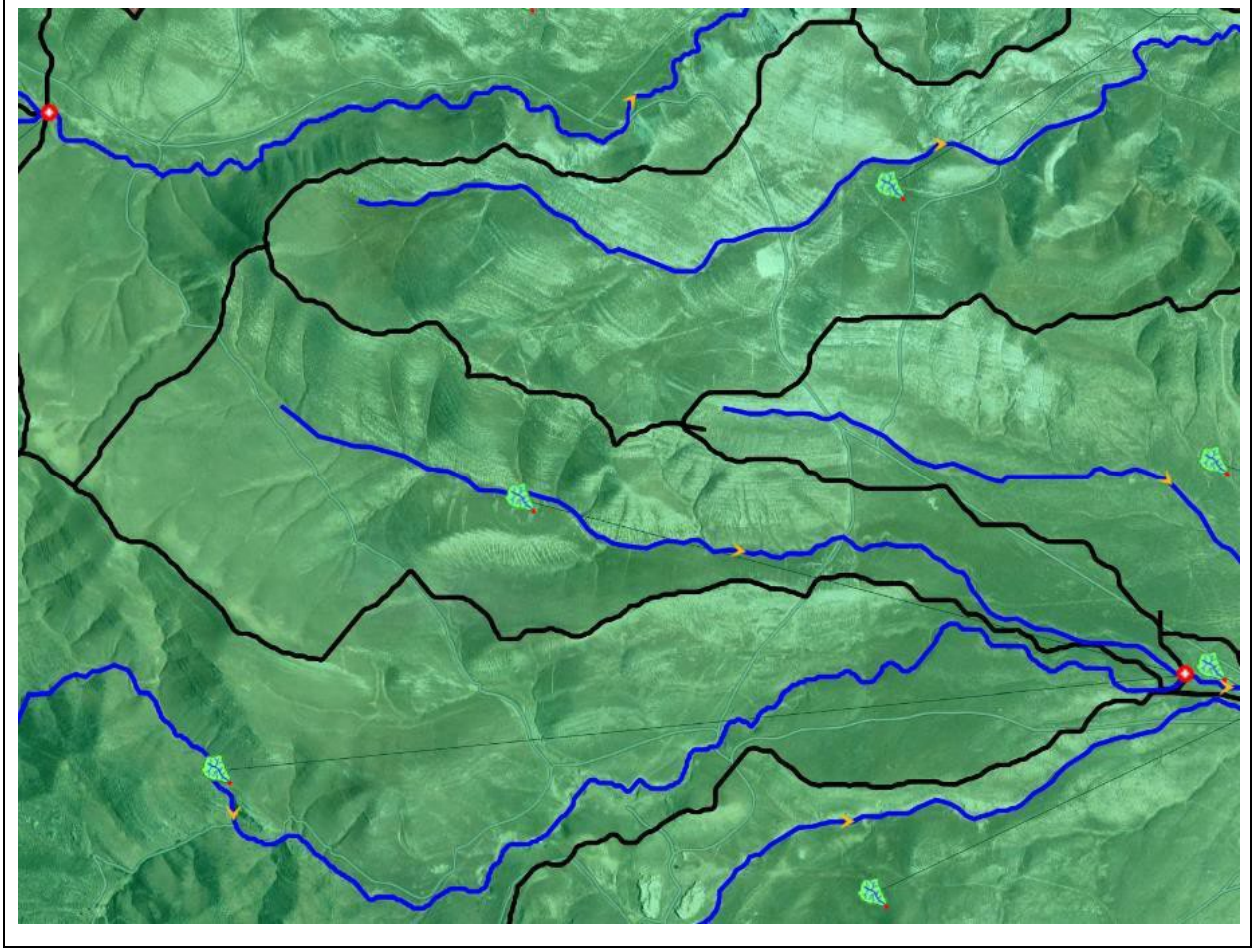
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
0.098	0.01	30.00	Undeveloped, Shrub/Scrub
37.733	5.70	67.01	Developed, Open Space
624.245	94.29	55.43	Undeveloped, Grassland
662.076	**100.00**	**56.09**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
14.40	100.00	0.24257	1.8297	Sheet Flow
1.26	869.08	0.51033	23.5902	Shallow Concentrated Flow
1.44	665.78	0.22832	15.7788	Shallow Concentrated Flow
3.67	1,184.85	0.11132	11.0178	Shallow Concentrated Flow
18.74	7,536.85	0.04100	6.6863	Channel Flow
13.43	4,799.21	0.03234	5.9389	Channel Flow
52.94	**15,155.77**	**Total**	**Lag Time = 31.77 minutes**	





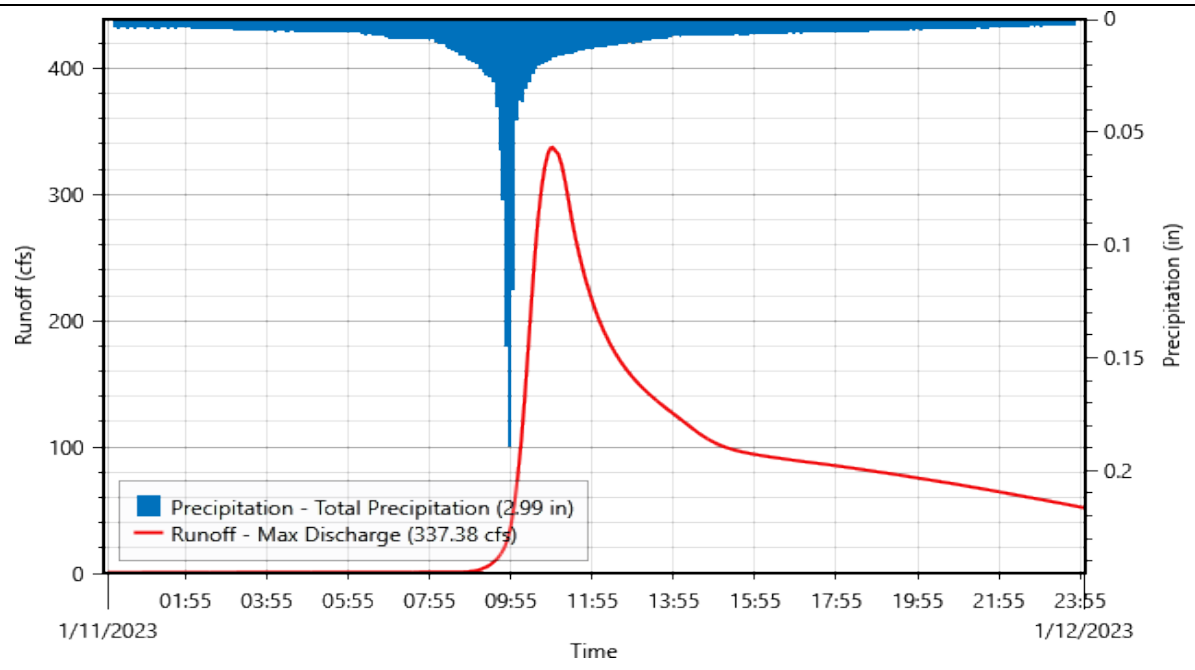
Subbasin ID:	**Sub-25**			
Scenario:	**Proposed Development 100yr**		**Depth**	**Volume**
Peak discharge:	337.38 cfs	**Time of peak:**	11 Jan 2023, 10:55	
Drainage area:	1,694.320 acres	**Total rainfall:**	2.99 in	422.17204 ac-ft
Initial abstraction:	0.65 in	**Losses:**	2.01 in	283.42430 ac-ft
Curve Number:	75.41	**Precip excess:**	0.98 in	138.74773 ac-ft
Impervious surface:	0.25%	**Direct runoff:**	0.95 in	134.03 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	53.90 minutes	**Total runoff:**	0.95 in	134.03 ac-ft

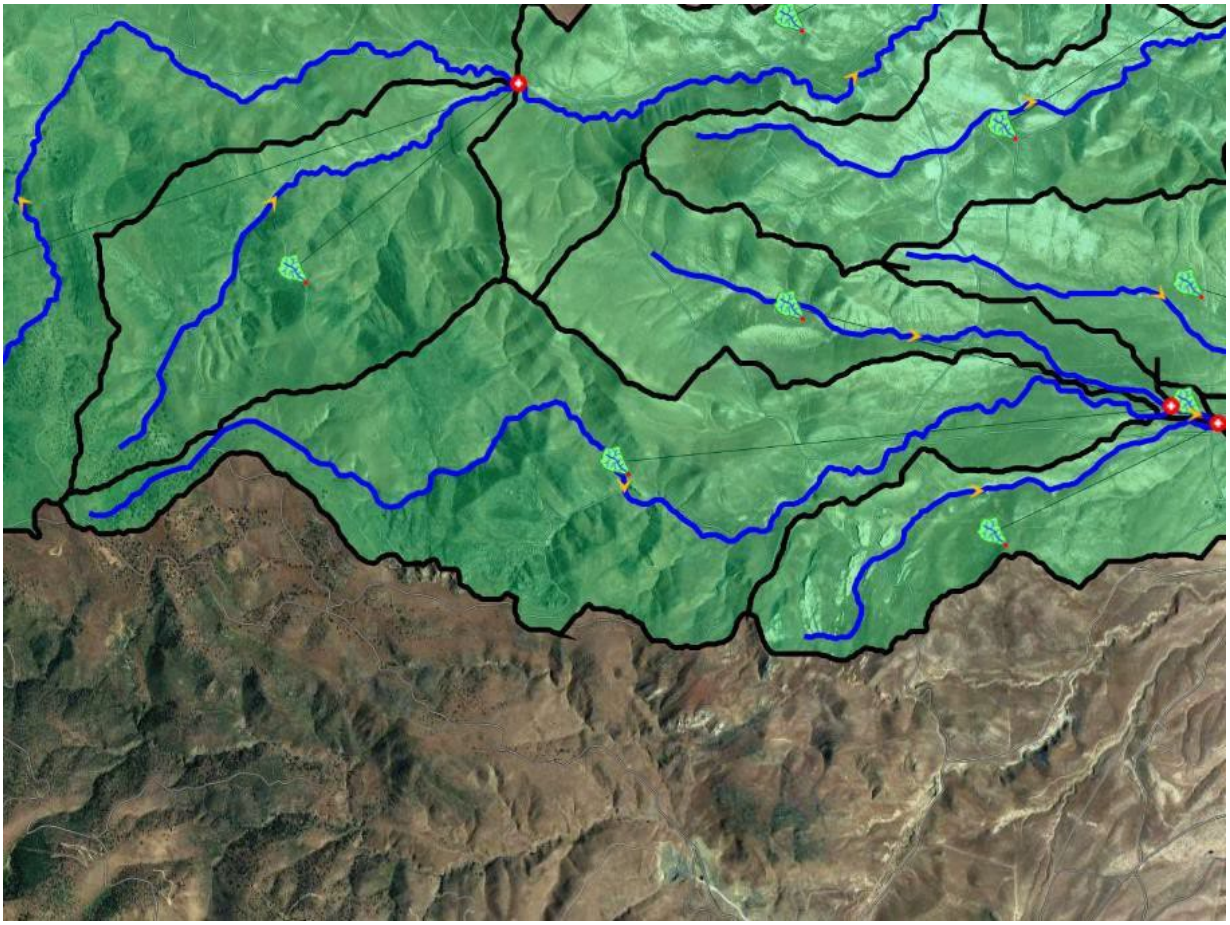
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
0.589	0.03	91.09	Developed, Medium Density
343.072	20.25	72.37	Undeveloped, Shrub/Scrub
1.038	0.06	86.45	Developed, Low Density
128.369	7.58	82.02	Developed, Open Space
1,221.252	72.08	75.55	Undeveloped, Grassland
1,694.320	**100.00**	**75.41**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
23.14	100.00	0.07413	1.0115	Sheet Flow
2.26	773.43	0.12489	11.6701	Shallow Concentrated Flow
2.16	1,933.44	0.20208	14.8446	Channel Flow
10.49	5,320.75	0.06516	8.4296	Channel Flow
3.64	2,816.87	0.15175	12.8636	Channel Flow
20.32	9,127.19	0.05113	7.4670	Channel Flow
27.81	10,228.78	0.03427	6.1135	Channel Flow
89.82	**30,300.46**	**Total**	**Lag Time = 53.90 minutes**	





Nodes

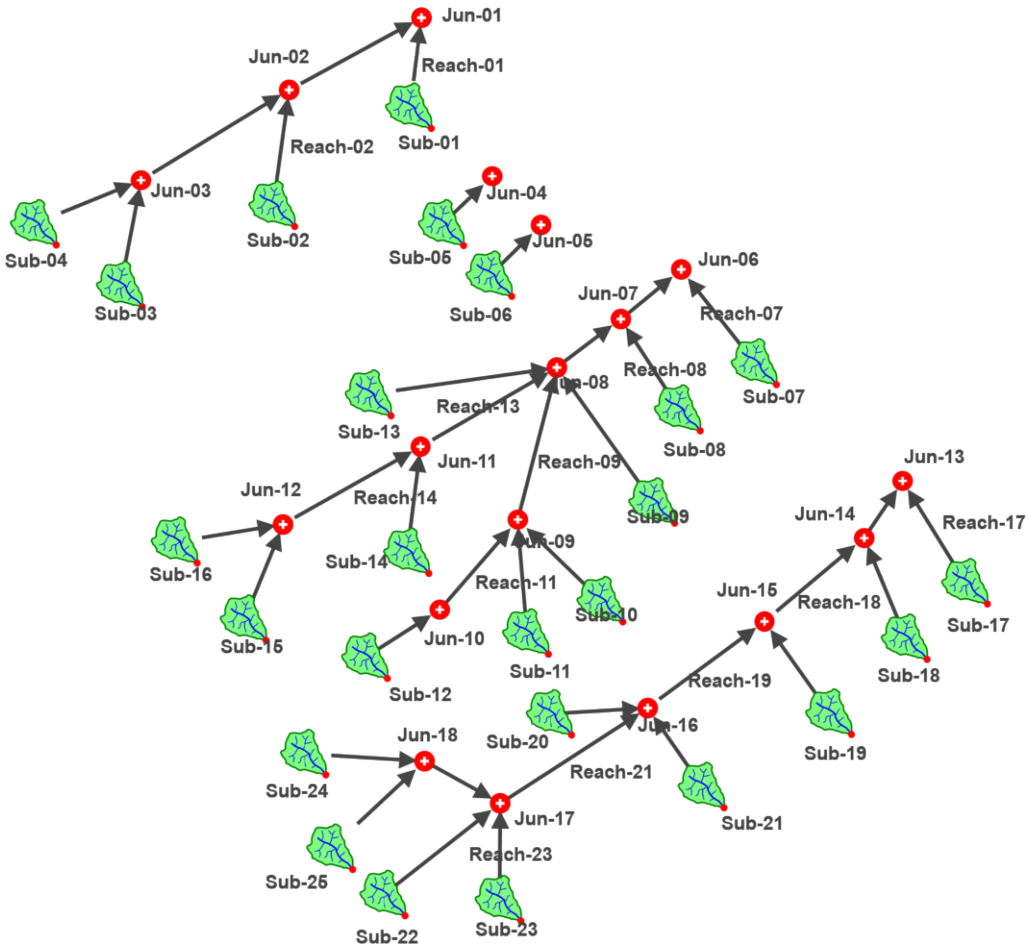
Element ID	Element Type	Peak Inflow (cfs)	Peak Outflow (cfs)	Peak Diverted Flow (cfs)
Jun-01	Junction	254.04	254.04	
Jun-02	Junction	221.03	221.03	
Jun-03	Junction	221.43	221.43	
Jun-04	Junction	26.44	26.44	
Jun-05	Junction	27.28	27.28	
Jun-06	Junction	688.43	688.43	
Jun-07	Junction	667.66	667.66	
Jun-08	Junction	668.08	668.08	
Jun-09	Junction	12.99	12.99	
Jun-10	Junction	4.46	4.46	
Jun-11	Junction	653.18	653.18	
Jun-12	Junction	652.10	652.10	
Jun-13	Junction	522.24	522.24	
Jun-14	Junction	496.28	496.28	
Jun-15	Junction	465.69	465.69	
Jun-16	Junction	461.08	461.08	
Jun-17	Junction	442.06	442.06	
Jun-18	Junction	342.92	342.92	

Routing Reaches

Reach ID	Peak Inflow (cfs)	Peak Outflow (cfs)	Attenuated Flow (cfs)
Reach-01	221.03	208.01	13.02
Reach-02	221.43	220.83	0.60
Reach-03	0.00	0.00	0.00
Reach-04	0.00	0.00	0.00
Reach-05	0.00	0.00	0.00
Reach-06	0.00	0.00	0.00
Reach-07	667.66	667.04	0.62
Reach-08	668.08	662.55	5.53
Reach-09	12.99	12.98	0.01
Reach-10	0.00	0.00	0.00
Reach-11	4.46	3.15	1.31
Reach-12	0.00	0.00	0.00
Reach-13	653.18	652.47	0.71
Reach-14	652.10	652.04	0.06
Reach-15	0.00	0.00	0.00
Reach-16	0.00	0.00	0.00
Reach-17	496.28	495.71	0.57
Reach-18	465.69	455.51	10.18
Reach-19	461.08	459.78	1.30
Reach-20	0.00	0.00	0.00
Reach-21	442.06	440.76	1.30
Reach-22	0.00	0.00	0.00
Reach-23	342.92	342.77	0.15
Reach-24	0.00	0.00	0.00
Reach-25	0.00	0.00	0.00

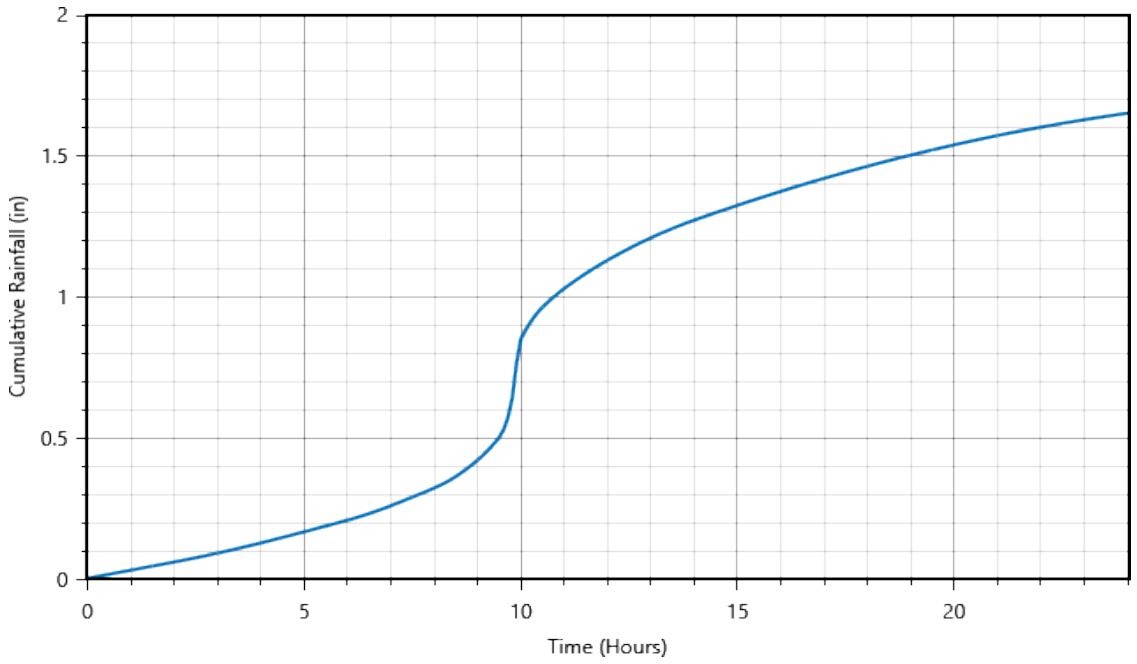
Proposed Development 10 yr

Watershed Routing Diagram



Design Storm

Precipitation type: SCS Storm
SCS storm distribution: Type I
Rainfall depth: 1.65 in



Watershed Summary

Subbasin ID	Drainage Area (acres)	Initial Abstraction (in)	Curve Number	Impervious Surface (%)	Lag Time (minutes)	Peak Discharge (cfs)
Sub-01	1,269.566	1.23	61.84		0.00	4.49
Sub-02	337.798	2.28	46.74		0.00	0.20
Sub-03	169.707	2.61	43.39		0.00	0.10
Sub-04	1,961.124	0.86	70.00		0.00	19.93
Sub-05	685.814	1.94	50.82		0.00	14.58
Sub-06	856.439	1.86	51.75		0.00	14.71
Sub-07	269.771	1.05	65.60		0.00	7.85
Sub-08	503.505	1.48	57.53		0.00	4.98
Sub-09	1,130.587	2.84	41.33		0.00	3.62
Sub-10	1,153.361	1.94	50.79		0.00	5.66
Sub-11	161.318	4.26	31.97		0.00	1.11
Sub-12	952.517	3.33	37.51		0.00	2.46
Sub-13	1,426.690	3.40	37.06		0.00	3.12
Sub-14	1,158.859	2.01	49.91		0.00	1.17
Sub-15	1,054.808	0.70	74.04		0.00	23.28
Sub-16	3,426.802	0.76	72.40		0.00	51.16
Sub-17	337.184	0.97	67.43		0.00	10.83
Sub-18	1,474.591	1.47	57.69		0.00	14.37
Sub-19	787.670	2.86	41.19		0.00	4.12
Sub-20	714.148	2.82	41.47		0.00	2.02
Sub-21	140.608	0.83	70.73		0.00	1.69
Sub-22	624.791	0.70	74.21		0.00	14.26
Sub-23	13.631	1.27	61.18		0.00	0.09
Sub-24	662.076	1.57	56.09		0.00	0.51
Sub-25	1,694.320	0.65	75.41		0.00	43.47

Subbasins

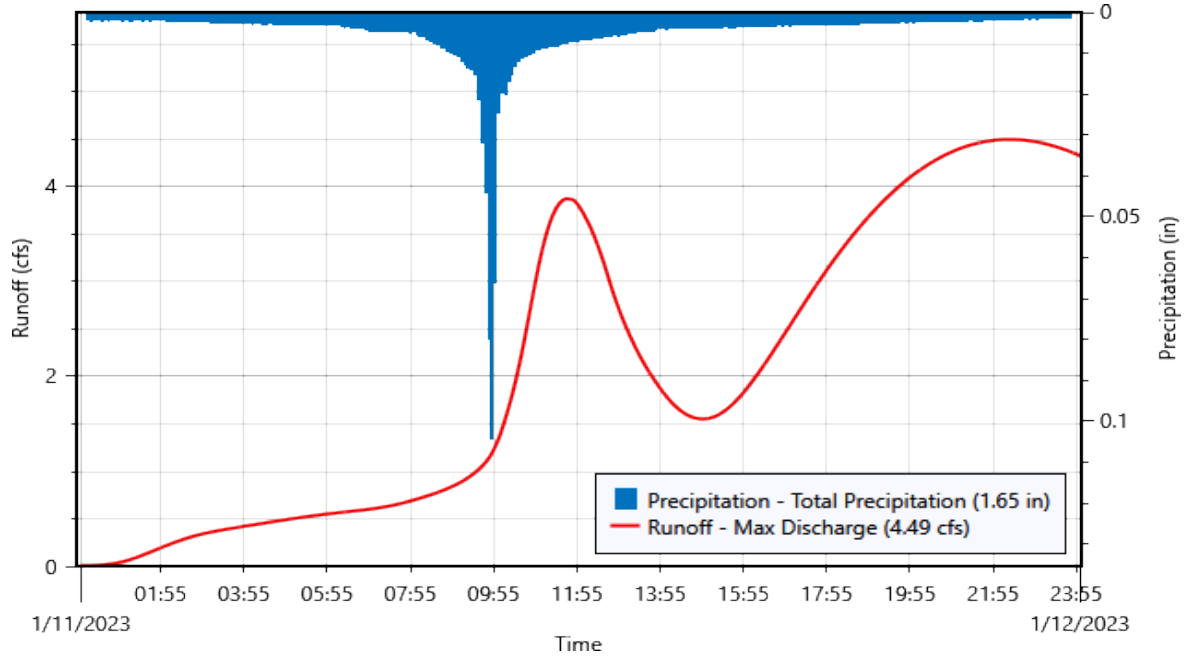
Subbasin ID:	**Sub-01**			
Scenario:	**Proposed Development 10 yr**		**Depth**	**Volume**
Peak discharge:	4.49 cfs	**Time of peak:**	11 Jan 2023, 10:20	
Drainage area:	1,269.566 acres	**Total rainfall:**	1.65 in	174.56559 ac-ft
Initial abstraction:	1.23 in	**Losses:**	1.60 in	169.70749 ac-ft
Curve Number:	61.84	**Precip excess:**	0.05 in	4.85810 ac-ft
Impervious surface:	%	**Direct runoff:**	0.04 in	4.07 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	0.00 minutes	**Total runoff:**	0.04 in	4.07 ac-ft

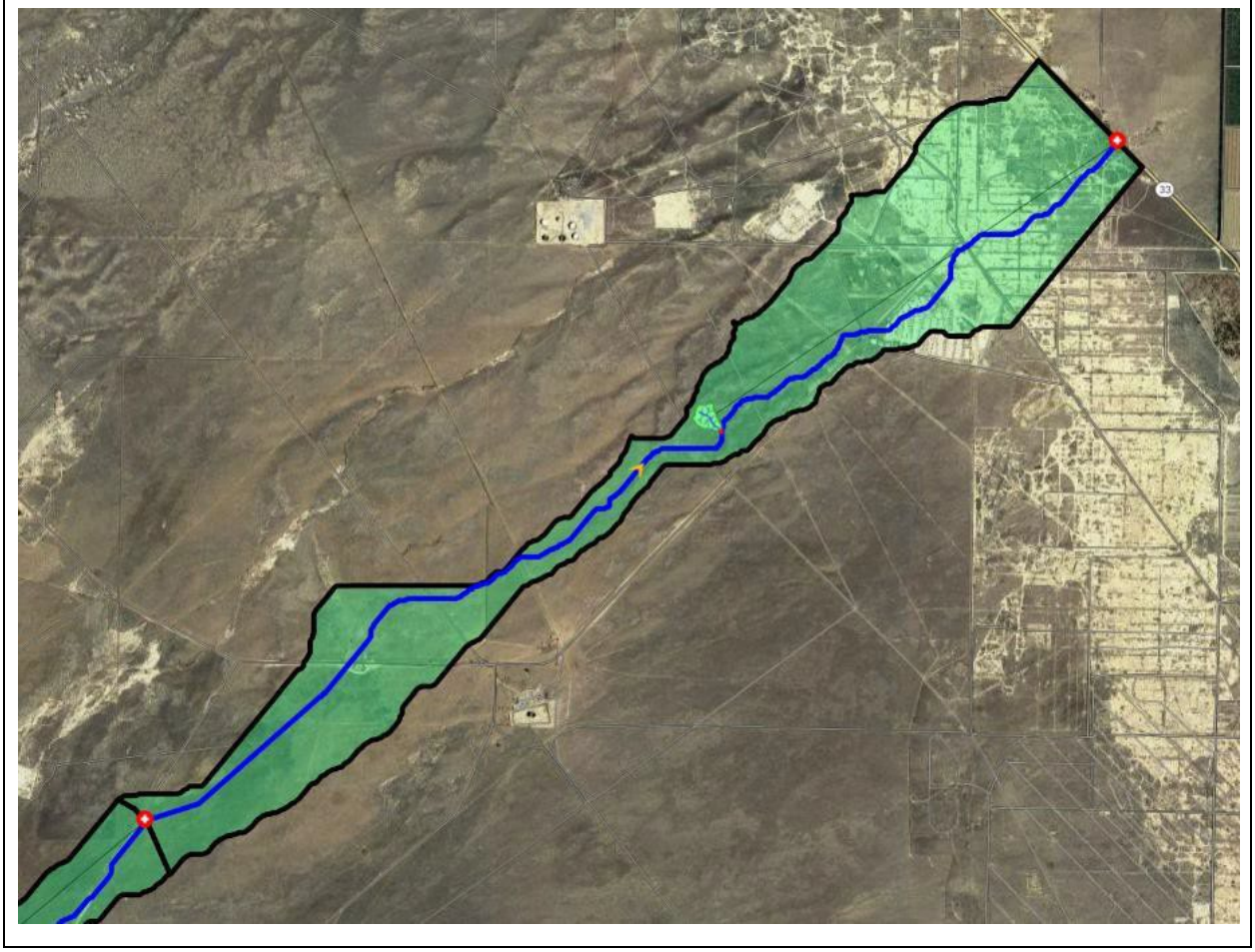
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
2.200	0.17	77.00	Developed, Medium Density
72.954	5.75	73.69	Agricultural, Cultivated Crops
12.818	1.01	73.61	Developed, Low Density
248.559	19.58	68.81	Developed, Open Space
2.419	0.19	77.00	Undeveloped, Barren Land
930.614	73.30	58.81	Undeveloped, Grassland
1,269.566	**100.00**	**61.84**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
45.65	99.01	0.01330	0.4284	Sheet Flow
13.66	1,732.24	0.01717	4.3269	Shallow Concentrated Flow
119.26	26,180.93	0.01221	3.6493	Channel Flow
178.57	**28,012.18**	**Total**	**Lag Time = 107.15 minutes**	





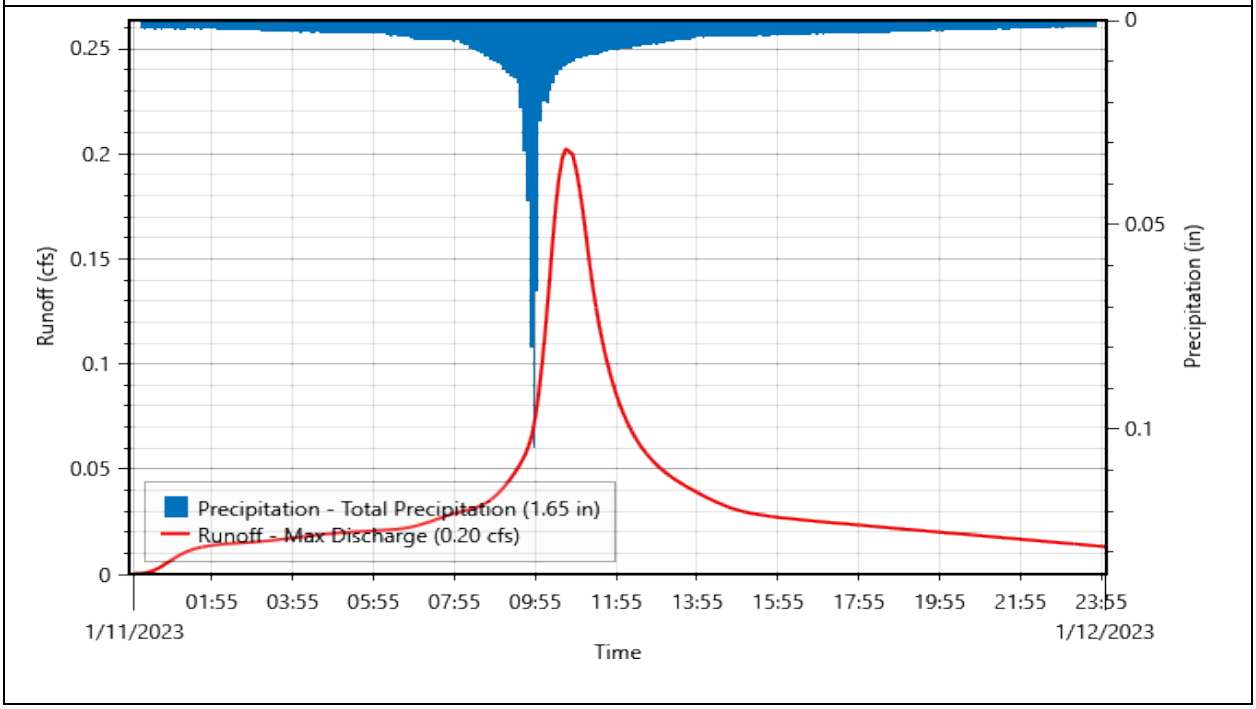
Subbasin ID:	Sub-02			
Scenario:	Proposed Development 10 yr		Depth	Volume
Peak discharge:	0.20 cfs	**Time of peak:**	11 Jan 2023, 10:45	
Drainage area:	337.798 acres	**Total rainfall:**	1.65 in	46.44640 ac-ft
Initial abstraction:	2.28 in	**Losses:**	1.65 in	46.37673 ac-ft
Curve Number:	46.74	**Precip excess:**	0.00 in	0.06967 ac-ft
Impervious surface:	%	**Direct runoff:**	0.00 in	0.07 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	0.00 minutes	**Total runoff:**	0.00 in	0.07 ac-ft

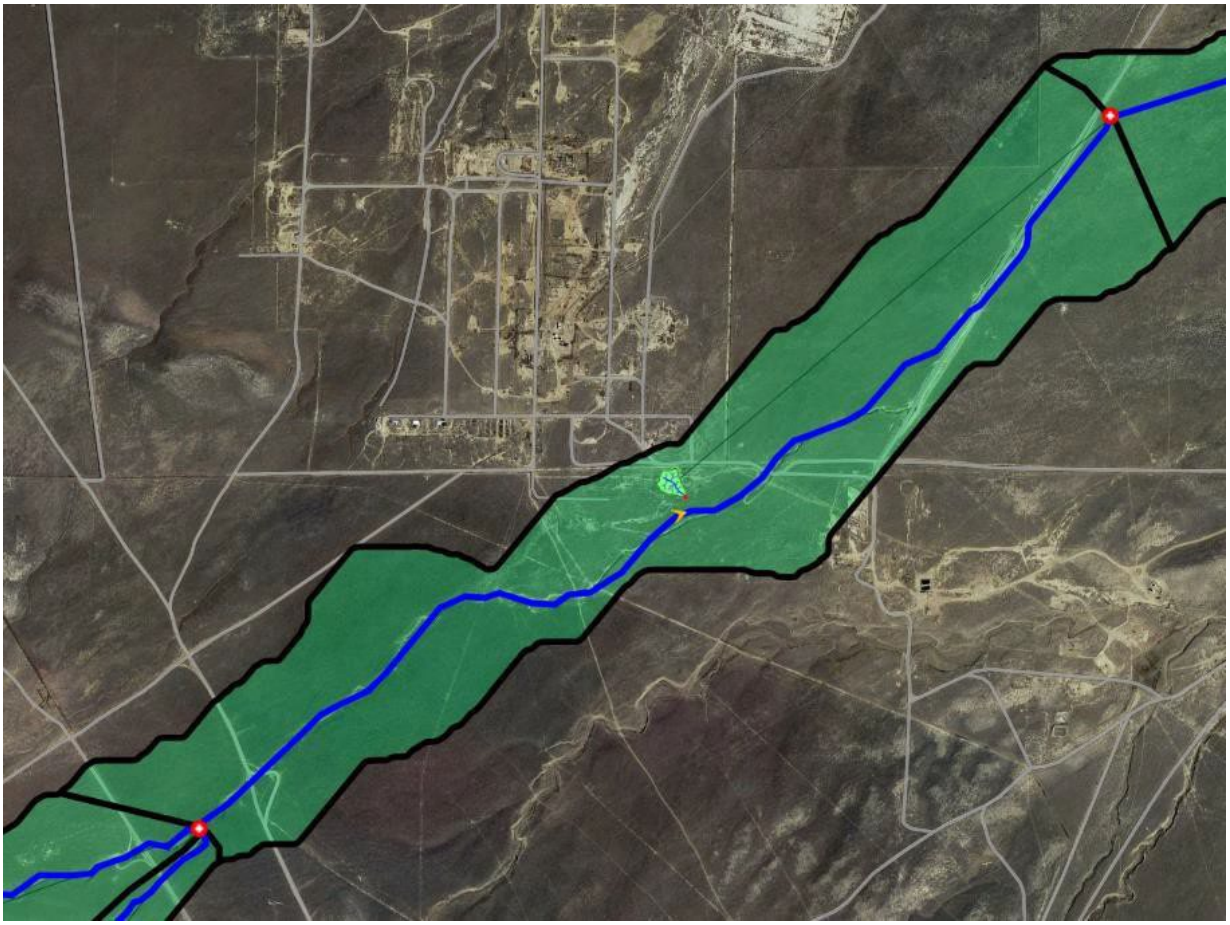
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
29.531	8.74	54.73	Developed, Open Space
308.267	91.26	45.97	Undeveloped, Grassland
337.798	**100.00**	**46.74**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
30.41	100.00	0.03745	0.7190	Sheet Flow
14.64	1,422.09	0.02620	5.3456	Shallow Concentrated Flow
39.18	10,516.23	0.01825	4.4614	Channel Flow
84.23	**12,038.32**	**Total**	**Lag Time = 50.54 minutes**	





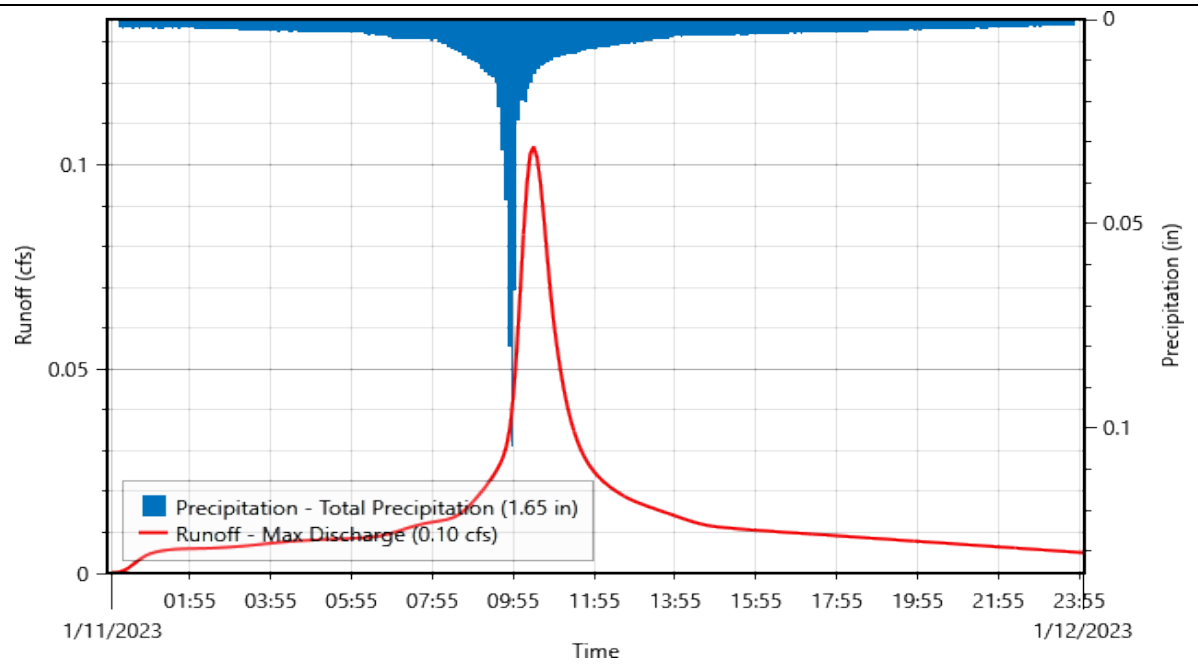
Subbasin ID:	Sub-03		Depth	Volume
Scenario:	Proposed Development 10 yr			
Peak discharge:	0.10 cfs	**Time of peak:**	11 Jan 2023, 10:25	
Drainage area:	169.707 acres	**Total rainfall:**	1.65 in	23.33760 ac-ft
Initial abstraction:	2.61 in	**Losses:**	1.65 in	23.30959 ac-ft
Curve Number:	43.39	**Precip excess:**	0.00 in	0.02801 ac-ft
Impervious surface:	%	**Direct runoff:**	0.00 in	0.03 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	0.00 minutes	**Total runoff:**	0.00 in	0.03 ac-ft

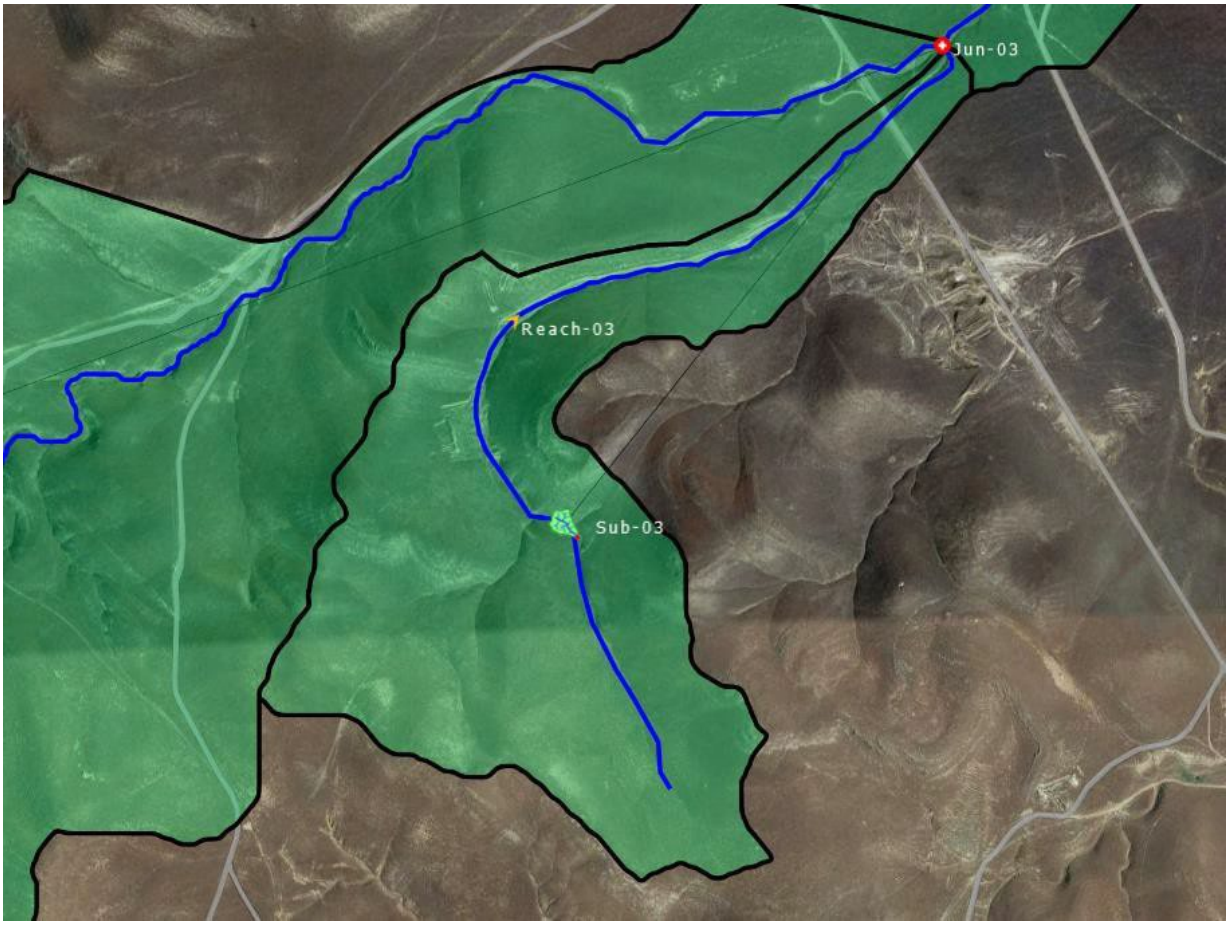
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
1.174	0.69	79.00	Developed, Open Space
168.533	99.31	43.14	Undeveloped, Grassland
169.707	**100.00**	**43.39**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
33.11	110.46	0.03693	0.7140	Sheet Flow
3.55	740.31	0.12053	11.4645	Shallow Concentrated Flow
17.32	6,423.63	0.03486	6.1655	Channel Flow
53.98	**7,274.40**	**Total**	**Lag Time = 32.39 minutes**	




Jun-03
Reach-03
Sub-03

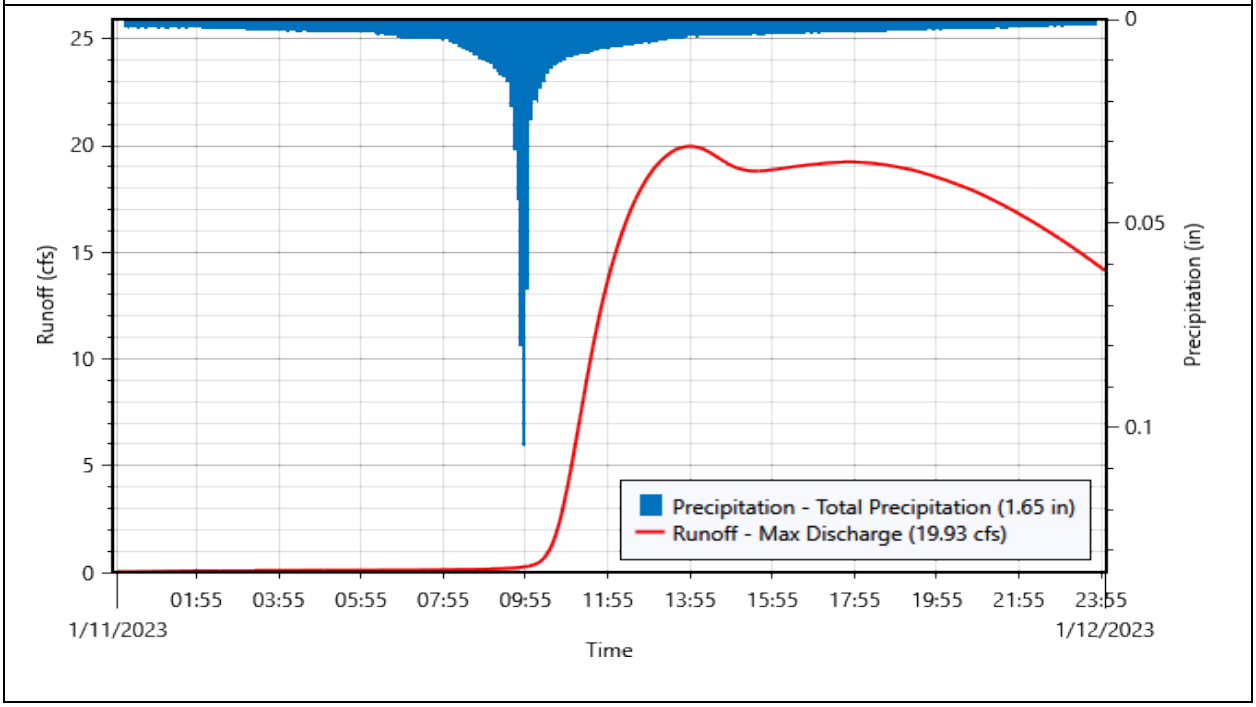
Subbasin ID:	Sub-04		Depth	Volume
Scenario:	Proposed Development 10 yr			
Peak discharge:	19.93 cfs	**Time of peak:**	11 Jan 2023, 01:55	
Drainage area:	1,961.124 acres	**Total rainfall:**	1.65 in	269.65839 ac-ft
Initial abstraction:	0.86 in	**Losses:**	1.53 in	249.33883 ac-ft
Curve Number:	70.00	**Precip excess:**	0.12 in	20.31956 ac-ft
Impervious surface:	%	**Direct runoff:**	0.12 in	18.92 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	0.00 minutes	**Total runoff:**	0.12 in	18.92 ac-ft

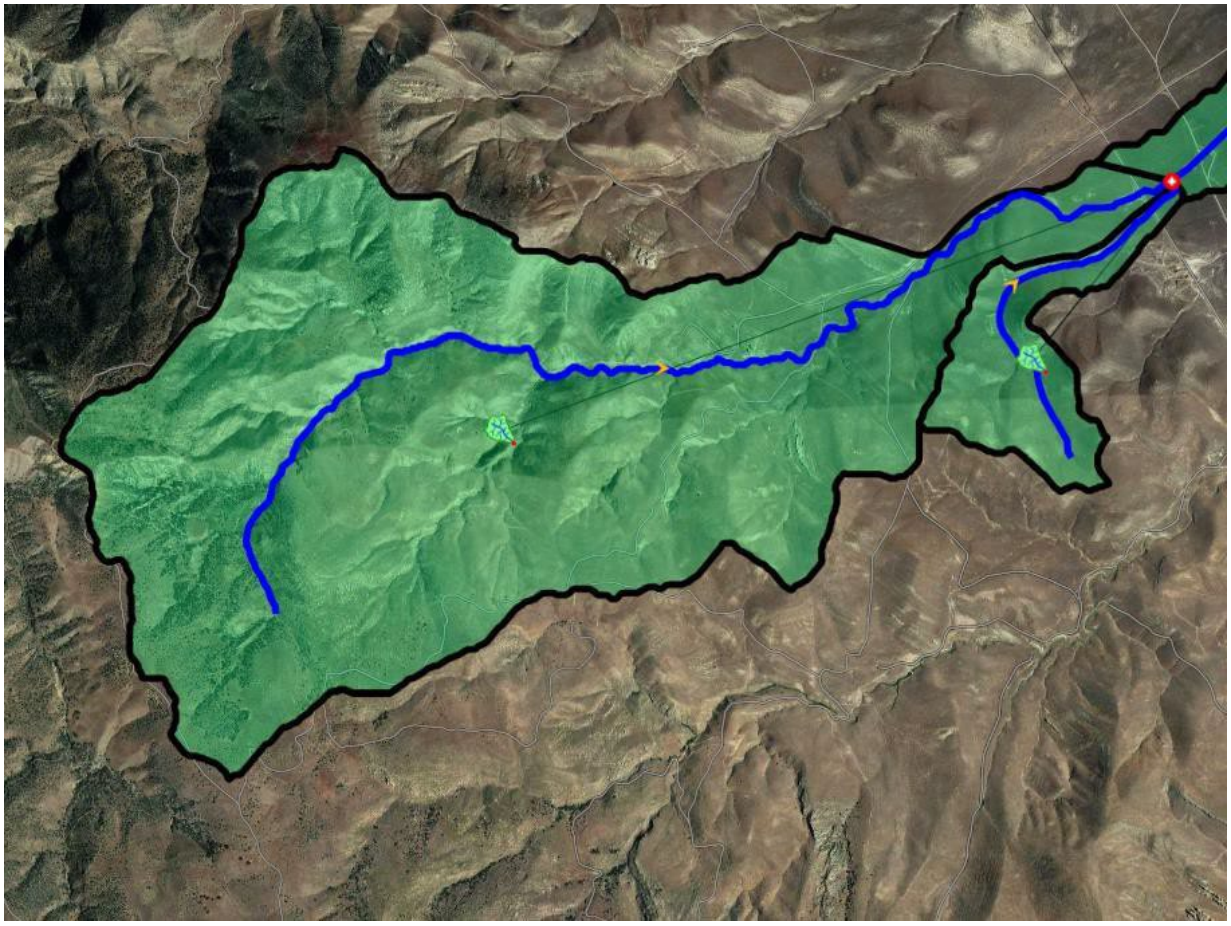
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
0.431	0.02	91.30	Developed, Medium Density
150.381	7.67	71.94	Undeveloped, Shrub/Scrub
0.305	0.02	74.40	Developed, Low Density
75.153	3.83	71.78	Developed, Open Space
1.186	0.06	88.55	Undeveloped, Barren Land
1,733.667	88.40	69.74	Undeveloped, Grassland
1,961.124	**100.00**	**70.00**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
30.90	112.95	0.04590	0.7959	Sheet Flow
13.24	3,235.61	0.16593	13.4514	Shallow Concentrated Flow
5.71	4,473.99	0.15548	13.0208	Channel Flow
46.85	15,930.03	0.02929	5.6514	Channel Flow
96.70	**23,752.58**	**Total**	**Lag Time = 58.02 minutes**	





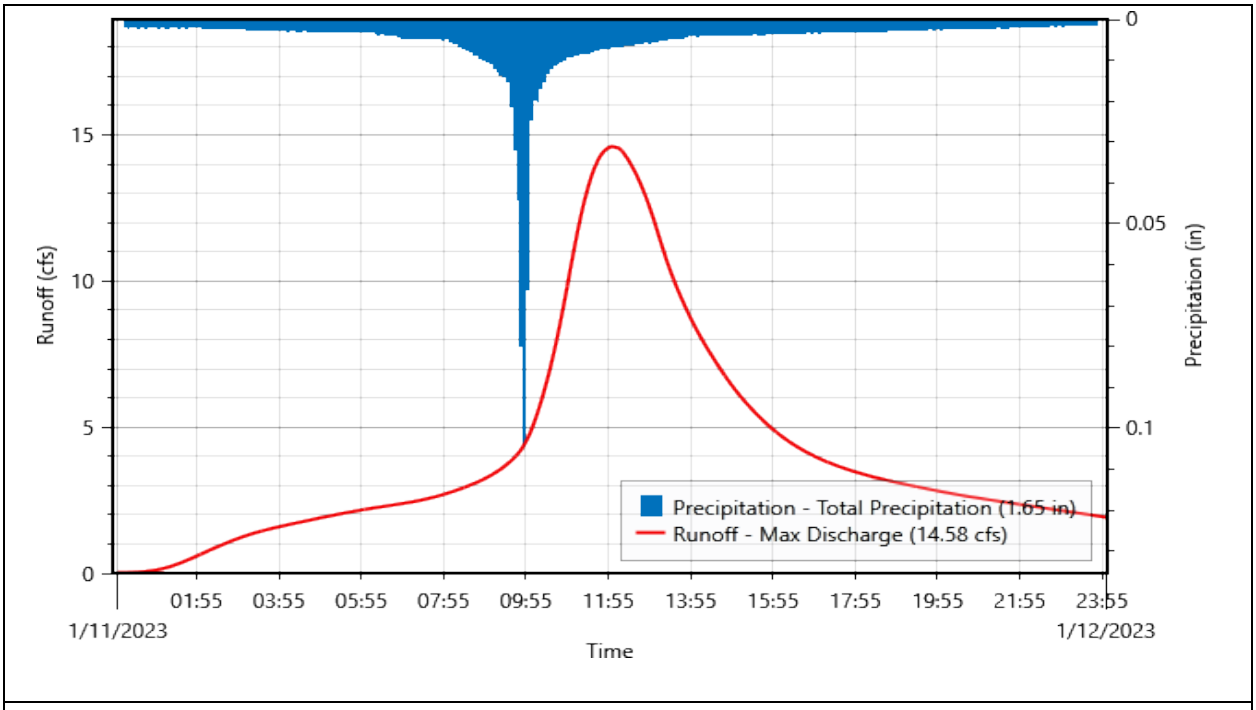
Subbasin ID:	Sub-05			
Scenario:	Proposed Development 10 yr		Depth	Volume
Peak discharge:	14.58 cfs	**Time of peak:**	11 Jan 2023, 12:05	
Drainage area:	685.814 acres	**Total rainfall:**	1.65 in	94.30080 ac-ft
Initial abstraction:	1.94 in	**Losses:**	1.50 in	85.78543 ac-ft
Curve Number:	50.82	**Precip excess:**	0.15 in	8.51536 ac-ft
Impervious surface:	%	**Direct runoff:**	0.14 in	8.14 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	0.00 minutes	**Total runoff:**	0.14 in	8.14 ac-ft

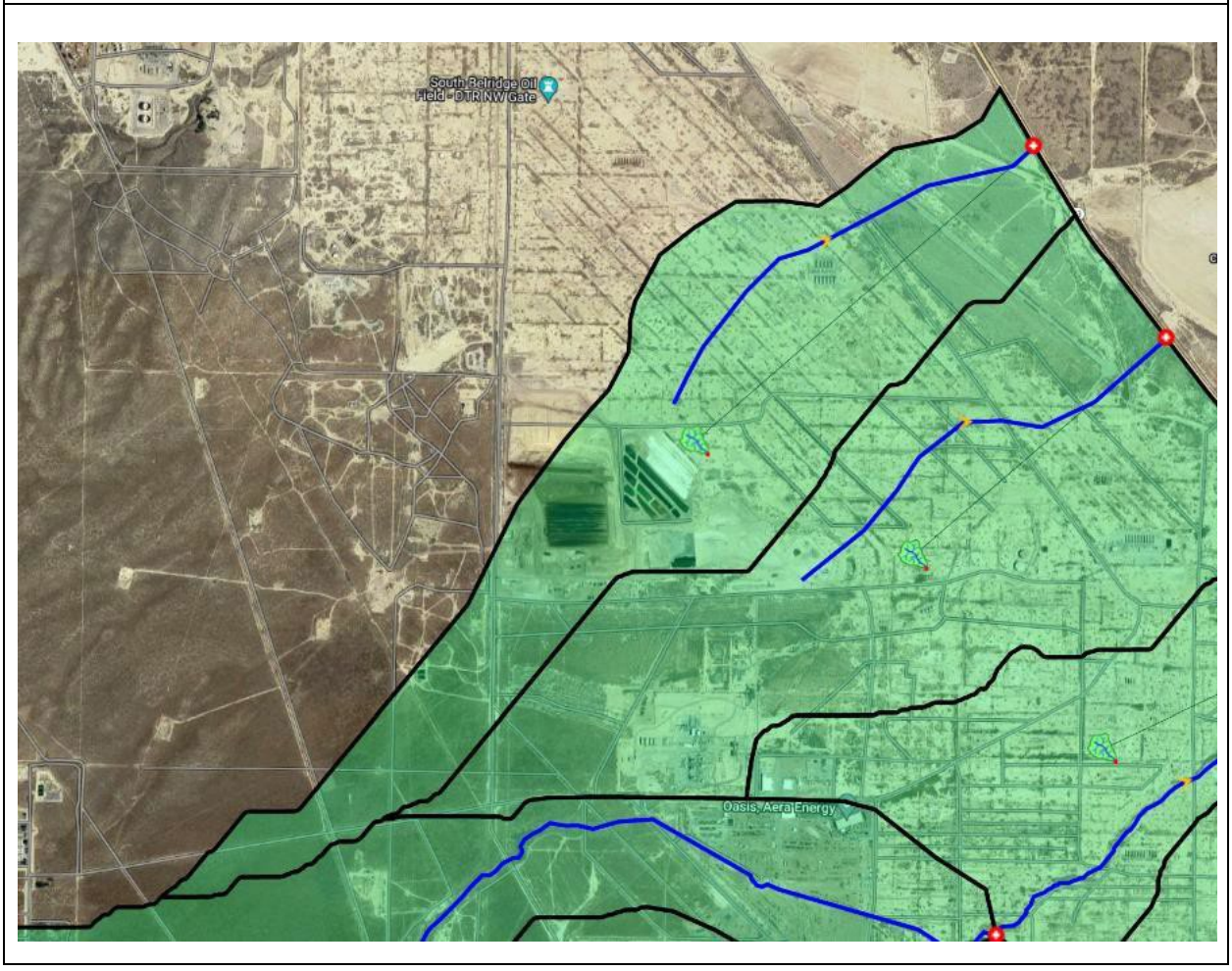
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
68.817	10.03	67.00	Agricultural, Cultivated Crops
17.830	2.60	77.74	Developed, Medium Density
42.537	6.20	78.26	Undeveloped, Barren Land
32.828	4.79	63.81	Developed, Low Density
201.828	29.43	57.17	Developed, Open Space
3.731	0.54	30.00	Undeveloped, Shrub/Scrub
0.288	0.04	100.00	Open Water
11.792	1.72	89.57	Developed, High Density
306.163	44.64	34.93	Undeveloped, Grassland
685.814	**100.00**	**50.82**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
51.04	100.00	0.01026	0.3762	Sheet Flow
84.98	9,730.86	0.01400	3.9073	Shallow Concentrated Flow
10.33	2,732.44	0.01773	4.3971	Channel Flow
62.57	3,381.56	0.00074	0.8982	Channel Flow
208.92	**15,944.86**	**Total**	**Lag Time = 125.36 minutes**	


Runoff (cfs)
Precipitation (in)
Time
1/11/2023
1/12/2023
Precipitation - Total Precipitation (1.65 in)
Runoff - Max Discharge (14.58 cfs)


South Belridge Oil Field - DTR NW Gate
Oasis, Aera Energy

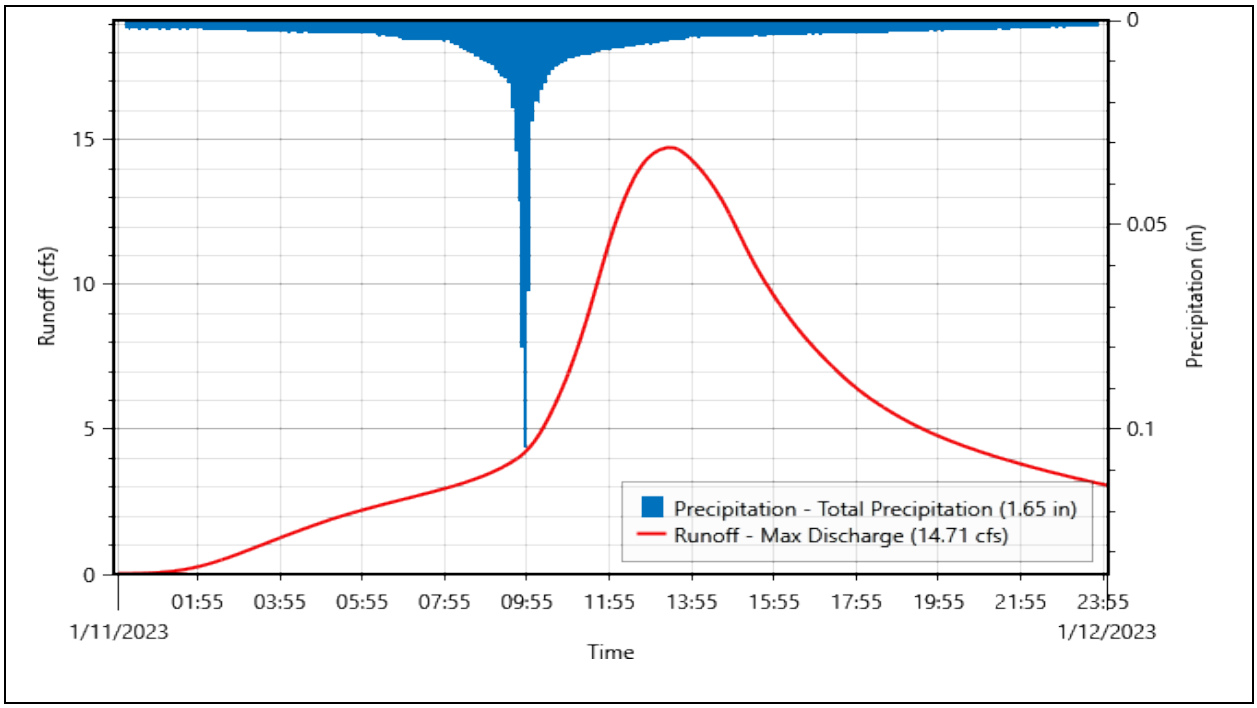
Subbasin ID:	Sub-06			
Scenario:	Proposed Development 10 yr		Depth	Volume
Peak discharge:	14.71 cfs	**Time of peak:**	11 Jan 2023, 01:25	
Drainage area:	856.439 acres	**Total rainfall:**	1.65 in	117.76160 ac-ft
Initial abstraction:	1.86 in	**Losses:**	1.49 in	106.46826 ac-ft
Curve Number:	51.75	**Precip excess:**	0.16 in	11.29334 ac-ft
Impervious surface:	%	**Direct runoff:**	0.15 in	10.39 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	0.00 minutes	**Total runoff:**	0.15 in	10.39 ac-ft

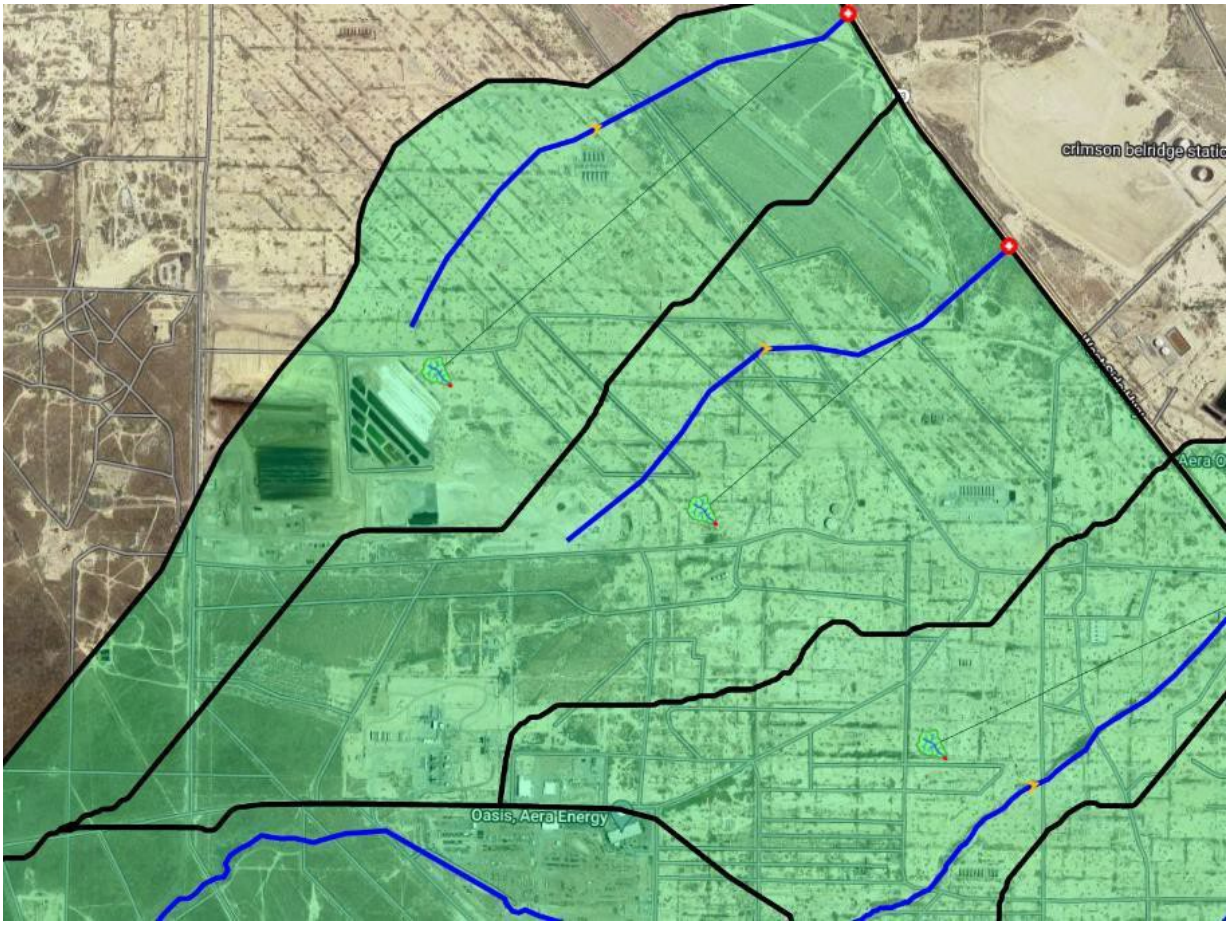
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
18.520	2.16	78.52	Developed, Medium Density
40.292	4.70	67.00	Agricultural, Cultivated Crops
0.191	0.02	30.00	Undeveloped, Shrub/Scrub
68.504	8.00	66.60	Developed, Low Density
7.679	0.90	89.48	Developed, High Density
305.373	35.66	61.82	Developed, Open Space
32.256	3.77	78.97	Undeveloped, Barren Land
383.625	44.79	35.15	Undeveloped, Grassland
856.439	**100.00**	**51.75**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
42.34	100.00	0.01637	0.4753	Sheet Flow
56.02	6,131.50	0.01279	3.7342	Shallow Concentrated Flow
2.24	757.49	0.12183	11.5262	Shallow Concentrated Flow
231.04	6,158.14	0.00018	0.4458	Channel Flow
331.64	**13,147.13**	**Total**	**Lag Time = 198.99 minutes**	


Runoff (cfs)
15
10
5
0
0
0.05
0.1
Precipitation (in)
Precipitation - Total Precipitation (1.65 in)
Runoff - Max Discharge (14.71 cfs)
01:55
03:55
05:55
07:55
09:55
11:55
13:55
15:55
17:55
19:55
21:55
23:55
1/11/2023
1/12/2023
Time


Oasis, Aera Energy

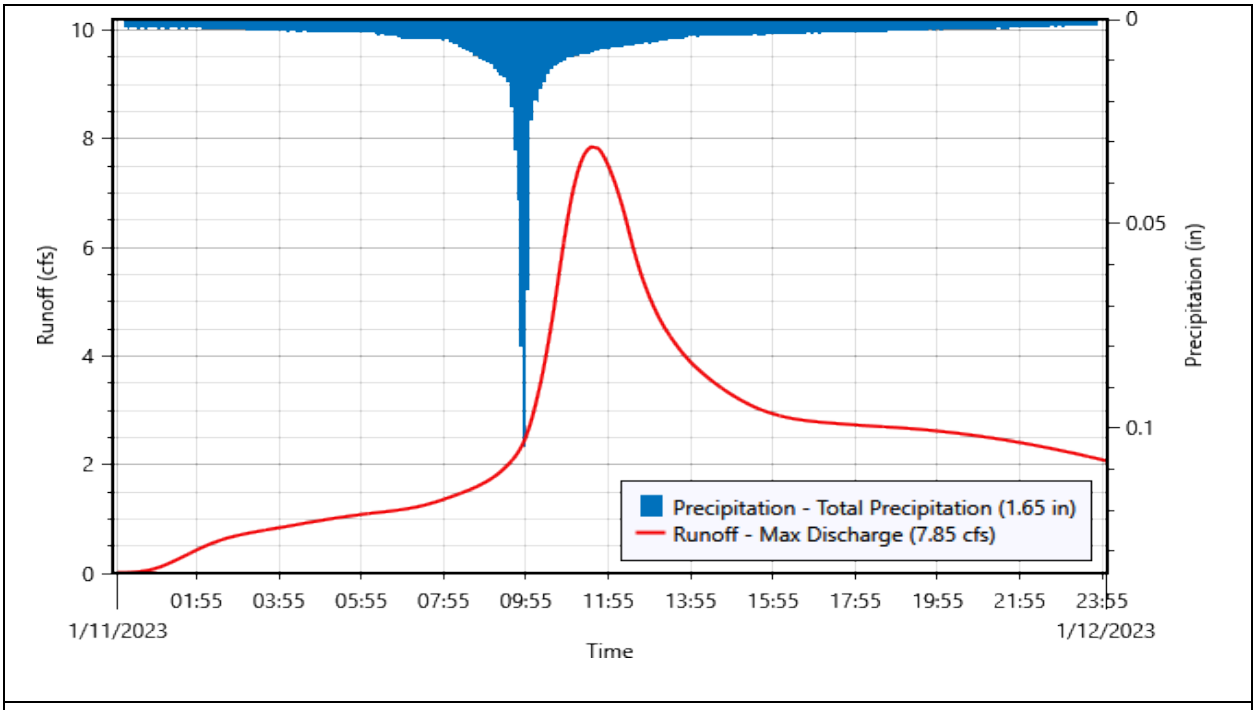
Subbasin ID:	Sub-07			
Scenario:	Proposed Development 10 yr		Depth	Volume
Peak discharge:	7.85 cfs	**Time of peak:**	11 Jan 2023, 11:35	
Drainage area:	269.771 acres	**Total rainfall:**	1.65 in	37.09200 ac-ft
Initial abstraction:	1.05 in	**Losses:**	1.42 in	31.88293 ac-ft
Curve Number:	65.60	**Precip excess:**	0.23 in	5.20907 ac-ft
Impervious surface:	%	**Direct runoff:**	0.22 in	4.87 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	0.00 minutes	**Total runoff:**	0.22 in	4.87 ac-ft

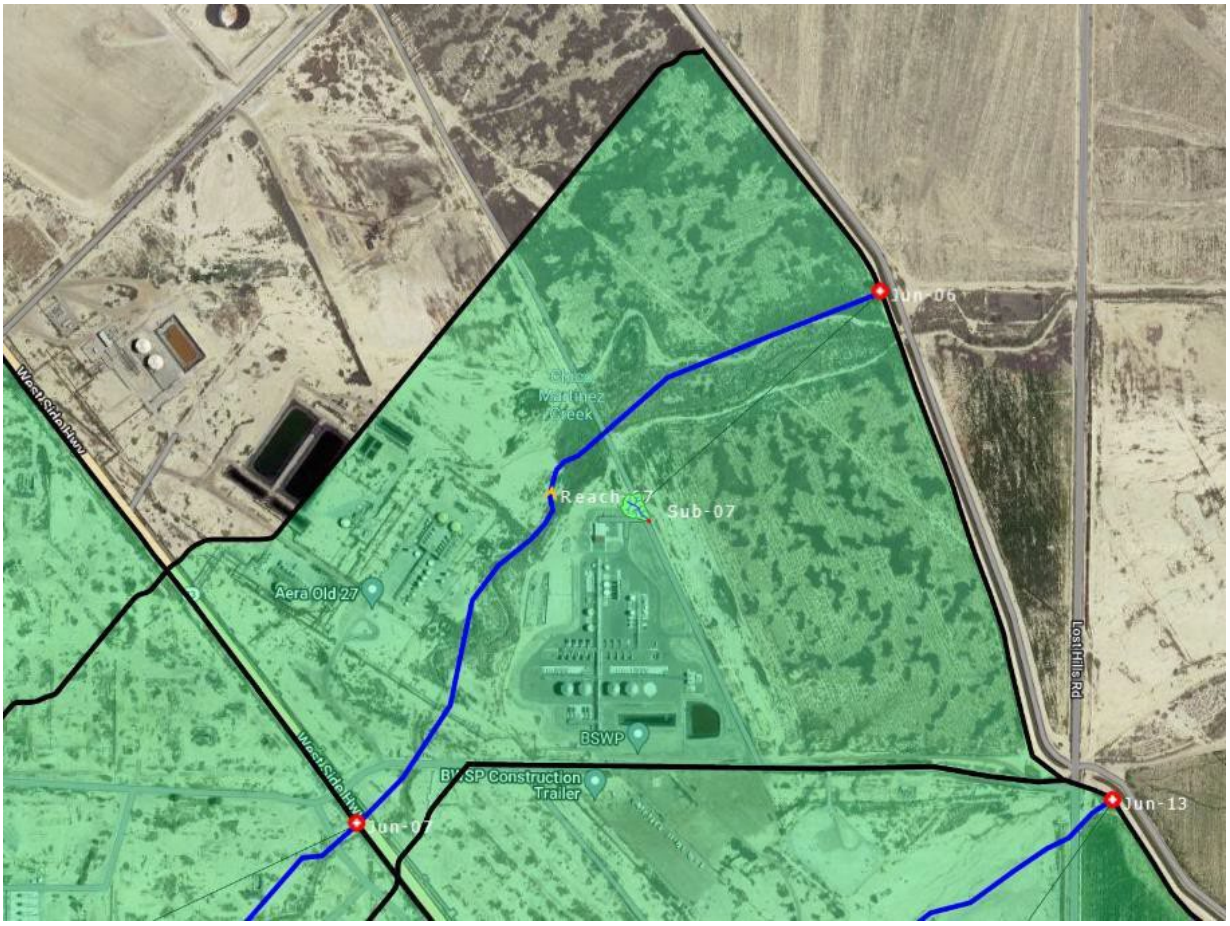
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
9.365	3.47	78.39	Developed, Medium Density
7.664	2.84	30.00	Undeveloped, Shrub/Scrub
17.372	6.44	67.37	Developed, Low Density
12.494	4.63	89.14	Developed, High Density
43.223	16.02	56.26	Developed, Open Space
5.238	1.94	77.67	Undeveloped, Barren Land
29.711	11.01	41.49	Undeveloped, Grassland
144.704	53.64	71.71	Agricultural, Cultivated Crops
269.771	**100.00**	**65.60**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
62.62	95.81	0.00565	0.2792	Sheet Flow
1.69	168.18	0.01057	3.3952	Shallow Concentrated Flow
0.84	253.65	0.09785	10.3295	Shallow Concentrated Flow
33.38	2,278.13	0.00118	1.1339	Channel Flow
1.39	551.42	0.03999	6.6036	Channel Flow
64.20	1,275.51	0.00010	0.3284	Channel Flow
164.12	**4,622.70**	**Total**	**Lag Time = 98.48 minutes**	


Runoff (cfs)
Precipitation (in)
Time
1/11/2023
1/12/2023
Precipitation - Total Precipitation (1.65 in)
Runoff - Max Discharge (7.85 cfs)


Jun-06
Reach-7
Sub-07
Aera Old 27
BSWP
Jun-07
Jun-13
Lost Hills Rd

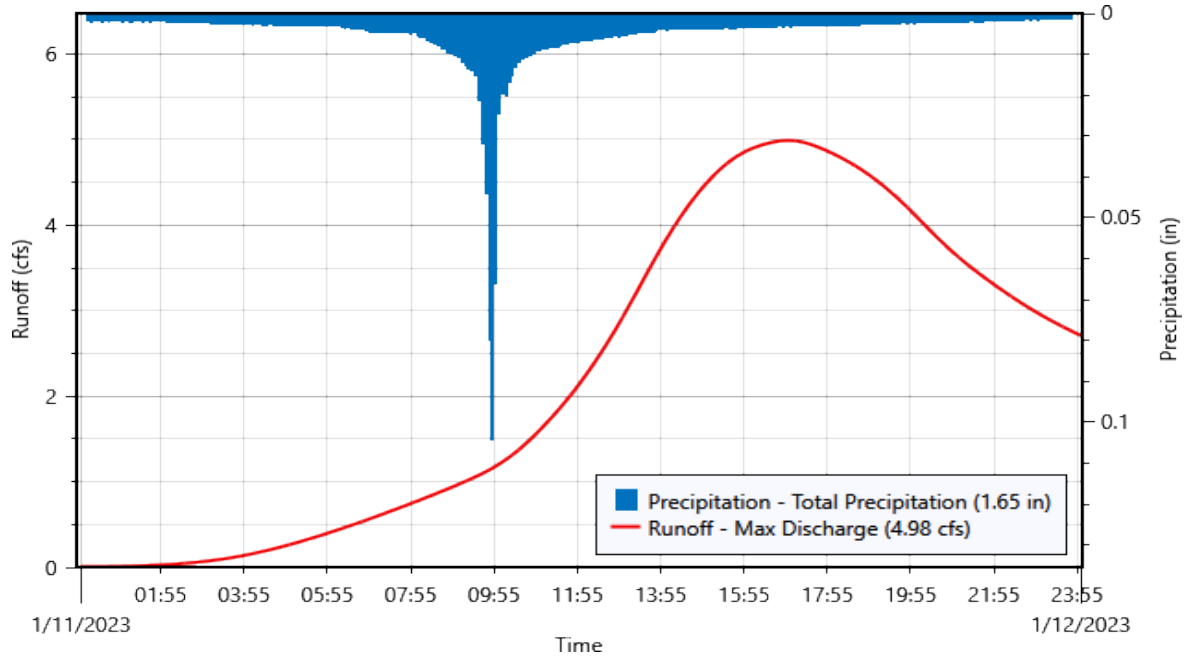
Subbasin ID:	Sub-08		Depth	Volume
Scenario:	Proposed Development 10 yr			
Peak discharge:	4.98 cfs	**Time of peak:**	11 Jan 2023, 05:00	
Drainage area:	503.505 acres	**Total rainfall:**	1.65 in	69.22960 ac-ft
Initial abstraction:	1.48 in	**Losses:**	1.51 in	63.28105 ac-ft
Curve Number:	57.53	**Precip excess:**	0.14 in	5.94854 ac-ft
Impervious surface:	%	**Direct runoff:**	0.11 in	4.45 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	0.00 minutes	**Total runoff:**	0.11 in	4.45 ac-ft

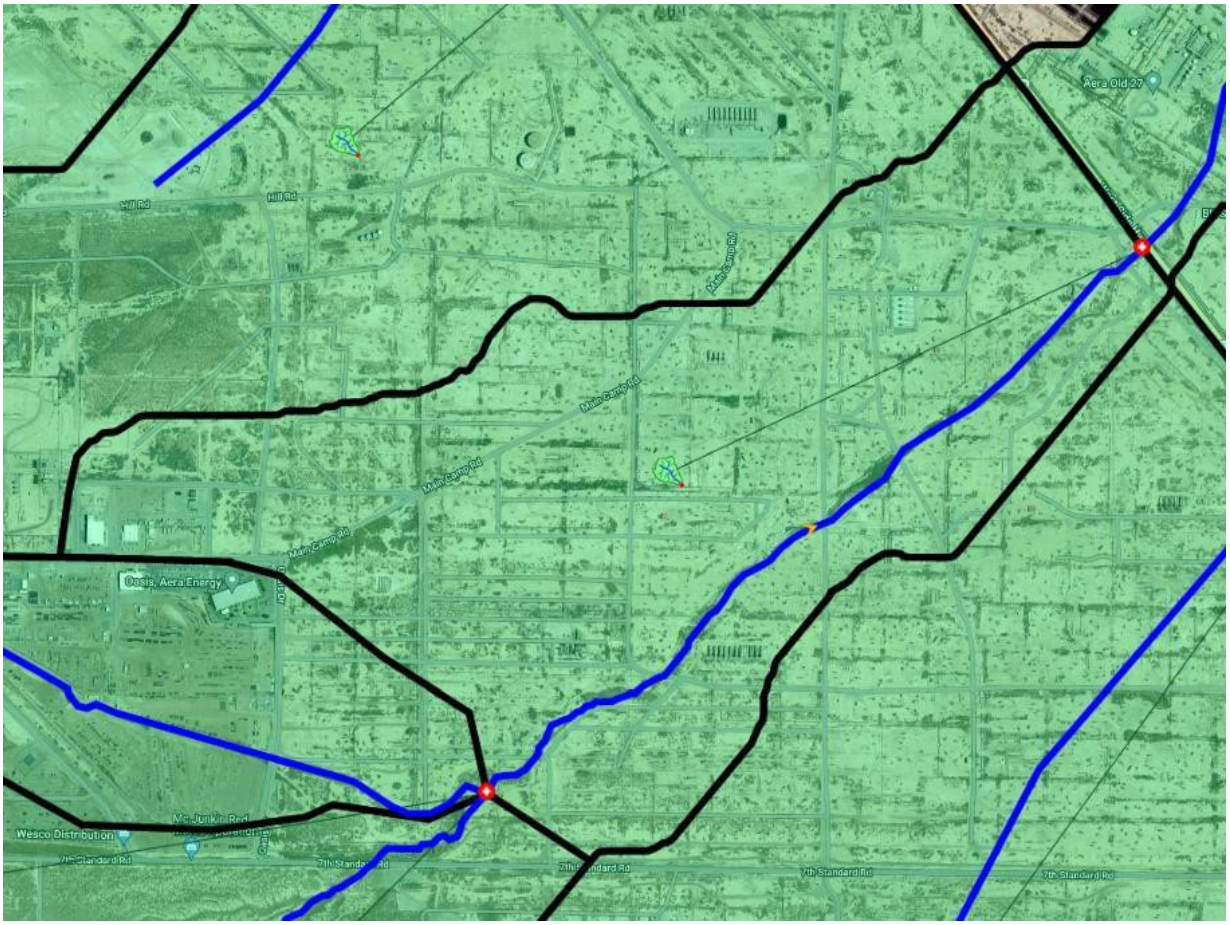
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
9.083	1.80	80.87	Developed, Medium Density
32.953	6.54	70.08	Developed, Low Density
4.702	0.93	89.23	Developed, High Density
9.827	1.95	87.02	Undeveloped, Barren Land
151.885	30.17	41.68	Undeveloped, Grassland
295.055	58.60	62.08	Developed, Open Space
503.505	**100.00**	**57.53**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
52.03	100.00	0.00978	0.3674	Sheet Flow
49.64	4,709.72	0.00961	3.2380	Shallow Concentrated Flow
2.39	661.27	0.08149	9.4267	Shallow Concentrated Flow
9.76	489.72	0.00269	1.7139	Shallow Concentrated Flow
545.21	3,425.21	0.00001	0.1271	Channel Flow
659.03	**9,385.92**	**Total**	**Lag Time = 395.42 minutes**	




Aera Old 27
Hill Rd
Main Camp Rd
Oasis, Aera Energy
Wesco Distribution
7th Standard Rd

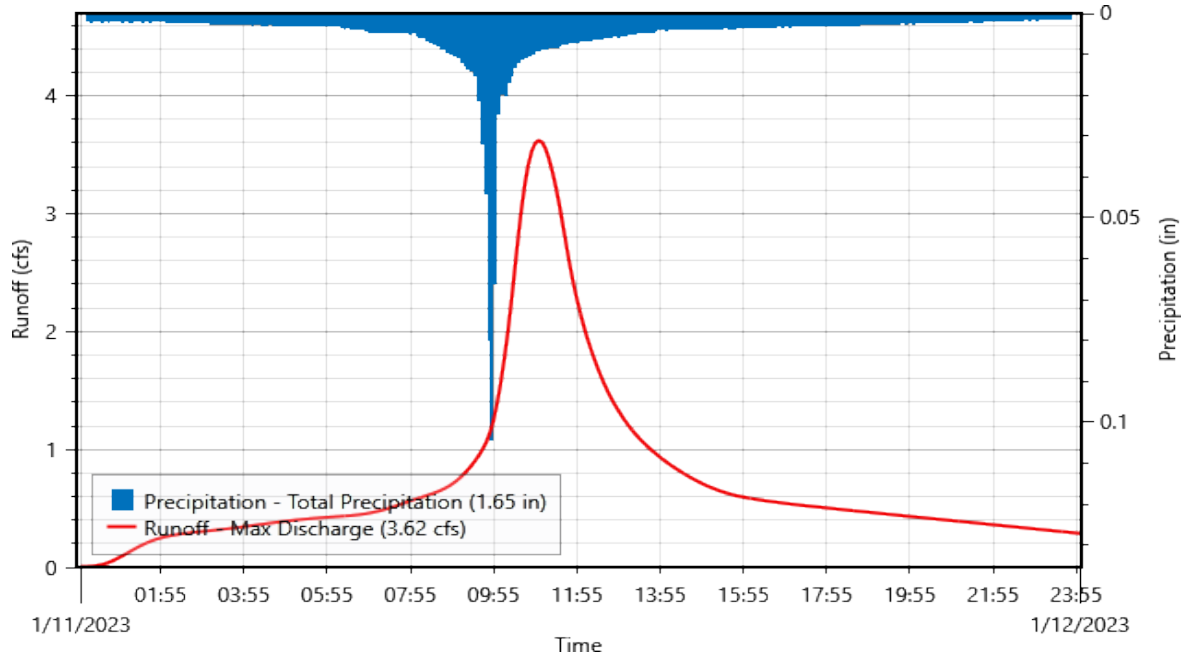
Subbasin ID:	**Sub-09**			
Scenario:	**Proposed Development 10 yr**		**Depth**	**Volume**
Peak discharge:	3.62 cfs	**Time of peak:**	11 Jan 2023, 11:00	
Drainage area:	1,130.587 acres	**Total rainfall:**	1.65 in	155.45199 ac-ft
Initial abstraction:	2.84 in	**Losses:**	1.63 in	153.99074 ac-ft
Curve Number:	41.33	**Precip excess:**	0.02 in	1.46125 ac-ft
Impervious surface:	%	**Direct runoff:**	0.02 in	1.43 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	0.00 minutes	**Total runoff:**	0.02 in	1.43 ac-ft

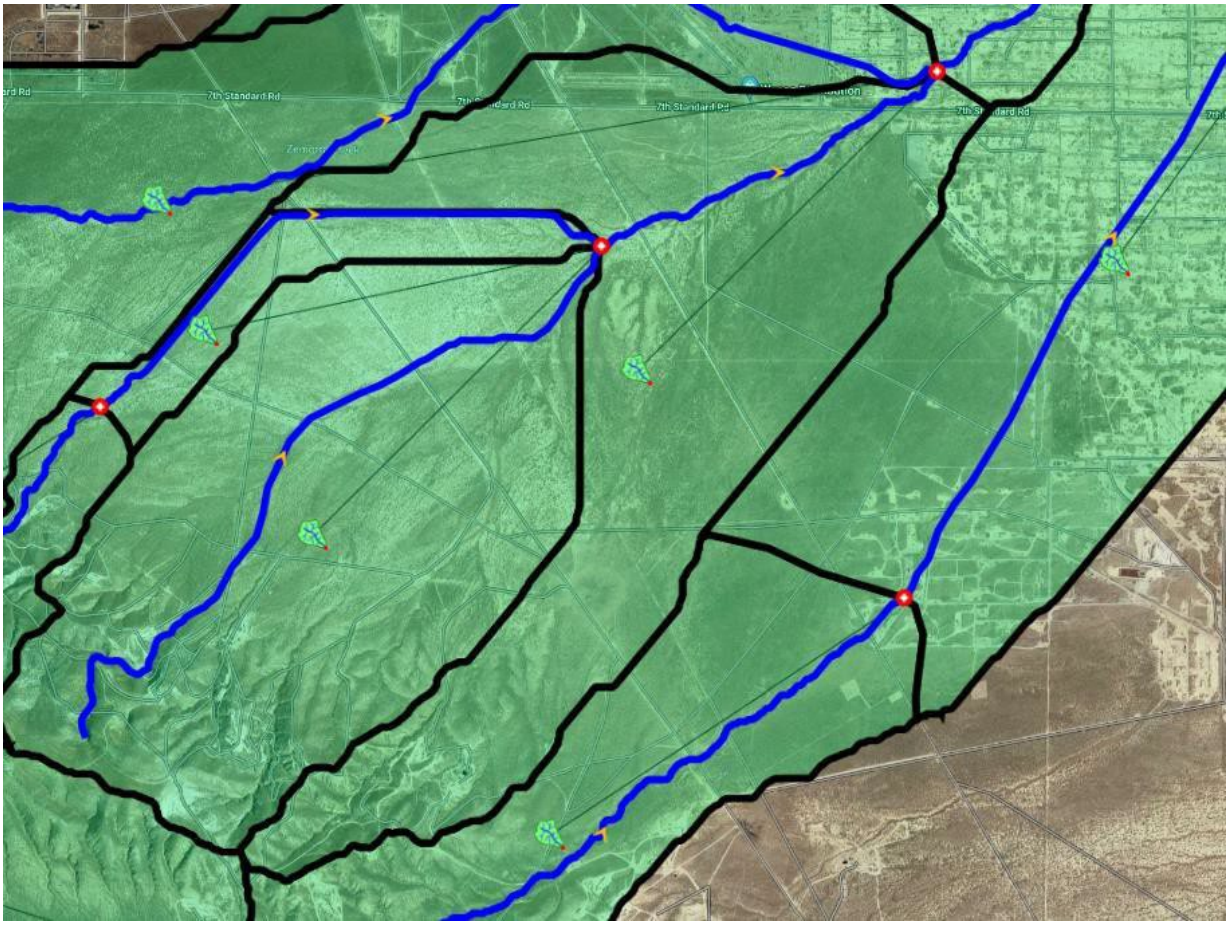
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
1.638	0.14	82.99	Developed, Medium Density
49.357	4.37	35.62	Undeveloped, Shrub/Scrub
4.469	0.40	61.00	Developed, Low Density
0.293	0.03	89.00	Developed, High Density
80.882	7.15	53.22	Developed, Open Space
3.542	0.31	77.00	Undeveloped, Barren Land
990.407	87.60	40.34	Undeveloped, Grassland
1,130.587	**100.00**	**41.33**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
16.78	99.98	0.16549	1.5113	Sheet Flow
0.86	365.47	0.19372	14.5341	Shallow Concentrated Flow
8.54	4,728.14	0.04703	9.2075	Channel Flow
60.10	7,738.83	0.01770	4.3931	Shallow Concentrated Flow
25.53	5,047.31	0.00990	3.2859	Channel Flow
111.81	**17,979.73**	**Total**	**Lag Time = 67.09 minutes**	




7th Standard Rd
7th Standard Rd
7th Standard Rd

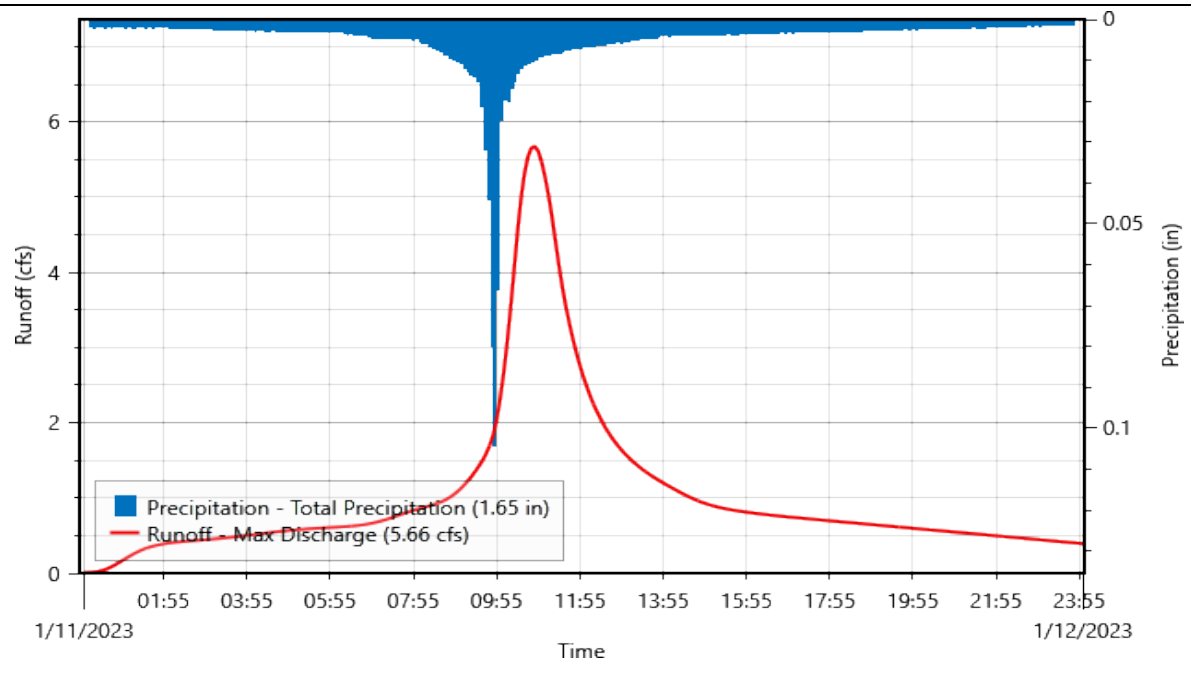
Subbasin ID:	**Sub-10**			
Scenario:	**Proposed Development 10 yr**		**Depth**	**Volume**
Peak discharge:	5.66 cfs	**Time of peak:**	11 Jan 2023, 10:50	
Drainage area:	1,153.361 acres	**Total rainfall:**	1.65 in	158.58479 ac-ft
Initial abstraction:	1.94 in	**Losses:**	1.63 in	156.52319 ac-ft
Curve Number:	50.79	**Precip excess:**	0.02 in	2.06160 ac-ft
Impervious surface:	%	**Direct runoff:**	0.02 in	2.03 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	0.00 minutes	**Total runoff:**	0.02 in	2.03 ac-ft

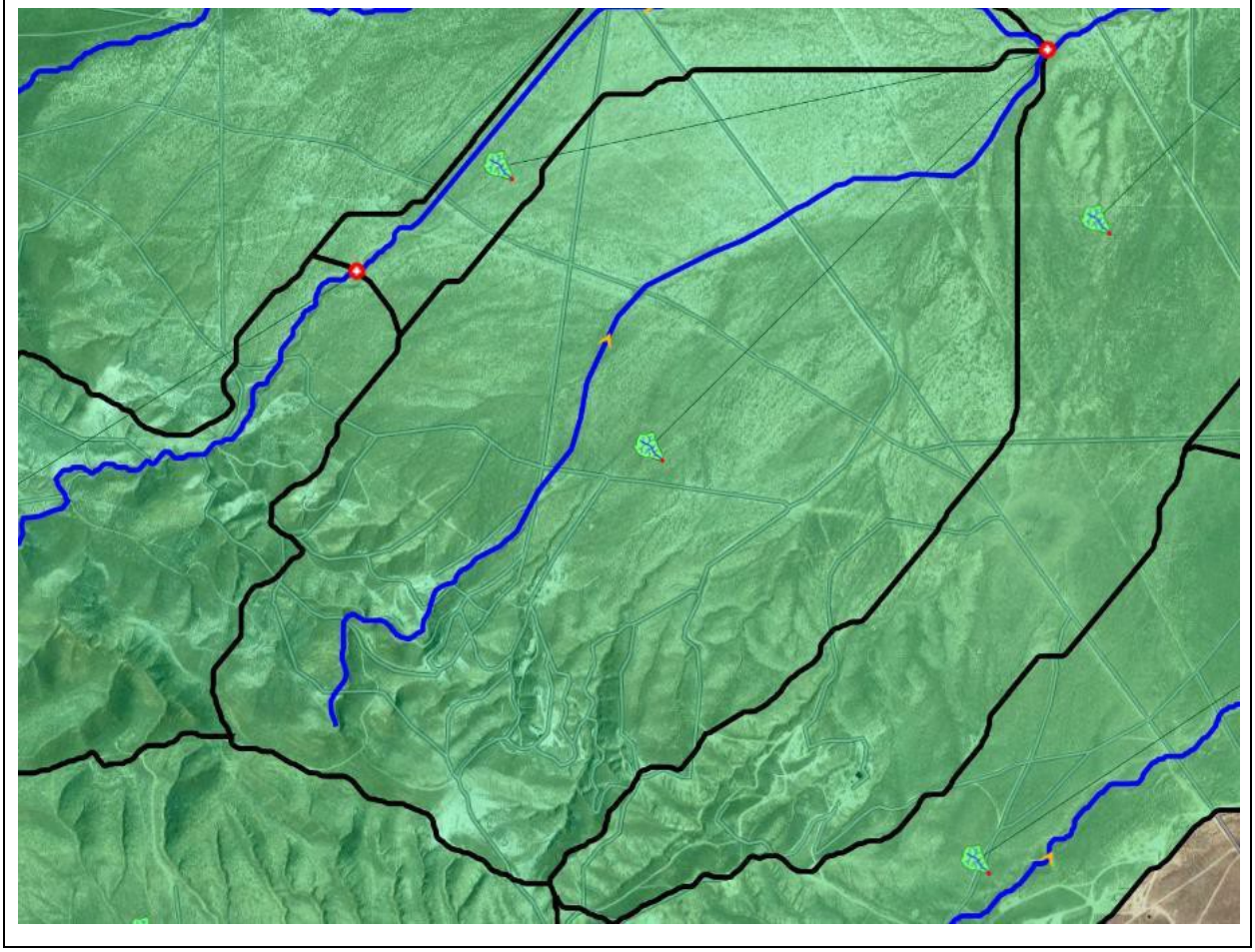
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
10.397	0.90	79.49	Developed, Medium Density
59.382	5.15	50.07	Undeveloped, Shrub/Scrub
3.103	0.27	80.28	Developed, Low Density
151.032	13.09	67.65	Developed, Open Space
2.360	0.20	91.00	Undeveloped, Barren Land
927.088	80.38	47.56	Undeveloped, Grassland
1,153.361	**100.00**	**50.79**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
21.17	100.00	0.09259	1.1304	Sheet Flow
2.60	1,127.24	0.20010	14.7716	Shallow Concentrated Flow
9.39	4,900.89	0.06895	8.6712	Channel Flow
0.40	386.93	0.23496	16.0068	Channel Flow
42.25	2,796.45	0.00111	1.0981	Channel Flow
17.39	4,299.00	0.01549	4.1093	Channel Flow
93.20	**13,610.51**	**Total**	**Lag Time = 55.92 minutes**	





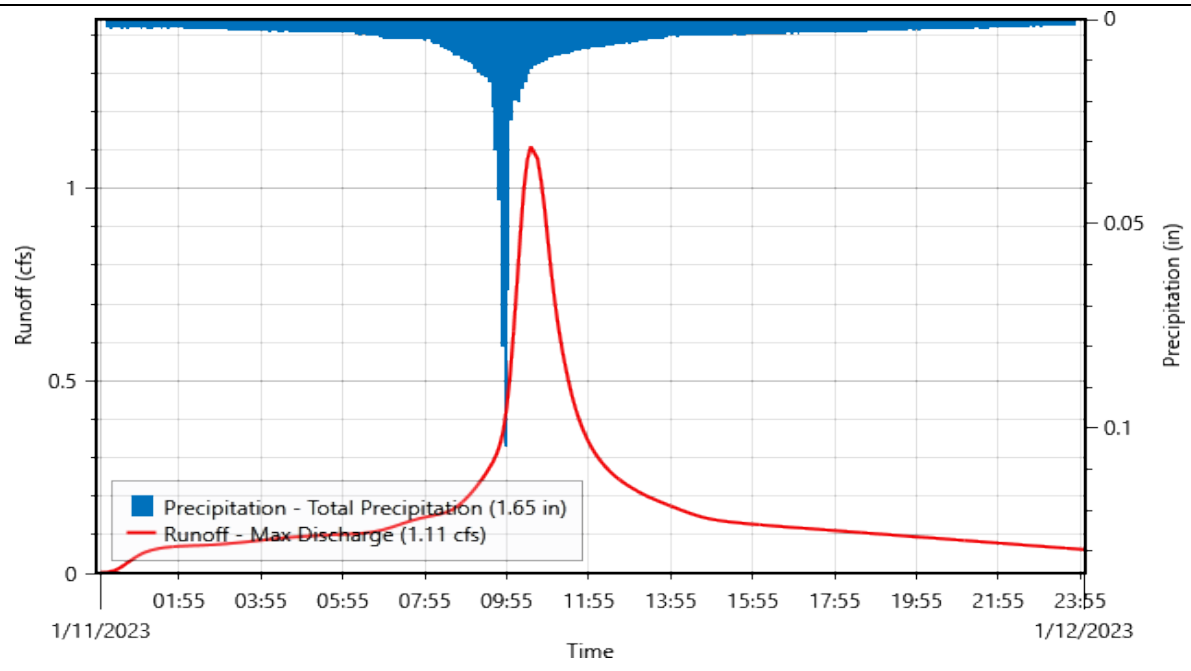
Subbasin ID:	Sub-11			
Scenario:	Proposed Development 10 yr		Depth	Volume
Peak discharge:	1.11 cfs	**Time of peak:**	11 Jan 2023, 10:30	
Drainage area:	161.318 acres	**Total rainfall:**	1.65 in	22.18480 ac-ft
Initial abstraction:	4.26 in	**Losses:**	1.63 in	21.84981 ac-ft
Curve Number:	31.97	**Precip excess:**	0.02 in	0.33499 ac-ft
Impervious surface:	%	**Direct runoff:**	0.02 in	0.33 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	0.00 minutes	**Total runoff:**	0.02 in	0.33 ac-ft

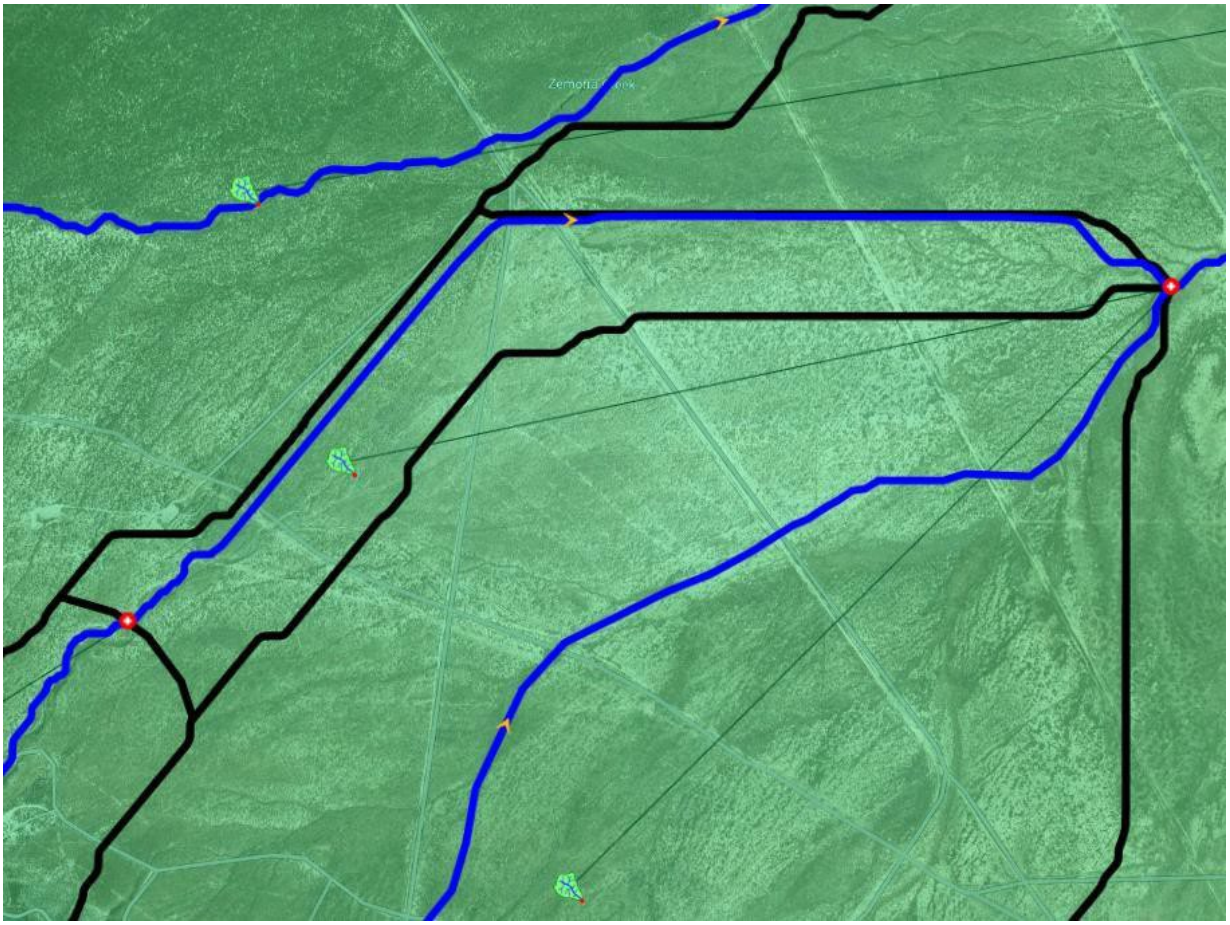
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
4.560	2.83	77.00	Developed, Medium Density
4.792	2.97	49.00	Developed, Open Space
151.966	94.20	30.08	Undeveloped, Grassland
161.318	**100.00**	**31.97**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
28.76	100.00	0.04304	0.7707	Sheet Flow
6.52	1,112.40	0.03107	5.8206	Shallow Concentrated Flow
31.55	8,418.65	0.01804	4.4358	Channel Flow
66.83	**9,631.05**	**Total**	**Lag Time = 40.10 minutes**	





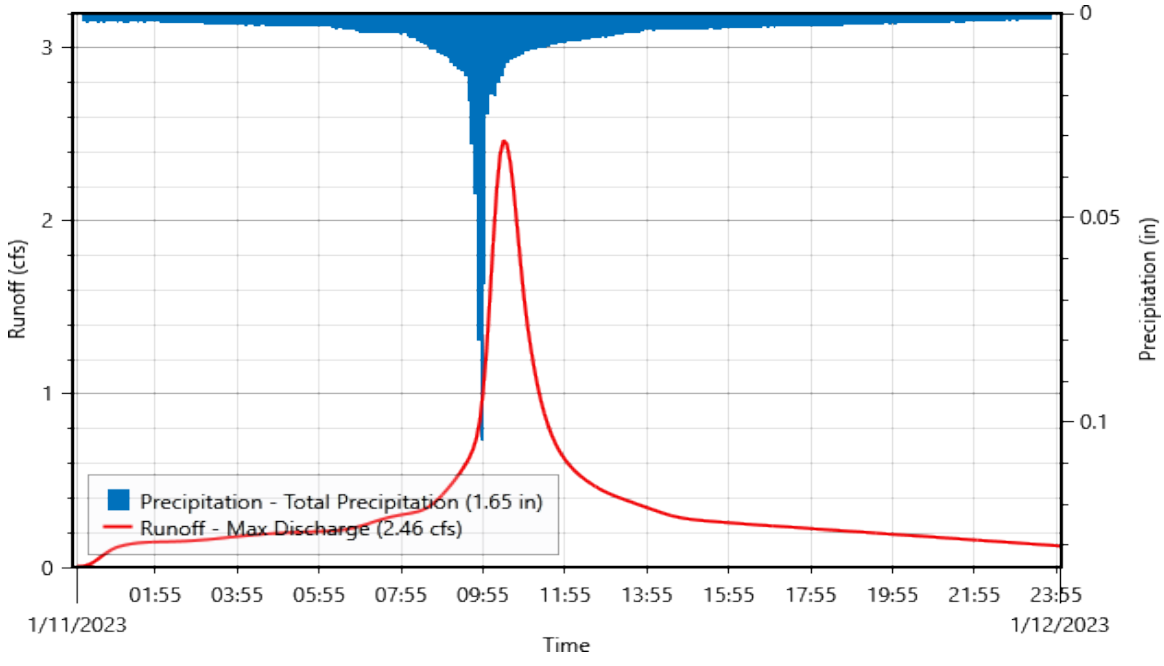
Subbasin ID:	Sub-12		Depth	Volume
Scenario:	Proposed Development 10 yr			
Peak discharge:	2.46 cfs	**Time of peak:**	11 Jan 2023, 10:25	
Drainage area:	952.517 acres	**Total rainfall:**	1.65 in	130.97039 ac-ft
Initial abstraction:	3.33 in	**Losses:**	1.64 in	130.28935 ac-ft
Curve Number:	37.51	**Precip excess:**	0.01 in	0.68105 ac-ft
Impervious surface:	%	**Direct runoff:**	0.01 in	0.67 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	0.00 minutes	**Total runoff:**	0.01 in	0.67 ac-ft

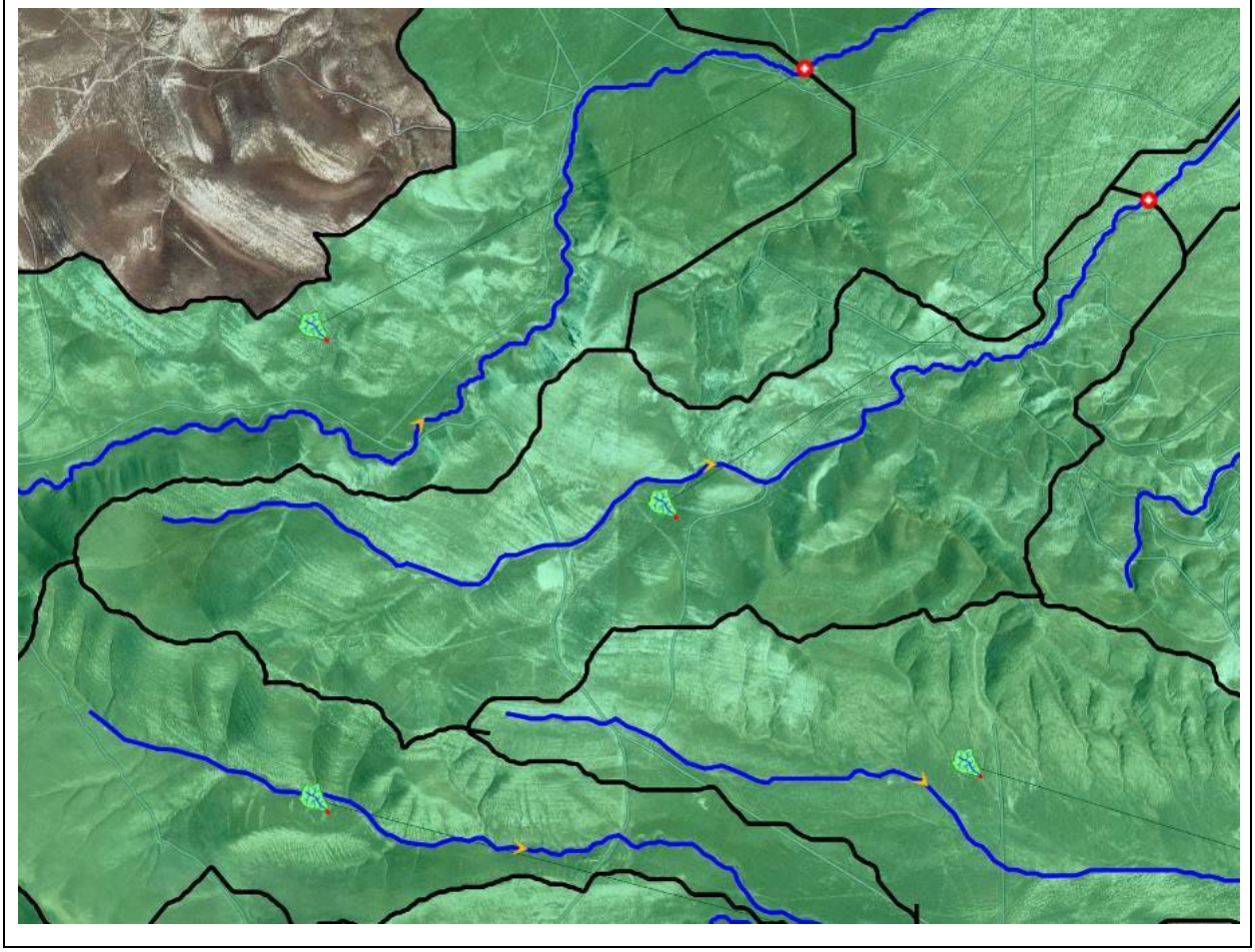
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
2.973	0.31	80.98	Developed, Medium Density
103.318	10.85	38.00	Undeveloped, Shrub/Scrub
0.143	0.02	75.00	Developed, Low Density
0.294	0.03	92.00	Developed, High Density
75.514	7.93	56.10	Developed, Open Space
770.275	80.87	35.42	Undeveloped, Grassland
952.517	**100.00**	**37.51**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
11.42	100.00	0.43323	2.4452	Sheet Flow
1.09	682.84	0.41878	21.3698	Shallow Concentrated Flow
1.93	655.49	0.12346	11.6028	Shallow Concentrated Flow
3.76	2,062.80	0.07622	9.1166	Channel Flow
38.83	14,034.51	0.03310	6.0076	Channel Flow
57.03	**17,535.64**	**Total**	**Lag Time = 34.22 minutes**	





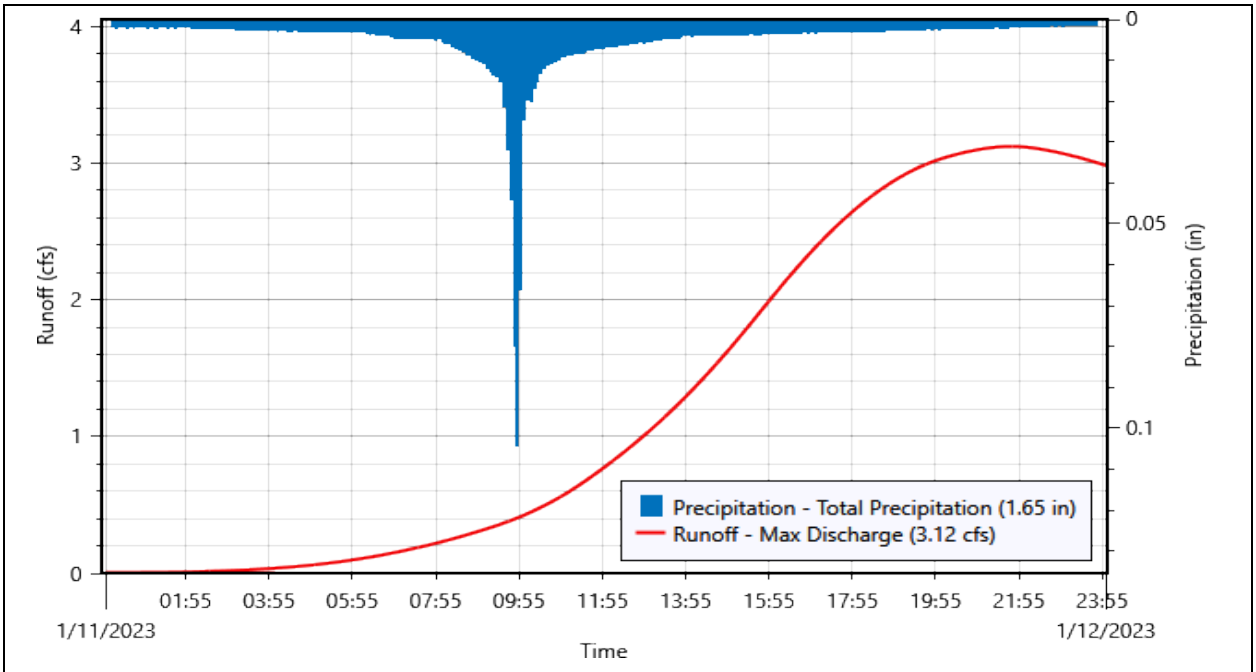
Subbasin ID:	Sub-13			
Scenario:	Proposed Development 10 yr		Depth	Volume
Peak discharge:	3.12 cfs	**Time of peak:**	11 Jan 2023, 09:45	
Drainage area:	1,426.690 acres	**Total rainfall:**	1.65 in	196.16959 ac-ft
Initial abstraction:	3.40 in	**Losses:**	1.61 in	191.18688 ac-ft
Curve Number:	37.06	**Precip excess:**	0.04 in	4.98271 ac-ft
Impervious surface:	%	**Direct runoff:**	0.02 in	2.51 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	0.00 minutes	**Total runoff:**	0.02 in	2.51 ac-ft

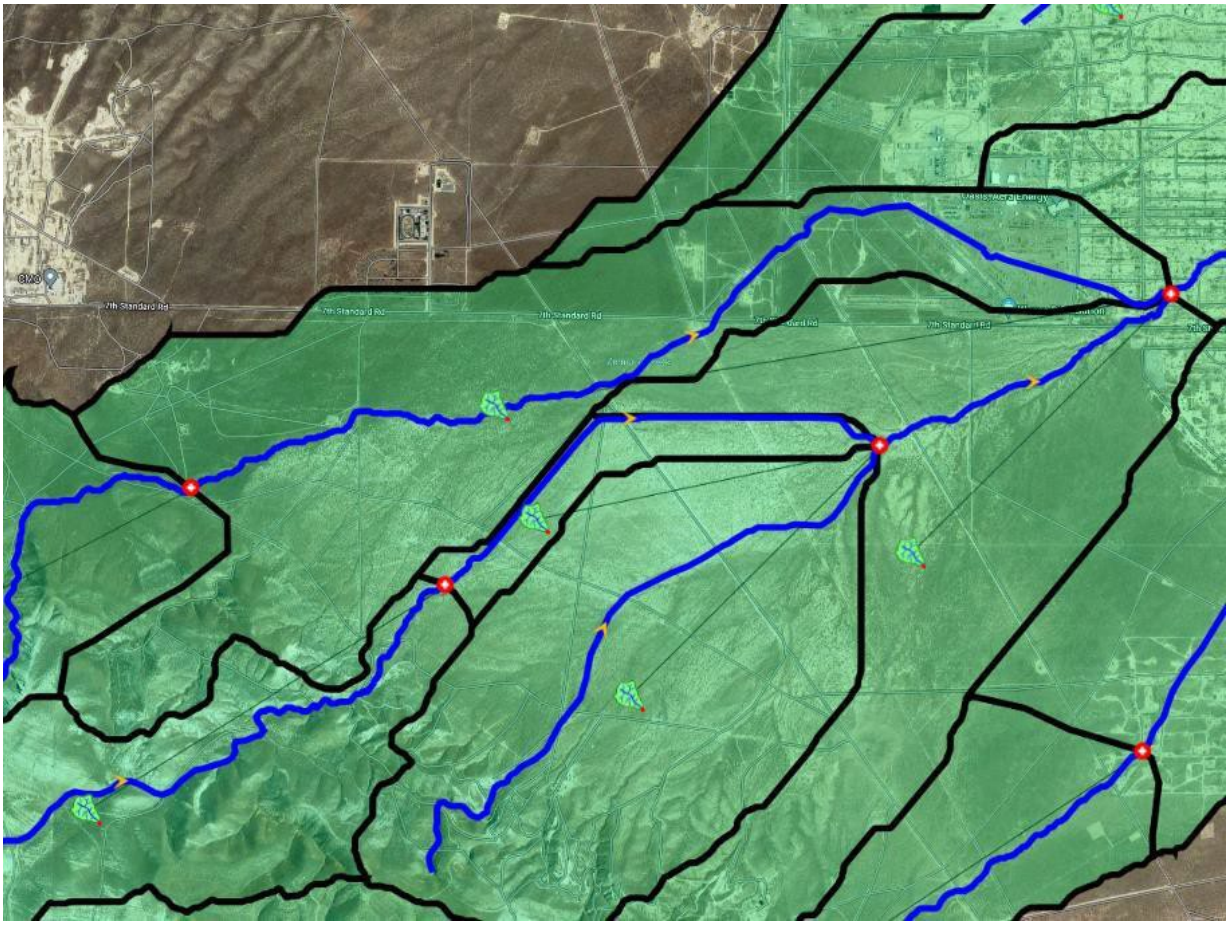
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
17.729	1.24	77.00	Developed, Medium Density
3.229	0.23	67.00	Agricultural, Cultivated Crops
80.460	5.64	37.13	Undeveloped, Shrub/Scrub
17.221	1.21	61.00	Developed, Low Density
15.586	1.09	89.00	Developed, High Density
152.768	10.71	52.06	Developed, Open Space
3.509	0.25	77.00	Undeveloped, Barren Land
1,136.188	79.64	33.14	Undeveloped, Grassland
1,426.690	**100.00**	**37.06**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
20.36	100.00	0.10212	1.1872	Sheet Flow
0.80	390.34	0.25255	16.5951	Shallow Concentrated Flow
8.53	4,253.88	0.06305	8.2916	Channel Flow
15.47	2,983.05	0.03970	6.5798	Shallow Concentrated Flow
43.39	10,314.70	0.01432	3.9513	Channel Flow
0.39	285.53	0.13608	12.1816	Channel Flow
993.25	6,239.98	0.00001	0.1044	Channel Flow
1,082.19	**24,567.48**	**Total**	**Lag Time = 649.32 minutes**	


Runoff (cfs)
Precipitation (in)
Time
1/11/2023
1/12/2023
Precipitation - Total Precipitation (1.65 in)
Runoff - Max Discharge (3.12 cfs)



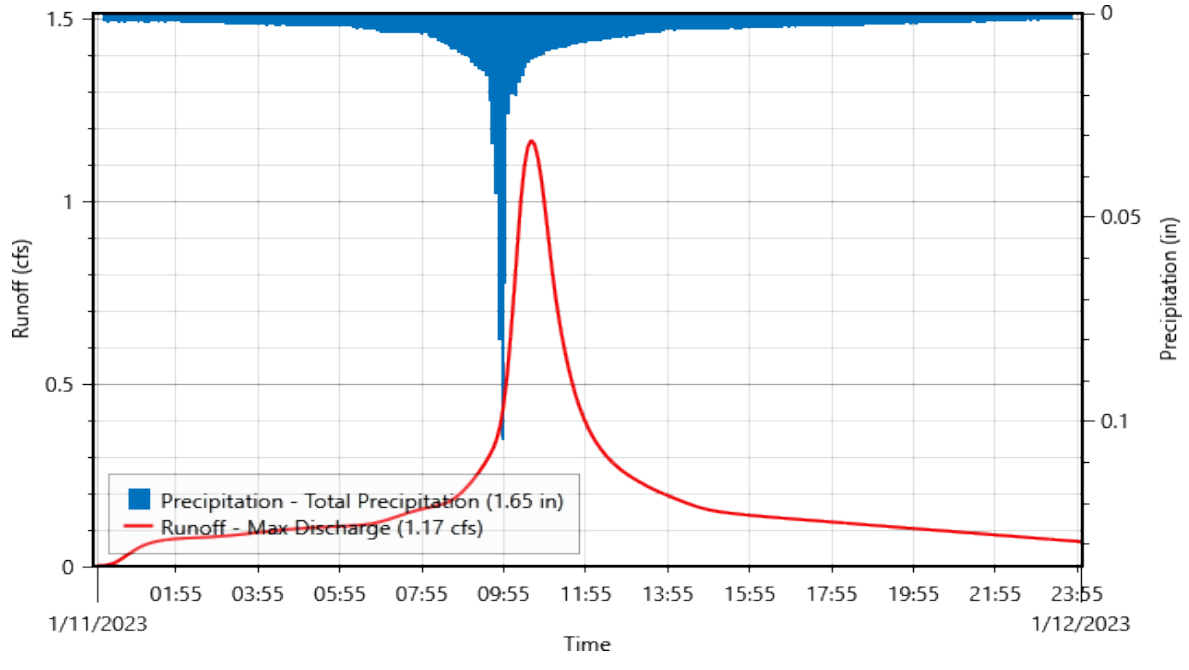
Subbasin ID:	Sub-14			
Scenario:	Proposed Development 10 yr		Depth	Volume
Peak discharge:	1.17 cfs	**Time of peak:**	11 Jan 2023, 10:35	
Drainage area:	1,158.859 acres	**Total rainfall:**	1.65 in	159.34159 ac-ft
Initial abstraction:	2.01 in	**Losses:**	1.65 in	158.97511 ac-ft
Curve Number:	49.91	**Precip excess:**	0.00 in	0.36649 ac-ft
Impervious surface:	%	**Direct runoff:**	0.00 in	0.36 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	0.00 minutes	**Total runoff:**	0.00 in	0.36 ac-ft

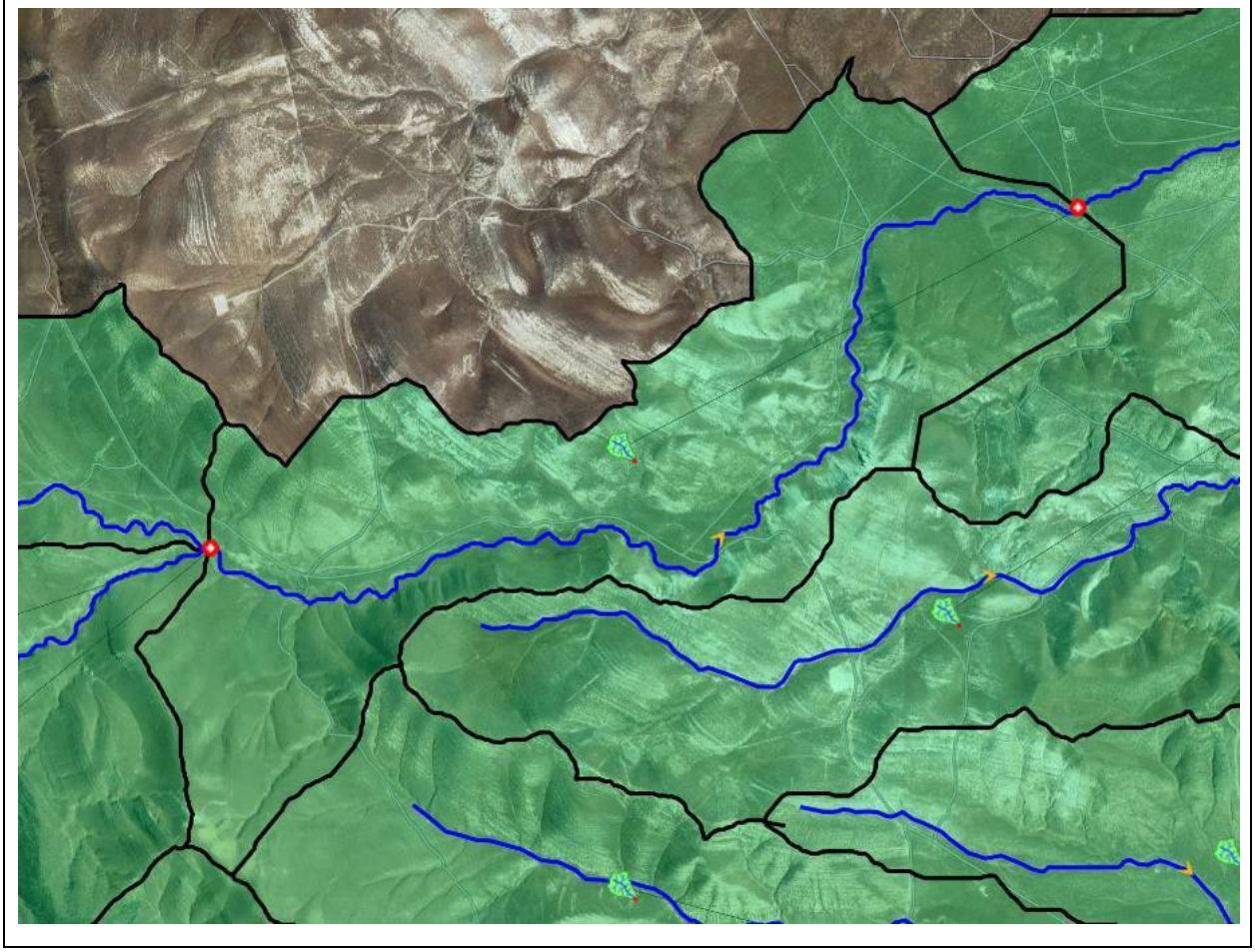
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
128.595	11.10	40.16	Undeveloped, Shrub/Scrub
0.289	0.02	61.00	Developed, Low Density
89.373	7.71	62.75	Developed, Open Space
940.602	81.17	50.02	Undeveloped, Grassland
1,158.859	**100.00**	**49.91**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
15.07	100.00	0.21650	1.7286	Sheet Flow
1.46	911.67	0.41691	21.3220	Shallow Concentrated Flow
2.49	2,157.30	0.19089	14.4277	Channel Flow
2.91	1,629.56	0.07940	9.3053	Channel Flow
49.93	15,884.87	0.02564	5.2879	Channel Flow
71.86	**20,683.40**	**Total**	**Lag Time = 43.12 minutes**	





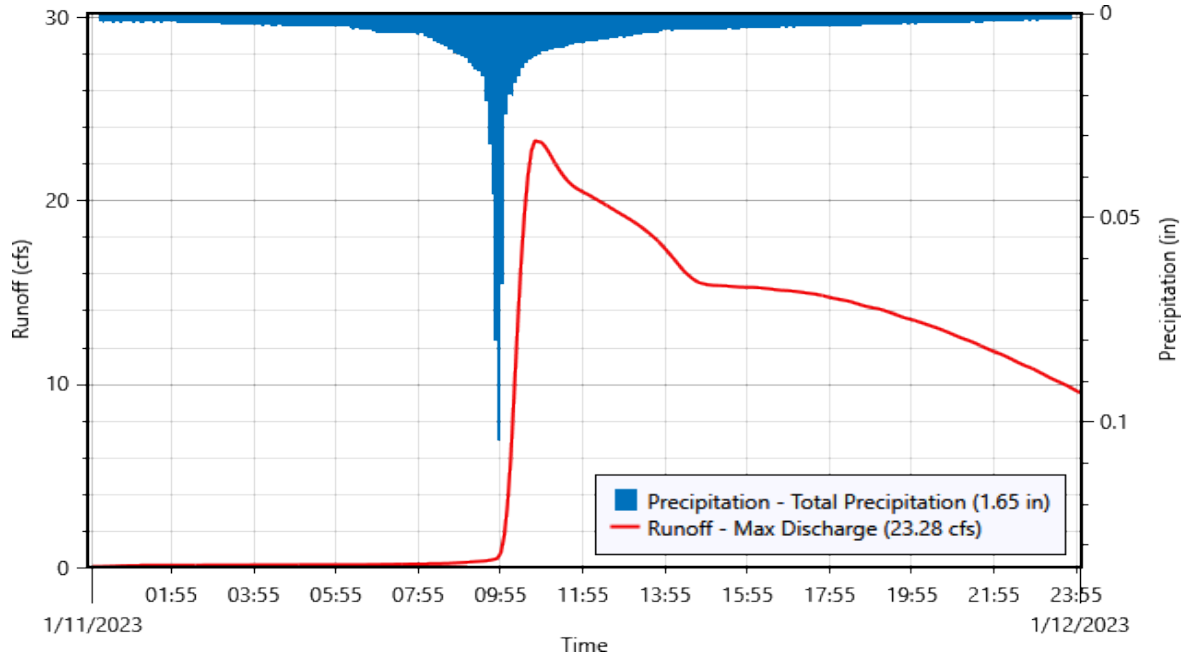
Subbasin ID:	Sub-15			
Scenario:	Proposed Development 10 yr		Depth	Volume
Peak discharge:	23.28 cfs	**Time of peak:**	11 Jan 2023, 10:50	
Drainage area:	1,054.808 acres	**Total rainfall:**	1.65 in	145.03279 ac-ft
Initial abstraction:	0.70 in	**Losses:**	1.44 in	126.93838 ac-ft
Curve Number:	74.04	**Precip excess:**	0.21 in	18.09442 ac-ft
Impervious surface:	%	**Direct runoff:**	0.20 in	17.58 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	0.00 minutes	**Total runoff:**	0.20 in	17.58 ac-ft

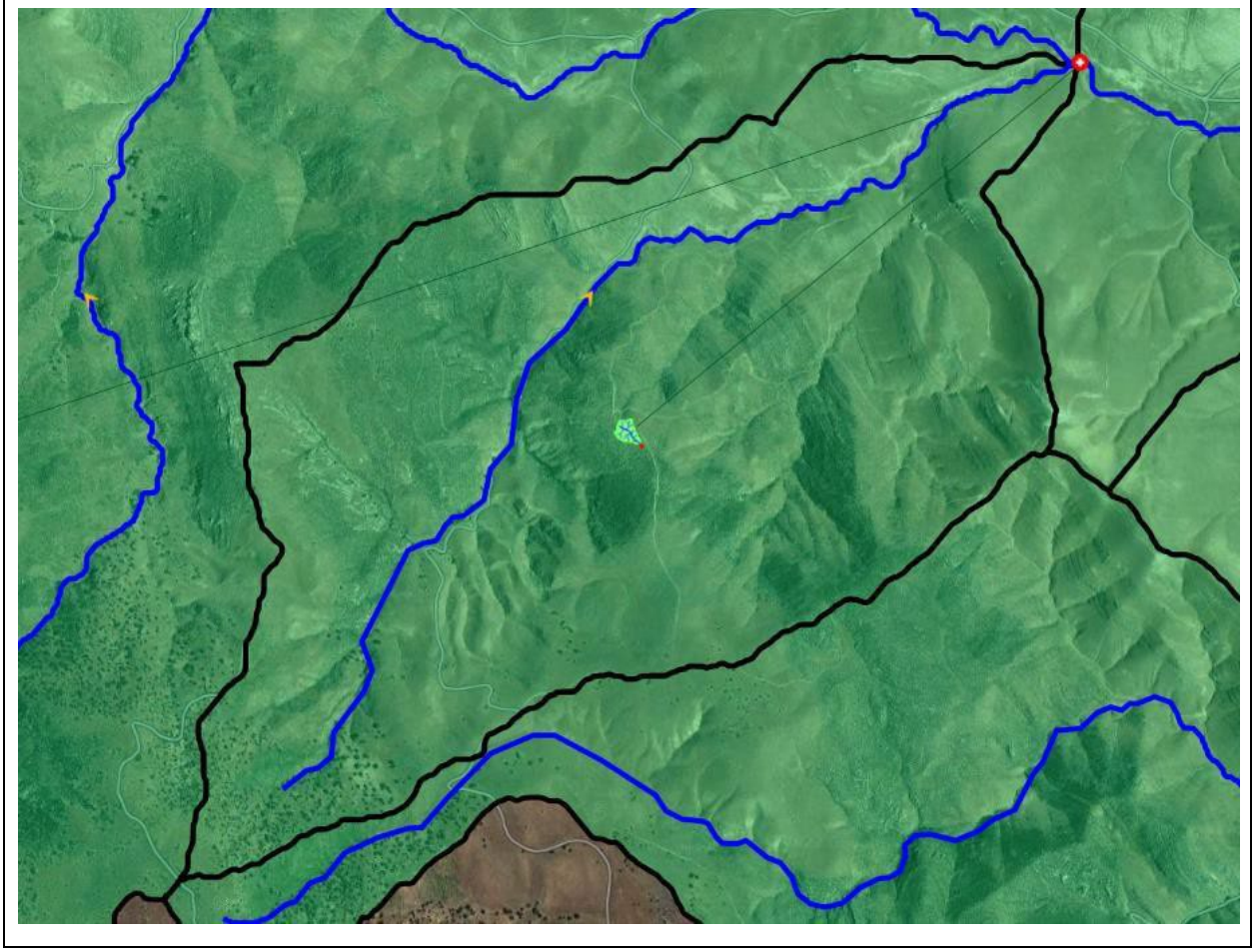
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
0.440	0.04	90.67	Developed, Medium Density
314.541	29.82	70.23	Undeveloped, Shrub/Scrub
3.839	0.36	84.20	Developed, Low Density
56.493	5.36	82.98	Developed, Open Space
679.496	64.42	74.98	Undeveloped, Grassland
1,054.808	**100.00**	**74.04**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
25.00	100.00	0.06109	0.9182	Sheet Flow
2.53	1,452.21	0.35050	19.5503	Shallow Concentrated Flow
1.74	1,776.43	0.26336	16.9464	Channel Flow
21.82	11,269.67	0.06761	8.5864	Channel Flow
51.09	**14,598.31**	**Total**	**Lag Time = 30.66 minutes**	





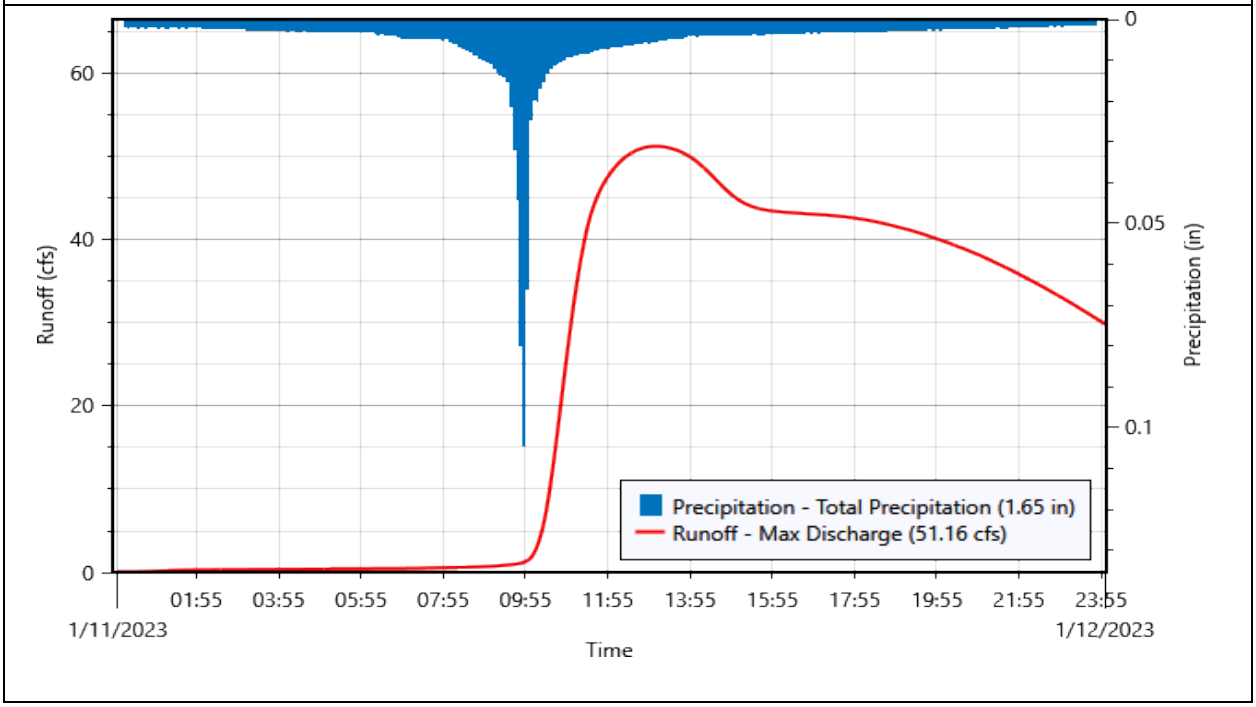
Subbasin ID:	Sub-16			
Scenario:	Proposed Development 10 yr		Depth	Volume
Peak discharge:	51.16 cfs	**Time of peak:**	11 Jan 2023, 01:05	
Drainage area:	3,426.802 acres	**Total rainfall:**	1.65 in	471.18718 ac-ft
Initial abstraction:	0.76 in	**Losses:**	1.48 in	421.98190 ac-ft
Curve Number:	72.40	**Precip excess:**	0.17 in	49.20528 ac-ft
Impervious surface:	%	**Direct runoff:**	0.16 in	46.17 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	0.00 minutes	**Total runoff:**	0.16 in	46.17 ac-ft

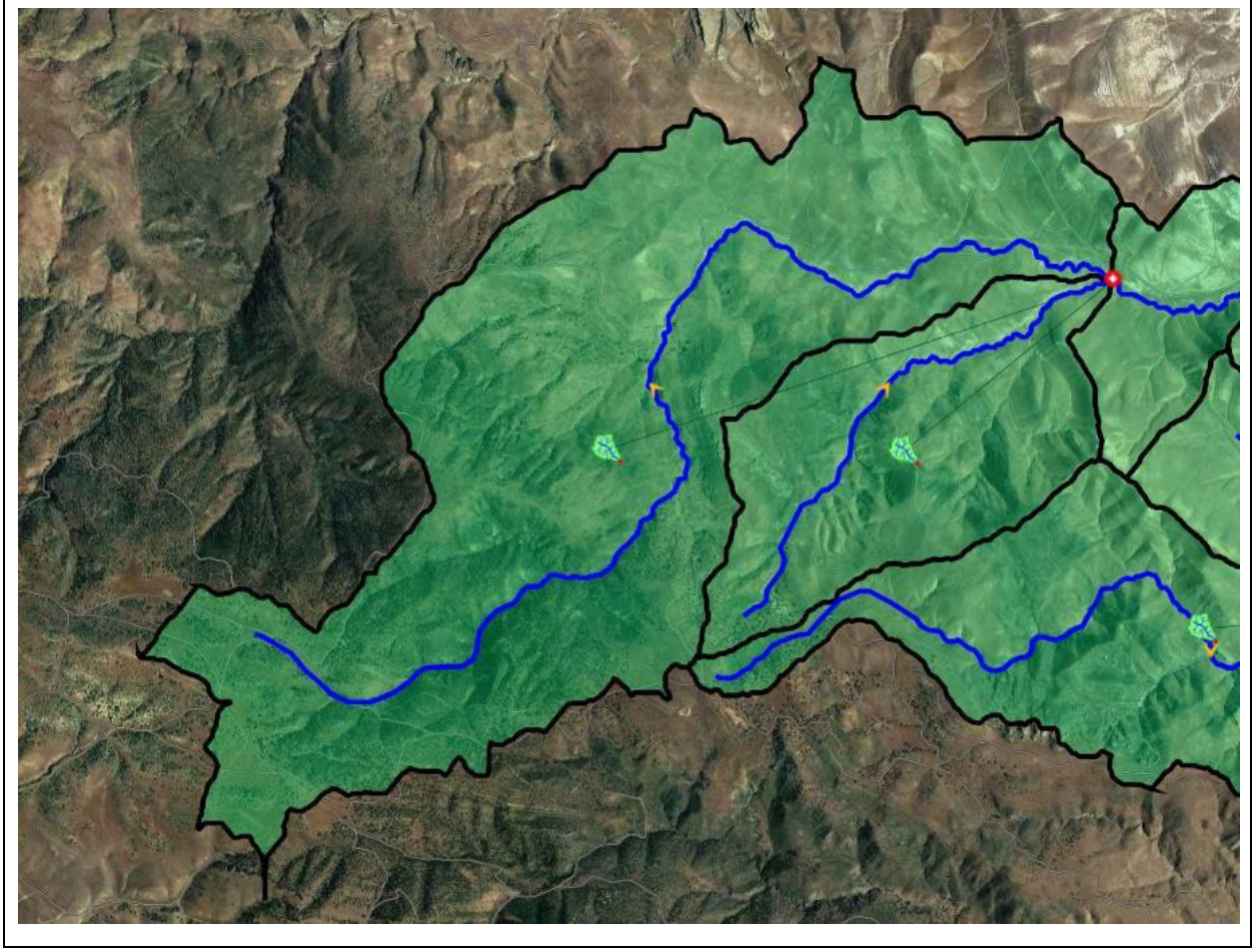
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
1.435	0.04	90.36	Developed, Medium Density
1,371.868	40.03	69.50	Undeveloped, Shrub/Scrub
7.071	0.21	85.60	Developed, Low Density
212.323	6.20	80.36	Developed, Open Space
1,834.106	53.52	73.58	Undeveloped, Grassland
3,426.802	**100.00**	**72.40**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
19.42	100.00	0.11493	1.2594	Sheet Flow
1.56	667.95	0.19509	14.5854	Shallow Concentrated Flow
13.71	2,461.83	0.03444	6.1282	Shallow Concentrated Flow
8.43	4,539.75	0.07343	8.9483	Channel Flow
9.74	7,174.45	0.13760	12.2496	Channel Flow
46.74	18,531.20	0.03983	6.5902	Channel Flow
99.60	**33,475.18**	**Total**	**Lag Time = 59.76 minutes**	





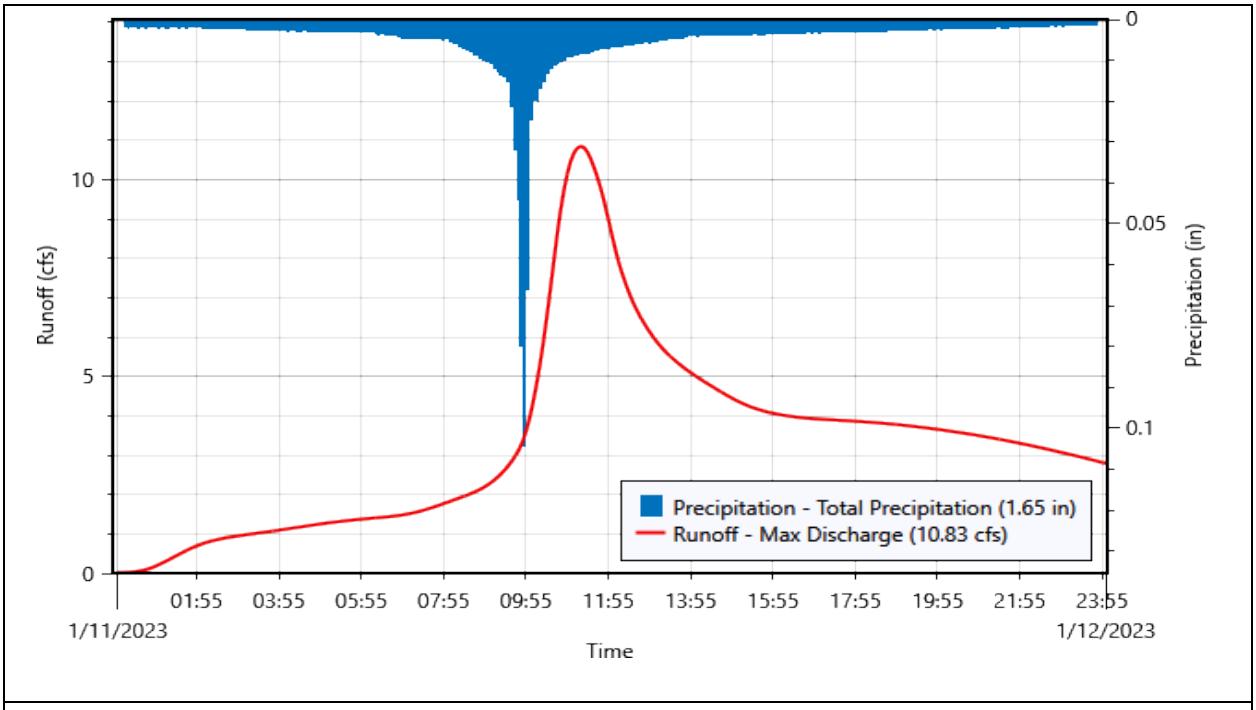
Subbasin ID:	Sub-17			
Scenario:	Proposed Development 10 yr		Depth	Volume
Peak discharge:	10.83 cfs	**Time of peak:**	11 Jan 2023, 11:15	
Drainage area:	337.184 acres	**Total rainfall:**	1.65 in	46.35840 ac-ft
Initial abstraction:	0.97 in	**Losses:**	1.40 in	39.39819 ac-ft
Curve Number:	67.43	**Precip excess:**	0.25 in	6.96021 ac-ft
Impervious surface:	%	**Direct runoff:**	0.23 in	6.59 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	0.00 minutes	**Total runoff:**	0.23 in	6.59 ac-ft

Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
11.293	3.35	79.56	Developed, Medium Density
11.056	3.28	57.09	Undeveloped, Shrub/Scrub
67.566	20.04	78.79	Agricultural, Cultivated Crops
47.927	14.21	72.20	Developed, Low Density
0.803	0.24	90.30	Developed, High Density
1.132	0.34	86.00	Undeveloped, Barren Land
45.684	13.55	49.39	Undeveloped, Grassland
151.725	45.00	65.89	Developed, Open Space
337.184	**100.00**	**67.43**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
51.35	100.00	0.01011	0.3736	Sheet Flow
17.31	2,002.38	0.01428	3.9466	Shallow Concentrated Flow
0.33	116.98	0.13224	12.0085	Shallow Concentrated Flow
61.55	2,055.00	0.00119	1.1398	Shallow Concentrated Flow
3.43	792.13	0.01352	3.8394	Channel Flow
133.97	**5,066.49**	**Total**	**Lag Time = 80.39 minutes**	


Runoff (cfs)
10
5
0
0
0.05
0.1
Precipitation (in)
01:55
03:55
05:55
07:55
09:55
11:55
13:55
15:55
17:55
19:55
21:55
23:55
1/11/2023
1/12/2023
Time
Precipitation - Total Precipitation (1.65 in)
Runoff - Max Discharge (10.83 cfs)


BSWP
Jun-13
Jun-14
Reach-17
Sub-17
Lost Hills Rd
Entrance A

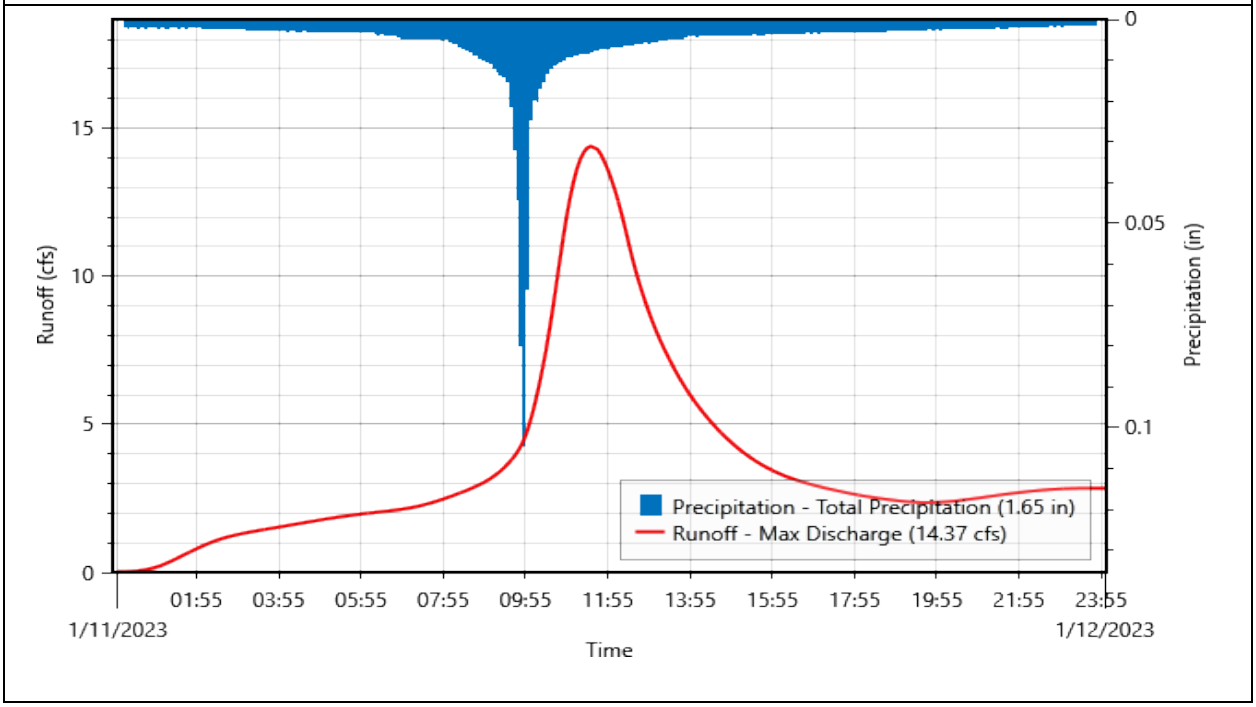
Subbasin ID:	Sub-18			
Scenario:	Proposed Development 10 yr		Depth	Volume
Peak discharge:	14.37 cfs	**Time of peak:**	11 Jan 2023, 11:30	
Drainage area:	1,474.591 acres	**Total rainfall:**	1.65 in	202.75199 ac-ft
Initial abstraction:	1.47 in	**Losses:**	1.59 in	195.04325 ac-ft
Curve Number:	57.69	**Precip excess:**	0.06 in	7.70874 ac-ft
Impervious surface:	%	**Direct runoff:**	0.06 in	7.23 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	0.00 minutes	**Total runoff:**	0.06 in	7.23 ac-ft

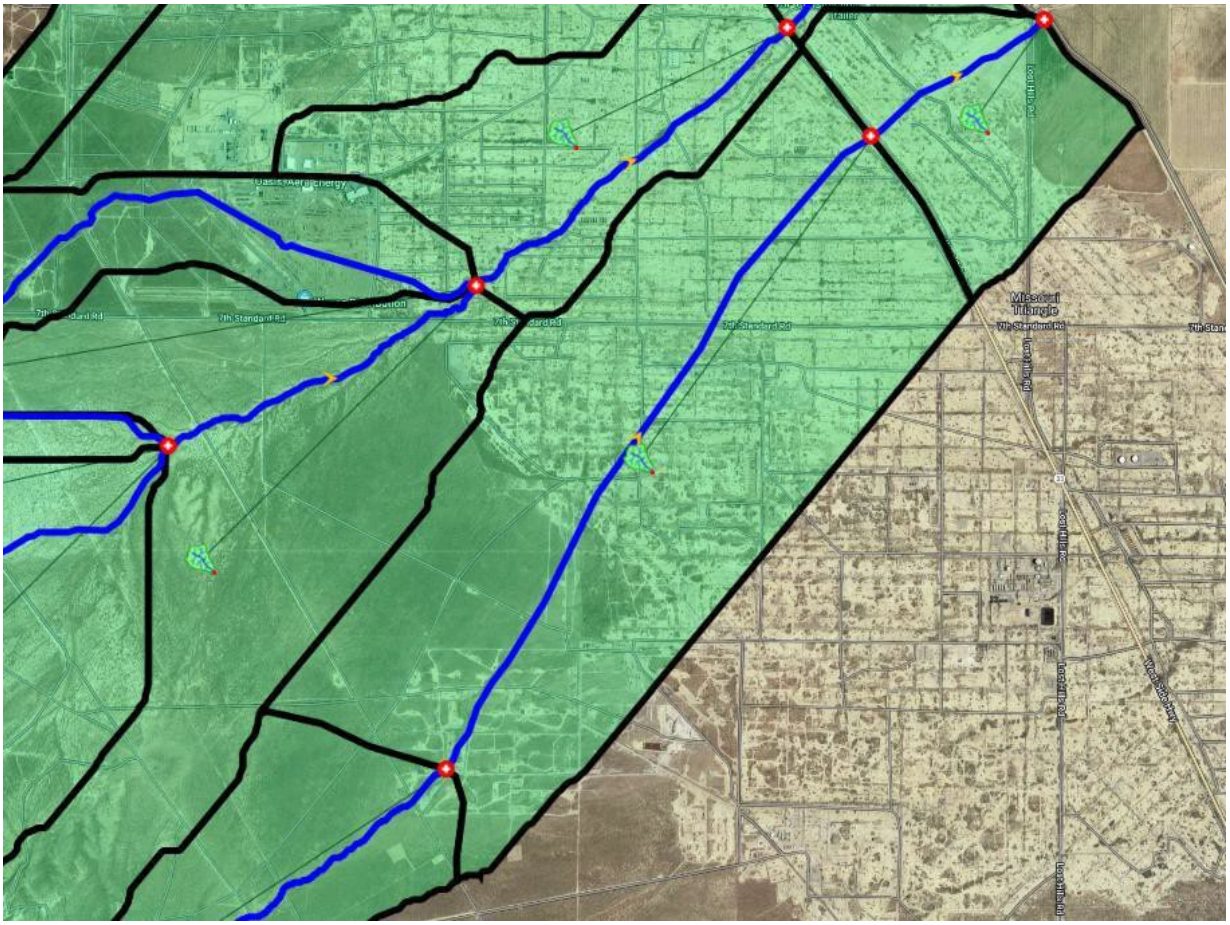
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
3.985	0.27	88.87	Developed, Medium Density
5.873	0.40	43.83	Undeveloped, Shrub/Scrub
60.728	4.12	78.75	Developed, Low Density
0.093	0.01	92.00	Developed, High Density
624.729	42.37	71.04	Developed, Open Space
3.600	0.24	89.56	Undeveloped, Barren Land
775.583	52.60	45.08	Undeveloped, Grassland
1,474.591	**100.00**	**57.69**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
47.88	100.00	0.01204	0.4077	Sheet Flow
16.47	2,024.74	0.01613	4.1935	Shallow Concentrated Flow
47.40	10,905.83	0.01341	3.8241	Channel Flow
49.39	438.84	0.00002	0.1541	Channel Flow
161.14	**13,469.41**	**Total**	**Lag Time = 96.69 minutes**	




7th Standard Rd
Missouri Triangle
Loop 1 Hwy
Loop 1 Rd
Loop 1 Rd
Loop 1 Rd
Loop 1 Rd

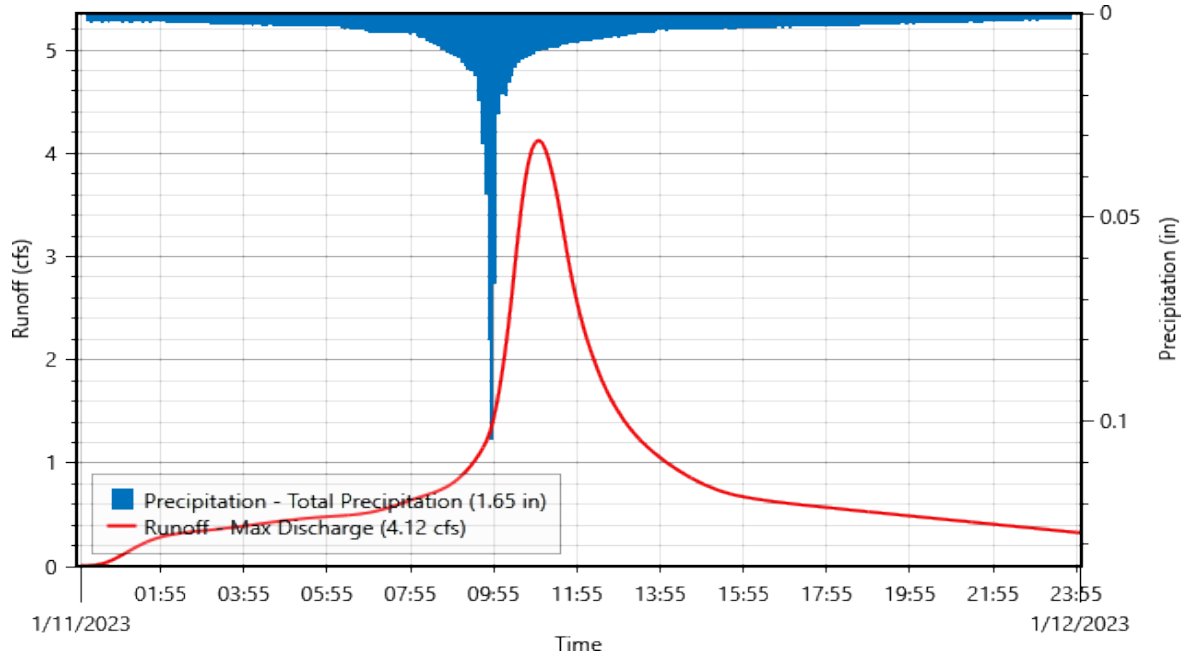
Subbasin ID:	Sub-19		Depth	Volume
Scenario:	Proposed Development 10 yr			
Peak discharge:	4.12 cfs	**Time of peak:**	11 Jan 2023, 11:00	
Drainage area:	787.670 acres	**Total rainfall:**	1.65 in	108.30160 ac-ft
Initial abstraction:	2.86 in	**Losses:**	1.62 in	106.64458 ac-ft
Curve Number:	41.19	**Precip excess:**	0.03 in	1.65701 ac-ft
Impervious surface:	%	**Direct runoff:**	0.02 in	1.62 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	0.00 minutes	**Total runoff:**	0.02 in	1.62 ac-ft

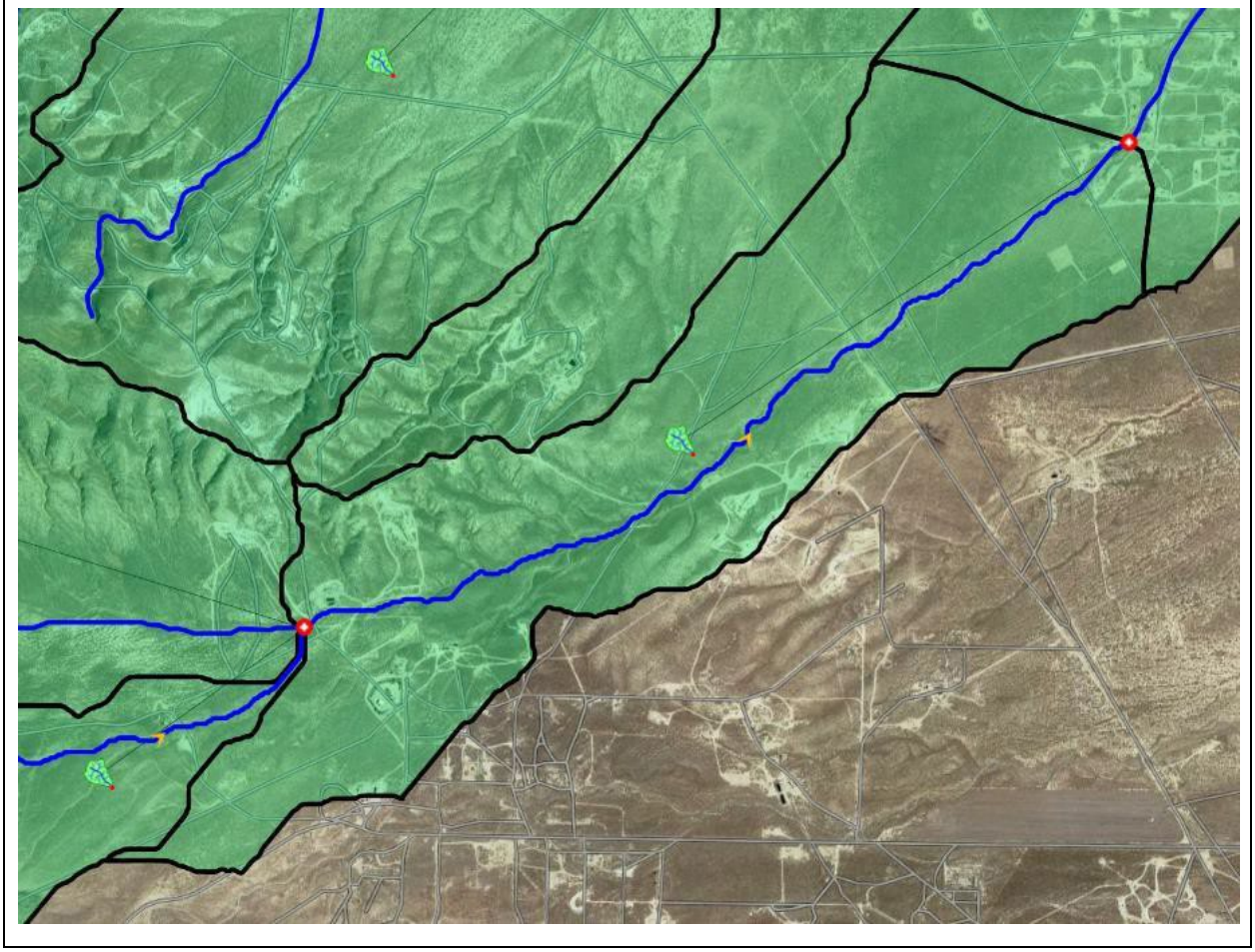
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
1.108	0.14	85.00	Developed, Medium Density
3.612	0.46	36.54	Undeveloped, Shrub/Scrub
0.954	0.12	61.03	Developed, Low Density
92.294	11.72	56.80	Developed, Open Space
0.138	0.02	77.00	Undeveloped, Barren Land
689.564	87.54	39.02	Undeveloped, Grassland
787.670	**100.00**	**41.19**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
29.59	100.00	0.04010	0.7440	Sheet Flow
29.99	4,469.59	0.02372	5.0858	Shallow Concentrated Flow
13.10	1,472.11	0.00320	1.8666	Channel Flow
38.21	10,337.14	0.01854	4.4965	Channel Flow
110.89	**16,378.84**	**Total**	**Lag Time = 66.54 minutes**	





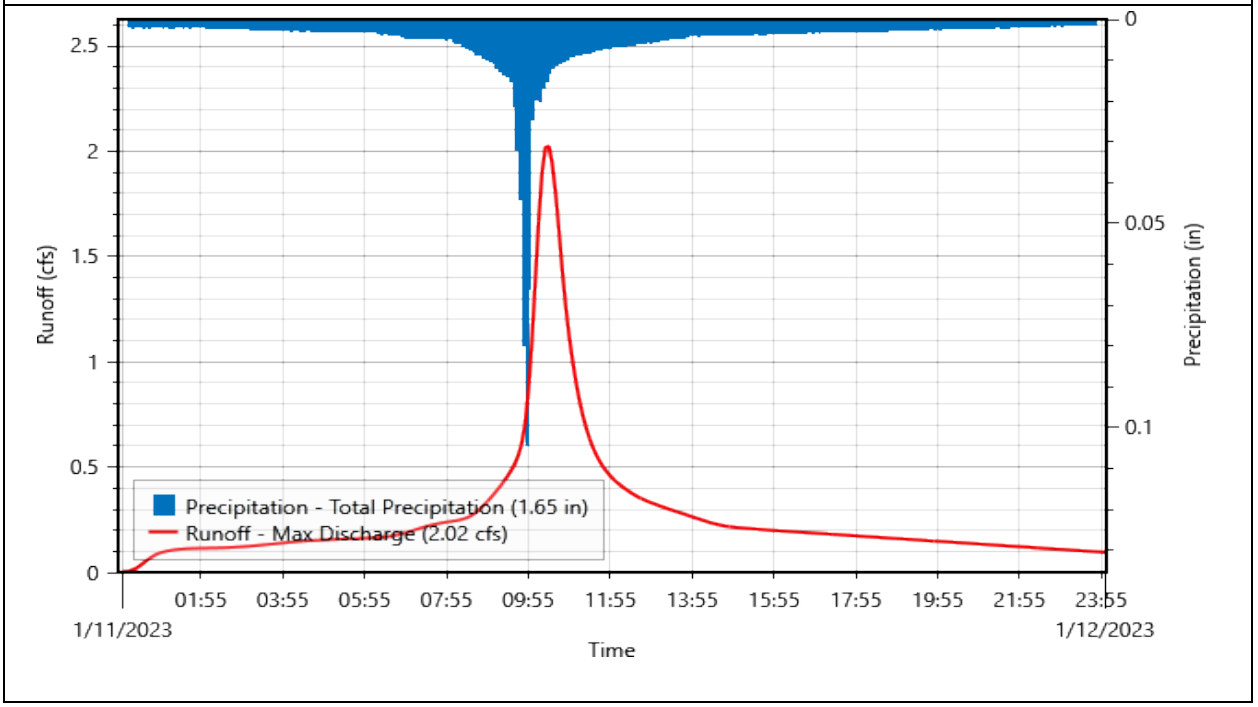
Subbasin ID:	Sub-20			
Scenario:	Proposed Development 10 yr		Depth	Volume
Peak discharge:	2.02 cfs	**Time of peak:**	11 Jan 2023, 10:25	
Drainage area:	714.148 acres	**Total rainfall:**	1.65 in	98.19920 ac-ft
Initial abstraction:	2.82 in	**Losses:**	1.64 in	97.66892 ac-ft
Curve Number:	41.47	**Precip excess:**	0.01 in	0.53028 ac-ft
Impervious surface:	%	**Direct runoff:**	0.01 in	0.53 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	0.00 minutes	**Total runoff:**	0.01 in	0.53 ac-ft

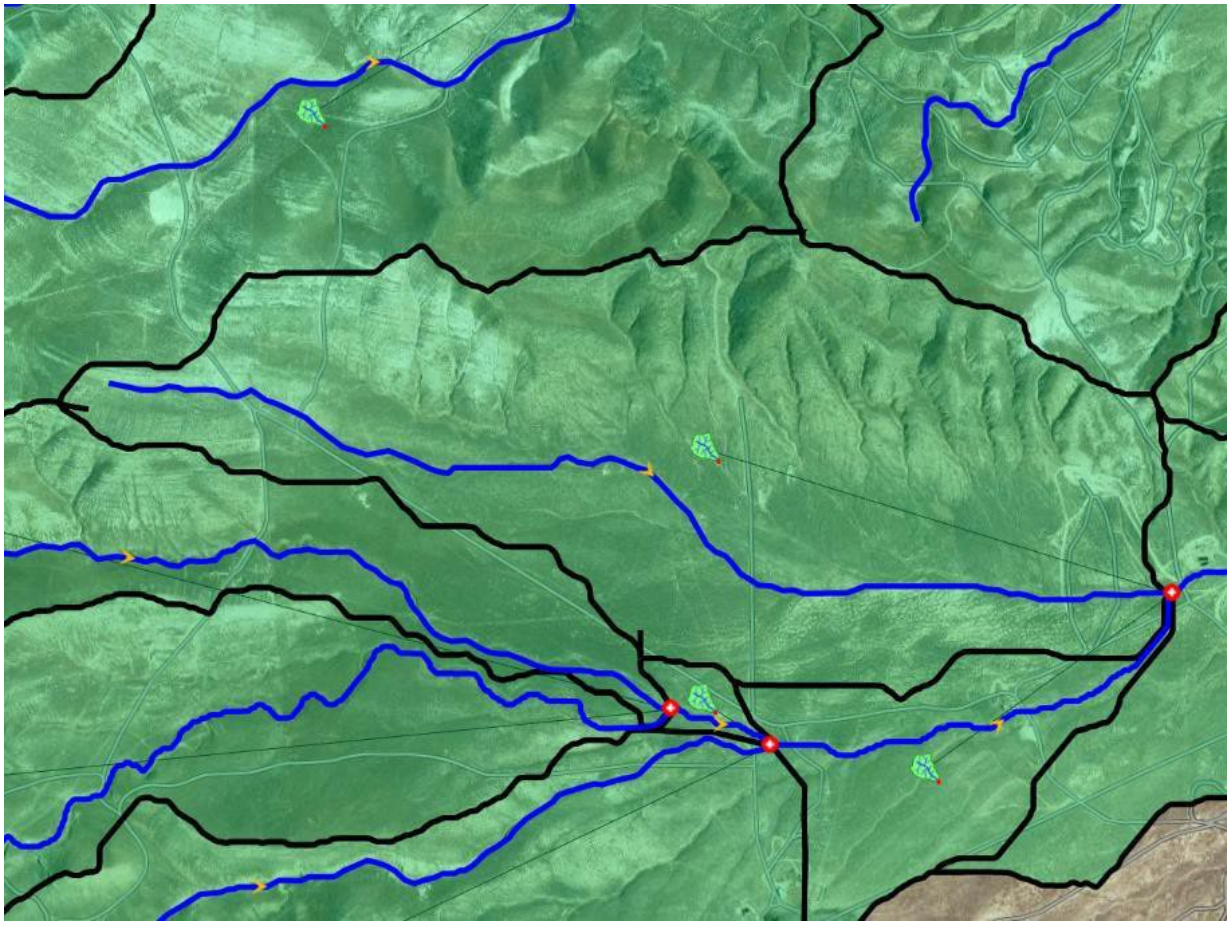
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
1.599	0.22	79.30	Developed, Medium Density
24.804	3.47	30.65	Undeveloped, Shrub/Scrub
0.430	0.06	61.00	Developed, Low Density
60.511	8.47	56.19	Developed, Open Space
626.805	87.77	40.37	Undeveloped, Grassland
714.148	**100.00**	**41.47**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
16.55	100.00	0.17144	1.5382	Sheet Flow
1.01	456.12	0.21931	15.4645	Shallow Concentrated Flow
0.89	623.85	0.12498	11.6744	Channel Flow
18.86	7,625.25	0.04142	6.7210	Channel Flow
9.23	2,974.94	0.02631	5.3566	Channel Flow
4.84	334.47	0.00121	1.1467	Channel Flow
51.38	**12,114.63**	**Total**	**Lag Time = 30.83 minutes**	





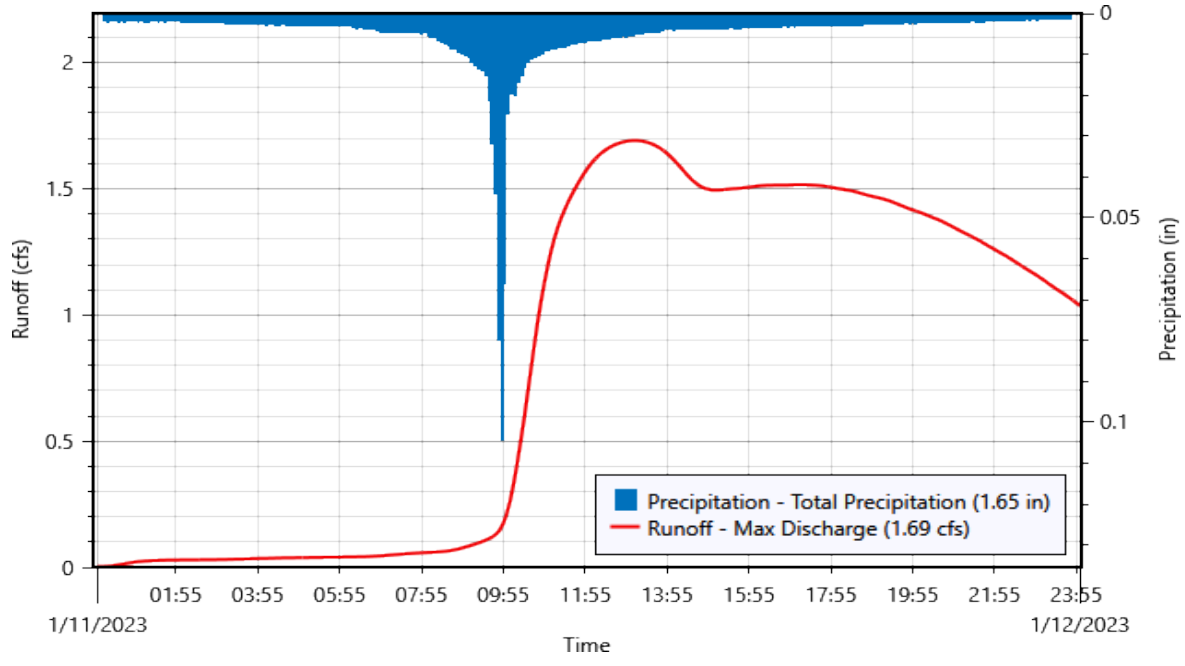
Subbasin ID:	Sub-21			
Scenario:	Proposed Development 10 yr		Depth	Volume
Peak discharge:	1.69 cfs	**Time of peak:**	11 Jan 2023, 01:05	
Drainage area:	140.608 acres	**Total rainfall:**	1.65 in	19.33360 ac-ft
Initial abstraction:	0.83 in	**Losses:**	1.50 in	17.62925 ac-ft
Curve Number:	70.73	**Precip excess:**	0.15 in	1.70435 ac-ft
Impervious surface:	%	**Direct runoff:**	0.14 in	1.64 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	0.00 minutes	**Total runoff:**	0.14 in	1.64 ac-ft

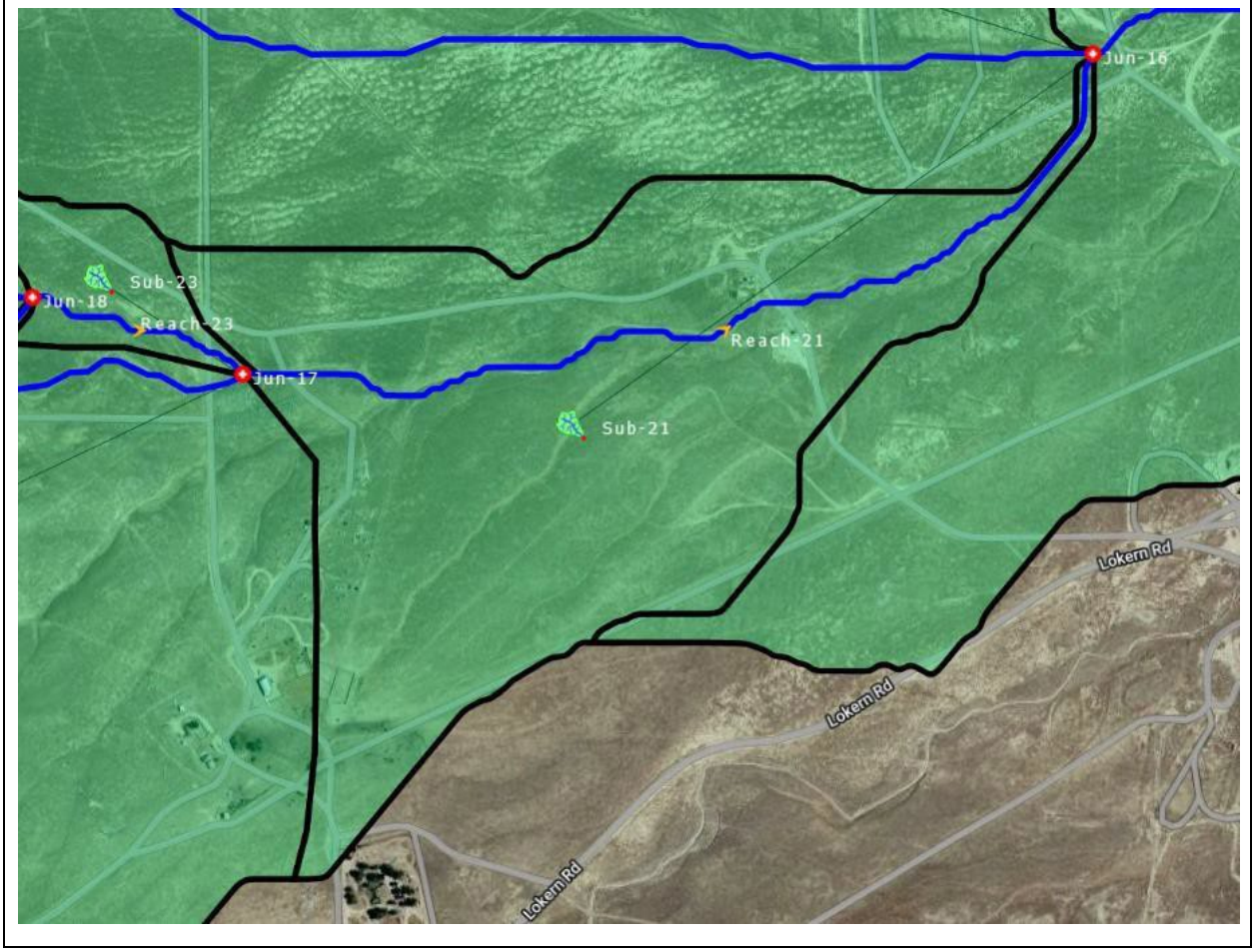
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
0.048	0.03	73.00	Undeveloped, Shrub/Scrub
23.066	16.40	70.83	Developed, Open Space
117.494	83.56	70.70	Undeveloped, Grassland
140.608	**100.00**	**70.73**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
34.47	100.00	0.02738	0.6147	Sheet Flow
19.66	3,615.01	0.03610	6.2745	Shallow Concentrated Flow
5.94	1,258.40	0.01138	3.5222	Channel Flow
1.95	736.77	0.03618	6.2812	Channel Flow
62.02	**5,710.18**	**Total**	**Lag Time = 37.22 minutes**	




Jun-16
Sub-23
Jun-18
Reach-23
Reach-21
Jun-17
Sub-21
Lokern Rd
Lokern Rd
Lokern Rd

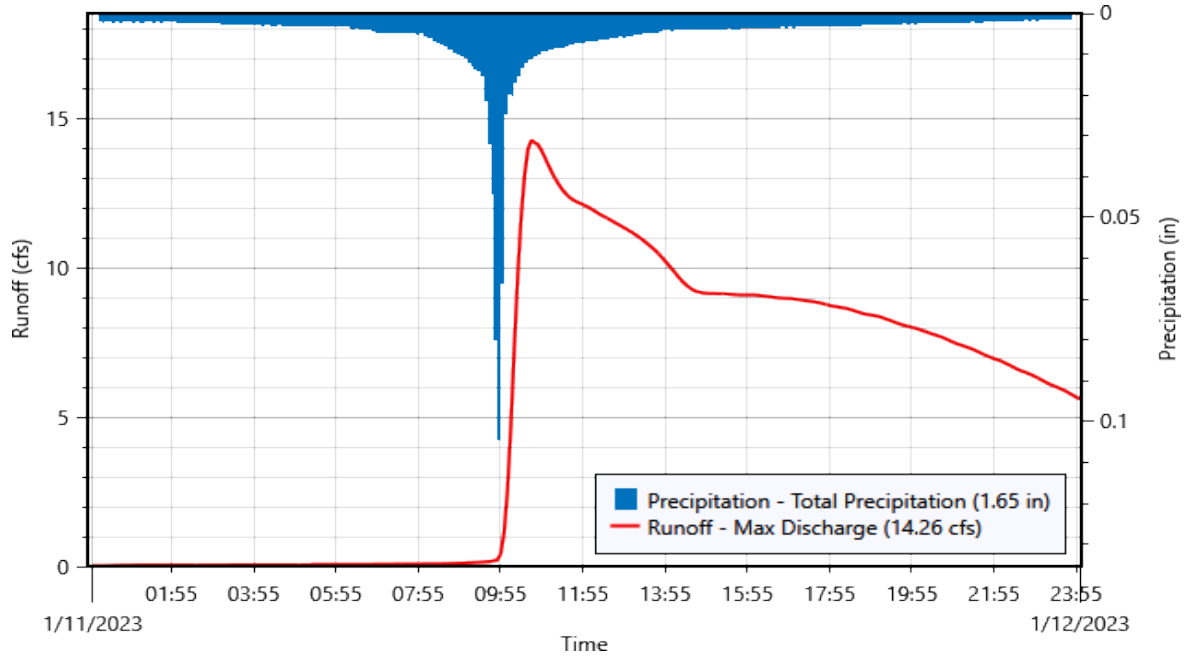
Subbasin ID:	**Sub-22**			
Scenario:	**Proposed Development 10 yr**		**Depth**	**Volume**
Peak discharge:	14.26 cfs	**Time of peak:**	11 Jan 2023, 10:40	
Drainage area:	624.791 acres	**Total rainfall:**	1.65 in	85.90560 ac-ft
Initial abstraction:	0.70 in	**Losses:**	1.44 in	75.17462 ac-ft
Curve Number:	74.21	**Precip excess:**	0.21 in	10.73098 ac-ft
Impervious surface:	%	**Direct runoff:**	0.20 in	10.47 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	0.00 minutes	**Total runoff:**	0.20 in	10.47 ac-ft

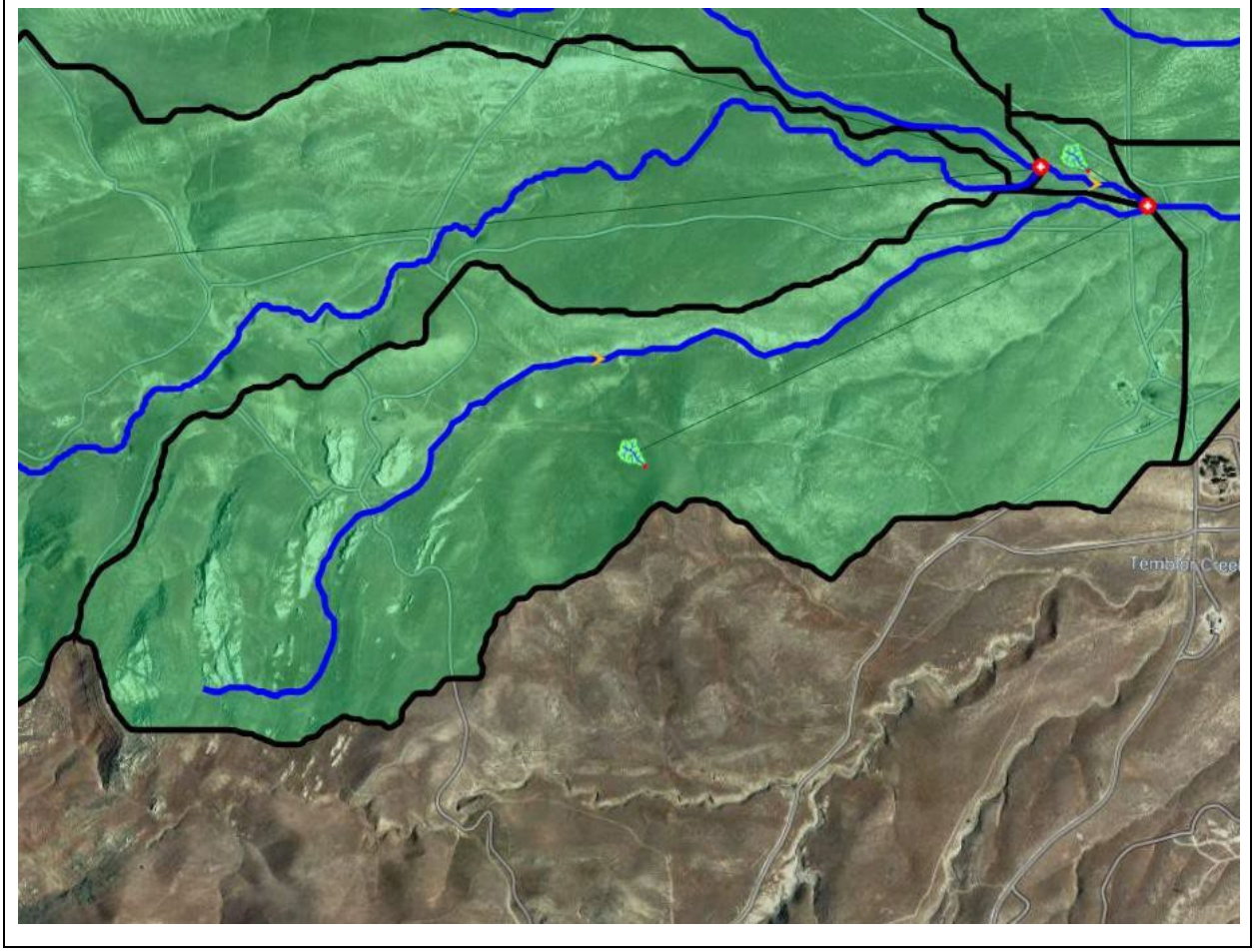
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
15.298	2.45	65.31	Undeveloped, Shrub/Scrub
44.349	7.10	81.50	Developed, Open Space
565.143	90.45	73.87	Undeveloped, Grassland
624.791	**100.00**	**74.21**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
14.10	100.00	0.25569	1.8785	Sheet Flow
1.03	658.49	0.44023	21.9101	Shallow Concentrated Flow
0.57	222.33	0.16461	13.3980	Shallow Concentrated Flow
5.54	2,803.60	0.06494	8.4151	Channel Flow
23.12	8,603.50	0.03510	6.1869	Channel Flow
44.36	**12,387.92**	**Total**	**Lag Time = 26.62 minutes**	





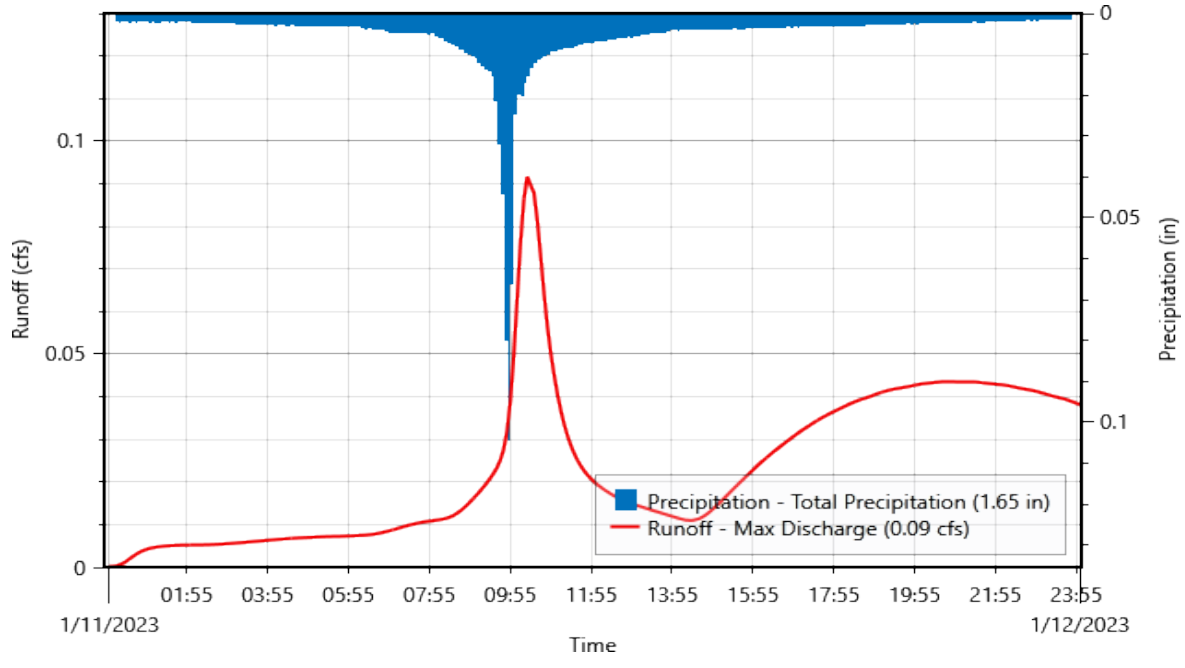
Subbasin ID:	**Sub-23**			
Scenario:	**Proposed Development 10 yr**		**Depth**	**Volume**
Peak discharge:	0.09 cfs	**Time of peak:**	11 Jan 2023, 10:25	
Drainage area:	13.631 acres	**Total rainfall:**	1.65 in	1.87440 ac-ft
Initial abstraction:	1.27 in	**Losses:**	1.61 in	1.82633 ac-ft
Curve Number:	61.18	**Precip excess:**	0.04 in	0.04807 ac-ft
Impervious surface:	%	**Direct runoff:**	0.04 in	0.05 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	0.00 minutes	**Total runoff:**	0.04 in	0.05 ac-ft

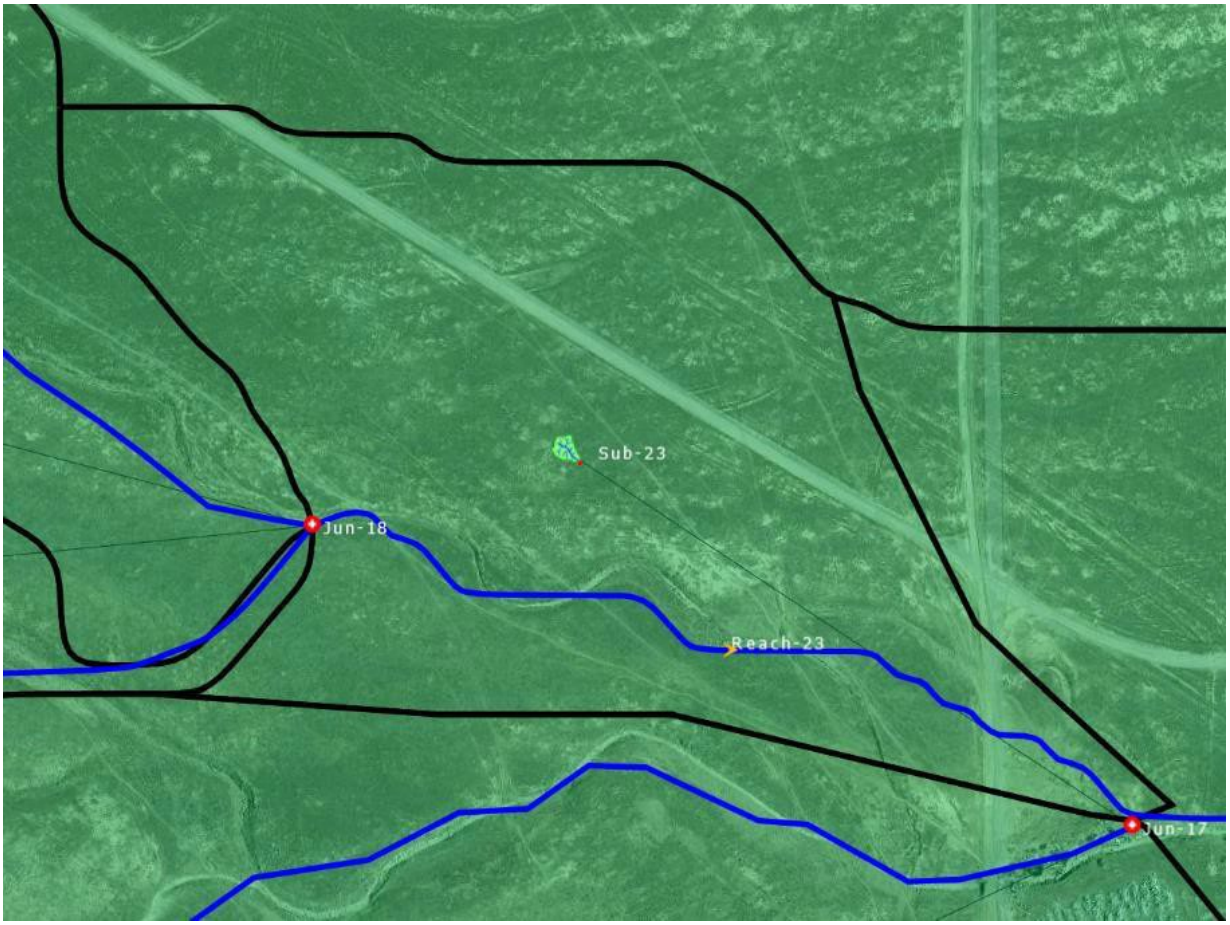
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
3.902	28.63	69.00	Developed, Open Space
9.729	71.37	58.05	Undeveloped, Grassland
13.631	**100.00**	**61.18**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
44.71	100.00	0.01429	0.4440	Sheet Flow
1.98	295.62	0.02383	5.0982	Shallow Concentrated Flow
0.56	163.06	0.09046	9.9322	Shallow Concentrated Flow
0.38	151.74	0.16695	13.4926	Shallow Concentrated Flow
0.27	66.19	0.06214	8.2320	Shallow Concentrated Flow
3.19	963.56	0.02314	5.0234	Channel Flow
51.09	**1,740.17**	**Total**	**Lag Time = 30.66 minutes**	




Sub-23
Jun-18
Reach-23
Jun-17

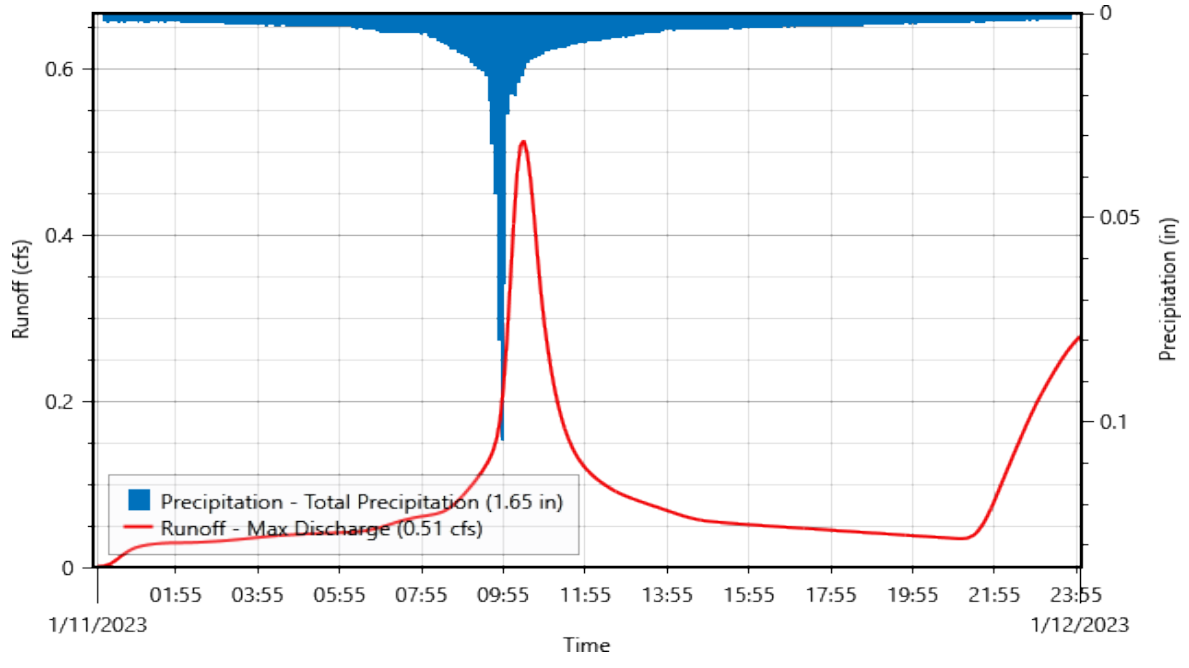
Subbasin ID:	Sub-24		Depth	Volume
Scenario:	Proposed Development 10 yr			
Peak discharge:	0.51 cfs	**Time of peak:**	11 Jan 2023, 10:25	
Drainage area:	662.076 acres	**Total rainfall:**	1.65 in	91.03600 ac-ft
Initial abstraction:	1.57 in	**Losses:**	1.65 in	90.85486 ac-ft
Curve Number:	56.09	**Precip excess:**	0.00 in	0.18114 ac-ft
Impervious surface:	%	**Direct runoff:**	0.00 in	0.16 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	0.00 minutes	**Total runoff:**	0.00 in	0.16 ac-ft

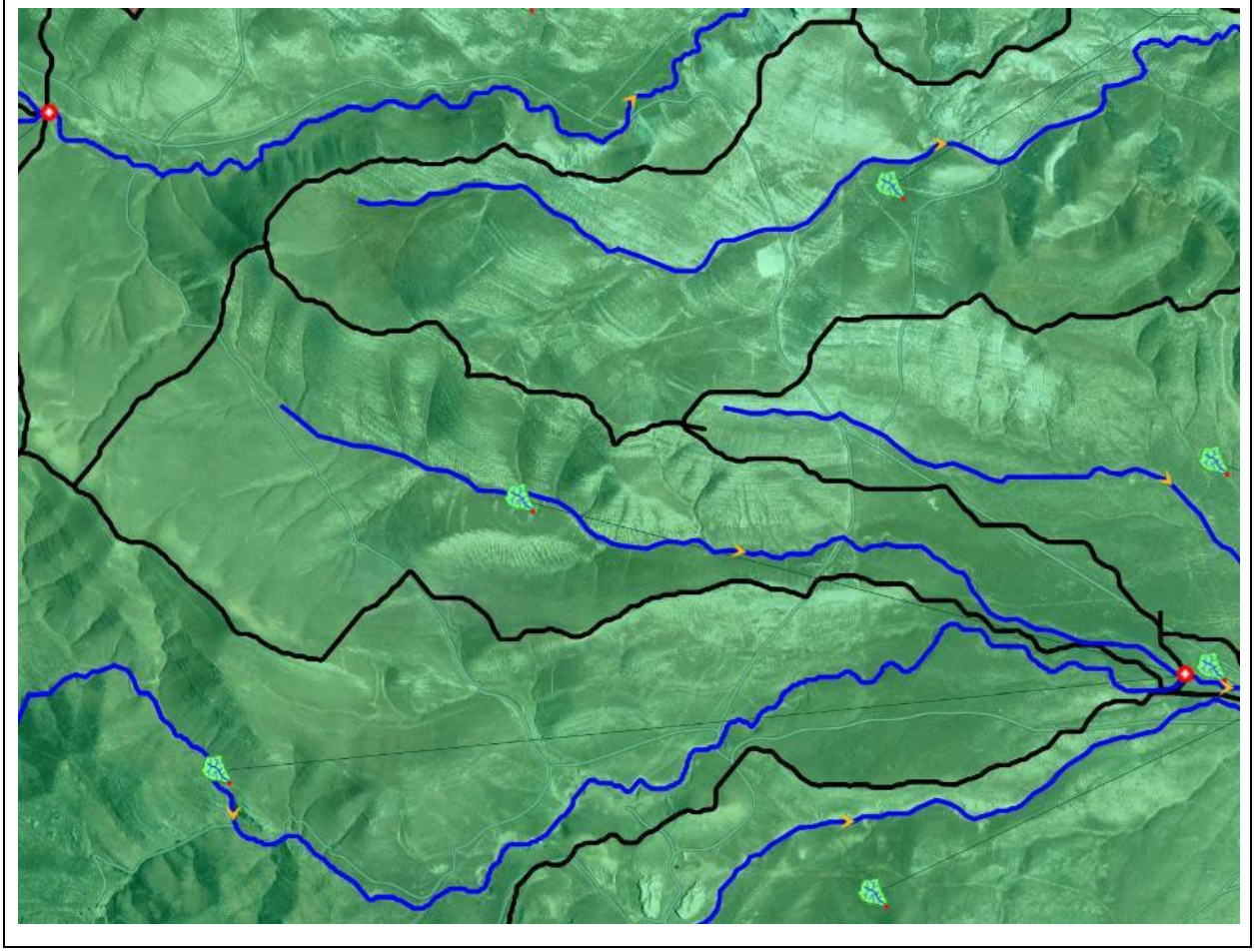
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
0.098	0.01	30.00	Undeveloped, Shrub/Scrub
37.733	5.70	67.01	Developed, Open Space
624.245	94.29	55.43	Undeveloped, Grassland
662.076	**100.00**	**56.09**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
14.40	100.00	0.24257	1.8297	Sheet Flow
1.26	869.08	0.51033	23.5902	Shallow Concentrated Flow
1.44	665.78	0.22832	15.7788	Shallow Concentrated Flow
3.67	1,184.85	0.11132	11.0178	Shallow Concentrated Flow
18.74	7,536.85	0.04100	6.6863	Channel Flow
13.43	4,799.21	0.03234	5.9389	Channel Flow
52.94	**15,155.77**	**Total**	**Lag Time = 31.77 minutes**	





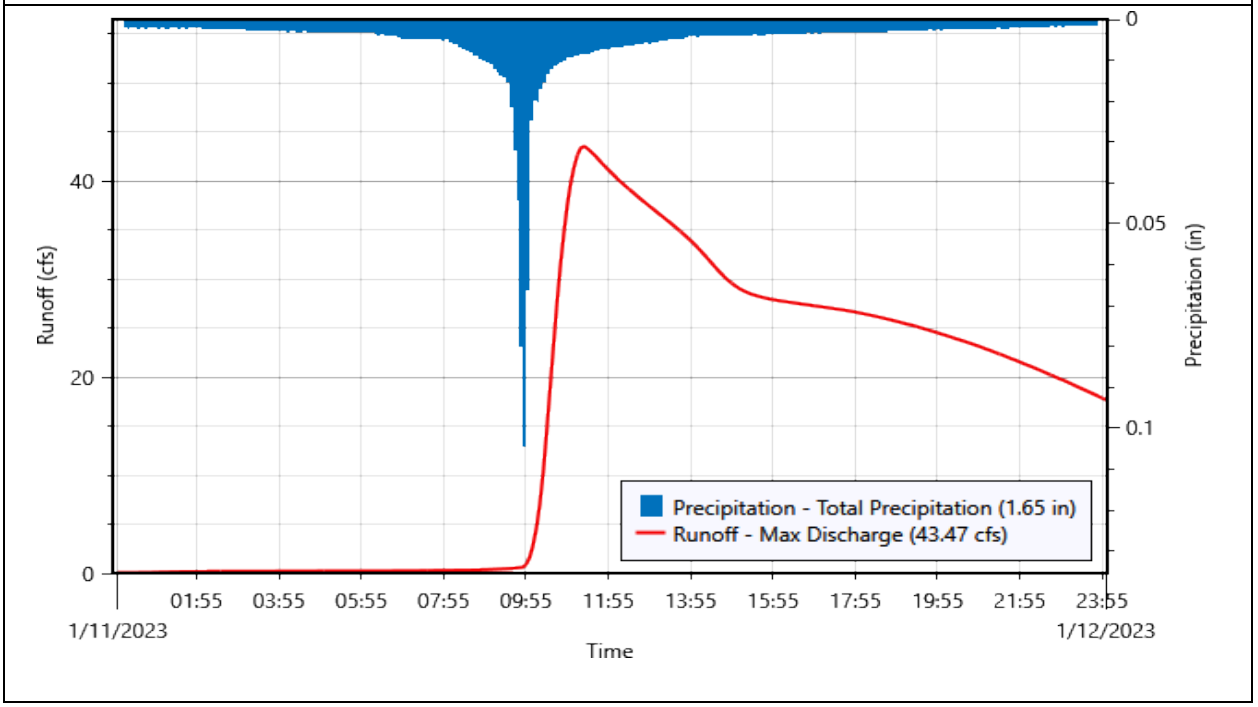
Subbasin ID:	Sub-25			
Scenario:	Proposed Development 10 yr		Depth	Volume
Peak discharge:	43.47 cfs	**Time of peak:**	11 Jan 2023, 11:20	
Drainage area:	1,694.320 acres	**Total rainfall:**	1.65 in	232.97119 ac-ft
Initial abstraction:	0.65 in	**Losses:**	1.41 in	199.33386 ac-ft
Curve Number:	75.41	**Precip excess:**	0.24 in	33.63733 ac-ft
Impervious surface:	%	**Direct runoff:**	0.23 in	32.01 ac-ft
Peaking factor:	484	**Baseflow:**	0.00 in	0.00 ac-ft
Lag time:	0.00 minutes	**Total runoff:**	0.23 in	32.01 ac-ft

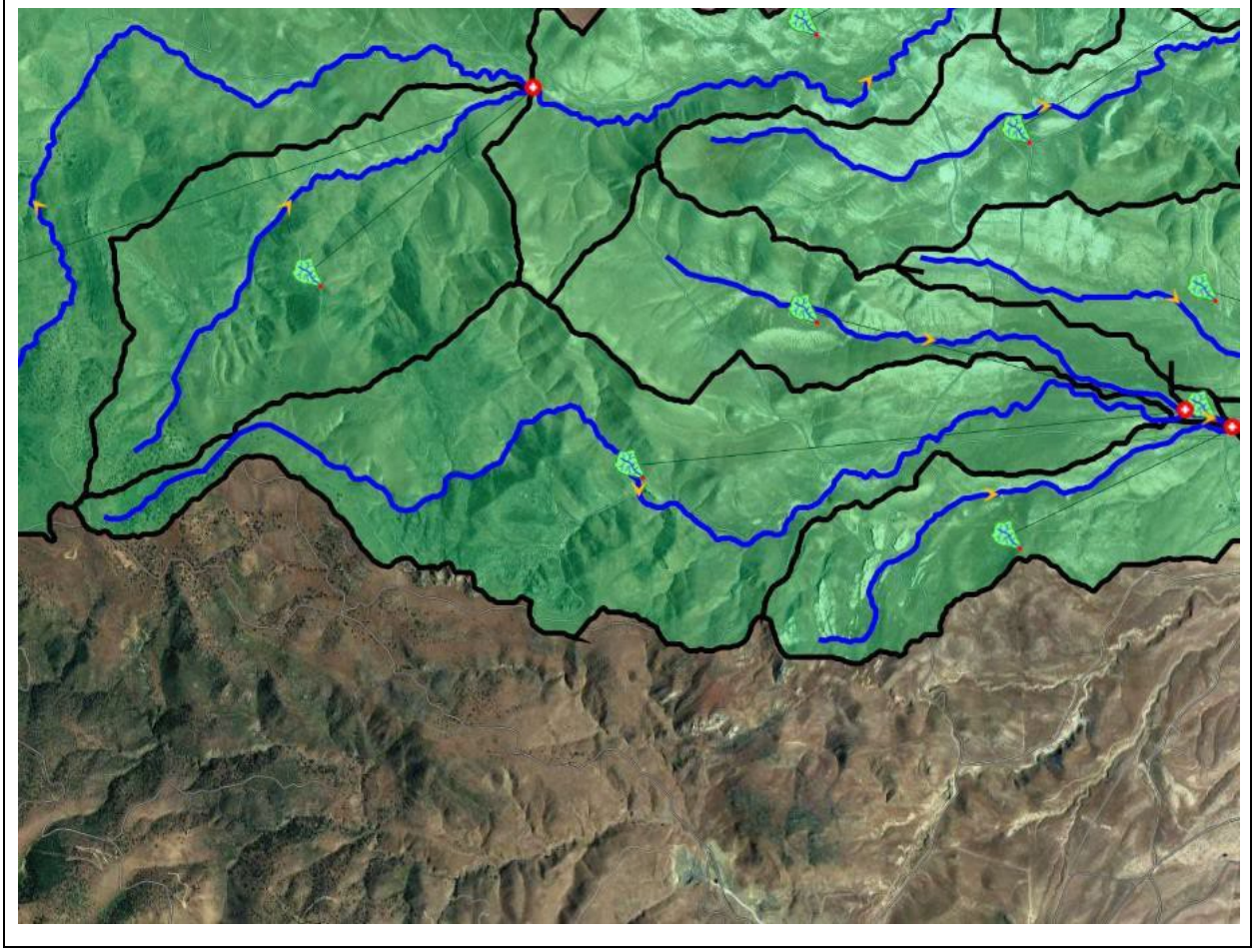
Weighted Curve Number Calculations

Area (acres)	Area (%)	CN	Description
0.589	0.03	91.09	Developed, Medium Density
343.072	20.25	72.37	Undeveloped, Shrub/Scrub
1.038	0.06	86.45	Developed, Low Density
128.369	7.58	82.02	Developed, Open Space
1,221.252	72.08	75.55	Undeveloped, Grassland
1,694.320	**100.00**	**75.41**	**Weighted Average**

Time of Concentration (TOC) / Lag time Calculations

TOC (min)	Length (ft)	Slope (ft/ft)	Velocity (ft/s)	Description
23.14	100.00	0.07413	1.0115	Sheet Flow
2.26	773.43	0.12489	11.6701	Shallow Concentrated Flow
2.16	1,933.44	0.20208	14.8446	Channel Flow
10.49	5,320.75	0.06516	8.4296	Channel Flow
3.64	2,816.87	0.15175	12.8636	Channel Flow
20.32	9,127.19	0.05113	7.4670	Channel Flow
27.81	10,228.78	0.03427	6.1135	Channel Flow
89.82	**30,300.46**	**Total**	**Lag Time = 53.90 minutes**	





Nodes

Element ID	Element Type	Peak Inflow (cfs)	Peak Outflow (cfs)	Peak Diverted Flow (cfs)
Jun-01	Junction	23.68	23.68	
Jun-02	Junction	19.94	19.94	
Jun-03	Junction	19.95	19.95	
Jun-04	Junction	14.58	14.58	
Jun-05	Junction	14.71	14.71	
Jun-06	Junction	82.75	82.75	
Jun-07	Junction	79.89	79.89	
Jun-08	Junction	75.09	75.09	
Jun-09	Junction	7.00	7.00	
Jun-10	Junction	2.46	2.46	
Jun-11	Junction	70.51	70.51	
Jun-12	Junction	70.31	70.31	
Jun-13	Junction	65.72	65.72	
Jun-14	Junction	61.52	61.52	
Jun-15	Junction	59.52	59.52	
Jun-16	Junction	58.07	58.07	
Jun-17	Junction	56.37	56.37	
Jun-18	Junction	43.65	43.65	

Nodes

Reach ID	Peak Inflow (cfs)	Peak Outflow (cfs)	Attenuated Flow (cfs)
Reach-01	19.94	19.73	0.21
Reach-02	19.95	19.91	0.04
Reach-03	0.00	0.00	0.00
Reach-04	0.00	0.00	0.00
Reach-05	0.00	0.00	0.00
Reach-06	0.00	0.00	0.00
Reach-07	79.89	79.89	0.00
Reach-08	75.09	75.08	0.01
Reach-09	7.00	6.24	0.76
Reach-10	0.00	0.00	0.00
Reach-11	2.46	1.58	0.88
Reach-12	0.00	0.00	0.00
Reach-13	70.51	70.47	0.04
Reach-14	70.31	70.30	0.01
Reach-15	0.00	0.00	0.00
Reach-16	0.00	0.00	0.00
Reach-17	61.52	61.52	0.00
Reach-18	59.52	57.51	2.01
Reach-19	58.07	57.83	0.24
Reach-20	0.00	0.00	0.00
Reach-21	56.37	56.05	0.32
Reach-22	0.00	0.00	0.00
Reach-23	43.65	43.56	0.09
Reach-24	0.00	0.00	0.00
Reach-25	0.00	0.00	0.00

Appendix D Scour Calculations

Potential Produced Water Line

Location: Chico Martinez Creek north of Roustabout Rd County

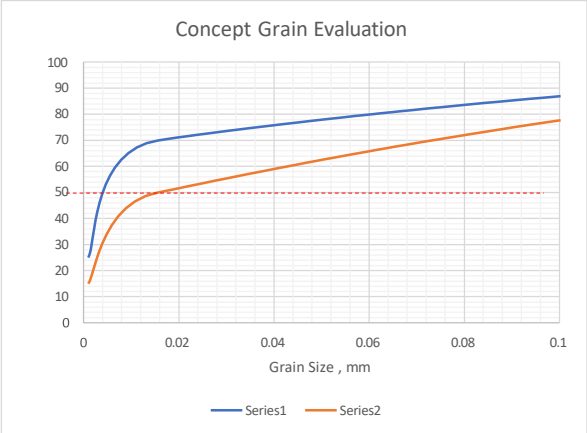
Sediment Evaluation



Typical Soil Profile in Area of Crossing

Soil Series: Panoche
Decription: Panoche loam

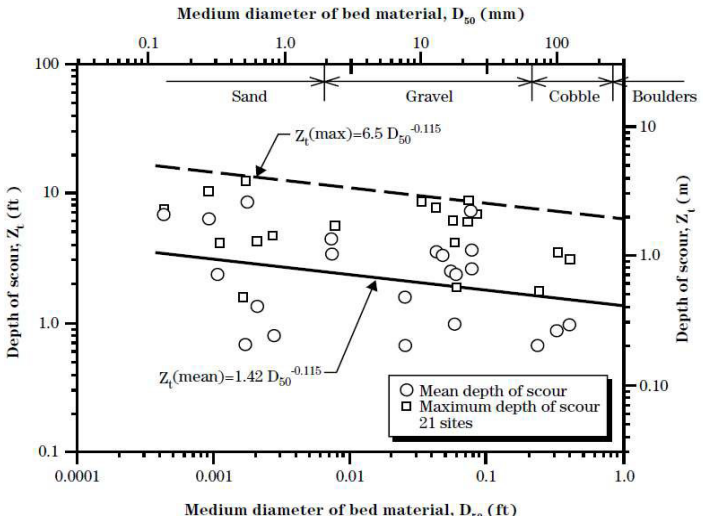
			Percent			
Profile	**Depth, in**	**Description**	**Gravel**	**Sand**	**Silt**	**Clay**
Ap	0 to 7	loam	0	23-52	28-50	7-27
Bw	7 to 24	loam	0	23-52	28-50	7-27
Bk	24 to 60	loam	0	23-52	28-50	7-27



General Scour

Method 1 Per Blodgett (1986)

Figure TS14B–1 Scour observations from typical reaches of alluvial rivers



z_t (mean) = $KD_{50}^{-0.1}$

K^t=	1.42	
D_{50} =	0.004	mm
z_t (mean) =	2.47	ft

z_t (max) = $KD_{50}^{-0.11}$

K =	6.5	
D_{50} =	0.004	mm
z_t (max) =	11.93	ft

Method 2 per Pemberton and Lara (1984)

$z_t = KQ_d^a W_f^b D^c$

Where:

z_t =	maximum sour depth at the cross section, ft	
K =	Coefficient (table TS14B-8)	0.195
Q_d =	design discharge, cfs	688.43
W_f =	flow width at design discharge, ft	110
D_{50} =	median size of bed material, mm	0.004
a, b, c =	exponents (table TS14B-8)	0.3333333 (a), 0 (b), -0.16667 (c) Lacey

Table TS14B–8 Constants for Lacey and Blench relations, U.S. units (D_{50} in mm)

Condition	Lacey				Blench			
	K	a	b	c	K	a	b	c
Straight reach	0.097	1/3	0	–1/6	0.530	2/3	–2/3	–0.1092
Moderate bend	0.195	1/3	0	–1/6	0.530	2/3	–2/3	–0.1092
Severe bend	0.292	1/3	0	–1/6	0.530	2/3	–2/3	–0.1092
Right angle bend	0.389	1/3	0	–1/6	1.105	2/3	–2/3	–0.1092
Vertical rock wall	0.487	1/3	0	–1/6				

Lacey

zt = 4.32 ft

Blench

K =	Coefficient (table TS14B-8)	
Q_d =	design discharge, cfs	
W_f =	flow width at design discharge, ft	
D_{50} =	median size of bed material, mm	
a, b, c =	exponents (table TS14B-8)	

z_t = 3.29 ft

0.53		
688.43		
110		Blench
0.004		
0.6666667 (a)	-0.66667 (b)	-0.1092 (c)

Blench

Conclusion

Scour estimates range from 3.29 to 11.93

Use Blodgett (Method 1) 11.93

Estimated General Scour = 12.0 feet

Potential Produced Water Line

Location: Chico Martinez Creek north of Roustabout Rd County Kern

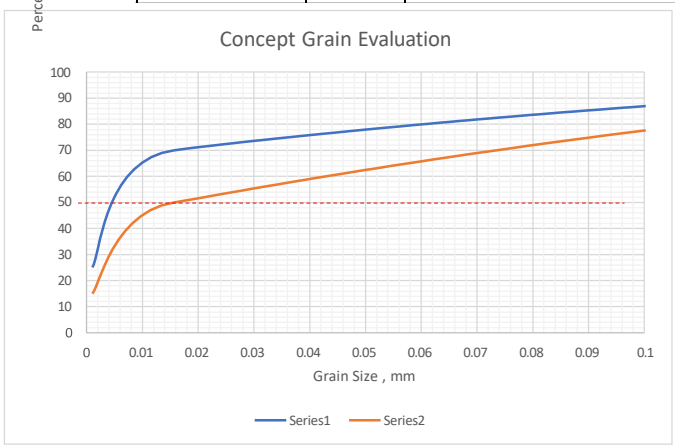
Sediment Evaluation



Typical Soil Profile in Area of Crossing

Soil Series: Panoche
Decription: Panoche loam

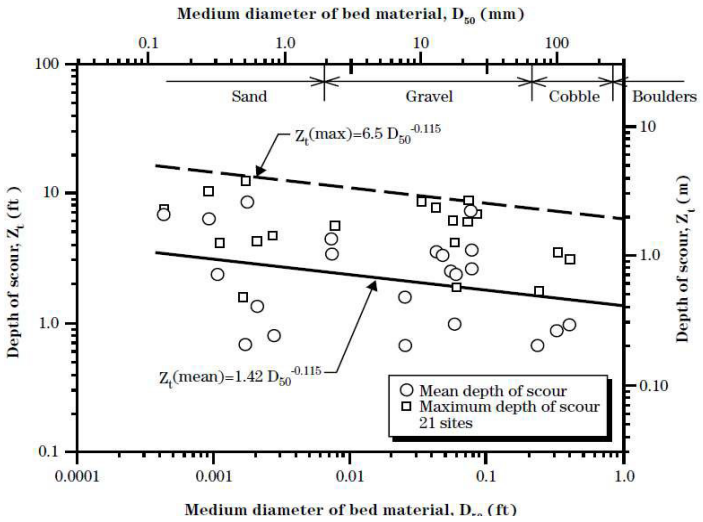
Profile	Depth, in	Description	Percent Gravel	Sand	Silt	Clay
Ap	0 to 7	loam	0	23-52	28-50	7-27
Bw	7 to 24	loam	0	23-52	28-50	7-27
Bk	24 to 60	loam	0	23-52	28-50	7-27



General Scour

Method 1 Per Blodgett (1986)

Figure TS14B–1 Scour observations from typical reaches of alluvial rivers



z_t (mean) = $KD_{50}^{-0.1}$

K =	1.42	
D_{50} =	0.004	mm
z_t (mean) =	2.47	ft

z_t (max) = $KD_{50}^{-0.11}$

K =	6.5	
D_{50} =	0.004	mm
z_t (max) =	11.93	ft

Method 2 per Pemberton and Lara (1984)

$z_t = KQ_d^a W_f^b D^c$

Where:

z_t =	maximum sour depth at the cross section, ft	
K =	Coefficient (table TS14B-8)	0.195
Q_d =	design discharge, cfs	82.75
W_f =	flow width at design discharge, ft	30
D_{50} =	median size of bed material, mm	0.004
a, b, c =	exponents (table TS14B-8)	0.3333333 (a) 0 (b) -0.16667 (c) Lacey

Table TS14B–8 Constants for Lacey and Blench relations, U.S. units (D_{50} in mm)

Condition	Lacey				Blench			
	K	a	b	c	K	a	b	c
Straight reach	0.097	1/3	0	–1/6	0.530	2/3	–2/3	–0.1092
Moderate bend	0.195	1/3	0	–1/6	0.530	2/3	–2/3	–0.1092
Severe bend	0.292	1/3	0	–1/6	0.530	2/3	–2/3	–0.1092
Right angle bend	0.389	1/3	0	–1/6	1.105	2/3	–2/3	–0.1092
Vertical rock wall	0.487	1/3	0	–1/6				

Lacey

zt = 2.13 ft

Blench

K =	Coefficient (table TS14B-8)	
Q_d =	design discharge, cfs	
W_f =	flow width at design discharge, ft	
D_{50} =	median size of bed material, mm	
a, b, c =	exponents (table TS14B-8)	

z_t = 1.91 ft

0.53
82.75
30
0.004
0.6666667 (a) -0.66667 (b) -0.1092 (c) Blench

Blench

Conclusion

Scour estimates range from 1.91 to 11.93

Use Blodgett (Method 1) 11.93

Estimated General Scour = 12.0 feet

Tulare CVR to GP32

Location: Chico Martinez Creek south of Entrance A Road County Kern

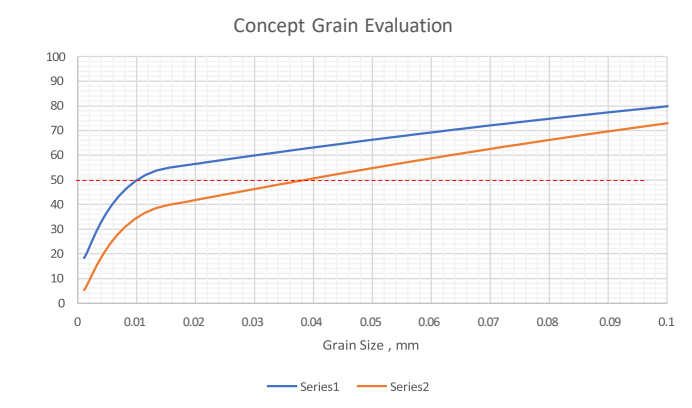
Sediment Evaluation

NO PICTURE AVAILABLE

Percent Passing

Typical Soil Profile in Area of Crossing

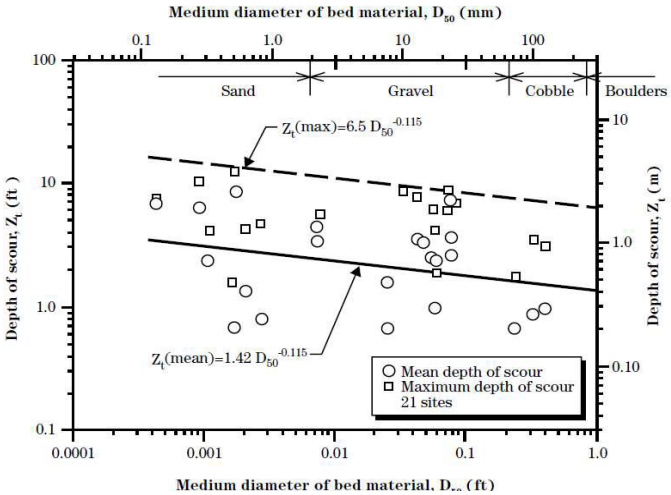
Soil Series:	Kimberlina					
Decription:	Kimberlina Fine Sandy Loam		Percent			
Profile	**Depth, in**	**Description**	**Gravel**	**Sand**	**Silt**	**Clay**
Ap	0 to 9	fine sandy loam	0	50-70	0-50	0-20
C1	9 to 31	fine sandy loam	0	50-70	0-50	0-20
C2	31 to 45	fine sandy loam	0	50-70	0-50	0-20
2C3	45 to 71	silt loam	0	20-50	74-88	0-27



General Scour

Method 1 Per Blodgett (1986)

Figure TS14B–1 Scour observations from typical reaches of alluvial rivers



$z_t(mean) = KD_{50}^{-0.1}$

K =	1.42	
D_{50} =	0.010	mm
z_t (mean) =	2.25	ft

$z_t(max) = KD_{50}^{-0.11}$

K =	6.5	
D_{50} =	0.010	mm
z_t (max) =	10.79	ft

Method 2 per Pemberton and Lara (1984)

$z_t = KQ_d{}^a W_f{}^b D_{50}{}^c$

Where:

z_t =	maximum sour depth at the cross section, ft
K =	Coefficient (table TS14B-8)
Q_d =	design discharge, cfs
W_f =	flow width at design discharge, ft
D_{50} =	median size of bed material, mm
a, b, c =	exponents (table TS14B-8)

0.195			
668.08			
265			
0.010			
0.33333333	0	-0.16667	Lacey
a	b	c	

Table TS14B–8 Constants for Lacey and Blench relations, U.S. units (D_{50} in mm)

Condition	Lacey				Blench			
	K	a	b	c	K	a	b	c
Straight reach	0.097	1/3	0	–1/6	0.530	2/3	–2/3	–0.1092
Moderate bend	0.195	1/3	0	–1/6	0.530	2/3	–2/3	–0.1092
Severe bend	0.292	1/3	0	–1/6	0.530	2/3	–2/3	–0.1092
Right angle bend	0.389	1/3	0	–1/6	1.105	2/3	–2/3	–0.1092
Vertical rock wall	0.487	1/3	0	–1/6				

Lacey

zt =	3.67	ft

Blench

K =	Coefficient (table TS14B-8)
Q_d =	design discharge, cfs
W_f =	flow width at design discharge, ft
D_{50} =	median size of bed material, mm
a, b, c =	exponents (table TS14B-8)

z_t =	1.62	ft

Blench

0.53			
668.08			
265			
0.010			
0.66666667	-0.66667	-0.1092	
a	b	c	

Blench

Conclusion

Scour estimates range from 1.62 to 10.79

Use Blodgett (Method 1) 10.79

Estimated General Scour =	11.0	feet

Tulare CVR to GP32

Location: Chico Martinez Creek south of Entrance A Road County Kern

Sediment Evaluation

NO PICTURE AVAILABLE

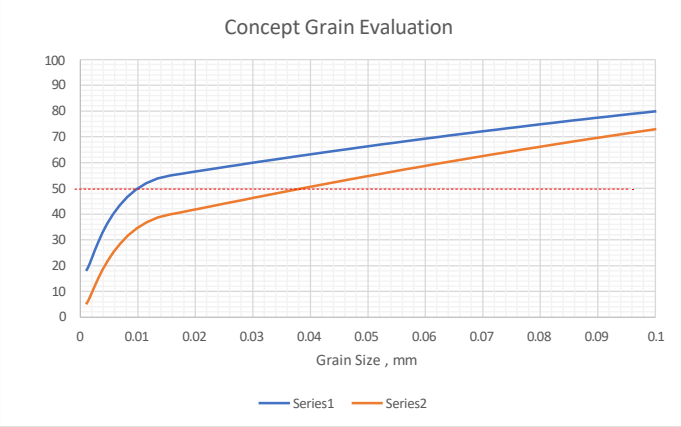
Percent Passing

Typical Soil Profile in Area of Crossing

Soil Series: Kimberlina

Decription: Kimberlina Fine Sandy Loam

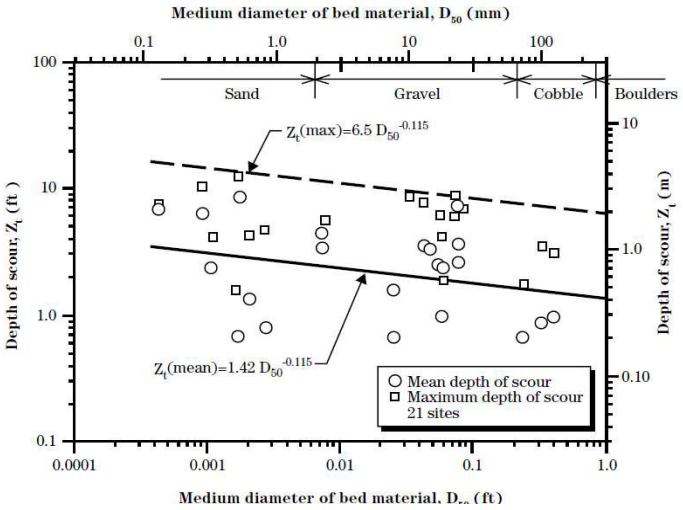
Profile	Depth, in	Description	Percent Gravel	Sand	Silt	Clay
Ap	0 to 9	fine sandy loam	0	50-70	0-50	0-20
C1	9 to 31	fine sandy loam	0	50-70	0-50	0-20
C2	31 to 45	fine sandy loam	0	50-70	0-50	0-20
2C3	45 to 71	silt loam	0	20-50	74-88	0-27



General Scour

Method 1 Per Blodgett (1986)

Figure TS14B–1 Scour observations from typical reaches of alluvial rivers



$z_t(mean) = KD_{50}^{-0.1}$

K =	1.42	
D_{50} =	0.010	mm
z_t (mean) =	2.25	ft

$z_t(max) = KD_{50}^{-0.11}$

K =	6.5	
D_{50} =	0.010	mm
z_t (max) =	10.79	ft

Method 2 per Pemberton and Lara (1984)

$z_t = KQ_d^a W_f^b D^c$

Where:

z_t =	maximum sour depth at the cross section, ft	
K =	Coefficient (table TS14B-8)	0.195
Q_d =	design discharge, cfs	75.09
W_f =	flow width at design discharge, ft	109
D_{50} =	median size of bed material, mm	0.010
a, b, c =	exponents (table TS14B-8)	0.33333333 (a) 0 (b) -0.16667 (c) Lacey

Table TS14B–8 Constants for Lacey and Blench relations, U.S. units (D_{50} in mm)

Condition	Lacey				Blench			
	K	a	b	c	K	a	b	c
Straight reach	0.097	1/3	0	–1/6	0.530	2/3	–2/3	–0.1092
Moderate bend	0.195	1/3	0	–1/6	0.530	2/3	–2/3	–0.1092
Severe bend	0.292	1/3	0	–1/6	0.530	2/3	–2/3	–0.1092
Right angle bend	0.389	1/3	0	–1/6	1.105	2/3	–2/3	–0.1092
Vertical rock wall	0.487	1/3	0	–1/6				

Lacey

zt = 1.77 ft

Blench

K =	Coefficient (table TS14B-8)
Q_d =	design discharge, cfs
W_f =	flow width at design discharge, ft
D_{50} =	median size of bed material, mm
a, b, c =	exponents (table TS14B-8)

z_t = 0.68 ft

0.53	
75.09	
109	
0.010	Blench
0.66666667 (a)	-0.66667 (b) -0.1092 (c)

Blench

Conclusion

Scour estimates range from 0.68 to 10.79

Use Blodgett (Method 1) 10.79

Estimated General Scour = 11.0 feet

Existing Del Sur Gas Line

Location: Chico Martinez Creek north of 7th Standard Road County Kern

Sediment Evaluation

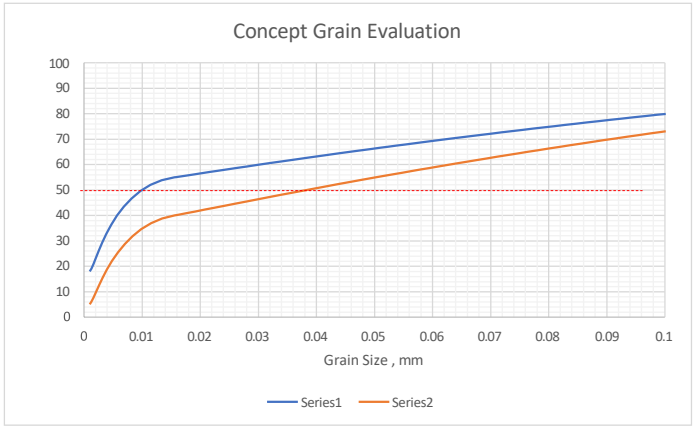


Typical Soil Profile in Area of Crossing

Soil Series: Kimberlina

Decription: Kimberlina Fine Sandy Loam

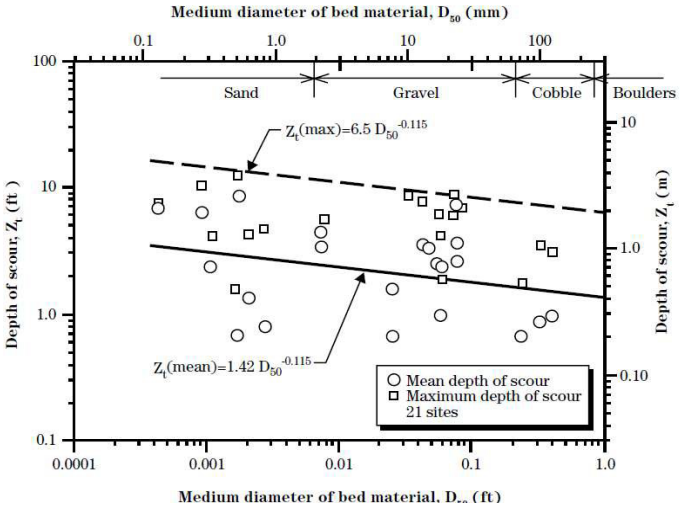
Profile	Depth, in	Description	Percent Gravel	Sand	Silt	Clay
Ap	0 to 9	fine sandy loam	0	50-70	0-50	0-20
C1	9 to 31	fine sandy loam	0	50-70	0-50	0-20
C2	31 to 45	fine sandy loam	0	50-70	0-50	0-20
2C3	45 to 71	silt loam	0	20-50	74-88	0-27



General Scour

Method 1 Per Blodgett (1986)

Figure TS14B–1 Scour observations from typical reaches of alluvial rivers



$z_t(mean) = KD_{50}^{-0.1}$

K=	1.42	
D_{50} =	0.010	mm
z_t (mean) =	2.25	ft

$z_t(max) = KD_{50}^{-0.11}$

K =	6.5	
D_{50} =	0.010	mm
z_t (max) =	10.79	ft

Method 2 per Pemberton and Lara (1984)

$z_t = KQ_d^a W_f^b D^c$

Where:

z_t =	maximum sour depth at the cross section, ft	
K =	Coefficient (table TS14B-8)	0.195
Q_d =	design discharge, cfs	668.08
W_f =	flow width at design discharge, ft	264
D_{50} =	median size of bed material, mm	0.010
a, b, c =	exponents (table TS14B-8)	0.3333333 (a) 0 (b) -0.16667 (c) Lacey

Table TS14B–8 Constants for Lacey and Blench relations, U.S. units (D_{50} in mm)

Condition	Lacey				Blench			
	K	a	b	c	K	a	b	c
Straight reach	0.097	1/3	0	–1/6	0.530	2/3	–2/3	–0.1092
Moderate bend	0.195	1/3	0	–1/6	0.530	2/3	–2/3	–0.1092
Severe bend	0.292	1/3	0	–1/6	0.530	2/3	–2/3	–0.1092
Right angle bend	0.389	1/3	0	–1/6	1.105	2/3	–2/3	–0.1092
Vertical rock wall	0.487	1/3	0	–1/6				

Lacey

zt = 3.67 ft

Blench

K =	Coefficient (table TS14B-8)	
Q_d =	design discharge, cfs	
W_f =	flow width at design discharge, ft	
D_{50} =	median size of bed material, mm	
a, b, c =	exponents (table TS14B-8)	

z_t = 1.63 ft

0.53		
668.08		
264		
0.010		Blench
0.6666667 (a)	-0.66667 (b)	-0.1092 (c)

Blench

Conclusion

Scour estimates range from 1.63 to 10.79

Use Blodgett (Method 1) 10.79

Estimated General Scour = 11.0 feet

Existing Del Sur Gas Line

Location: Chico Martinez Creek north of 7th Standard Road County Kern

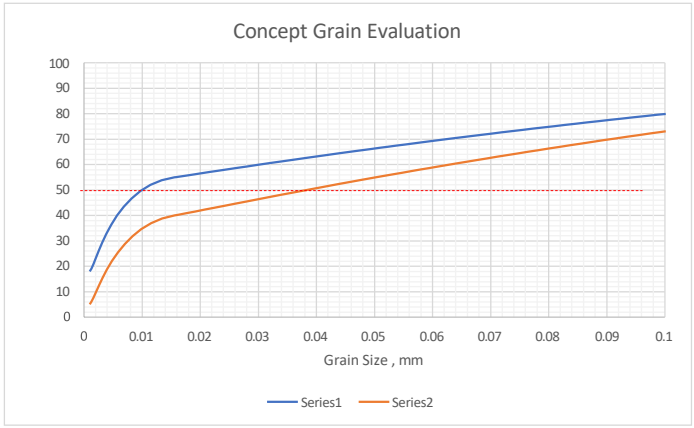
Sediment Evaluation



Typical Soil Profile in Area of Crossing

Soil Series: Kimberlina
Decription: Kimberlina Fine Sandy Loam

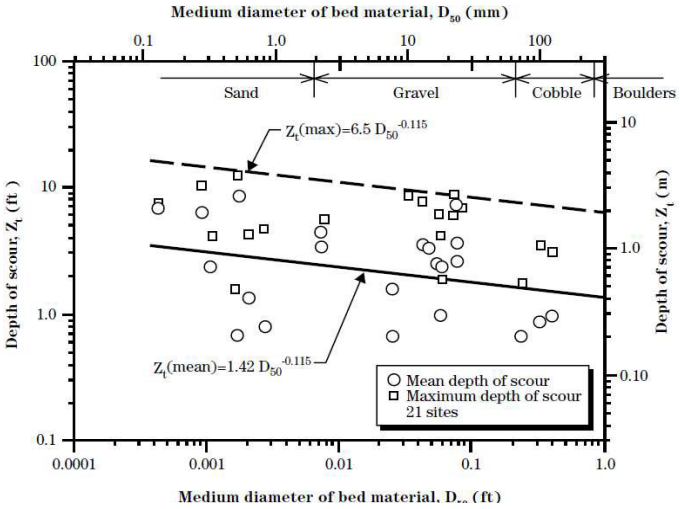
Profile	Depth, in	Description	Percent Gravel	Sand	Silt	Clay
Ap	0 to 9	fine sandy loam	0	50-70	0-50	0-20
C1	9 to 31	fine sandy loam	0	50-70	0-50	0-20
C2	31 to 45	fine sandy loam	0	50-70	0-50	0-20
2C3	45 to 71	silt loam	0	20-50	74-88	0-27



General Scour

Method 1 Per Blodgett (1986)

Figure TS14B–1 Scour observations from typical reaches of alluvial rivers



$z_t(mean) = KD_{50}^{-0.1}$

K=	1.42	
D_{50} =	0.010	mm
z_t (mean) =	2.25	ft

$z_t(max) = KD_{50}^{-0.11}$

K =	6.5	
D_{50} =	0.010	mm
z_t (max) =	10.79	ft

Method 2 per Pemberton and Lara (1984)

$z_t = KQ_d^a W_f^b D^c$

Where:

z_t =	maximum sour depth at the cross section, ft	
K =	Coefficient (table TS14B-8)	0.195
Q_d =	design discharge, cfs	75.09
W_f =	flow width at design discharge, ft	181
D_{50} =	median size of bed material, mm	0.010
a, b, c =	exponents (table TS14B-8)	0.3333333 (a), 0 (b), -0.16667 (c) Lacey

Table TS14B–8 Constants for Lacey and Blench relations, U.S. units (D_{50} in mm)

Condition	Lacey				Blench			
	K	a	b	c	K	a	b	c
Straight reach	0.097	1/3	0	–1/6	0.530	2/3	–2/3	–0.1092
Moderate bend	0.195	1/3	0	–1/6	0.530	2/3	–2/3	–0.1092
Severe bend	0.292	1/3	0	–1/6	0.530	2/3	–2/3	–0.1092
Right angle bend	0.389	1/3	0	–1/6	1.105	2/3	–2/3	–0.1092
Vertical rock wall	0.487	1/3	0	–1/6				

Lacey

zt = 1.77 ft

Blench

K =	Coefficient (table TS14B-8)
Q_d =	design discharge, cfs
W_f =	flow width at design discharge, ft
D_{50} =	median size of bed material, mm
a, b, c =	exponents (table TS14B-8)

z_t = 0.49 ft

0.53 (a), 75.09, 181, 0.010, 0.6666667 (a), -0.66667 (b), -0.1092 (c) Blench

Blench

Conclusion

Scour estimates range from 0.49 to 10.79

Use Blodgett (Method 1) 10.79

Estimated General Scour = 11.0 feet

G.2 Water Supply Assessment

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AERA CARBONFRONTIER PROJECT

Water Supply Assessment

July 19, 2023

Prepared for:

Aera Energy LLC
10000 Ming Avenue
Bakersfield, CA 93311

Prepared by:

Stantec Consulting Services Inc.
2646 Santa Maria Way, Suite 107
Santa Maria, CA 93455

Project No.: 158505372

This document entitled Aera CarbonFrontier Project Water Supply Assessment was prepared by Stantec Consulting Services Inc. (“Stantec”) for the account of Aera Energy LLC (the “Applicant”). Any reliance on this document by any third party is strictly prohibited. The material in it reflects Stantec’s professional judgment in light of the scope, schedule and other limitations stated in the document and in the contract between Stantec and the Client. The opinions in the document are based on conditions and information existing at the time the document was published and do not take into account any subsequent changes. In preparing the document, Stantec did not verify information supplied to it by others. Any use which a third party makes of this document is the responsibility of such third party. Such third party agrees that Stantec shall not be responsible for costs or damages of any kind, if any, suffered by it or any other third party as a result of decisions made or actions taken based on this document.

Prepared by _____

Thomas M. Regan, Hydrogeologist

Reviewed by _____

Thomas M. Regan, Technical Reviewer

Approved by _____

Eric Snelling, Project Manager

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Executive Summary

Stantec Consulting Services Inc. (Stantec) completed a Water Supply Assessment (WSA) report on behalf of Aera Energy LLC (Aera) for the construction and operation of the Aera CarbonFrontier Project (Project). This WSA was conducted in conformance with the requirements of the California Water Code (Water Code), as amended in 2002 by the passage of Senate Bill (SB) 610, except as may have been modified by the scope of work and terms and conditions requested by Aera.

The Project would consist of 49 parcels, totaling approximately 13,243 gross acres of privately owned land parcels predominately developed with oil and gas production and accessory facilities and infrastructure within the South Belridge Oil Field and North Belridge Oil Field in unincorporated Kern County, California. The proposed carbon dioxide (CO_2) sequestration field would be located in the North Belridge Oil Field and would occupy approximately 2,636 acres of land (lateral extent of CO_2 plume).

The Project is located in the San Joaquin Valley portion of western Kern County about seven miles southwest of the community of Lost Hills and about 40 miles west-northwest of Bakersfield. The Project would be bordered on the east by State Route (SR) 33 and on the west, south and north by oil field land parcels and grazing land. The CO_2 generated by the Project would be injected into a designated underground sequestration zone, known as the 64 Zone at depths of approximately 8,500 feet below ground surface.

Aera is seeking approval of a land use application package to the Kern County Planning and Natural Resources Department (Kern County) for a Zone Classification Change and Conditional Use Permit (CUP), and any other required approvals, if any, for the construction and operation of a CCS Project. The Applicant proposes to construct, own, and operate the Project and would also obtain Underground Injection Control (UIC) Class VI injection well permits from the U.S. Environmental Protection Agency (EPA). Stantec analyzed water supplies available to serve the Project, including the water demand anticipated during construction and through operation of the Project facilities.

According to the requirements of Water Code Section 10910(c)(3) the WSA shall include a discussion of, “whether the public water system’s total projected water supplies available will meet the projected water demand associated with proposed Project, in addition to the public water system’s existing and planned future uses.” In summary:

- The Project will be under environmental review pursuant to the requirements of California Environmental Quality Act (CEQA); therefore, the information contained in this assessment will be used to support the analysis contained in the CEQA document.
- The Project meets the definition of a “Project” under Water Code Section 10912(a).
- The Project is located in portions of multiple sections in Townships 27, 28 and 29 South and Ranges 20 and 21 East, Mount Diablo Base and Meridian.

- Portions of the Project are located within the service area of the Belridge Water Storage District (BWSD) which relies on imported State Water Project (SWP) surface water supplies from the California Aqueduct purchased through Kern County Water Agency (KCWA), a State Water Contractor, to meet the water supply needs of its Water Users (BWSD, 2020). BWSD predominantly delivers SWP water to Water Users for agricultural purposes but also provides a small amount of water for industrial use in oil recovery operations at the North Belridge Oil Field and South Belridge Oil Field (Aquilogic, 2022). Buena Vista Water Storage District (BVWSD) relies on Kern River water and to a much lesser extent on purchased SWP water from KCWA. Like BWSD, BVWSD delivers most of their surface water supplies for agricultural use. BWSD has a Table A entitlement of 121,508 acre-feet per year (afy) of SWP water; however, annual allocations and deliveries vary significantly from year to year based on water supply conditions in the State, SWP water conveyance facilities maintenance and Endangered Species Act requirements, the latter as described in *Biological Assessment on the Long-Term Operations, Criteria and Plan for the Central Valley Project and State Water Project* (U.S. Bureau of Reclamation, 2008) and taking into account subsequent Biological Opinions with Reasonable and Prudent Alternative actions prepared by the U.S. Fish and Wildlife Service (USFWS) (USFWS, 2008) and the National Marine Fisheries Service (NMFS, 2009, 2019). BVWSD has a Kern River entitlement of 156,000 afy which varies from year to year based on hydrologic conditions in the Kern River watershed. BVWSD also has a Table A entitlement of 21,300 afy and Article 21 entitlement of 3,750 afy of SWP water which varies due to the same conditions affecting BWSD's SWP entitlement. Domestic water demands will be served by Aera's two groundwater wells

- The Project estimates a water demand of approximately 400 acre-feet (af) over an approximate 3-year construction period and an average of up to approximately 1,223 afy (26,000 barrels per day) for the commercial operation.

- Proposed construction water demands for the Project are anticipated to be purchased from existing BWSD SWP entitlements and other existing long-term water contracts with individuals and delivered to the Project Area via BWSD's 415 North Canal and/or 500 Canal and existing pipeline. Aera also has approximately 7,000AF of surplus SWP and Kern River water banked in various groundwater banking projects through the BWSD that may be accessed at any time, subject to the groundwater bank's pumping capacity. Water demands for commercial operation will be provided by treated produced water from Aera.

- Proposed domestic water demands for commercial operation of the Project are estimated to be 21.72 afy and will be provided by two existing Aera-owned groundwater wells located in the BVWSD.

  Groundwater production from these two wells is 707.48 afy and historical demand over the past five years was 685.93 afy. Total projected water demand is estimated to be 690.50 afy which includes the Project's estimated domestic water demand.

- Groundwater pumped from Aera's two groundwater wells would be provided to meet Project domestic water demands. The groundwater pumped would be extracted from the Kern County Subbasin (Subbasin, Department of Water Resources [DWR] Bulletin 118 Subbasin No. 5-

022.14; DWR, 2021) in the San Joaquin Valley Groundwater Basin. The Subbasin occupies the western part of Kern County in the San Joaquin Valley.

- The Subbasin has been designated as a critically overdrafted high-priority basin by the Department of Water Resources (DWR) (https://gis.water.ca.gov/app/bp-dashboard/final/# accessed January 8, 2022). Five Groundwater Sustainability Plans (GSPs) representing 11 Groundwater Sustainability Agencies (GSAs) were submitted to DWR as required under the Sustainable Groundwater Management Act (SGMA). The five GSPs were prepared by a combined 11 GSAs and including 16 member agencies in the Kern Groundwater Authority (KGA) GSP to sustainably manage the Subbasin under the SGMA. The Project Area is located within the Westside District Water Authority (WDWA) plan area of the KGA GSP (Aquilogic, 2022; GEI, 2022a). A GSP chapter was prepared for the WDWA by Aquilogic (2022), a member agency of the KGA. The WDWA includes the BWSD, Berenda Mesa Water District (BMWD) and Lost Hills Water District (LHWD) in northwestern Kern County.

- Aera's groundwater wells are located in the BVGSA, which is a member agency of the KGA. A GSP chapter was prepared for the BVGSA (GEI, 2022b) and incorporated in the KGA "Umbrella" GSP (GEI, 2022a). The BVGSA corresponds to the BVWSD service area and includes a subset of the BVWSD called the Buttonwillow Management Area (BMA). The BMA occupies 91% percent of the BVWSD service area while the Maples Management Area is non-contiguous and is included in the Kern River GSA GSP (GEI, 2022b). Because the BMA portion of the BVWSD and BVGSA contains Aera's groundwater wells this WSA addresses water supply conditions in the BMA portion of the BVGSA.

- According to the WDWA GSP chapter (Aquilogic, 2022), groundwater production in the WDWA plan area for Water Year (WY)1995 to WY2014 (historical condition) is estimated to be 3,000 afy. Groundwater production in 2020 in the WDWA is reported to be 10,276 af based on the 2020 Agricultural Management Plans (AWMPs) for BWSD, BMWD and LHWD (BWSD, 2021; BMWD, 2021; LHWD, 2021).

- According to the BVGSA GSP chapter (GEI, 2022b), groundwater production in the BVGSA plan area for WY1993 to WY2015 (historical condition) is estimated to be 62,742 afy. Groundwater production in 2020 is not available. BVWSD (personal communication, June 30, 2023) estimated the 2040 water demand to be 140,000 af.

- BVWSD is entitled to 156,000 afy of surface water from the Kern River; however, during the period 2006 to 2015 Kern River deliveries via the East Side Canal averaged 40,887 afy. BVWSD is also contracted with the Kern County Water Agency to receive 21,300 afy of Table A SWP water and 3,750 afy of Article 21 SWP water. During the period 2006 through 2015, BVWSD received an average of 53,099 afy of SWP water via the California Aqueduct (GEI, 2022b). Average surface water deliveries from 2006 to 2015 averaged 93,986 afy. Estimated 2020, 2030 and 2070 surface water deliveries to the BVWSD are 164,192 af, 161,306 af and 160,864 af, respectively (GEI, 2022b). The estimated cumulative and annual decline in groundwater in storage in the BVGSA between WY1993 and WY2015 is 275,480 af and 11,977 afy, respectively

(GEI, 2022b). The estimated annual change in ground in storage between WY1995 and WY2014 using the C2VSimFG-Kern groundwater model is -17,362 afy (Todd, 2019).

- According to the BVGSA GSP (GEI, 2022b), under the 2070 climate change factor, BVGSA has estimated a reduced Kern River entitlement of 147,000 af in 2040, a reduced SWP Table A entitlement of 9,642 afy and a slightly increased Article 21 SWP entitlement of 3,900 afy in 2040.
- According to the KGA GSP (GEI, 2022a), groundwater production in the Subbasin for WY1995-WY2014 (historical condition) is estimated to be 1,590,373 af based on a groundwater model simulation using CV2SimFG-Kern (Todd, 2020) in GEI (2022a).
- Projected groundwater production in the WDWA plan area and the Subbasin is projected to increase to 25,400 (Aquilogic, 2022) and 1,648,770 afy (Todd, 2020) in GEI (2022a), respectively, from WY2021 to WY2040, the latter, based on the CV2SimFG-Kern 2070 climate change conditions and implementation of projects and management actions scenario.
- Estimations of the total storage capacity of the Subbasin were reported in DWR (2006) based on data in 2002 to be 40,000,000 af (KCWA, 2002). The dewatered storage at this time was also reported to be 10,000,000 af (KCWA, 2002). The estimated amount of groundwater in storage from WY1995 to WY2014 in the WDWA is reported to be 42,400,000 af (Aquilogic, 2022). However, this latter estimate appears to more closely coincide with the estimated storage capacity of the Subbasin, not the WDWA, as noted above (DWR, 2006; KCWA, 2002).
- Change in groundwater in storage in the Subbasin between WY1995-WY2014 is estimated to have declined by 5,542,280 af based on an annual decline of 277,114 afy (Todd, 2020) in GEI (2022a).
- Change in groundwater in storage in the Subbasin between WY1995-WY2021 is estimated to yield a decline of 1,812,211 af (Todd, 2020) in GEI (2022a) based on an annual decline of 69,700 afy (Todd, 2020) in GEI (2022).
- The projected average and cumulative change in groundwater in storage in the Subbasin from WY2021 to WY2040 is a decline of about 224,286 afy and 4,485,720 af, respectively (Todd, 2020) in GEI (2022a), based on the CV2SimFG-Kern groundwater model simulated 2070 climate change conditions and implementation of projects and management actions scenario.
- The projected annual average decline in the amount of groundwater in storage in the WDWA plan area from WY2021 to WY2040 taking into account 2070 climate change conditions and implementation of projects and management actions is estimated to be 46,000 afy (Todd, 2020) in (GEI, 2022) and revised to approximately 22,000 afy by Aquilogic (2022) based on assumed modeling discrepancies related to the amount of groundwater production using the CV2SimFG-Kern groundwater model simulation.
- The estimated groundwater recharge in the Subbasin and WDWA plan area in WY1995-WY2014 is 1,400,362 afy (Todd, 2020) in GEI (2022) and 92,341 afy (Aquilogic, 2022), respectively, based on CV2SimFG-Kern groundwater modeling simulations (Todd, 2020) in GEI (2022).

- The estimated WY1995-WY2014 sustainable yield in the Subbasin and the WDWA plan area is 1,313,260 afy (Todd, 2020) in GEI (2022) and 34,079 afy (Aquilogic, 2022), respectively.

Abbreviations

°F	degrees Fahrenheit
AC	alternating electrical current
af	acre-feet
afy	acre-feet per year
APN	Assessor's Parcel Number
Applicant	Aera Energy LLC
AWMP	Agricultural Water Management Plan
BWSD	Belridge Water Storage District
BMWD	Berenda Mesa Water District
BVGSA	Buena Vista Groundwater Sustainability Agency
BVWSD	Buena Vista Water Storage District
CASGEM	California Statewide Groundwater Elevation Monitoring
CCS	carbon capture and sequestration
CEQA	California Environmental Quality Act
CUP	conditional use permit
CVP	Central Valley Project
CVR	Casing Vapor Recovery
DWR	California Department of Water Resources
EPA	United States Environmental Protection Agency
ERP	Emergency Response Plan
gpm	gallons per minute
GSA	Groundwater Sustainability Agency
GSP	Groundwater Sustainability Plan
In	inches
KCWA	Kern County Water Agency
KGA	Kern Groundwater Authority
kV	kilovolts
LHWD	Lost Hills Water District

mg/l	Milligram/liter
NGL	Natural gas liquid
NMFS	National Marine Fisheries Service
O&M	operations and maintenance
Post-C	Post-combustion
Pre-C	Pre-combustion
Project	Aera CarbonFrontier Project
ROW	right-of-way
SB	Senate Bill
SGMA	Sustainable Groundwater Management Act of 2014
SMCL	Secondary Drinking Water Maximum Contaminant Levels
SOX	Sulferox
Stantec	Stantec Consulting Services Inc.
SR	State Route
SWP	State Water Project
TDS	Total Dissolved Solids
UIC	Underground Injection Control
USFWS	United States Fish and Wildlife Service
UWMP	Urban Water Management Plan
Water Code	California Water Code
WDWA	Westside District Water Authority
WSA	Water Supply Assessment
WY	Water Year



1.0 INTRODUCTION

Stantec Consulting Services Inc. (Stantec) conducted a water supply assessment on behalf of Aera Energy LLC (Aera) for the Aera CarbonFrontier Project (Project) located in an unincorporated area of Kern County, California. This water supply assessment was conducted in support of the proposed construction and operation of a carbon capture and sequestration (CCS) facility.

1.1 PROJECT DESCRIPTION

Aera has submitted an application to the Kern County Planning and Natural Resources Department to request approval of a Zone Change and Conditional Use Permit (CUP) for the construction and operation of the proposed Project in the South and North Belridge oil fields.

The proposed Project would capture carbon dioxide (CO_2) from existing produced-gas streams (pre-combustion) and emissions from existing stationary sources (post-combustion) and transport the CO_2 through a pipeline to the North Belridge Oil Field for injection via nine dedicated Underground Injection Control (UIC) Class VI injection wells. It is anticipated that the proposed Project would sequester approximately 30 million metric tons of CO_2 throughout its estimated 20-year lifetime[1].

The Project site is primarily contained within the South and North Belridge oil fields, in the Central Valley portion of western Kern County. The South Belridge and North Belridge oil fields are contiguous and cover an area of approximately 13 miles long and three miles wide. The proposed CO_2 capture facilities are located within the developed portion of the South Belridge Oil Field and include the separation, dehydration, compression, and cooling of CO_2 from both pre-combustion (Pre-C) and produced gas streams from post-combustion (Post-C) flue gas. The proposed CO_2 sequestration field is located within the North Belridge Oil Field, which is predominately developed with oil and gas production.

Gas produced from the Tulare and Diatomite formations via existing oil wells within South and North Belridge would be mixed and conditioned using existing and modified process equipment. Mixing of the Diatomite and Tulare gas streams would start at the Del Sur Field Compressors. Using the existing (modified) compressors, the mixed stream would be transported, via an existing 16” Del Sur gas pipeline to a pre-combustion CO_2 capture facility to be located near Gas Plant 32. The carbon capture facility will include three steel towers of varying height (not exceeding 120 feet), and between 2 to 12 feet in diameter. The gas stream would first be treated to remove sulfur through an existing sulferox (SOX) plant. The de-sulfurized stream would then be cooled to reduce water content and condense heavy hydrocarbons. The CO_2 would be removed from the non-hydrocarbon gas stream using a physical solvent or a traditional amine absorption process. The resulting CO_2 product stream would be cooled, compressed, and piped to the sequestration site.

[1] Note, the operational life of the proposed Project will be controlled by the sequestration reservoir’s storage capacity (currently undergoing review) and volume of CO_2 captured per year which will fluctuate.

In each of the three post-combustion CO_2 capture facilities within Co-generation Plant 32 (at Gas Plant 32) and Steam Generator Stations (SGS) 2862 and 2972, the flue gas would be cooled, then passed through an absorber column where an absorbent will chemically react with and bind about 90% of the CO_2. The remaining flue gas (primarily oxygen, nitrogen, and the remaining uncaptured CO_2), would be vented to atmosphere. The rich absorbent carrying CO_2 is piped to the regenerator column, where through the application of heat, the CO_2 would be released and captured in relatively pure concentration. The CO_2 would be compressed, dehydrated, stripped of oxygen, and piped to the sequestration site. Oil and gas production activities within the underground formation where CO_2 would be stored, known as the 64 zone, would cease as a result of the implementation of the proposed Project.

A new approximately 10-mile, 6- to 12-inch pipeline would be constructed to deliver CO_2 from the capture facilities to the proposed injection wells. The pipeline would be primarily installed aboveground, except where the pipeline would cross main access roads (below ground) within the oil field properties. Distribution piping, each approximately 4- to 8-inches in size, would extend from the main pipeline to the proposed injection wells. The distribution pipelines would also be primarily aboveground on pipe supports, except where the pipelines cross main access roads (below ground) within the oil field.

The proposed Project includes re-purposing five existing oil wells and drilling four new wells for CO_2 injection. Additionally, four existing wells would be converted to monitoring wells to monitor the CO_2 plume. Up to four additional monitoring wells may also be constructed, either as re-purposed oil wells and/or new wells. The proposed Project would also require plugging and abandonment of up to 40 existing oil wells within the North Belridge Oil Field in accordance with state and federal requirements to prevent leakage of CO_2 from the sequestration zone. Additionally, up to 40 wells previously abandoned within the North Belridge Oil Field would be re-abandoned to meet current state and federal plugging requirements. Finally, 13 wells that are adjacent to SGS 2868 and SGS 2972 will need to be abandoned prior to construction of the CO_2 capture facilities at these two locations.

1.1.1 Project Area Information

The Project is comprised of 49 assessor's parcels (Project Area) totaling approximately 13,243 gross acres (Table 1). The permanent disturbance acreage associated with development of the CCS project and associated infrastructure would be less than the gross acreage of the Project Area. The proposed carbon dioxide (CO2) capture facilities are located within the developed portion of the South Belridge Oil Field. The proposed Project Area (including CO2 capture facilities, pipelines, sequestration field, and supporting facilities) is made up of privately owned parcels totaling approximately 13,243 acres of land, predominately developed with oil and gas production and accessory facilities and infrastructure.

Table 1: Belridge CCS Project Parcels

No.	APN	Acres
1	**068-210-13**	**240**
2	**068-210-35**	**120**
3	**068-210-34**	**40**
4	**068-210-19**	**120**

No.	APN	Acres
5	**068-200-30**	**44.7**
6	**068-200-37**	**37.23**
7	**068-200-33**	**192.34**
8	***068-200-41**	**66.84**
9	**068-220-55**	**152.36**
10	**068-220-42**	**123.6**
11	***068-220-39**	**26.17**
12	**068-220-37**	**18.52**
13	**068-210-18**	**360**
14	**068-200-16**	**40**
15	**068-230-04**	**640**
16	**068-220-01**	**640**
17	**068-220-36**	**324.1**
18	**068-220-25**	**40**
19	**068-220-26**	**118.85**
20	**068-220-13**	**640**
21	**068-220-44**	**78.29**
22	**068-220-08**	**80**
23	**085-110-10**	**554.84**
24	**085-110-13**	**160**
25	**085-110-14**	**160**
26	**085-110-16**	**80**
27	**085-110-32**	**382.33**
28	**085-110-50**	**462.54**
29	**085-190-27**	**64.77**
30	**085-190-28**	**309.82**
31	**085-210-43**	**530.22**
32	**085-210-40**	**135.3**
33	**085-210-42**	**313.16**
34	**085-210-18**	**619.15**
35	**085-230-05**	**640**
36	**085-230-26**	**493.18**
37	**085-230-07**	**631.36**
38	**085-230-09**	**636.36**
39	**085-230-25**	**139.79**
40	**085-220-36**	**274.99**
41	**085-220-37**	**366.45**

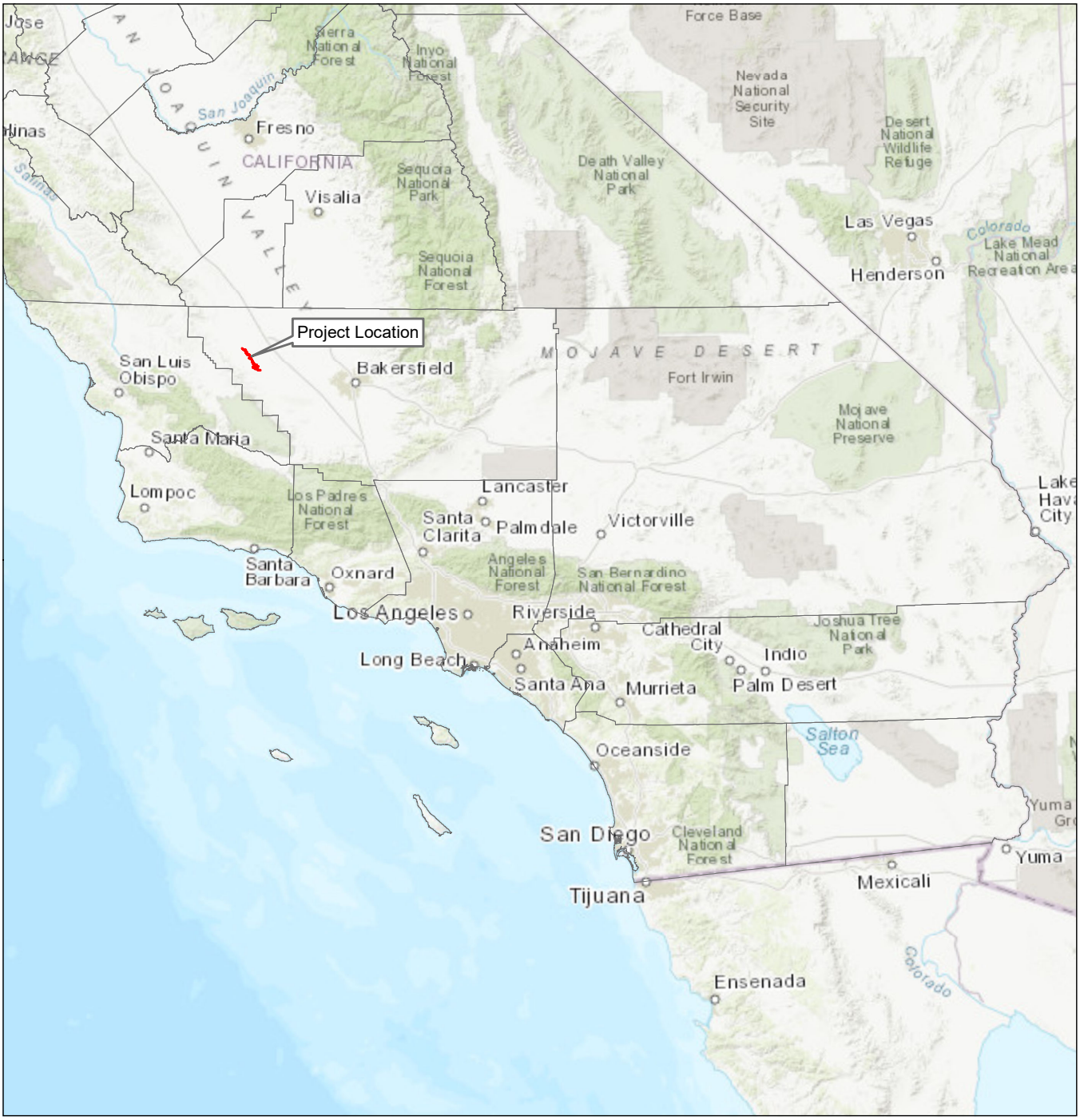


No.	APN	Acres
42	**085-220-19**	**14.77**
43	**085-220-21**	**287.87**
44	**085-220-22**	**336.16**
45	**098-111-01**	**315.78**
46	**098-111-03**	**320**
47	**098-112-01**	**277.07**
48	**098-112-02**	**276.98**
49	**098-120-10**	**317.04**
TOTAL:		**13,242.93**

* *Provisional*
Note:
APN = Assessor Parcel Number

1.1.2 Location

The Project Area is located within the Central Valley portion of western Kern County. The South Belridge and North Belridge oil fields are contiguous and located approximately seven miles southwest of the community of Lost Hills and west of SR 33 (Figure 1). Together, the two Belridge oil fields cover an area of approximately thirteen miles long and 3 miles wide.





Project Location

0 30 60 Miles

(At original document size of 8.5x11)
1:3,801,600

N

Stantec AERA

Project Location	Prepared by DL on 2023-05-24
Kern County,	TR by SET on 2023-05-24
California	IR by ES on 2023-05-24
Client/Project	185805407

Aera Energy LLC
Aera CarbonFrontier Project

Figure No.
1

Title
Project Location

Notes
1. Coordinate System: NAD 1983 StatePlane California V FIPS 0405 Feet
2. Data Sources: CalGEM 2019,2022,2023, Stantec 2022, 2023.
3. Background: Sources: Esri, GEBCO, NOAA, National Geographic, Garmin, HERE, Geonames.org, and other contributors
Sources: Esri, HERE, Garmin, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), (c) OpenStreetMap contributors, and the GIS User Community
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors

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Disclaimer: This document has been prepared based on information provided by others as cited in the Notes section. Stantec has not verified the accuracy and/or completeness of this information and shall not be responsible for any errors or omissions which may be incorporated herein as a result. Stantec assumes no responsibility for data supplied in electronic format, and the recipient accepts full responsibility for verifying the accuracy and completeness of the data.

1.2 DESCRIPTION OF PROPOSED PROJECT

Aera proposes to construct and operate a CCS project, with the CO_2 capture facilities located within the South Belridge Oil Field and transport the CO_2 by pipeline to the North Belridge Oil Field for permanent sequestration via CO_2 injection wells into a designated underground sequestration zone, known as the 64 zone, at depths of approximately 8,500 feet below ground surface. Presented below is a brief discussion of each of the Project components.

New processing facilities and field systems will be constructed. Processing facilities will include: 1) carbon capture facilities constructed adjacent to existing oil field equipment within the South Belridge Oil Field, 2) pipelines to transport the CO_2 stream to the North Belridge Oil Field, 3) dedicated injection wells within the North Belridge Oil Field to inject CO_2 into the dedicated CO_2 sequestration zone. Existing oil wells that penetrate the dedicated CO_2 sequestration zone will be permanently plugged and abandoned (including the removal of surface wellheads) in accordance with applicable laws and regulations.

Field systems will include: 1) additional pipelines to convey produced gas, steam within South Belridge Oil Field, 2) water treatment facilities, and 3) electrical power distribution and supervisory control and data acquisition networks. Project infrastructure will also include on-site road maintenance. Monitoring systems will be constructed, including re-purposing of existing wells, to monitor the CO_2 injection operations in accordance with state and federal requirements. All employee facilities needed to manage the Project will be provided by the existing Aera Belridge facilities.

After the useful life of the Project, the Project infrastructure would be disassembled, and the Project Area would be restored to its pre-development condition.

1.2.1 CO_2 Capture Facilities

Proposed CO_2 capture facilities include the separation, dehydration, compression, and cooling of CO_2 from both pre-combustion (Pre-C) produced gas stream and from post-combustion (Post-C) flue gas. A general discussion of each facility is presented below.

Pre-Combustion Components

Del Sur to GP 32 Line. Gas produced from the Tulare Formation via existing oil wells within the South Belridge Oil Field is transported, via an existing 16-inch diameter 3.3-mile long Wet Gas High Pressure Del Sur pipeline to the Del Sur compressor station and on to GP 32. The Tulare Associated gas stream would need to go through the Del Sur Compressor Station to increase pressure before being transported to GP 32, which would require a short “jumper” line to be constructed. The new jumper line would be approximately 200 feet long.

Tulare Casing Vapor Recover (CVR) to GP 32 Pipeline. Alternatively, gas produced from existing wells in the Tulare Formation will be transported by installing a new 12- to 16-inch 3.5-mile-long pipeline extending from the SOX 2-3 facility east of SR 33 to the existing SOX 3-2 facility, terminating at the GP32 location. The proposed pipeline will be installed primarily aboveground on pipe supports. The pipeline would cross State Route 33 and Seventh Standard Road using horizontal boring techniques.



Section 32 Gas Treating Complex. Prior to CO2 removal, the Tulare gas stream will first be treated to remove sulfur through one of two alternative methods: 1) treatment at the existing SOX Plants 3-2 and 2-3 or 2) the gas will be treated at the existing SOX Plant within the Section 32 Gas Treating Complex. CO_2 will be removed from the combined produced gas stream (Tulare and Diatomite production) using a physical solvent and traditional amine absorption process. Aera has not selected a specific amine solution vendor at this time.

Post-Combustion Capture Facilities

Post-C facilities will be constructed at three existing facilities within the South Belridge Oil Field: Section 32 Cogeneration Facility, Steam Generator Setting 2868, and Steam Generator Setting 2972. Flue gas from each post combustion source will be ducted to its own CO_2 capture facility. CO_2 will be captured using a combination of cooling and amine absorption. The concentrated CO_2 would then be compressed, dehydrated, and stripped of oxygen.

1.2.2 CO_2 Pipelines

Main Pipeline. A new approximately 10-mile, 6- to 12-inch pipeline will be constructed to deliver CO_2 from the capture facilities to the proposed injection wells. The pipeline will be primarily installed aboveground on pipe supports, except where the pipeline will cross main access roads within the oil field properties.

Booster Pump Station. A new booster pump station will be constructed adjacent to the existing Compressor Station 49. The booster pump station would include electric-driven pumps to increase flow rates between the CO_2 capture facilities and the injection wells. Alternatively, booster pumps may be installed within each capture facility.

Distribution Pipelines. Distribution piping, each approximately 4- to 8-inches in size, will extend from the main pipeline to the proposed injection wells. The distribution pipelines will be primarily aboveground on pipe supports, except where the pipelines cross main access roads within the oil field. The pipelines will be installed below ground at the main access road crossings.

1.2.3 Wells

The proposed Project includes re-purposing five existing oil wells and four new wells for use for CO_2 injection activities. Well locations have been carefully selected to minimize disturbance by reusing existing well pads, where feasible, and to allow for the permanent CO_2 sequestration within the dedicated zone. Well pads have been designed to minimize the amount of surface disturbance while meeting the technical constraints of drilling and operating the wells. Additionally, four existing wells will be converted to observation wells to monitor the CO_2 plume. Up to four additional monitoring wells may also be constructed, either as repurposed oil wells and/or new wells.

As part of the proposed Project, up to 40 existing oil wells would be plugged and abandoned within the North Belridge Oil Field in accordance with state and federal requirements to prevent leakage of CO_2 from the sequestration zone. Up to 40 additional wells, previously abandoned within the North Belridge Oil Field, would be re-abandoned to ensure



CO2 will be permanently sequestered. Lastly, 13 existing wells that are adjacent to SGS 2862 and SGS 2972 will need to be plugged and abandoned prior to construction of the CO_2 capture facilities at these two locations.

1.2.4 Support Infrastructure

Water Systems

The proposed Project will require, on average, approximately 1,223 afy (26,000 barrels or 1.09 million gallons per day) of water for use in the CO_2 capture facilities. The proposed Project would primarily use produced water from the Belridge Oil Field. Additional water treatment facilities will be installed at each CO_2 capture facility to treat produced water. Water pipelines would be constructed primarily aboveground to supply water to each of the CO_2 capture facilities.

Steam Lines

One of the project objectives is to reduce the carbon intensity of Aera Energy's produced oil and gas. Approximately nine miles of new 6- to 14-inch diameter steam pipelines would be installed to distribute steam from the SGS 2972 and SGS 2868 sites to areas of the field where steam would otherwise be generated without CO_2 capture. These new steam lines would allow Aera Energy to prioritize generating and supplying steam from the SGS 2972 and SGS 2868 sites with CO_2 capture. An approximately three-mile steam pipeline, constructed primarily aboveground on pipe supports, would extend from SGS 2972 to near Seventh Standard Road, along with an approximately 1.5-mile parallel pipeline from SGS 2868 to near Seventh Standard Road. Also, an approximately four-mile pipeline would extend from SGS 2972 northward to Section 12. Two shorter sections of steam piping would also be installed in other areas of the South Belridge field.

Electrical System Upgrades

Electrical system upgrades will be required to supply electricity to the new facilities. This includes approximately 5,700-feet of 115 kiloVolt (kV) overhead transmission lines from the existing electrical supply grid to two new electrical substations located adjacent to each of the CO_2 capture facilities. Additionally, approximately 13,000 feet of new 12 kV overhead distribution powerlines would extend from the proposed electrical substations to each CO_2 capture facility.

Access Roads

No new roads are proposed as part of the Project. Existing lease roads would be utilized whenever feasible to access the proposed Project areas. Aera Energy will maintain and repair existing roads within the North Belridge Oil Field to provide safe and efficient access to the injection wells and pipelines.

1.2.5 Water Usage

Commercial water demand for the Project CO_2 capture facilities is expected to be on average 1,223 afy (26,000 barrels per day). Water demands for the CO_2 capture facilities will be supplied by treated produced water from the Belridge Oil Field, and SWP water will only be used if sufficient water is



allocated under Aera Energy's water rights. Groundwater would be minimally used as potable water to control rooms, fire/emergency supply as needed, facility housekeeping, and chemical dilution. Water usage during construction, primarily for dust-suppression purposes, is not expected to exceed 400 af. Fresh water demands for the Project are anticipated to be purchased from existing BWSD SWP entitlements and other existing long-term water contracts with individuals and delivered to the Project Area via BWSD's 415 North Canal and/or 500 Canal and existing pipeline. Aera also has approximately 7,000AF of surplus SWP water stored in various groundwater banking projects through the BWSD that may be accessed at any time, subject to the groundwater banking project's pumping capacity. Domestic water demands estimated at 21.72 afy, will be supplied by Aera's two existing groundwater wells in the BVWSD.

1.2.6 Water Storage Tanks

Existing water storage tanks would be utilized for the proposed Project.

1.3 ANNUAL SEQUESTRATION

It is anticipated that the proposed Project would capture and sequester up to 1.6 million metric tonnes of CO_2 per year beginning in 2027 and will contribute to California's goal of carbon net-neutrality by 2045 (Governor's Executive Order B-55-18) by reducing industrial CO_2 emissions.

1.4 CONSTRUCTION ACTIVITIES

The construction period for the Project, from site preparation through construction, testing, and commercial operation, could commence as early as Q1 2025 and would extend for approximately 2.5 years.

Construction of the facility would include the following activities:

- Site preparation;
- Well construction;
- Well abandonments;
- Grading and earthwork;
- Concrete foundations;
- Facility construction;
- Pipeline construction;
- Electrical/instrumentation work;
- Utility connections; and
- Road maintenance.

Construction traffic and operations-related tanker traffic would likely use SR 33 to access the site via Seventh Standard Road. Construction traffic would access the site from SR 33 at existing facility entrances, and Seventh Standard Road. It is estimated that up to 300 workers per day (during peak construction periods) would be required during the construction of the Project.



Construction is expected to primarily occur between 6:00 AM and 5:00 PM, Monday through Friday. Additional hours may be necessary to make up schedule deficiencies or to complete critical construction activities. Some activities may continue 24 hours per day, seven days per week. Well drilling activities will occur 24-hours per day for a period of approximately two weeks per well.

Materials and supplies would be delivered to the Project Area by truck. Truck deliveries would normally occur during daylight hours; however, there may be offloading and/or transporting to the Project Area on weekends and during evening hours.

Earth-moving activities are expected to be limited to the construction of the access roads, well pad preparation, facility pad preparation, and substations. Final grading may include revegetation with low-lying grass or applying earth-binding materials to disturbed areas.

1.5 WORK FORCE

Once the Project is constructed, maintenance would generally be limited to the following:

1. Monitoring CO_2 injection activities;
2. Injection well work-overs;
3. Providing site security; and
4. Facility maintenance.

It is expected that the project would require an operational staff of up to ten full-time employees. The proposed Project would utilize maintenance staff that are currently employees within the South Belridge Oil Field.

The facility would operate seven days a week, 24 hours a day. Maintenance activities may occur seven days a week, 24 hours a day to ensure continuous operations.

1.6 PROJECT FEATURES AND BEST MANAGEMENT PRACTICES

The following sections describe standard Project features and best management practices that would be applied during construction and long-term operation of the Project to maintain safety and minimize or avoid environmental impact.

1.6.1 Waste and Hazardous Materials Management

The Project would have minimal levels of materials onsite that have been defined as hazardous under 40 Code of Federal Regulations, Part 261. The following materials are expected to be used during the construction, operation, and long-term maintenance of the Project:

- Insulating oil for electrical equipment;
- Lubricating oil for maintenance vehicles;
- Various solvents and detergents for equipment cleaning; and
- Gasoline/Diesel for maintenance vehicles.



Hazardous materials and wastes would be managed, used, handled, stored, and transported in accordance with applicable local and state regulations. All hazardous wastes would be maintained at quantities below the threshold requiring a Hazardous Material Management Program: one 55-gallon drum. Though not expected, should any on-site storage of hazardous materials exceed one 55-gallon drum, a Hazardous Material Management Plan would be prepared and implemented.

1.6.2 Spill Prevention and Containment

Hazardous materials would be stored on-site and provided with secondary containment. Spill prevention and containment for construction and operation of the Project would adhere to the EPA's guidance on Spill Prevention Control and Countermeasures Plan and hazardous materials business plan requirements.

1.6.3 Wastewater/Septic System

Existing available domestic water and septic systems are available at existing buildings. Domestic water for the two new control rooms will be supplied by Aera's two existing groundwater production wells located in the Buena Vista Water Storage District (BVWSD). New septic systems or holding tanks will be installed at the new control rooms.

1.6.4 Inert Solids

Inert solid wastes resulting from construction activities may include recyclable items such as paper, cardboard, solid concrete and block, metals, wire, glass, type 1-4 plastics, drywall, wood, lubricating oils and food wastes. Non-recyclable items include insulation, other plastics, vinyl flooring and base, carpeting, paint containers, packing materials, and other construction wastes. A construction waste management plan would be prepared for review by Kern County. Consistent with local regulations and the California Green Building Code, the plan would provide for diversion of a minimum of 50 percent of construction waste from landfill.

Chemical storage tanks (if any) would be designed and installed to meet applicable local and state regulations. Any wastes classified as hazardous, such as solvents, degreasing agents, concrete curing compounds, paints, adhesives, chemicals, or chemical containers, would be stored in an approved storage facility/shed/structure and disposed of as required by local and state regulations. Material quantities of hazardous wastes are not expected.

1.6.5 Health and Safety

Safety precautions and emergency systems would be implemented as part of the design and construction of the Project to ensure safe and reliable operation. Administrative controls would include classroom and hands-on training in O&M procedures, general safety items, and a planned maintenance program. These would work with the system design and monitoring features to enhance safety and reliability.



The Project would have an emergency response plan (ERP). The ERP would address potential emergencies including chemical releases, fires, and injuries. All employees would be provided with communication devices, cell phones, or radios to provide aid in the event of an emergency.

1.7 CLIMATE

The southern San Joaquin Valley region has a semi-arid climate that is characterized by hot, dry summers and cool dry winters. Most of the annual precipitation occurs during the period from November through April. The average minimum and maximum annual temperatures are 49.4 and 77.5 degrees Fahrenheit (°F), respectively, although it is not unusual for the maximum daily temperature to exceed 100 °F in summer (Table 2).

Table 2: Average Monthly Precipitation, Evapotranspiration and Temperature

Month	Average Monthly Precipitation (inches)	Average Monthly Evapotranspiration (inches)	Average Minimum and Maximum Monthly Temperature (°F)	
January	0.94	1.49	36.8	58.5
February	0.73	2.40	40.0	64.7
March	0.71	4.15	43.6	69.9
April	0.70	5.62	47.1	75.5
May	0.24	7.49	52.9	83.6
June	0.03	8.22	59.1	91.7
July	0.07	8.40	63.7	97.4
August	0.01	7.59	62.4	96.4
September	0.09	5.77	58.6	91.1
October	0.18	3.90	50.2	80.0
November	1.09	2.10	41.3	67.4
December	2.15	1.07	37.1	54.2
Annual	6.93	58.20	49.4	77.5

Notes:

°F = degrees Fahrenheit

Source: California Irrigation Management Information System (CIMIS) data for Station 146, Belridge; Calendar Year 1999 – 2022.

California has experienced three declared droughts in the last three decades. In 1976, the state received an average of only 7.4 inches of rain. Until recently, the drought of 1987–1992 was considered the most severe drought in California's history. However, the severity of that drought period has been eclipsed by the historic drought experienced from 2011–2016 and the most recent drought that occurred between 2020 and 2022. Conversely, these drought periods are often offset by periods of intense rainfall that can lead to flooding (e.g., WY2022-2023). This extreme climatic variability is common throughout California.

2.0 WATER SUPPLY PLANNING UNDER SENATE BILL 610

Senate Bill (SB) 610 was passed into law on January 1, 2002. This legislation identified the need to incorporate water supply and demand analysis at the earliest possible stage in the planning process. SB 610 amended portions of the Water Code, including Section 10631, which contains the Urban Water Management Planning Act, as well as adding Sections 10910, 10911, 10912, 10913, and 10915, which describe the required elements of a WSA.

A WSA is designed to build on the information that is typically contained in an Urban Water Management Plan (UWMP). The amendments to Water Code Section 10631 were designed to make WSAs and UWMPs consistent. A key difference between WSAs and UWMPs is that UWMPs are required to be revised every five years, in years ending with either zero or five, while WSAs are required as part of the environmental review process for each individually qualifying Project. Not all providers who prepare a WSA are required to prepare an UWMP.

A companion bill (SB 221) was also passed at the same time as SB 610. This law requires that approval by a city or county of certain residential subdivisions, as defined by California Government Code Section 66473.7(a)(1), must include an affirmative written verification of sufficient water supply. SB 221 is designed as a fail-safe mechanism to ensure that collaboration on identifying water supplies to serve a new large subdivision occurs early in the planning process. This verification must also include documentation of historical water deliveries for the previous 20 years, as well as a description of foreseeable impacts on the availability of water resources in the region of the proposed subdivision.

2.1 WATER SUPPLY ASSESSMENT

The WSA process involves answering the following questions:

- Is the Project subject to CEQA?
- Is it a Project under SB 610?
- Is there a public water system?
- Is there current UWMP that accounts for the Project demand?
- Is groundwater a component of the supplies for the Project?
- Are there sufficient supplies available to serve the Project over the next 20 years?

2.1.1 Is the Project Subject to CEQA?

The first step in the WSA process is determining whether the Project is subject to CEQA. SB 610 amended Public Resources Code Section 21151.9 to read, “Whenever a city or county determines that a Project, as defined in Section 10912 of the Water Code, is subject to this division [i.e., CEQA], it shall comply with part 2.10 (commencing with Section 10910) of Division 6 of the Water Code.”

Conclusion: *The proposed Project will undergo environmental review pursuant to the requirements of CEQA; therefore, the information contained in this assessment would be used to support the analysis contained in the CEQA document.*

2.1.2 Is It a Project Under Senate Bill 610?

The second step in the SB 610 process is to determine if a Project meets the definition of a "Project" under Water Code Section 10912 (a). Under this section, a "Project" is defined as meeting any of the following criteria:

- A proposed residential development of more than 500 dwelling units;
- A proposed shopping center or business establishment employing more than 1,000 persons or having more than 500,000 square feet of floor space;
- A commercial building employing more than 1,000 persons or having more than 250,000 square feet of floor space;
- A hotel or motel with more than 500 rooms; and
- A proposed industrial, manufacturing, or processing plant, or industrial park, planned to house more than 1,000 persons, occupying more than 40 acres of land, or having more than 650,000 square feet of floor area.

The proposed Project would occupy approximately 13,242 acres of land and therefore is considered a Project under Section 19012(a) of the Water Code.

Conclusion: *The proposed Belridge CCS Project meets the definition of a "Project" under Water Code Section 10912(a).*

2.1.3 Is There a Public Water System?

The third step in the WSA process is determining if there is a "public water system" to serve the Project. Section 10912 (c) of the Water Code states, "[A] public water system means a system for the provision of piped water to the public for human consumption that has 3,000 or more service connections."

Conclusion: *Aera's two existing groundwater wells in the BVWSD will provide domestic water supplies to the Project. The Aera wells represent a small non-transient non-community public water system in the Project vicinity serving domestic water supplies to an estimated population of 1,500 through 17 commercial and industrial service connections (https://sdwis.waterboards.ca.gov/PDWW/JSP/WaterSystemDetail.jsp?tinwsys_is_number=1356&tinwsys_st_code=CA&wsnumber=CA1500495). The Aera wells deliver treated domestic water from two active groundwater production wells, Wells 9 and 10. The production capacity of the two wells is 707.48 afy. Historical water demand in the water system over the past five years was 685.93 afy. Projected water demand is estimated to be 690.50 afy which includes the Project domestic water demand.*

2.1.4 Is There a Current UWMP That Accounts for the Project Demand?

Step four in the WSA process involves determining if there is a current UWMP that considers the projected water demand for the Project. The Water Code requires that all public water systems providing water for municipal purposes to more than 3,000 customers, or supplying more than 3,000 afy, must prepare an UWMP, and this plan must be updated at least every 5 years on or before December 31, in the years ending in five and zero. Water Code Section 10910 (c) (2) states, "If the projected water demand associated with the proposed Project was accounted for in the most recently adopted urban water management plan, the public water system may incorporate the requested information from the UWMP in preparing the elements of the assessment required to comply with subdivisions (d), (e), (f), and (g) [i.e., the WSA]."

Conclusion: *Aera's two groundwater wells are located in the BVWSD service area; however, owing to its small number of service connections, 17, and 707.48 afy production capacity from the water system's two wells, it does not meet the minimum requirements for the preparation of an UWMP.*

The BWSD prepared a 2020 AWMP (BWSD, 2021) pursuant to Water Code Section 10826 and Executive Order B-29-15. BWSD currently has a SWP Table A Entitlement of 121,508 af which is allocated as follows (BWSD, 2021):

- *Agricultural Entitlement = 111,157 af*
- *Industrial Entitlement = 5,578 af*
- *Operational Water Losses = 4,773 af*

SWP and supplemental water deliveries by the BWSD between WY1986 and WY2015 based on CV2SimFG-Kern simulations ranged from 79,387 af in 1998 to 143,146 af in 1997 (Todd, 2020) in GEI (2022). Between 2016 and 2020, SWP and supplemental water deliveries by BWSD for agricultural irrigation ranged between 82,958 and 89,333 af and averaged 86,150 af (BWSD, 2021). Over the same time period, SWP and supplemental water deliveries by BWSD for industrial use at the South Belridge Oil Field and North Belridge Oil Field ranged from 587 to 1,077 af and averaged 885 af (BWSD, 2021). BWSD allows its supply contractors the option to pay to temporarily store the surplus water in the Berenda Mesa and/or Pioneer groundwater banking projects that are operated by the Kern County Water Agency (KCWA) (BWSD, 2021). As of 2020, BWSD had stored approximately 85,000 af in these banking projects (BWSD, 2021).

Regulatory restrictions or limitations in SWP Table A Entitlements that impact the amount of SWP water deliveries to BWSD include Endangered Species Act and Sacramento-San Joaquin Delta Biological Opinions by the U.S. Fish and Wildlife Service and National Marine Fisheries Service and water quality limitations promulgated by the State Water Resource Control Board. SWP water delivery restrictions also occur by the DWR for facility maintenance (BWSD, 2021). Climactic conditions such as dry years and extending to multi-year droughts limit the amount of SWP available for delivery.

2.1.5 Is Groundwater a Component of the Supplies of the Project?

This section addresses the requirements of the Water Code Section 110910 (f), paragraphs 1 through 5, which apply if groundwater is a water source for a proposed Project. Pursuant to Water Code Section 10910 (f), the groundwater analysis presented in this analysis focuses on the Kern County Subbasin (Subbasin) of the San Joaquin Valley Groundwater Basin (Figure 2).

Groundwater from Aera's water system will be used to provide domestic water supplies to the Project. The estimated annual commercial domestic water demand for the Project is 21.72 af which will be pumped from Aera's two production wells located in the Subbasin. According to DWR (2006), the Subbasin is located in the southernmost portion of the San Joaquin Valley Groundwater Basin within the southern portion of the Great Valley Geomorphic Province of California (California Geological Survey, 2002). The Great Valley is approximately 400 miles long and up to 70 miles wide in the central portion of the state. The northern third of the Great Valley is occupied by the Sacramento Valley. The southern two-thirds of the Great Valley is occupied by the San Joaquin Valley and is more than 250 miles long and between 20 and 55 miles wide (Burow, et al., 2004). The Great Valley is a northwest trending structural asymmetric trough with the axis located along the western portion of the valley. The San Joaquin Valley is filled with up to 6 miles (32,000 feet) of Jurassic to Holocene marine and continental (i.e., nonmarine) sedimentary deposits (Page, 1986). The San Joaquin Valley extends from the Sacramento-San Joaquin Delta/Stockton Arch on the north to the San Emigdio and Tehachapi Mountains on the south. It is bound on the east by the Sierra Nevada Mountains and on the west by the Coast Ranges, locally named the Temblor Range. Major streams in the San Joaquin Valley drain the western flank of the Sierra Nevada Mountains and include from south to north, the Kern River, Kings River, San Joaquin River and its major tributaries: Fresno, Chowchilla, Merced, Tuolumne, Stanislaus, Calaveras, Mokelumne and Cosumnes Rivers. The San Joaquin River discharges northward into the Sacramento-San Joaquin Delta. The Kern and Kings Rivers discharge internally onto the valley floor.

The Subbasin is bounded on the west by the Temblor Range, on the north by the Kings and Tulare County lines, on the east by the Sierra Nevada Mountains and on the south and southeast by the San Emigdio and Tehachapi mountains, respectively.

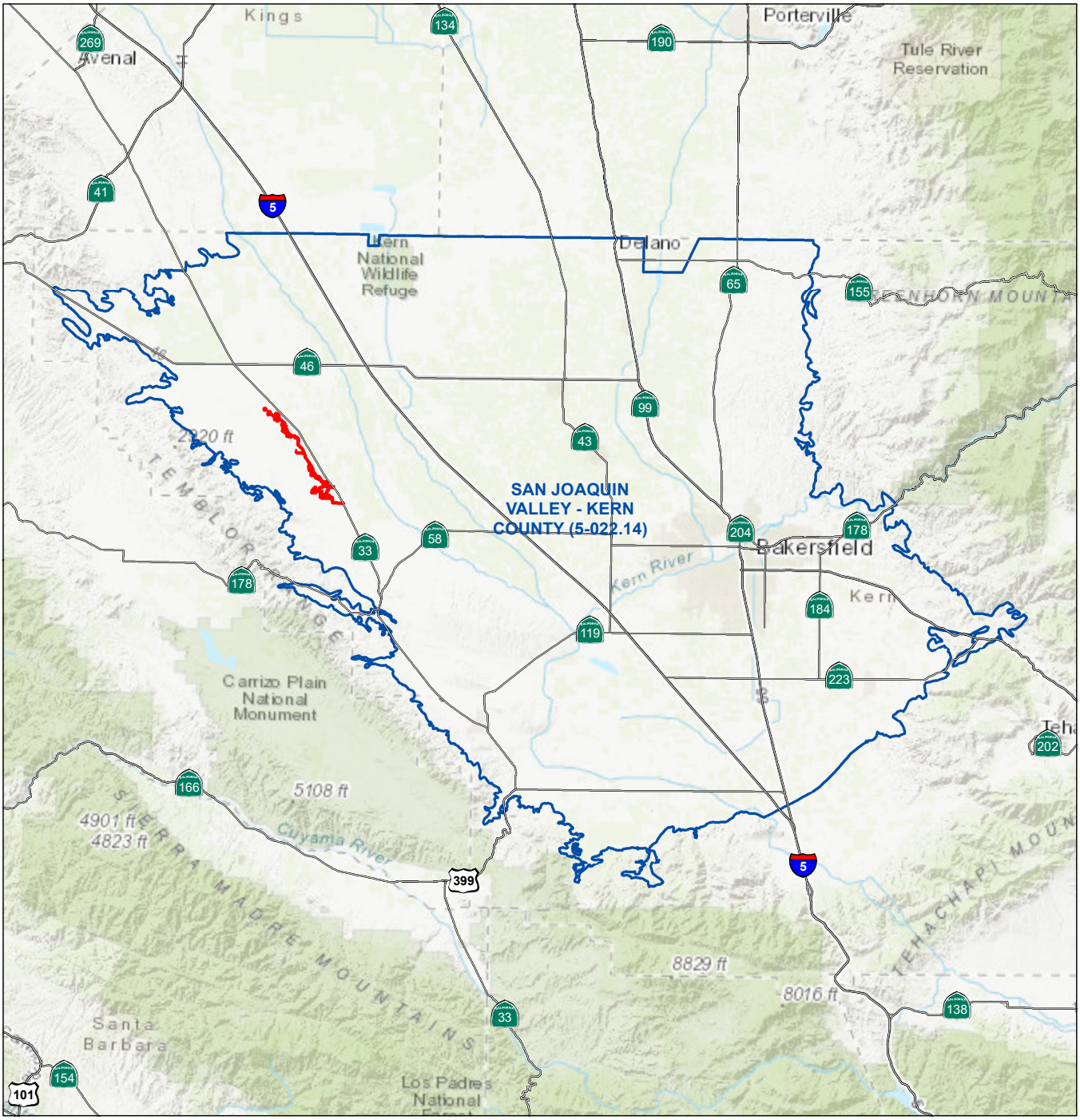
Average annual rainfall in the Subbasin averages about 7 inches. Surface water in the Subbasin drains westward from the Sierra Nevada Mountains, eastward from the Temblor Range, and northward from the Tehachapi and San Emigdio mountains. All watersheds that drain the bordering highlands discharge onto the valley floor. Major watersheds in the Subbasin that drain the Sierra Nevada Mountains include from north to south Poso Creek and the Kern River. Major watersheds that drain the Tehachapi Mountains include Caliente Creek and Tejon Creek. Major watersheds that drain the San Emigdio Mountains include from east to west Pleito Creek, San Emigdio Creek and Santiago Creek. There are numerous small watersheds, but no major watersheds in the Subbasin that drain the Temblor Range. Other than the Kern River, most Subbasin streams are ephemeral except during above normal and wet water years (GEI, 2022).

Flow in the Kern River is regulated by Isabella Lake Dam located about 40 miles northeast of Bakersfield to mitigate flooding and store water for agricultural, municipal and industrial uses. Lake Isabella provides

recreational opportunities. Portions of the discharges from the dam provide hydroelectric power. Once on the valley floor, streamflow in the Kern River is largely diverted for the above-mentioned uses while the residual streamflow percolates into the riverbed.

Construction water demand for the Project of approximately 400 af (Aera, 2022a) would be met by surface water deliveries from BWSD from the California Aqueduct. Commercial water demands averaging up to 1,223 afy will be supplied by produced water from the Belridge Oil Field, and SWP water will only be used if sufficient water is allocated under Aera Energy's water rights. BWSD imported water supplies would be delivered to the Project via the Industrial System that is owned and operated by the industrial Water Users including the Applicant and other South Belridge Oil Field and North Belridge Oil Field operators. The Industrial System consists of a pumping plant at BWSD Turnout No. 5 (Bel 5) on the California Aqueduct, and associated pipeline that conveys untreated SWP and supplemental water to the Industrial Zone (i.e., oil fields) (BWSD, 2021). Aera also has approximately 7,000AF of surplus SWP and Kern River water stored in various groundwater banking projects through the BWSD that may be accessed at any time, subject to the groundwater banking project's pumping capacity. As noted above, domestic water demands estimated at 21.72 afy will be provided by two existing groundwater production wells that comprise Aera'swater system.

Conclusion: *Groundwater from two existing groundwater production wells that comprise Aera's water system will be used to provide domestic water supplies to the Project.*





Project Location

San Joaquin Valley Groundwater Basin

0 7 14 Miles

(At original document size of 8.5x11)
1:887,040

N

Stantec AERA

Project Location	Prepared by DL on 2023-05-24
Kern County,	TR by SET on 2023-05-24
California	IR by ES on 2023-05-24
Client/Project	185805407

Aera Energy LLC
Aera CarbonFrontier Project

Figure No.
2

Title
Kern County Subbasin

Notes
1. Coordinate System: NAD 1983 StatePlane California V FIPS 0405 Feet
2. Data Sources: CalGEM, 2019, Basin/Subbasin data from California Department of Water Resources 2023. Stantec 2022,2023.
3. Background: Sources: Esri, HERE, Garmin, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), (c) OpenStreetMap contributors, and the GIS User Community. Imagery Dated 2021.

V:\185805\Active\185805xxxx_Aera\03_data\gis_cad\gis\185805372_BeiridgeCCSWaterSupplyAssessment_Figure2_GroundwaterBasinLimits_20230127.mxd Revised: 2023-05-24 By: Dalaw

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Groundwater Basin Description

The DWR has divided the State into ten hydrologic regions which have been further divided into groundwater basins and subbasins. The Subbasin is located within the San Joaquin Valley Groundwater Basin in the Tulare Lake Hydrologic Region. The Subbasin is underlain by Tertiary and Quaternary-aged unconsolidated non-marine/continental deposits and older Tertiary marine deposits. These deposits thicken toward the axis of the San Joaquin Valley, which in the Subbasin, extends northward beneath and along the western portion of the valley floor and forms an asymmetric trough (Bartow, 1991). Surficial alluvial deposits are generally coarser grained emanating from crystalline rock source areas such as those that comprise the Sierra Nevada, Tehachapi and San Emigdio mountains, but are finer grained near the Temblor Range which is underlain by sedimentary rocks. The alluvial deposits become finer grained with distance from their respective source areas culminating in a series of playa lakes including Kern Lake and Buena Vista Lake. These lakes were formed at the terminus of the Kern River prior to agricultural development in the mid-1800s and the establishment of riparian water rights of the Kern River beginning in the late-1800s which diverted upstream river flows.

Principal freshwater groundwater bearing units in the Subbasin include the following (GEI, 2022a):

- Younger alluvium and flood plain deposits (shallow unconfined aquifer);
- Older Alluvium (unconfined aquifer);
- Tulare Formation (semiconfined/confined aquifer); and
- Kern River Formation (unconfined/semiconfined).

Other locally important groundwater bearing units include the Santa Margarita Sandstone and Olcese Sand in the eastern and northeastern portions of the Subbasin (GEI, 2022a).

The Plio-Pleistocene non-marine Tulare Formation occurs in the central and western portions of the Subbasin and attains a maximum thickness of 2,200 feet (GEI, 2022a). The formation is separated into an upper and lower portion by a confining clay layer called the Corcoran Clay (Croft, 1972) or modified E-clay (Page, 1986). The upper aquifer is unconfined to semiconfined. The lower aquifer is confined. The Corcoran Clay extends from the western to the central portion of the Subbasin. The thickness of the Corcoran Clay ranges between 20 and 100 feet but is typically 10 to 30 feet thick (GEI, 2022).

The Mio-Pliocene to early Pleistocene Kern River Formation occurs along the eastern to central portion of the Subbasin and was derived from erosion of the Sierra Nevada Mountains (GEI, 2022a). The Kern River Formation attains a maximum thickness of 2,600 feet (Bartow and Pittman, 1983). The aquifer is largely unconfined although thin aquitards in the central portion of the Subbasin locally creates semiconfined conditions.

Older alluvial deposits of Pleistocene-age overlie the Tulare and Kern River formations and attain a maximum thickness of 250 feet. These deposits are often indistinguishable from the underlying Tulare and Kern River formations (DWR, 2006). The aquifer is unconfined. The Holocene-age younger alluvium and floodplain deposits are up to 150-feet thick and varies on lithology across the Subbasin. They are

generally coarser grained near the Subbasin boundaries and become finer grained toward the basin bottom where they underlie Kern and Buena Vista Lake beds (GEI, 2022a).

In the Project Area, the Tulare Formation is overlain by the Corcoran Clay Equivalent over most of the South Belridge Oil Field and in the southeastern portion of the North Belridge Oil Field (Gillespie et al, 2019; Aera, 2017). Alluvium overlies the Tulare formation in the South Belridge Oil Field but has been largely removed by erosion in the North Belridge Oil Field exposing the Tulare Formation (Dibblee, 2006a, 2006b). The Tulare Formation is partially saturated beneath the Project Area and is a source of produced water where wells extract oil from this formation. The alluvium in the eastern portion of the SBOF contains perched groundwater in up to two thin aquifers (Aera, 2022b), however, it is not utilized for water supply. Groundwater flow in the alluvium and Tulare formation is to the east and northeast (Aera, 2019). Most of the Project Area is within a California Geologic Energy Management Division-designated Tulare Aquifer Exemption Area (USEPA, 2020).

Groundwater production in the Subbasin for WY1995-WY2014 (current condition) is estimated to be 1,590,373 afy based on the CV2SimFG-Kern groundwater model simulation (Todd, 2020) in GEI (2022). Groundwater production in the WDWA during the same period is estimated to be 3,000 afy (Aquilogic, 2022) and 10,276 in 2020 based on the 2020 AWMPs for BWSD, BMWD and the LHWD (BWSD, 2021; BMWD, 2021; LHWD, 2021). Pumped groundwater is used for blending with SWP water due to the natural poor quality of groundwater for most beneficial uses (Aquilogic, 2022), and the reduced reliability of SWP water supplies (BWSD, 2021; BMWD, 2021; LHWD, 2021). Projected groundwater production in the WDWA and the Subbasin is projected to increase to 25,400 (Aquilogic, 2022) and 1,648,770 afy (Todd, 2020) in GEI (2022a), respectively, from WY2021 to WY2040, the latter, based on the CV2SimFG-Kern 2070 climate change and implementation of projects and management actions scenario. Groundwater production in the BVGSA plan area for WY1993 to WY2015 is estimated to be 62,742 afy (GEI, 2022b).

Estimations of the total storage capacity of the Subbasin were reported in DWR (2006) based on data in 2002 to be 40,000,000 af (KCWA, 2002). The dewatered storage at this time was also reported to be 10,000,000 (KCWA, 2002). The estimated amount of groundwater in storage from WY1995 to WY2014 in the WDWA is 42,400,000 af (Aquilogic, 2022). However, this latter estimate appears to more closely coincide with the estimated storage capacity of the Subbasin, not the WDWA, as noted above (DWR, 2006; KCWA, 2002).

Change in groundwater in storage in the Subbasin between WY1995 and 2014 is estimated to have declined by 5,542,280 af based on an annual decline of 277,114 afy (GEI, 2022a; Todd, 2020). Change in groundwater in storage in the Subbasin between WY1995-2021 is estimated to yield a decline of 1,812,211 af based on an annual decline of 69,700 afy (Todd, 2020) in GEI (2022a). The projected average and cumulative change in groundwater in storage in the Subbasin from WY2021 to WY2040 is a decline of about 224,286 afy and 4,485,720 af, respectively (Todd, 2020) in GEI (2022a), using the CV2SimFG-Kern groundwater model under the 2070 climate change and implementation of projects and management actions scenario. The estimated change in groundwater in storage in the WDWA is estimated to be 46,000 afy using the CV2SimFG-Kern groundwater model simulation and about 22,000 afy by Aquilogic (2022), based on assumed modeling discrepancies related to the amount of groundwater production using the CV2SimFG-Kern groundwater model simulation. The estimated cumulative and annual decline in

groundwater in storage in the BVGSA between WY1993 and WY2015 is 275,480 af and 11,977 afy, respectively (GEI, 2022b). The estimated annual change in groundwater in storage between WY1995 and WY2014 using the C2VSimFG-Kern groundwater model is -17,362 afy (Todd, 2019)

Groundwater recharge in the Subbasin and the WDWA between WY1995 and WY2014 is estimated to be 1,400,362 afy (Todd, 2020) in GEI (2022a) and 92,341 afy based on groundwater model simulation using CV2SimFG-Kern (Aquilogic, 2022). The estimated WY1995-WY2014 sustainable yield in the Subbasin and the WDWA plan area is 1,313,260 afy based on groundwater recharge and outflow (Todd, 2020) in GEI (2022a) and 34,079 afy (Aquilogic, 2022), respectively.

Groundwater quality within the Subbasin is generally good for most beneficial uses and is supplemented with imported SWP, Central Valley Project water and Kern River diversions. However, in the WDWA, groundwater quality is characterized by mostly elevated Total Dissolved Solids (TDS), sulfate and chloride concentrations occurring above California Secondary Drinking Water Maximum Contaminant Levels (SMCLs) of 500 milligrams per liter (mg/l), 250 mg/l and 250 mg/l, respectively (Aquilogic, 2022). Moreover, the TDS concentrations throughout the WDWA often exceed 1,000 mg/l and are considered brackish or saline at higher concentrations. In addition, arsenic occurs locally in groundwater at concentrations exceeding the California Primary Drinking Water MCLs of 10 micrograms per liter (ug/l, Aquilogic, 2022). Although Boron does not have a California or Federal drinking water MCL, California does have a Notification Level of 1,000 ug/l and an agricultural goal of 700 ug/l. Boron concentrations in groundwater in the WDWA largely exceed both the Notification Level and the agricultural goal. Owing to the elevated TDS, chloride, sulfate and boron concentrations groundwater use in the WDWA is primarily used for blending with SWP water for agricultural irrigation (Aquilogic, 2022; BWSD, 2021; BMWD; LHWD, 2021).

Groundwater quality in the BVGSA is variable with TDS concentrations in the northern portion of the plan area greater than 1,500 mg/l and less than 1,000 mg/l in the southern portion of the plan area (GEI, 2022b). Nitrate (as N) concentrations are generally less than 10 mg/l except in the northernmost portion of the plan area where it exceeds 20 mg/l (GEI, 2022b). Arsenic concentrations locally exceed the Primary Drinking Water MCL of 10 ug/l throughout the plan area (GEI, 2022b).

BVWSD is entitled to 156,000 afy of surface water from the Kern River; however, during the period 2006 to 2015 Kern River deliveries via the East Side Canal averaged 40,887 afy. BVWSD is also contracted with the KCWA to receive 21,300 afy of Table A SWP water and 3,750 afy of Article 21 SWP water. During the period 2006 through 2015, BVWSD received an average of 53,099 afy of SWP water via the California Aqueduct (GEI, 2022b). Average surface water deliveries from 2006 to 2015 averaged 93,986 afy. Estimated 2020 and 2040 surface water deliveries to the BVWSD are not individually provided in the BVGSA GSP chapter (GEI, 2022b) or the KGA “Umbrella” GSP (GEI, 2022a). According to the BVGSA GSP (GEI, 2022b), under the 2070 climate change factor, BVGSA has estimated a reduced Kern River entitlement of 147,000 af in 2040, a reduced SWP Table A entitlement of 9,642 afy and a slightly increased Article 21 SWP entitlement of 3,900 afy in 2040.

Groundwater Management

In November 2009, the Governor signed into law SBx7-6, which established the California Statewide Groundwater Elevation Monitoring (CASGEM) Program. Groundwater level data entered into DWR's online CASGEM reporting system by monitoring entities beginning in January 2012 were used to establish groundwater basin prioritization as part of the enactment of the SGMA of 2014. Enactment of the SGMA amended Water Code Section 10720 *et al*. in an effort to provide a statewide system for the sustainable management of groundwater. For medium- and high-priority groundwater basins, SGMA requires the designation of a GSA. GSAs have broad groundwater management powers. For example, GSAs may require groundwater well registration, measurement of groundwater extractions, and filing of annual extractions reports.

The SGMA authorizes GSAs to regulate groundwater extractions by imposing well spacing requirements, limiting extractions, and establishing extraction allocations. The legislation does not apply to adjudicated groundwater basins that are managed by the courts or to basins deemed by DWR to be low priority. The SGMA requires GSAs to adopt GSPs for medium- and high-priority basins. These plans must set the groundwater basin on a course toward sustainable management to eliminate adverse groundwater conditions specified as undesirable results. The law allows a local agency that has, "water supply, water management, or land use responsibilities within a groundwater basin, to elect to be a GSA." The Subbasin has been designated by DWR as a critically overdrafted high-priority basin by the DWR (https://gis.water.ca.gov/app/bp-dashboard/final/# accessed January 8, 2022).

Five GSPs representing 11 GSAs were submitted to DWR as required under the SGMA. The five GSPs were prepared by a combined 11 GSAs and included 16 member agencies in the Kern Groundwater Authority (KGA) GSP to sustainably manage the Subbasin under the SGMA. The Project Area is located within the WDWA plan area of the KGA GSP (Aquilogic, 2022; GEI, 2022). A GSP chapter was prepared for the WDWA by Aquilogic (2022), a member agency of the KGA. The WWDA includes the BWSD, BMWD and LHWD in northwestern Kern County (GEI, 2022, Aquilogic, 2022). Aera's water system is located in the BVWSD which coincides with the BMA in BVGSA. A GSP chapter was prepared for the BVGSA by GEI (2022b), also a member agency of the KGA.

Note: *A combined 11 GSAs were formed in the Subbasin and five GSPs were submitted to DWR. Groundwater management in the Project Area is governed by the KGA GSA.*

Governance and Local Control

The SGMA requires that all high- and medium-priority groundwater basins must establish governance under one or more GSAs by June 30, 2017. GSAs for high- and medium-priority basins must adopt their GSP by January 31, 2022. GSAs for critically overdrafted high-priority basins must adopt their GSP by January 31, 2020. Low-priority basins are not required to prepare a GSP.

The Subbasin is designated under CASGEM as a "critically overdrafted high-priority" groundwater basin. Five GSPs representing 11 GSAs submitted their GSPs to DWR in January 2020. Based on DWR comments to the GSPs, revised GSPs were submitted by the GSAs to DWR in July 2022 (GEI, 2022). On March 2, 2023, DWR deemed the revised KGA GSP (GEI, 2022a) as "inadequate" and jurisdiction of the

GSP was transferred to the State Water Resources Control Board to assist the GSAs in the correction of previously identified deficiencies and possible placement in probationary status.

Conclusion: *The Subbasin has been designated as a critically overdrafted high-priority basin. Five GSPs representing 11 GSAs were submitted to DWR in January 2020. Based on DWR comments to the GSPs, revised GSPs were submitted to DWR in July 2022. On March 2, 2023, DWR deemed the revised KGA GSP (GEI, 2022a) as "inadequate" and jurisdiction of the GSP was transferred to the State Water Resources Control Board to assist the GSAs in the correction of previously identified deficiencies and possible placement in probationary status.*

Groundwater Sustainability Plans

GSPs must include minimum thresholds and measurable objectives to achieve the goal of groundwater basin sustainability within 20 years of GSP implementation. The SGMA defines GSPs that achieve sustainable groundwater management by ensuring that the applicable basin is operated within the sustainable yield. Sustainable yield is defined as the maximum quantity of water that can be withdrawn over a period of years without causing an undesirable result. An undesirable result means one or more of the following effects caused by groundwater conditions occurring throughout the basin:

- Chronic lowering of groundwater levels;
- Significant and unreasonable reduction of groundwater storage;
- Significant and unreasonable seawater intrusion;
- Significant and unreasonably degraded water quality;
- Significant and unreasonable land subsidence that substantially interferes with surface land uses; and/or
- Depletions of interconnected surface water that have significant and unreasonable adverse impacts on beneficial uses of the surface water.

The GSP must include monitoring and management for the basin over a 50-year planning horizon, and plans must articulate measurable objectives to be achieved every 5 years. The DWR will review the plans and will have the power to request changes to a submitted plan. The plan must establish measurable objectives, as well as incremental milestones every 5 years in order to achieve the sustainability goals identified in the plan within 20 years.

As noted above, five GSPs representing 11 GSAs submitted their GSPs to DWR in January 2020. Based on DWR comments to the GSPs, revised GSPs were submitted by the GSAs to DWR in July 2022 (GEI, 2022a). The revised GSPs addressed the six GSP undesirable results and developed a strategy for monitoring five of the six undesirable results. Seawater intrusion was dismissed owing to the considerable distance inland the Subbasin is from a saline water body (e.g., San Francisco Bay and Pacific Ocean). On March 2, 2023, DWR deemed the revised KGA GSP (GEI, 2022a) as "inadequate" and jurisdiction of the GSP was transferred to the State Water Resources Control Board to assist the GSAs in the correction of previously identified deficiencies and possible placement in probationary status.

Conclusion: *The Subbasin has been designated as a critically overdrafted high-priority basin. Five GSPs representing 11 GSAs were submitted to DWR in January 2020. Based on DWR comments to the GSPs,*

revised GSPs were submitted to DWR in July 2022. The GSPs addressed five of the six undesirable results except seawater intrusion, the latter of which is not applicable due to the considerable distance the Subbasin is located from a saline water body. On March 2, 2023, DWR deemed the revised KGA GSP (GEI, 2022a) as "inadequate" and jurisdiction of the GSP was transferred to the State Water Resources Control Board to assist the GSAs in the correction of previously identified deficiencies and possible placement in probationary status.

2.1.6 Are There Sufficient Supplies to Serve the Project Over the Next Twenty Years?

The next step in the WSA process is to prepare the actual assessment of the available water supplies, including the availability of these supplies in all water-year conditions over a 20-year planning horizon and an assessment of how these supplies relate to Project-specific and cumulative demands over that same 20-year period. To be consistent, the analysis horizon of this WSA extends to 2040. Water Code Section 10910 (c)(4) states, "If the city or county is required to comply with this part pursuant to subdivision (b), the water assessment for the Project shall include a discussion with regard to whether the total projected water supplies, determined to be available by the city or county for the Project during normal, single dry, and multiple dry water years during a 20-year projection, will meet the projected water demand associated with the proposed Project, in addition to existing and planned future uses including agricultural and manufacturing uses." Tables 2 and 3 provide future water supply availability for the Project in the Subbasin. The estimates presented in Tables 2 and 3 are based on the Water Year (WY) which is the period October 1 through September 30 of the following year. For WY2020, the period of record is October 1, 2019 through September 30, 2020. The water supply and demand data for WY2020 were taken from *Kern County Subbasin Groundwater Sustainability Plans Second Annual Report Water Year 2020* (Todd, 2021). The water supply and demand data for WY2040 were taken from Attachment H (Todd, 2020) in GEI (2022) and is based on CV2SimFG-Kern groundwater model simulations assuming 2070 climate change conditions and implementation of projects and management actions.

The estimated water demand in the Subbasin in WY2020 is estimated to be 3,075,992 af (Todd, 2021). The projected WY2040 water demand is unknown due to lack of this data in Todd (2020) in GEI (2022a). Current and projected groundwater production in the Subbasin is estimated to be 1,835,054 af in WY2020 (Todd, 2021) and 1,793,459 af in WY2040 (Todd, 2020) in GEI (2022a). Current surface water supplies including imported SWP and CVP water, local streamflow and recycled/reused water is estimated to be 1,405,576 af in WY2020 (Todd, 2021); however, projected WY2040 surface water supplies are unknown due to lack of this data in Todd (2020) in GEI (2022a).

Calendar year 2020 (2020) surface water deliveries in the WDWA plan area, including imported SWP and other surface water and groundwater banking recovery and carryover water, is reported to be 275,522 af based on the 2020 AWMPs for BWSD (BWSD, 2021), BMWD (BMWD, 2021) and LHWD (LHWD, 2021). Projected (calendar year 2040) surface water supplies in the WDWA plan area are estimated to be 266,290 af based on implementation of WDWA plan area-specific projects and management actions (Aquilogic, 2022). 2020 groundwater production in the WDWA plan area of 10,276 af is based on the 2020 AWMPs for BWSD (BWSD, 2021), BMWD (BMWD, 2021) and LHWD (LHWD, 2021). Projected 2040 groundwater production is estimated to be 25,400 af based on implementation of WDWA plan area-

specific projects and management actions number 3c: pumping and reuse of 20,000 afy of brackish groundwater underflow (Aquilogic, 2022). Tables 3 and 4 show future (WY2040) water supply availability in the Subbasin and WDWA Plan Area, respectively.

BVWSD is entitled to 156,000 afy of surface water from the Kern River; however, during the period 2006 to 2015 Kern River deliveries via the East Side Canal averaged 40,887 afy. BVWSD is also contracted with the KCWA to receive 21,300 afy of Table A SWP water and 3,750 afy of Article 21 SWP water. During the period 2006 through 2015, BVWSD received an average of 53,099 afy of SWP water via the California Aqueduct (GEI, 2022b). Average surface water deliveries from 2006 to 2015 averaged 93,986 afy. Estimated 2020, 2030 and 2070 surface water deliveries to the BVWSD are 164,192 af, 161,306 af and 160,864 af, respectively (GEI, 2022b).

Table 3: Future (WY2040) Water Supply Availability in the Subbasin

Current Source	Current Water Year	Single Dry Water Year	Multiple Dry Water Years		
			Year 1	Year 2	Year 3
Groundwater (Subbasin)	1,835,054	1,835,054	1,835,054	1,835,054	1,835,054
Imported Surface Water (SWP and CVP), Local Streamflow, Recycled/Reused Water	1,405,576	1,405,576	1,405,576	1,405,576	1,405,576
Total Supply	3,240,630	3,240,630	3,240,630	3,240,630	3,240,630

Table 4: Future (2040) Water Supply Availability in the WDWA(a) and BVGSA Plan Areas

Current Source (b)	Current (2020) Water Supply (c)	Single Dry Year (d)	Multiple Dry Years (c)		
			Year 1	Year 2	Year 3
Groundwater (WDWA)	10,276	25,400	25,400	25,400	25,400
Groundwater (BVWSD)	62,742	62,742	62,742	62,742	62,742
Imported Surface Water (SWP), Groundwater Banking Recovery Water, and Carryover Water (WDWA)	275,522	266,290	266,290	266,290	266,290
Imported Surface Water (SWP), Kern River Water, and Groundwater Banking Recovery Water (BVGSA)	160,864	160,864	160,864	160,864	160,864
Total Supply	509,404	515,738	515,296	515,296	515,296

Notes:
(a) An estimate of available water supplies in 2040 in the BVGSA is unavailable due to lack of sufficient data in the BVGSA GSP chapter (GEI, 2022b) and KGA Umbrella GSP (GEI, 2022a).
(b) af = acre-feet
(c) WDWA current year (2020) groundwater production and imported surface water deliveries, including groundwater banking recovery and carryover water are based on the 2020 AWMPs for BWSD (BWSD, 2021), BMWD (BMWD, 2021) and LHWD (LHWD, 2021). BVGSA groundwater production estimated based on average annual production over the period WY1993 to WY2015 and estimated 2020 surface water deliveries (GEI, 2022b).

(d) Single and Multiple dry year projections are based on implementation of WDWA plan area-specific projects and management actions number 3c: pumping and reuse of 20,000 afy of brackish groundwater underflow and estimated surface water deliveries (Aquilogic, 2022). Single and multiple dry year projections for surface water deliveries to BVWSD are based on 2070 climate change factors (GEI, 2022b).

Aera's water system currently delivers treated domestic water from two active groundwater production wells, Wells 9 and 10, to industrial and commercial customers. The production capacity of the two wells is 707.48 afy. Historical water demand in the water system over the past five years was 685.93 afy. Projected water demand is estimated to be 690.50 afy which includes the Project domestic water demand. Table 5 presents future (2040) water supply in Aera's water system.

Table 5: Future (2040) Water Supply Availability in Aera's Water System

Current Source	Current (2020) Water Supply	Single Dry Year	Multiple Dry Years		
			Year 1	Year 2	Year 3
Groundwater	685.93	690.50	690.50	690.50	690.50
Total Supply	**685.93**	**690.50**	**690.50**	**690.50**	**690.50**

Notes:
All units in acre-feet

Conclusion: *Groundwater production in the Subbasin and WDWA plan area in WY2020 is estimated to be 1,835,054 af (Todd, 2020) in GEI (2022a). Groundwater production in the WDWA and BVGSA plan areas in 2020 is estimated to be 73,011 af (BWSD, 2021; BMWD, 2021; LHWD, 2021; GEI, 2022b). In 2040, projected groundwater production in the WDWA and BVGSA plan areas is estimated to be 88,142 af (Aquilogic, 2022; GEI, 2022b), which takes into account climate change factors and implementation of projects and management actions number 3 in the WDWA plan area. Surface water deliveries, streamflow diversions and water transfers and exchanges to the Subbasin in WY2020 are estimated to be 1,405,576 af (Todd, 2020) in GEI (2022a). Surface water deliveries in the WDWA plan area in 2020, including SWP and other surface water, and groundwater banking recovery and carryover water are estimated to be 275,522 af based on the AWMPs for BWSD (BWSD, 2021), BMWD (BMWD, 2021) and LHWD (LHWD, 2021). Surface water deliveries in the BVGSA plan area in WY2020 are estimated to be160,864 afy based on 2070 climate change factors (GEI, 2022b). Projected 2040 surface water deliveries in the WDWA plan area re estimated to be 266,290 af (Aquilogic, 2022), which takes into account climate change and implementation of projects and management actions. An estimation of available water supplies in 2040 in the BVGSA is unavailable due to lack of sufficient data in the BVGSA GSP chapter (GEI, 2022b) and KGA Umbrella GSP (GEI, 2022a). Estimated groundwater production in Aera's water system in 2020 is 685.93 af and is projected to increase to 690.50 afy through 2040 once commercial operation of the project commences.*

Project Water Demands

The Project estimates a construction water demand of 400 af over a 2.5-year period which is anticipated to be purchased from existing BWSD SWP entitlements and other existing long-term water contracts with individuals. An annual industrial demand of 1,223 af would be met by treated produced water from the Belridge Oil Field. Aera also has approximately 7,000AF of surplus SWP water stored in various groundwater banking projects through the BWSD that may be accessed at any time, subject to the groundwater banking project's pumping capacity. Domestic water demands estimated at 21.72 afy, will be supplied by Aera's water system, which consists of two production wells. This water demand represents a

de minimis use. It is anticipated that the annual demand will remain constant over the 20-year projection as shown in Table 6.

Table 6: Anticipated Future (2040) Project Water Demand

Land Use Category	Total Acres	Average Water Demand (afy/acre)	Estimated Total Water Demand (afy)
Unincorporated Kern County	13,243	0.092	1,223
TOTAL	13,243	0.092	1,223

Note:
afy = acre-feet per year

Comparison of Available Water Supplies Versus Demand

Section 10910 (c)(3) of the Water Code states, “The water supply assessment for the Project shall include a discussion with regard to whether the public water system’s total projected water supplies available for normal, dry, and multiple dry water years during a 20-year projection will meet the projected water demand associated with the proposed Project, in addition to the public water system’s existing and planned future uses, including agricultural and manufacturing uses.”

As described in *Belridge Water Storage District 2020 Agricultural Management Plan*, (BWSD, 2021), the BWSD has a Table A entitlement of SWP water of 121,508 afy of which 111,157 and 5,578 afy, respectively, are under contract for agricultural and industrial use. The balance, 4,773 afy, is held by BWSD for operational losses. The BWSD has also banked 85,000 af in the Pioneer and Berenda Mesa groundwater banks operated by KCWA. In 2020, surface water deliveries, including imported SWP and other surface water and groundwater banking recovery and carryover water, was reported to be 99,104 af (BWSD, 2021). In 2020, groundwater production in the BWSD was reported to be 1,187 af (BWSD, 2021). BVWSD has a Kern River entitlement of 156,000 afy and a SWP Table A entitlement of 21,300 afy almost all for agricultural use. Although BVWSD has historically stored surplus Kern River and SWP water in various local groundwater banks, the quantity of banked surface water supplies as of 2020 is not available in the BVGSA GSP (GEI, 2022b) or the KGS Umbrella GSP (GEI, 2022a).

In 2020, surface water deliveries, including imported SWP and other surface water and groundwater banking recovery and carryover water totaling 275,522 af was delivered to agricultural and industrial water users in the WDWA (BWSD, 2021; BMWD, 2021; LHWD, 2021). In 2020, groundwater production in the WDWA was 10,276 af (BWSD, 2021; BMWD, 2021; LHWD, 2021). According to the individual 2020 AWMPs for BWSD, BMWD and LHWD, the groundwater was pumped for blending with imported SWP and other surface water supplies due to poor groundwater quality and reduced reliability of SWP water supplies.

In 2020, agricultural and industrial water demands in the BWSD and WDWA plan area were reported to be 128,708 af (BWSD, 2021) and 331,000 af, (BWSD, 2021; BMWD, 2021; LHWD, 2021), respectively.

Tables 7 and 8 present future water supply versus Project water demand in WY2040 based on Attachment H (Todd, 2020) in *Kern Groundwater Authority Groundwater Sustainability Plan* (GEI, 2022a). The projected water budgets presented in GEI (2022a) extend from 2021 to 2070 and take into account

climate change factors and implementation of projects and management actions to sustainably manage groundwater supplies in the Subbasin. It should be noted that the Subbasin GSP water budgets do not quantify water supplies or demands at build-out for any municipality or unincorporated population center in the Subbasin. There are no municipalities in the WDWA and BVGSA plan areas; however, the unincorporated town of Lost Hills is located in the WDWA and the unincorporated town of Buttonwillow is located in the BVGSA. Nevertheless, as shown in Tables 6 and 7 there is ample supply of water available to the Project within the WDWA plan area to meet Project water demands.

Table 7: Future (WY2040) Water Supply Versus Project Water Demand at Build-Out in the Subbasin (a)

Current Source	Current Water Year	Single Dry Water Year	Multiple Dry Water Years		
			Year 1	Year 2	Year 3
Groundwater (Subbasin)	1,835,054	1,835,054	1,835,054	1,835,054	1,835,054
Imported Surface Water (SWP and CVP), Local Streamflow, Recycled/Reused Water	1,405,576	1,405,576	1,405,576	1,405,576	1,405,576
Total Project Demand	1,245	1,245	1,245	1,245	1,245
Total Supply	3,239,385	3,239,385	3,239,385	3,239,385	3,239,385

Note:

(a) All units in acre-feet

(b) Total Project demand is the sum of the estimated quantity of industrial water and domestic water.

Table 8: Future (2040) Water Supply Versus Project Demand at Build-Out in Aera's Water System

Current Source	Future (2040) Water Supply	Single Dry Year	Multiple Dry Years		
			Year 1	Year 2	Year 3
Groundwater	707.48	707.48	707.48	707.48	707.48
Total Project Demand*	21.72	21.72	21.72	21.72	21.72
Estimated Surplus/Shortfall	685.76	685.76	685.76	685.76	685.76

Notes:
All units in afy
Estimates from Aera
* Assumes only the commercial operation domestic water demand portion of the Project that may be supplied by Aera's water system

Conclusion: *The estimated annual demand for the Project is not a de minimis use compared to existing available water supplies in the Subbasin. However, commercial Project water demand is estimated to average up to 1,223 afy and will be produced water from Aera's Belridge Oil Field. Aera also has approximately 7,000AF of surplus surface water stored in various groundwater banking projects through the BWSD that may be accessed at any time, subject to the groundwater bank's pumping capacity.*

Domestic water demands for commercial operation of the Project are estimated to be 21.72 afy and will be provided by Aera's water system. As a result, there are adequate water supplies available in the WDWA and BVGSA plan areas to serve the proposed Project under all water year conditions.

2.1.7 Conclusions

According to the requirements of Water Code Section 10910(c)(3), the water supply assessment shall include a discussion of, "whether the public water system's total projected water supplies available will meet the projected water demand associated with proposed Project, in addition to the public water system's existing and planned future uses."

The following is a summary of the water supply assessment for this Project:

- The Project will be under environmental review pursuant to the requirements of CEQA; therefore, the information contained in this assessment will be used to support the analysis contained in the CEQA document.
- The Project meets the definition of a "Project" under Water Code Section 10912(a).
- The Project is located in the unincorporated portion of Kern County. Construction water demand, estimated to be 400 af over a 2.5-year period, will be served by BWSD and other existing long-term water contracts with individuals. Commercial water demand is estimated to average up to 1,223 afy and will be produced water from Aera. Aera also has approximately 7,000AF of surplus surface water stored in various groundwater banking projects through the BWSD that may be accessed at any time, subject to the groundwater bank's pumping capacity. Domestic water demands for commercial operation of the Project are estimated to be 21.72 afy and will be provided by Aera's water system.
- The construction water demand has not been accounted for in the *BWSD 2020 Agricultural Water Management Plan (BWSD, 2021),* however, 2020 industrial water use in the BWSD was 689 af, and 5,578 afy is budgeted annually by BWSD for industrial water use.
- Groundwater production capacity from Aera'swater system is 707.48 afy and historical demand over the past five years was 685.93 afy. Projected water system water demand is estimated to be 690.50 afy which includes the Project's domestic water demand. Aera'swater system wells are located within the BVWSD and BVGSA in the Subbasin. According to the BVGSA GSP chapter (GEI, 2022b), groundwater production in the BVGSA plan area for WY1993 to WY2015 (historical condition) is estimated to be 62,742 afy. Groundwater production in 2020 is not available. BVWSD (personal communication, June 30, 2023) estimated the 2040 water demand to be 140,000 af.
- BVWSD is entitled to 156,000 afy of surface water from the Kern River; however, during the period 2006 to 2015 Kern River deliveries via the East Side Canal averaged 40,887 afy. BVWSD is also contracted with the Kern County Water Agency to receive 21,300 afy of Table A State Water Project (SWP) water and 3,750 afy of Article 21 SWP water. During the period 2006 through 2015, BVWSD received an average of 53,099 afy of SWP water via the California

Aqueduct (GEI, 2022b). Average surface water deliveries from 2006 to 2015 averaged 93,986 afy. Estimated 2020 and 2040 surface water deliveries to the BVWSD are not individually provided in the BVGSA GSP chapter (GEI, 2022b) or the KGA "Umbrella" GSP (GEI, 2022a). The WSA addresses only the BMA portion of the BVGSA which occupies 91% percent of the BVWSD service area.

- The estimated cumulative and annual decline in groundwater in storage in the BVGSA between WY1993 and WY2015 is 275,480 af and 11,977 afy, respectively (GEI, 2022b). The estimated annual change in ground in storage between WY1995 and WY2014 using the C2VSimFG-Kern groundwater model is -17,362 afy (Todd, 2019).

- The Subbasin has been designated as a critically overdrafted high-priority basin by the DWR and is managed by 11 GSAs that submitted five original and revised GSPs to DWR in January 2020 and July 2022, respectively.

- According to Kern Groundwater Authority Groundwater Sustainability Plan (GEI, 2022a), groundwater production in the Subbasin in WY2020 is estimated to be 1,835,054 af and projected to be 1,648,770 af from WY2021 to WY2040 based on the CV2SimFG-Kern groundwater model simulations assuming 2070 climate change conditions and implementation of projects and management actions.

- According to DWR (2006), groundwater storage capacity in the Subbasin was estimated to be 40,000,000 af in 2002 (KCWA, 2002). The dewatered storage at this time was also reported to be 10,000,000 (KCWA, 2002).

- According to *Kern Groundwater Authority Groundwater Sustainability Plan* (GEI, 2022a), the cumulative change in the amount of groundwater in storage in the Subbasin between 1995 and 2021 is estimated to have declined by 1,812,211 af for an average decline of 69,700 afy.

- The projected cumulative and annual average decline in the amount of groundwater in storage in the Subbasin from WY2021 to WY2040 taking into account 2070 climate change conditions and implementation of projects and management actions is estimated to be 4,485,720 af and 224,286 afy, respectively (Todd, 2020) in (GEI, 2022a).

- The projected annual average decline in the amount of groundwater in storage in the WDWA plan area WY2021 to WY2040 taking into account 2070 climate change conditions and implementation of projects and management actions is estimated to be 46,000 afy (Todd, 2020) in (GEI, 2022a) and revised to approximately 22,000 afy by Aquilogic (2022) based on assumed modeling discrepancies related to the amount of groundwater production using the CV2SimFG-Kern groundwater model simulation.

- The estimated groundwater recharge in the Subbasin and WDWA plan area in WY1995-WY2014 is 1,400,362 afy (Todd, 2020) in (GEI, 2022a) and 92,341 afy (Aquilogic, 2022), respectively, based on CV2SimFG-Kern groundwater modeling simulations (Todd, 2020) in (GEI, 2022).

- The estimated WY1995-WY2014 sustainable yield in the Subbasin and the WDWA plan area is 1,313,260 afy (Todd, 2020) in (GEI, 2022a) and 34,079 afy (Aquilogic, 2022), respectively.

Although there is a historical and projected decline in groundwater in storage in the Subbasin and the WDWA and BVGSA plan areas, there is sufficient imported surface water available from BWSD and Aera's banked water to meet the construction water demands of the Project. In addition, commercial water demands will be met by produced water from Aera and domestic water demands will be served by Aera's water system. As a result, there is sufficient produced water and domestic water supplies available to meet the commercial water demands of the Project.

Based on the results of this assessment, sufficient water supply is available to serve the Project as proposed, and no further analysis should be required.

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Appendix H
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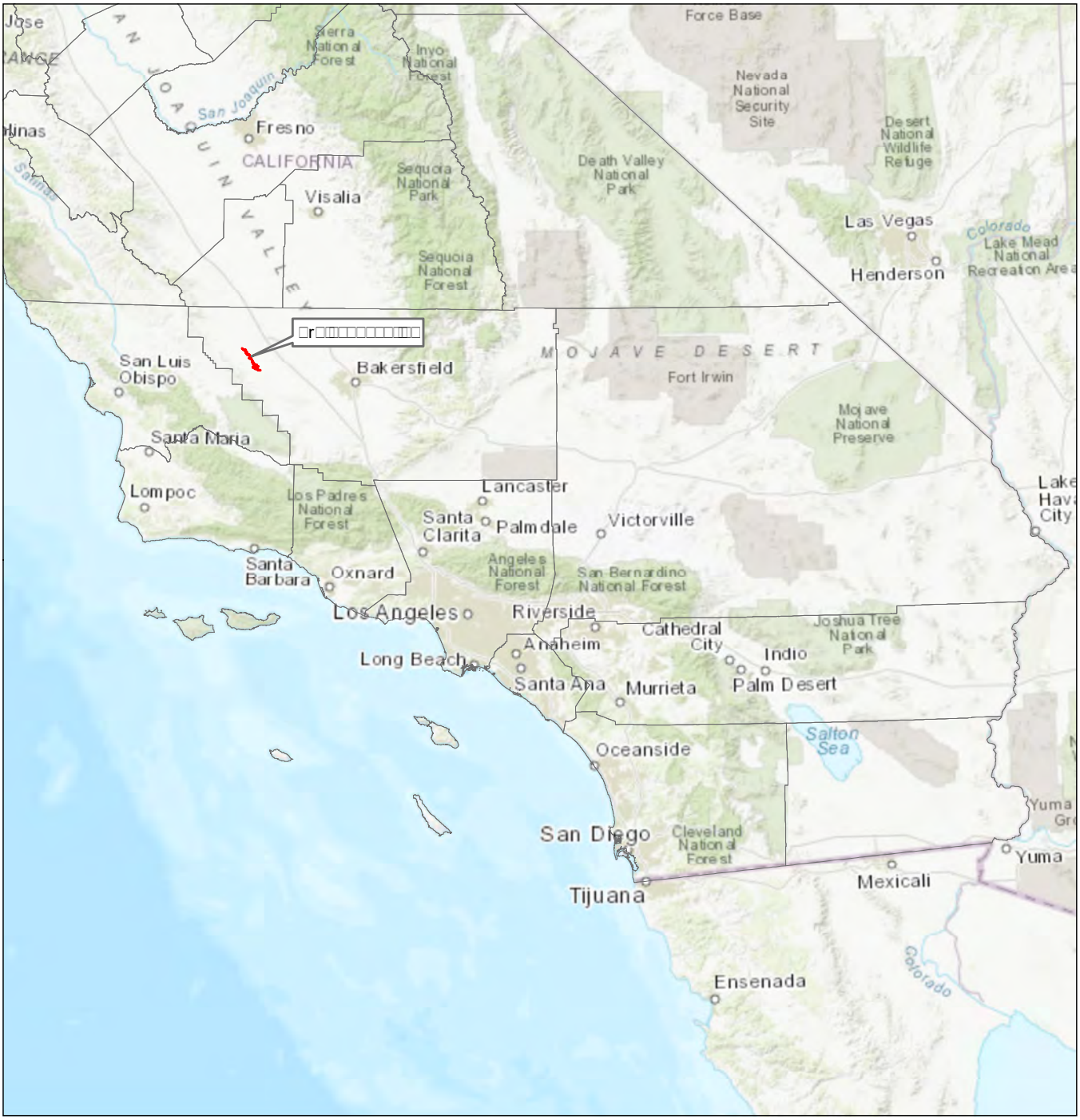
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1.3□ NOISE IMPACT FUNDAMENTALS AND TERMINOLOGY

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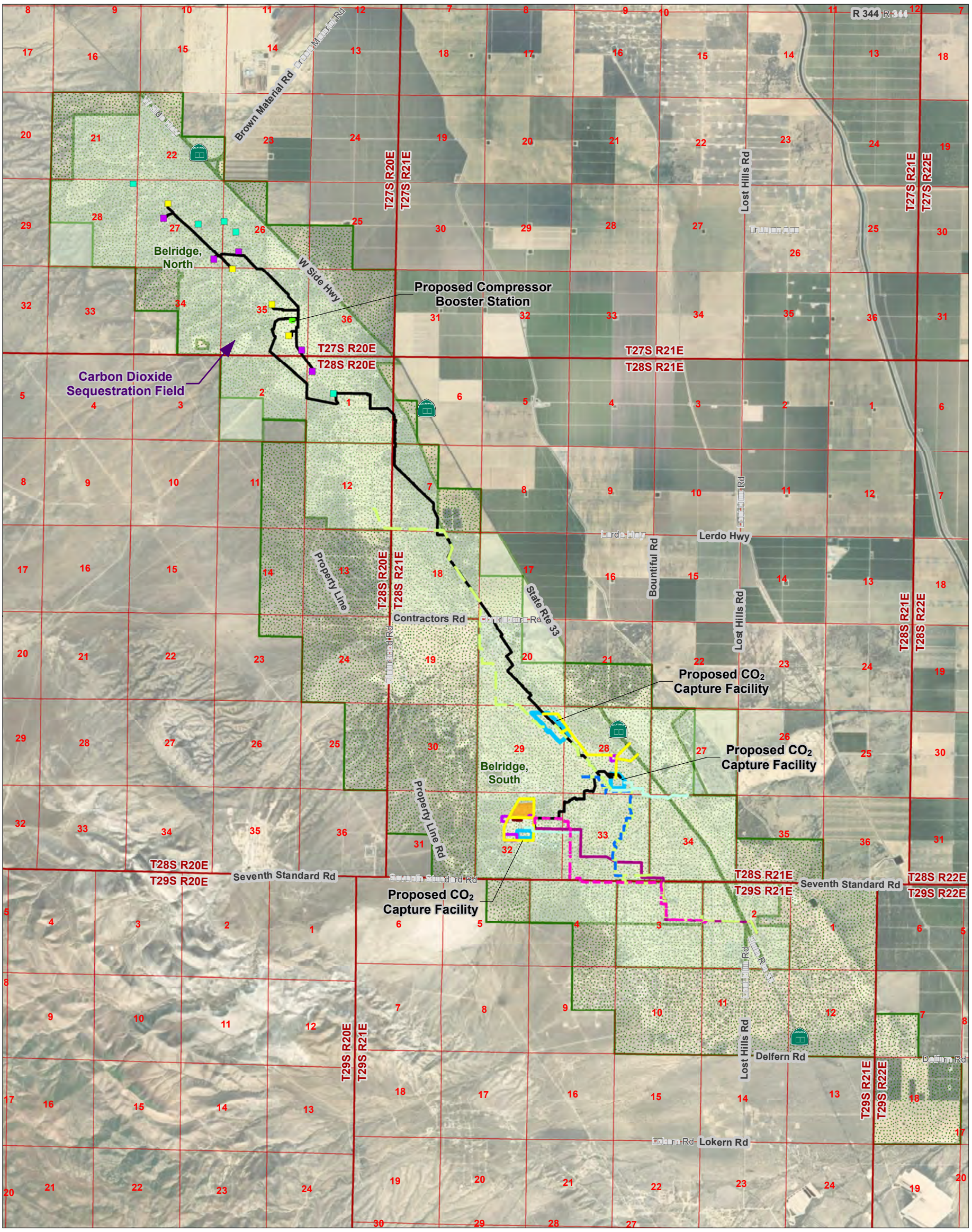
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Figure No.
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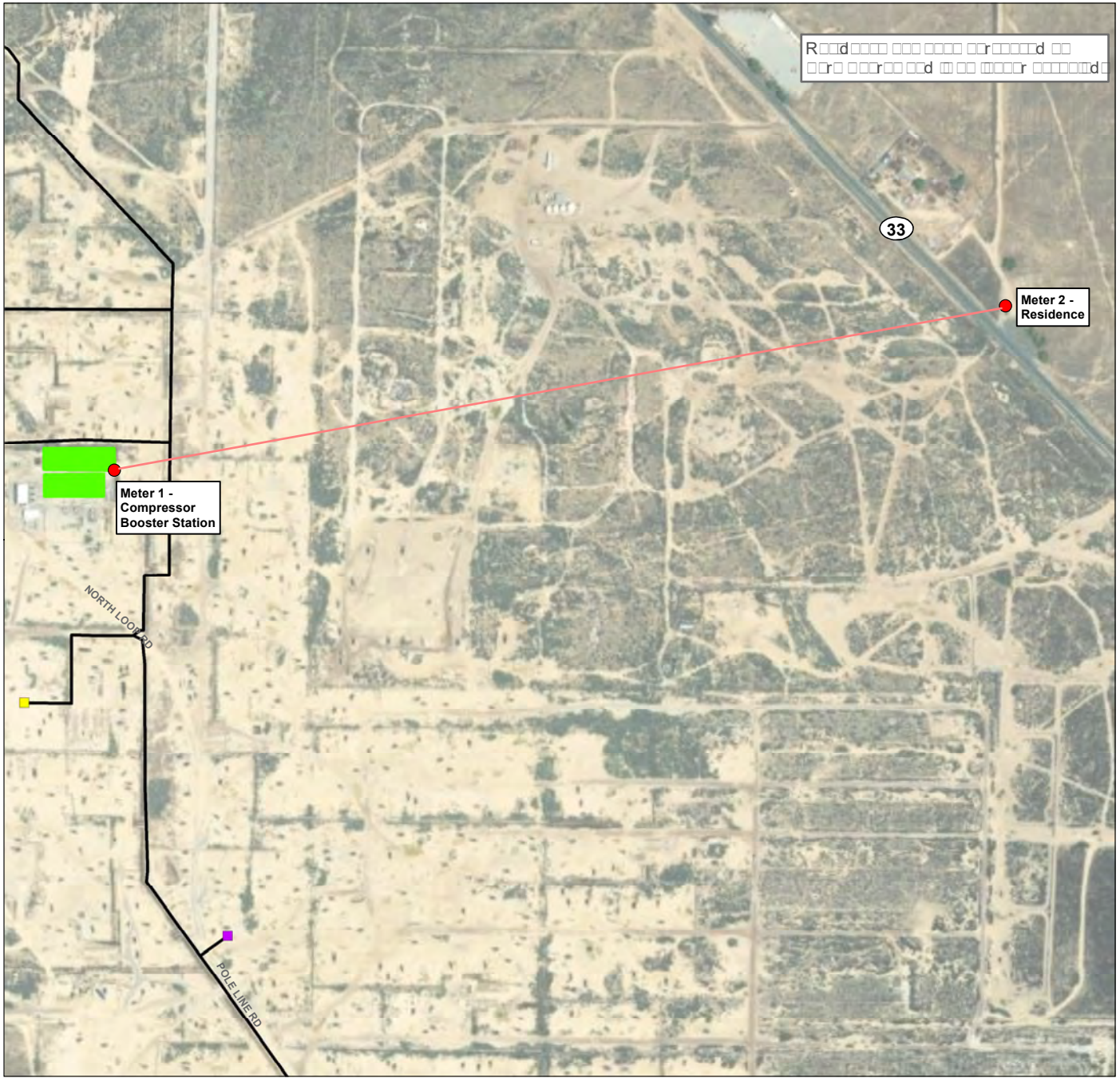
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Figure No.	2
Title	**Belridge Facilities and Pipeline Route**

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2.0□ REGULATORY SETTING

2.1□ COUNTY REGULATIONS

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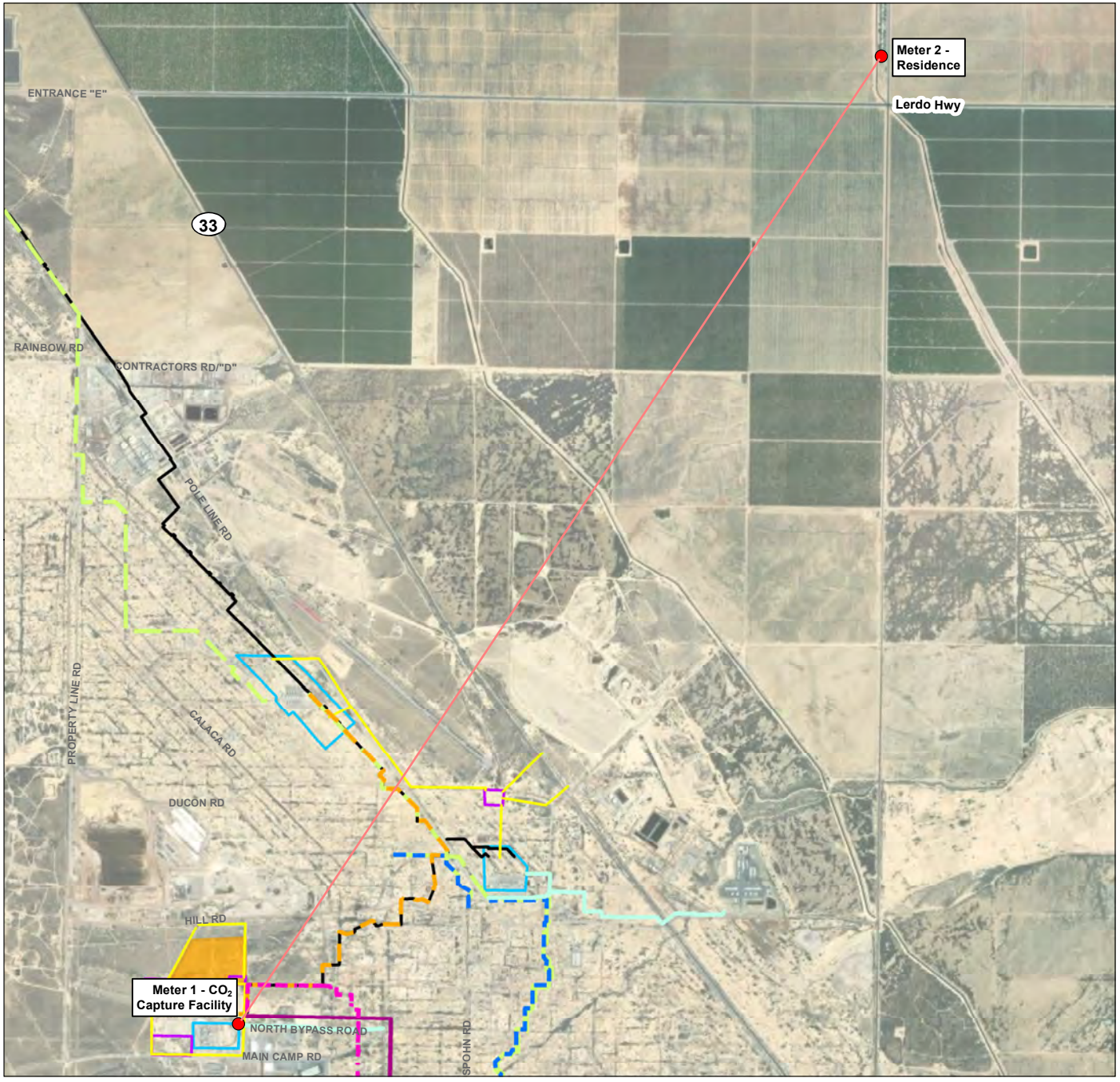
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Figure No.

3

Title

Measurement 1 Setup and Sound Meter Placement



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Figure No.

4

Title

Measurement 2 Setup and Sound Meter Placement

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3.2□ SOUNDPLAN PREDICTIVE MODEL

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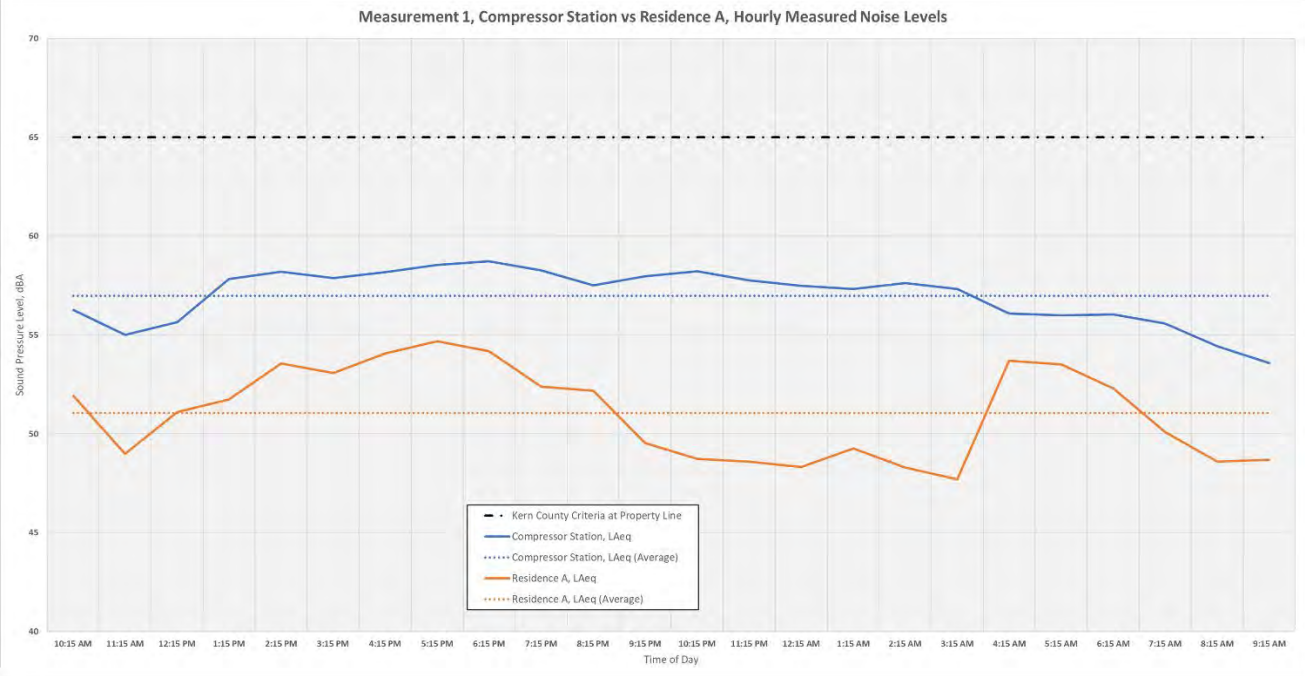
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4.0□ RESULTS AND DISCUSSION

4.1□ MEASURED NOISE LEVELS

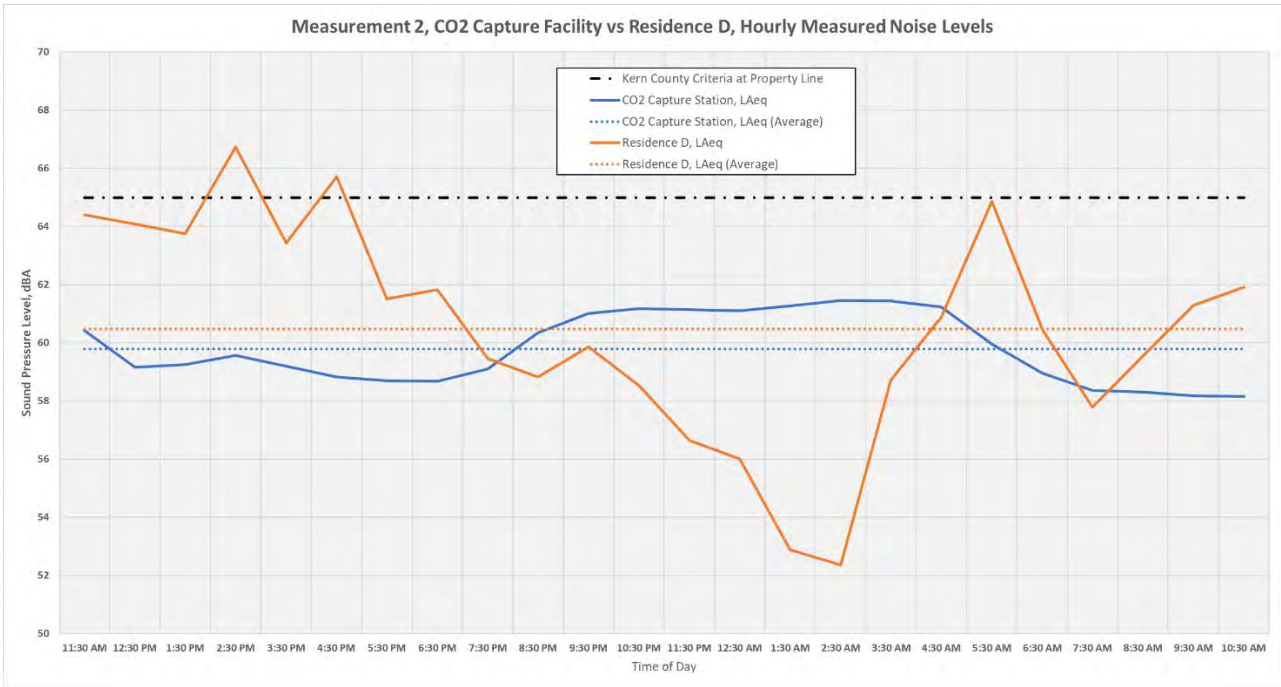
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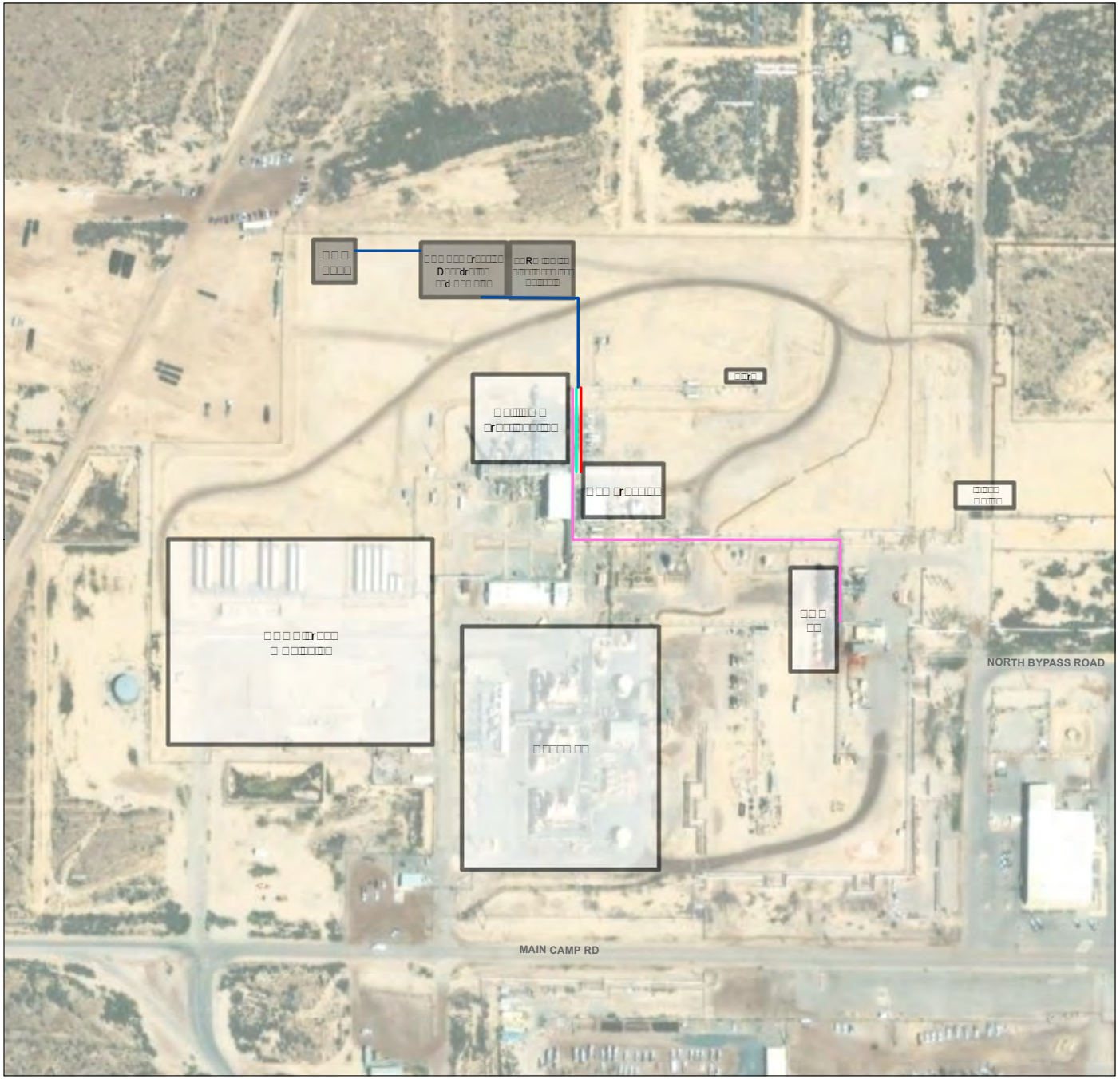


4.2□ SOUNDPLAN PREDICTIVE MODEL

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Stantec

AERA

N

Notes

1. Coordinate system: NAD 1983 UTM Zone 12N
2. Data sources: Aera Energy 2023, Stantec 2023.
3. Coordinates are approximate and may not be surveyed

Project Location

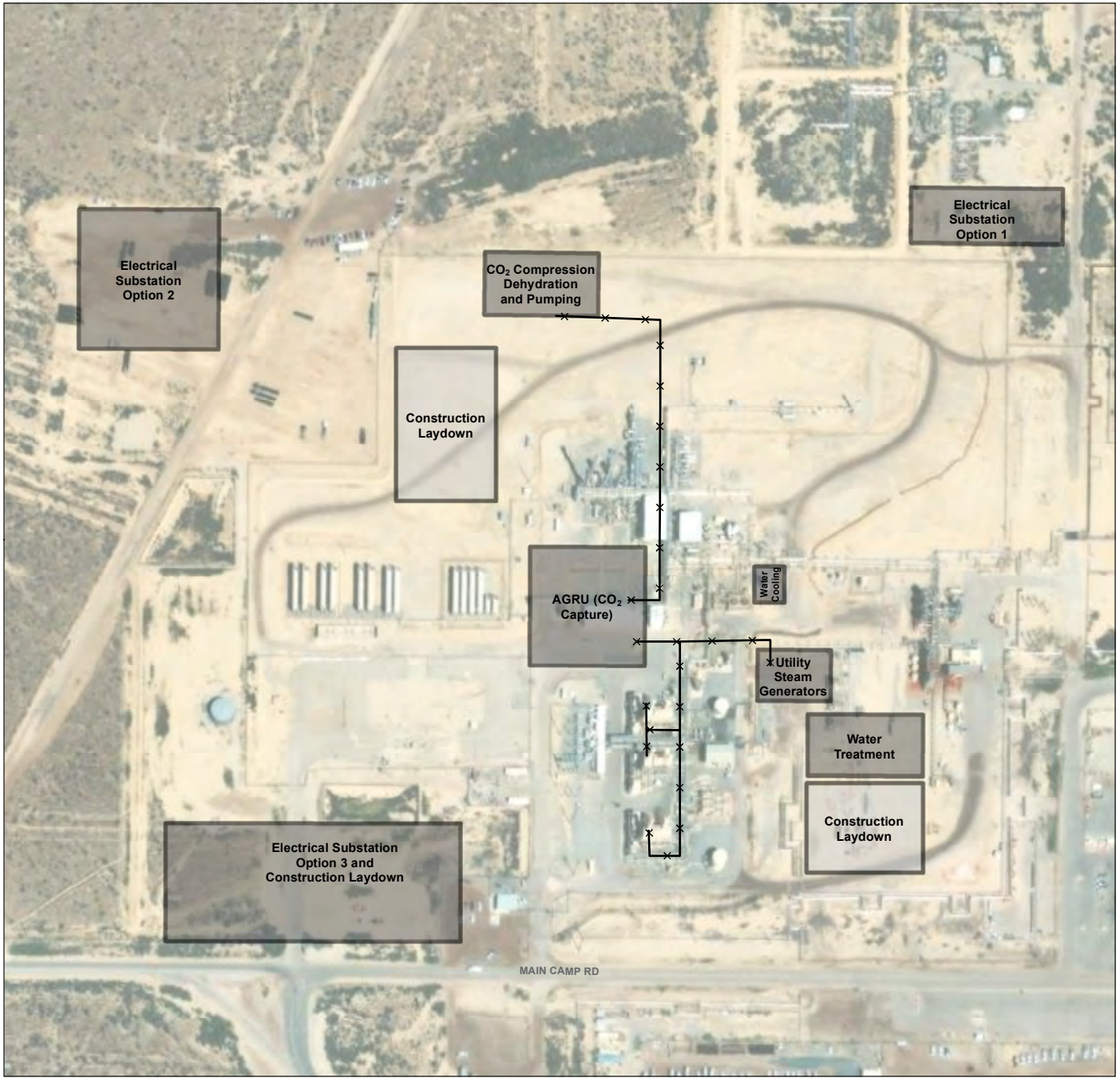
Client/Project

Figure No.

5A

Title

Pre-C Gas Plant 32 Equipment Locations per Configuration



Stantec AERA

N

Notes

1. [illegible]
2. Data source: Aera Energy 2023, Stantec 2023.
3. [illegible]

Project Location

[illegible]

Client/Project

[illegible]

Figure No.

5B

Title

Post-C Cogen 32 Equipment Locations per Configuration

[illegible]



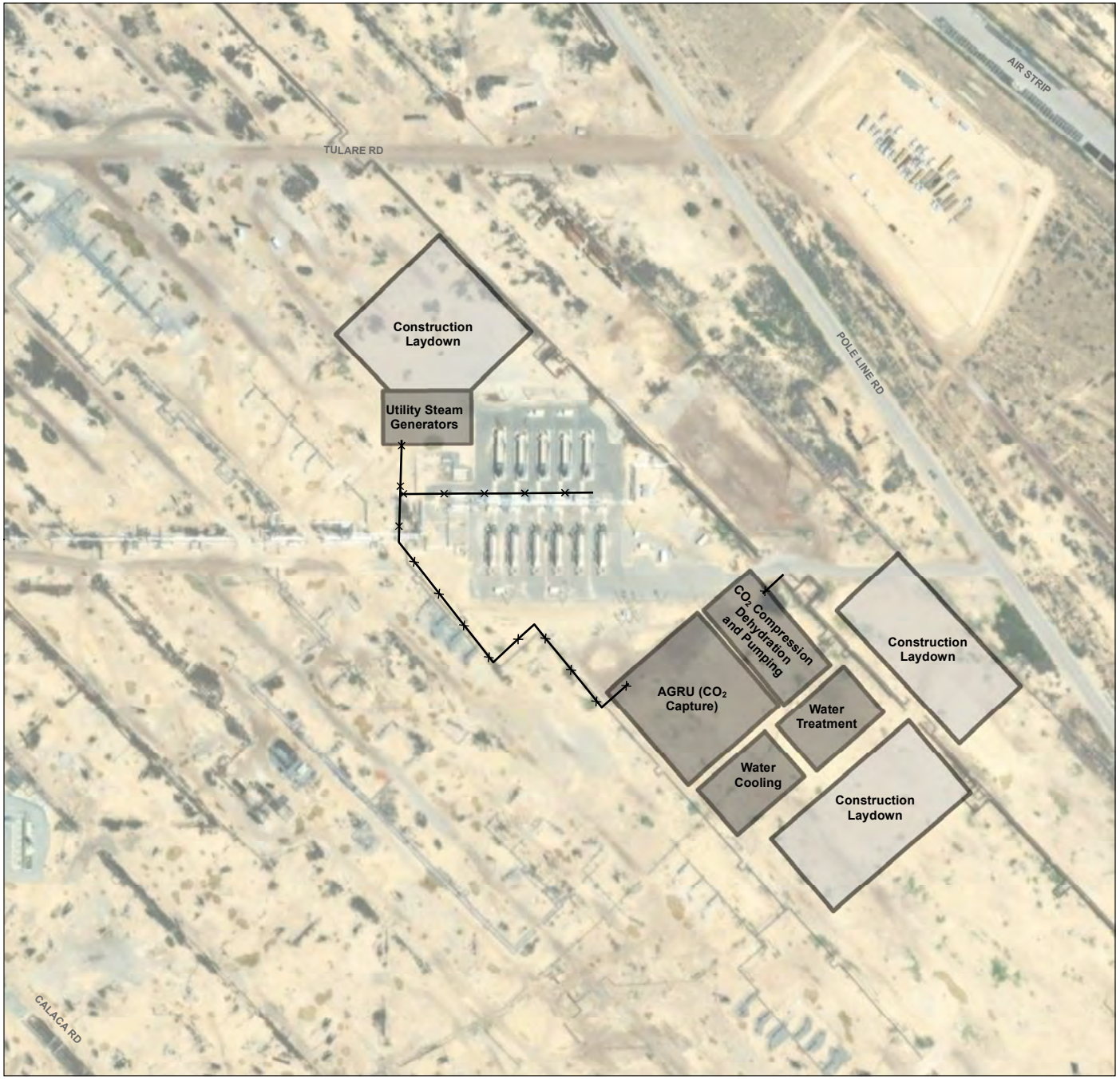
Stantec AERA

Project Location

Client/Project

Figure No.
5C

Title
Post-C SGS 2868 Equipment Locations per Configuration



Stantec AERA

N

Notes

1. [illegible]
2. [illegible] Aera Energy 2023, Stantec 2023.
3. [illegible]

Project Location

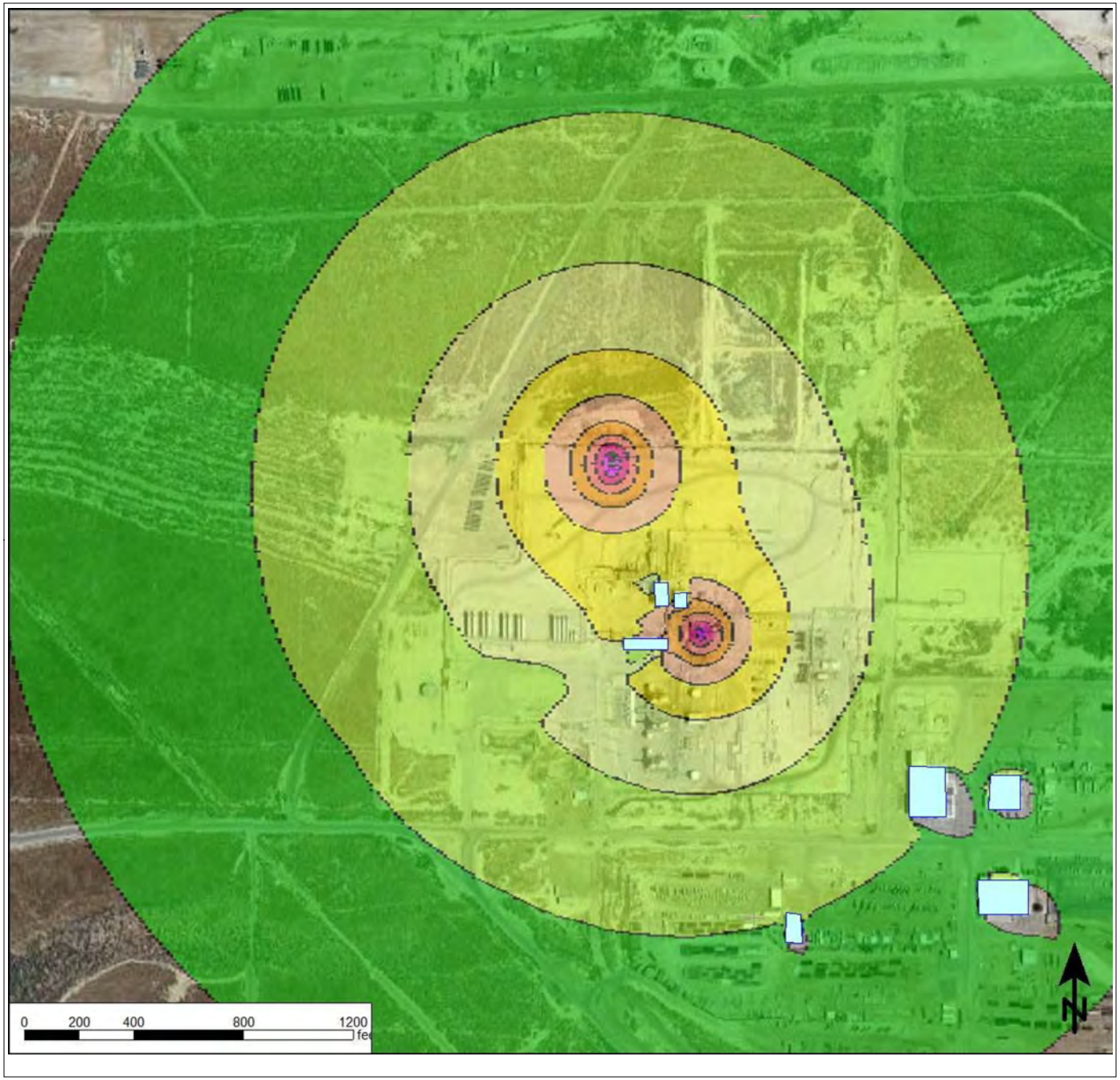
Client/Project

Figure No.

5D

Title

Post-C SGS 2972 Equipment Locations per Configuration



Stantec

Noise Level
Noise Level Day/ Night in dB(A)

>=	95
90 -	95
85 -	90
80 -	85
75 -	80
70 -	75
65 -	70
60 -	65
55 -	60
50 -	55
45 -	50
40 -	45

Legend

- Main building
- Receiver
- Industrial sources point

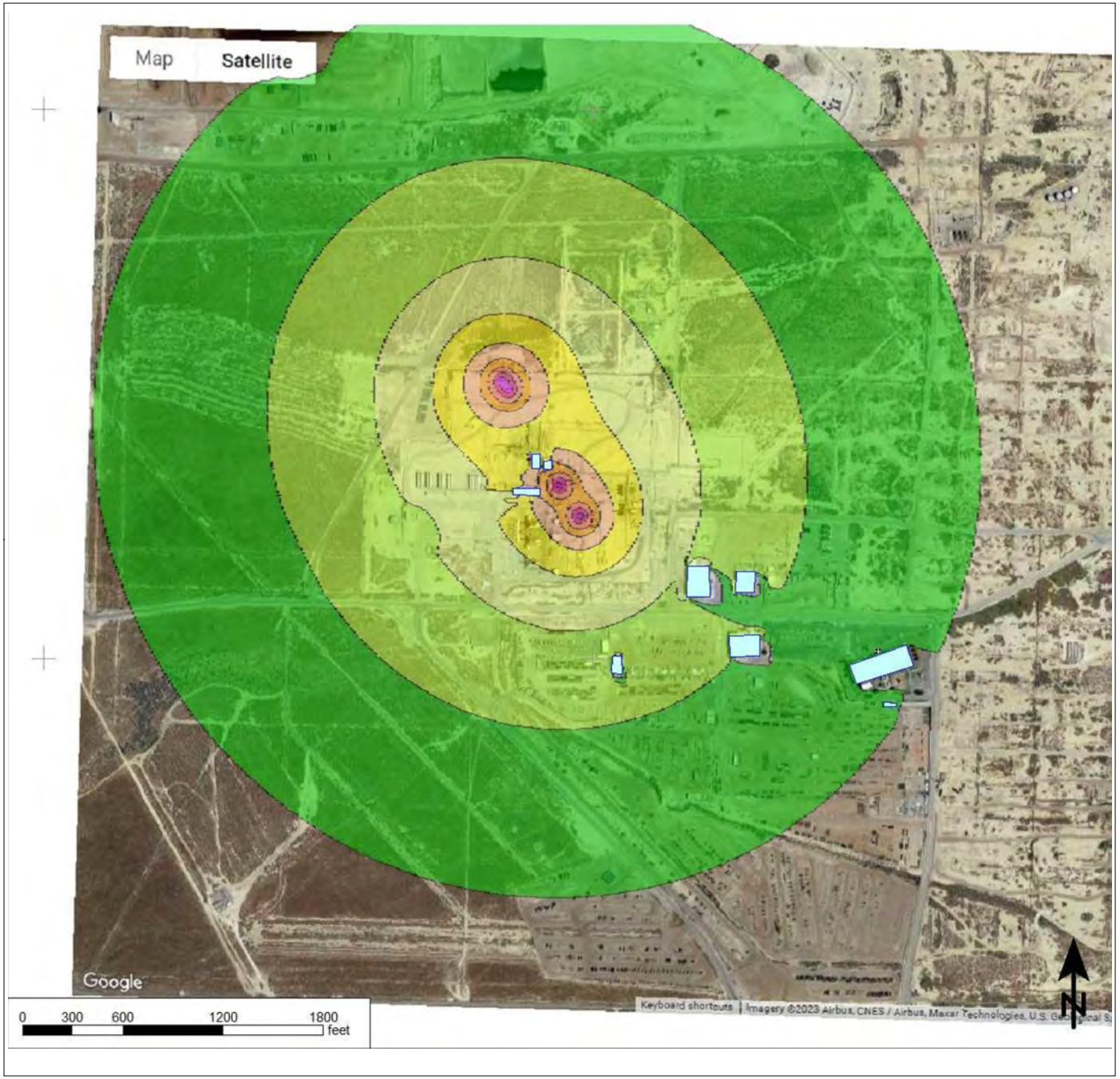
Notes

1. D□□ □□□r□□□□Stantec 2023
2. □□□□□r□□□d□Google Earth Imagery

Project Location	□r□□□r□d □□DL □□ □□23□8□3□
Kern County, California	□R □□SET □□2023-08-31
	□R b□CT □□2023-08-31
Client/Project	185805407
Aera Energy LLC CarbonFrontier Project	
Figure No.	**6**
Title	**Contour Plots for Pre-C Cogen 32 Layout**

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Stantec

Noise Level
Noise Level Day/ Night in dB(A)

>=	95
90 -	95
85 -	90
80 -	85
75 -	80
70 -	75
65 -	70
60 -	65
55 -	60
50 -	55
45 -	50
40 -	45

Legend
- Main building
- Receiver
- Industrial sources point

Notes
1. D□□ □□□r□□□□Stantec 2023
2. □□□□□r□□□d□Google Earth Imagery

Project Location
Kern County, California

□r□□□r□d □□DL □□ □□23□8□3□
□R □□SET □□2023-08-31
□R b□CT □□2023-08-31

Client/Project
185805407

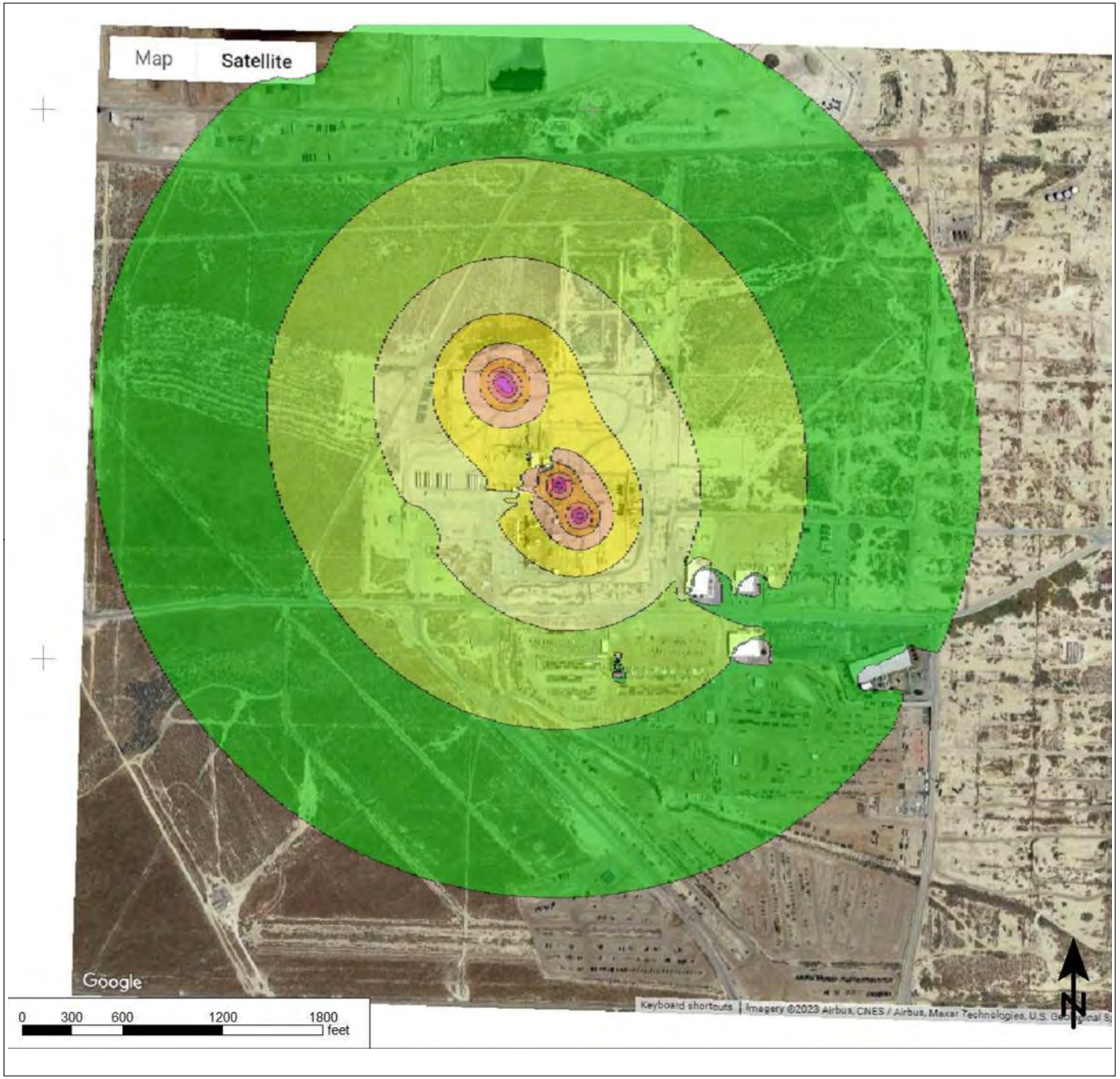
Aera Energy LLC
CarbonFrontier Project

Figure No.
7

Title
Contour Plots for Post-C Cogen 32 Layout

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Stantec

Noise Level
Noise Level Day/ Night in dB(A)

>=	95
90 -	95
85 -	90
80 -	85
75 -	80
70 -	75
65 -	70
60 -	65
55 -	60
50 -	55
45 -	50
40 -	45

Legend
- Main building
- Receiver
- Industrial sources point

Notes
1. D□□ □□□r□□□□Stantec 2023
2. □□□□□r□□□d□Google Earth Imagery

Project Location
Kern County, California

□r□□□r□d □□DL □□ □□23□8□3□
□R □□SET □□2023-08-31
□R b□CT □□2023-08-31

Client/Project
185805407

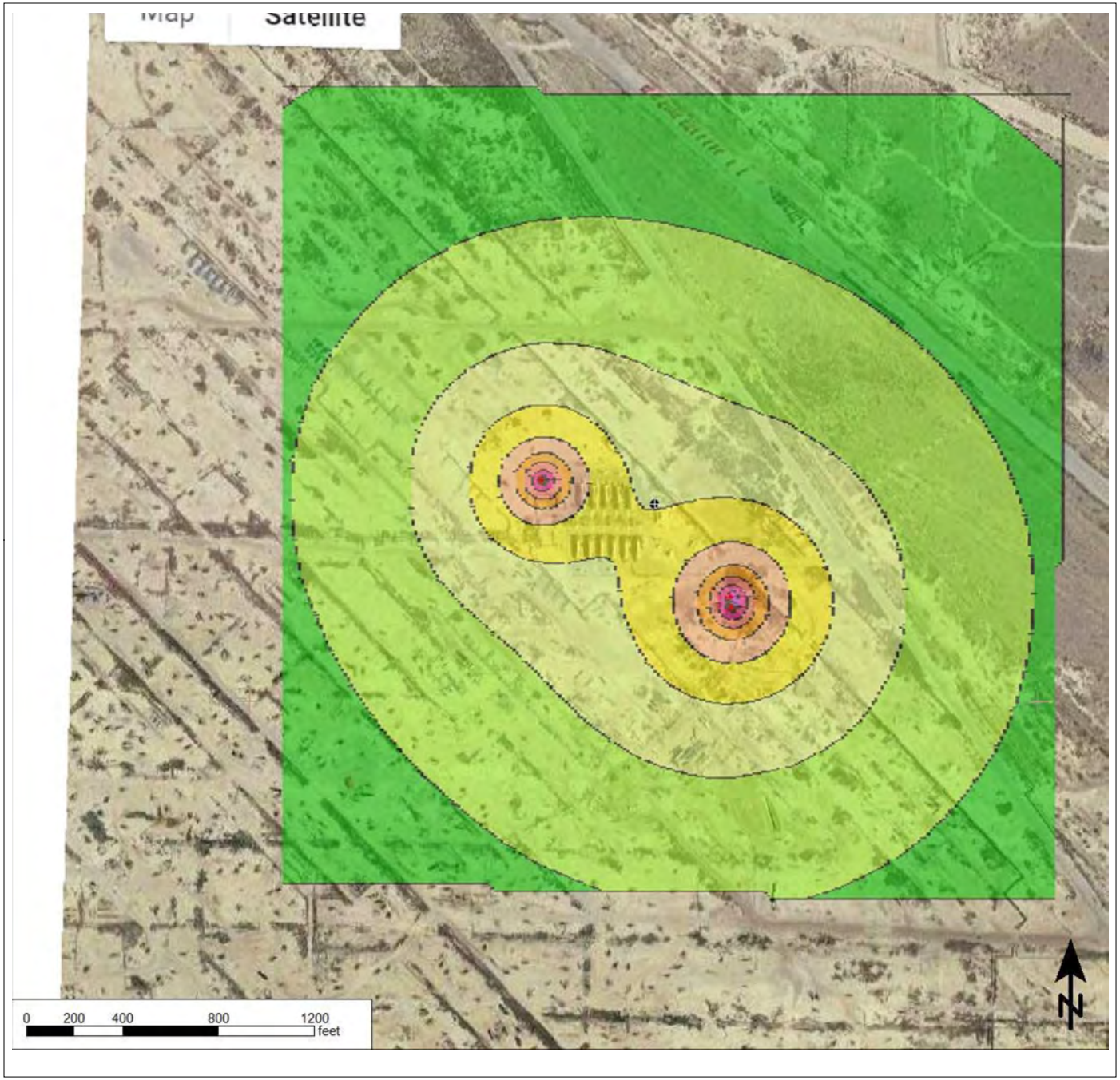
Aera Energy LLC
CarbonFrontier Project

Figure No.
8

Title
Contour Plots for Post-C SGS 2868 Layout

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Stantec

Noise Level
Noise Level Day/ Night in dB(A)

>=	95
90 -	95
85 -	90
80 -	85
75 -	80
70 -	75
65 -	70
60 -	65
55 -	60
50 -	55
45 -	50
40 -	45

Legend

- Main building
- Receiver
- Industrial sources point

Notes

1. D□□ □□r□□□Stantec 2023
2. □□□□r□□d□Google Earth Imagery

Project Location
Kern County, California

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Client/Project
185805407

Aera Energy LLC
CarbonFrontier Project

Figure No.
9

Title
Contour Plots for Post-C SGS 2972 Layout

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Appendix I

Traffic Impact Study

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CARBON FRONTIER PROJECT

Traffic Impact Study

September 28, 2023

Prepared for:
Aera Energy LLC
10000 Ming Avenue
Bakersfield, CA 93311

Prepared by:
Stantec Consulting Services Inc.
38 Technology Drive, Suite 200
Irvine, CA 92618

Project Number:
185805372

The conclusions in the Report titled *Aera Energy Carbon Frontier Project Traffic Impact Study* are Stantec's professional opinion, as of the time of the Report, and concerning the scope described in the Report. The opinions in the document are based on conditions and information existing at the time the scope of work was conducted and do not take into account any subsequent changes. The Report relates solely to the specific project for which Stantec was retained and the stated purpose for which the Report was prepared. The Report is not to be used or relied on for any variation or extension of the project, or for any other project or purpose, and any unauthorized use or reliance is at the recipient's own risk.

Stantec has assumed all information received from Aera Energy LLC (the "Client") and third parties in the preparation of the Report to be correct. While Stantec has exercised a customary level of judgment or due diligence in the use of such information, Stantec assumes no responsibility for the consequences of any error or omission contained therein.

This Report is intended solely for use by the Client in accordance with Stantec's contract with the Client. While the Report may be provided by the Client to applicable authorities having jurisdiction and to other third parties in connection with the project, Stantec disclaims any legal duty based upon warranty, reliance or any other theory to any third party, and will not be liable to such third party for any damages or losses of any kind that may result.

Prepared by: 

Sandhya Perumalla, ENV SP
Senior Transportation Planner

Reviewed by: 

Daryl Zerfass, PE, PTP
Principal, Transportation Planning & Traffic Engineering

Table of Contents

ACRONYMS / ABBREVIATIONS II

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APPENDIX A KERN COUNTY CUMULATIVE PROJECT LIST A-1

Acronyms / Abbreviations

AADT	Annual average daily traffic
ADT	Average daily traffic
Aera Energy	Aera Energy LLC
Caltrans	California Department of Transportation
CCS	Carbon capture and sequestration
CEQA	California Environmental Quality Act
CO_2	Carbon dioxide
COG	Council of Governments
HCM	Highway Capacity Manual
LOS	Level of Service
OPR	Office of Planning and Research
SB	Senate Bill
SCS	Sustainable Communities Strategy
SR	State Route
VMT	Vehicle Miles Traveled

1 Introduction

Stantec Consulting Services Inc. (Stantec) has performed a traffic impact study for the construction and operation of the proposed Aera Energy Carbon Frontier carbon capture and sequestration (CCS) project (Project), located within the South and North Belridge oil fields in western Kern County, California. See Figure 1 for Project Location Map showing the Project location. Aera Energy LLC (Aera Energy) is seeking approval of a conditional use permit for the Project from Kern County Planning and Natural Resources Department (County). The purpose of this analysis is to determine the amount of traffic generated by the Project during construction and operation and to identify the effect of the Project on the roadway circulation system.

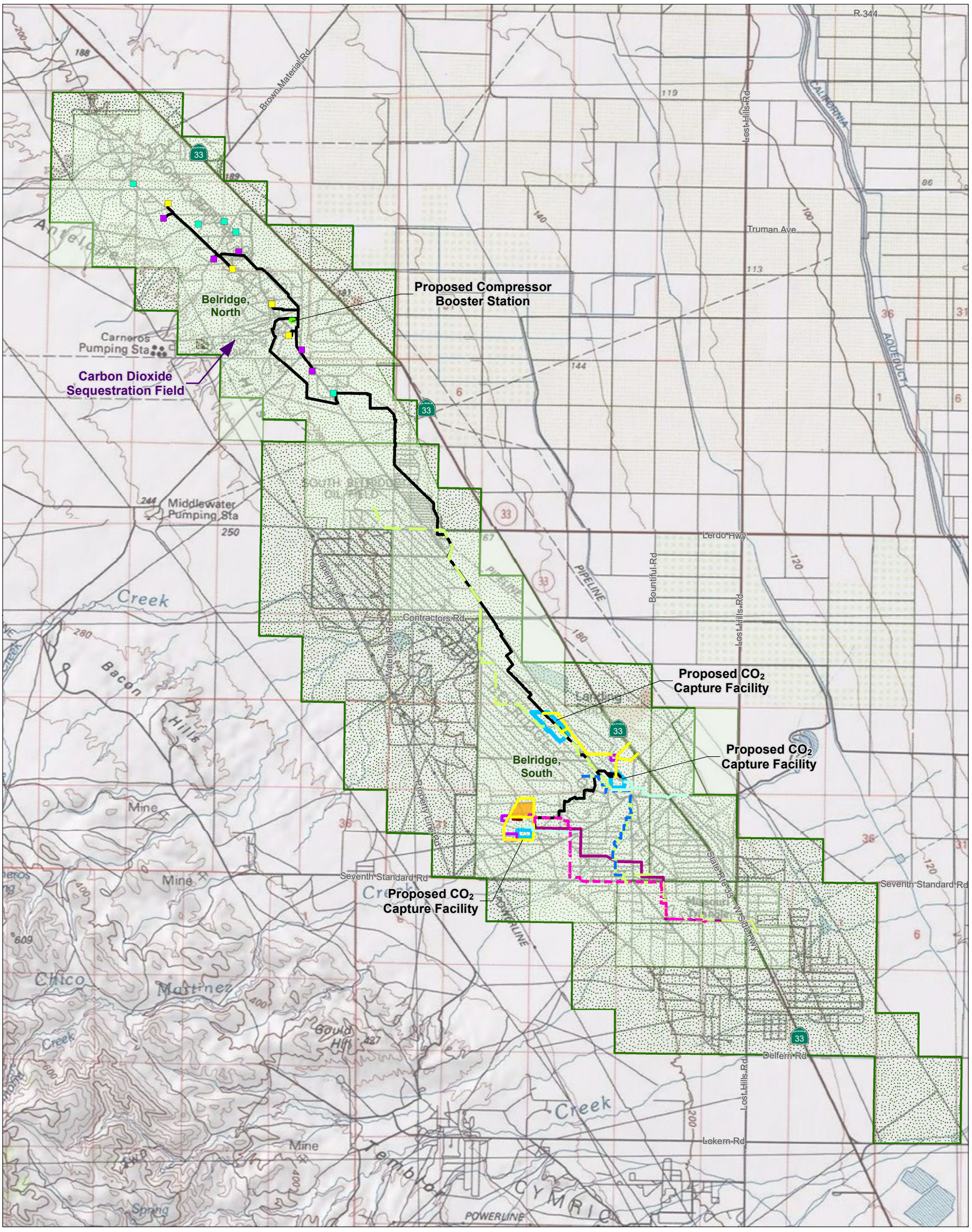
1.1 Proposed Project

The Project site is located within the Central Valley portion of western Kern County. The Project would capture CO_2 from existing produced gas streams (pre-combustion) and emissions from existing stationary sources (post-combustion) within the South Belridge Oil Field and transport the CO_2 through a pipeline to the North Belridge Oil Field for injection at dedicated Underground Injection Control (UIC) Class VI injection wells. The proposed underground CO_2 sequestration field, approximately 2,632 acres in size would be located within the North Belridge Oil Field. Oil and gas production activities within the North Belridge 64 zone would cease as a result of the implementation of the proposed Project.

The South Belridge and North Belridge oil fields are contiguous and located approximately seven miles southwest of the community of Lost Hills and west of State Route (SR) 33. Together, the two Belridge oil fields cover an area of approximately 13 miles long and three miles wide. The main entrance to the South Belridge Oil Field where the carbon dioxide (CO_2) capture facilities would be constructed, would be accessible by Main Camp Road, either from private Oasis Road off Seventh Standard Road or directly from Seventh Standard Road, west of SR 33.

The Project injection and monitoring wells, processing facilities, pipelines, and transportation infrastructure would be built out over a 3-year period, anticipated to start in 2025. The Project is expected to operate for up to 20 years until it is deemed uneconomic or undesirable to continue operation.

Based on the data provided by Aera Energy, the number of workers would vary throughout the course of any given year depending upon the construction activities underway. However, during peak construction periods, the estimated number of workers on-site at one time would be approximately 300 workers. After Project buildout, the Project would require an operational staff up to 10 employees on-site.





Notes
1. Coordinate System: NAD 1983 StatePlane California V FIPS 0405 Feet
2. Data Sources: CalGEM, 2019, Parcels from Kern County 2020. Stantec 2022, 2023.
3. Background: Sources: Esri, HERE, Garmin, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), (c) OpenStreetMap contributors, and the GIS User Community
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- Oil Field Administrative Boundary
- Proposed Preliminary CUP Boundary

Project Components

- Proposed CO_2 Injection Wells
- Existing Oil Wells to be Converted to CO_2 Injection Wells
- Proposed Monitoring Wells
- Existing Del Sur Gas Line to Gas Plant 32
- Existing Steam Line Routes
- Proposed CO_2 Pipelines
- Potential Produced Water Lines Routes
- Potential Power Line Routes
- Potential Steam Line Routes
- Tulare CVR to GP32 (Optional)
- Proposed Compressor Booster Station
- Potential Substation Locations
- Pre-Combustion Facilities
- Proposed CO_2 Capture Facility
- Proposed Staging Area Adjacent to Gas Plant 32

0 6,200 12,400 Feet

(At original document size of 11x17)
1:74,400

N

Stantec AERA

Project Location	Prepared by DL on 2023-09-28
Kern County,	TR by SET on 2023-09-28
California	IR by ES on 2023-09-28
Client/Project	185805407

Aera Energy LLC
CarbonFrontier Project

Figure No.
1

Title
Project Location Map

V:\1858\Active\185805372_BelridgeCCS\Figure1_RegionalVicinity_11x17_DL05042022.mxd Revised: 2023-09-28 By: Dalaw

Disclaimer: This document has been prepared based on information provided by others as cited in the Notes section. Stantec has not verified the accuracy and/or completeness of this information and shall not be responsible for any errors or omissions which may be incorporated herein as a result. Stantec assumes no responsibility for data supplied in electronic format, and the recipient accepts full responsibility for verifying the accuracy and completeness of the data.

2 Existing Conditions

2.1 Existing Roadway System

State Route 33 (SR 33) is a two-lane undivided highway, located approximately three miles east of the site, that provide regional access to the Project site. It runs north-south in the vicinity of the Project. Seventh Standard Road, Oasis Drive, and Main Camp Road are local roadways that provide access to the Project area. Access to the CO_2 facilities would be via Main Camp Road, either from the private Oasis Road off Seventh Standard Road or directly from Seventh Standard Road, west of SR 33.

2.2 Existing Traffic Data

This section summarizes existing traffic volumes on roadways that could be affected by the Project. Traffic count data was obtained from the California Department of Transportation (Caltrans) Traffic Census Program for 2021, which is the most recent available year. Table 1 summarizes the annual average daily traffic (AADT), which is the total volume of vehicle traffic for the year divided by 365 days, at three study locations along SR 33 in the vicinity of the Project.

Table 1. Annual Average Daily Traffic Volumes on Potentially Affected Roadway Segments

Roadway Segment	Average Annual Daily Traffic
1. SR 33 south of Junction Route 46	1,950
2. SR 33 south of Lost Hills Road (County Road P213)	1,900
3. SR 33 north of Lokern Road (County Road P208)	1,900

Source of AADT: 2021 Traffic Volumes, Caltrans Traffic Census Program (Caltrans, 2021).
Key: SR = State Route

3 Level of Service Methodology

Level of service (LOS) is a qualitative index of the performance of an element of a transportation system. The LOS for traffic is designated from A through F, with LOS A indicating free-flowing conditions and LOS F indicating severe traffic congestion and delays. The Highway Capacity Manual Sixth Edition (HCM 6), a standard reference published by the Transportation Research Board, contains specific criteria and methods for assessing LOS. LOS characteristics for roadway segments are presented in Table 2.

Table 2. Roadway Level of Service Descriptions

Level of Service	Traffic Flow Description
A	Minimal or no vehicle delay
B	Slight delay to vehicles
C	Moderate vehicle delays, traffic flow remains stable
D	More extensive delays at intersections
E	Long queues create lengthy delays
F	Severe delays and congestion

3.1 Significance Criteria

Kern County historically used a threshold of LOS D for the minimum acceptable operation of its transportation facilities. Facilities under the jurisdiction of Caltrans include freeway segments, ramps, ramp terminals, and arterials. Although Caltrans generally does not designate a LOS standard, for the purpose of this analysis, a Project would be considered to have undesirable effect on traffic and transportation if it would cause the operation of a transportation facility to worsen from LOS D or better.

Table 3 provides typical LOS and AADT volume thresholds for uninterrupted flow rural highways. As shown, a two-lane undivided highway such as SR 33 can typically carry up to 14,000 AADT for conditions of LOS D or better.

Table 3. Roadway Level of Service for Uninterrupted Flow Highways

Lanes	Median	A	B	C	D	E	F
2	Undivided	-	$\leq$ 4,600	8,200	14,000	28,500	> 28,500

3.2 Literature Review

3.2.1 KERN COUNTY GENERAL PLAN

The Kern County General Plan is the foundation and central feature of the local planning process. It is prepared, adopted, and maintained by the County to govern the physical development of all land area under its jurisdiction.

The Circulation Element of the Kern County General Plan consists of the general location and extent of existing and proposed major thoroughfares, transportation routes, terminal, and other local public utilities and facilities that are all corelated with the land use element of the general plan. The purpose of the circulation element is to set up local Goals and guiding Policies about building transportation improvements. Following is a list of the Plan's seven unique Goals:

- *To make certain that transportation facilities needed to support development are available. To ensure that these facilities occur in a timely manner so as to avoid traffic degradation.*
- *Kern County intends to provide plans for circulation infrastructure in support of the Land Use, Open Space and Conservation Element.*
- *To plan for transportation modes available to all segments of the population, including people with restricted mobility.*
- *Kern County will plan for a reduction of environmental effects without accepting a lower quality of life in the process.*
- *Maintain a minimum LOS D for all roads throughout the County unless the roads are part of an adopted Community Plan or Specific Plan which utilizes Smart Growth policies that encourage efficient multi-modal movements.*
- *Coordinate with the California Department of Transportation (Caltrans) regarding various transportation developments within the County.*
- *Kern County through its representatives on the Kern COG Board of Directors shall coordinate with Kern County cities and Caltrans to develop more effective transportation planning and congestion management programs.*

3.3 Existing Traffic Operations

Existing traffic conditions for the study roadway segments were evaluated based on the LOS and AADT thresholds for uninterrupted flow rural highways, shown in Table 3. The roadway capacities for the target LOS D for the county rural roadway segment were compared to the observed traffic volumes noted above in Table 1.

Table 4 shows the maximum daily traffic volumes that would allow the highway segments to maintain an acceptable LOS D, the existing AADT, and LOS. As shown, all the two-lane rural highway segments currently operate at an acceptable LOS ≤B.

Table 4. Existing Level of Service of Study Segments

Roadway Segment	Facility Type	Allowable Daily Service Volume (LOS D)	Average Annual Daily Traffic	LOS
1. SR 33 south of Junction Route 46	Two-lane Rural Highway	14,000	1,950	≤B
2. SR 33 south of Lost Hills Road (County Road P213)	Two-lane Rural Highway	14,000	1,900	≤B
3. SR 33 north of Lokern Road (County Road P208)	Two-lane Rural Highway	14,000	1,900	≤B

4 Project Trip Generation

4.1 Construction Trip Generation

Trip generation is defined as the number of vehicle trips produced by a particular type of land use or project. A trip is defined as vehicle movement in one direction. The total number of trips generated by a particular land use type or project includes both inbound and outbound trips.

During construction, truck trips would be routed on SR 33. Based on the information provided by Aera Energy, construction traffic would access the Project site from Main Camp Road, either from the private Oasis Road off Seventh Standard Road or directly from Seventh Standard Road, west of SR 33.

The proposed CO_2 sequestration field is contained within approximately 2,636 acres of land within the North Belridge Oil Field. Construction of the Project is expected to initiate in Q1 of 2025 and would take approximately 3 years to complete that includes the following tasks:

- Mobilization
- Demolition
- Well abandonments
- Surface Facility Construction
- Pipeline Construction
- Well Drilling/Well Conversion
- Facility Construction
- Pipeline Construction

The analysis of construction trip generation is based on the average daily volume of construction traffic. For the purposes of this analysis, the Project construction trip generation estimates are calculated based on the trips generated by heavy duty trucks (that include construction material delivery and dump trucks, water delivery trucks, etc.,) and the trips generated by the construction workers. Based on the annualized summary of anticipated equipment peak estimates during construction provided by Aera Energy, approximately 272 construction equipment vehicles are expected to travel to the site during the three-year construction period. Construction equipment vehicles would generate a total of 1,088 ADT (2 trips for inbound & outbound of construction equipment delivery to the site and 2 trips for inbound and outbound of construction equipment removal from the site) spread out over the three years of construction. Depending on the construction activities underway, the construction equipment requirements would vary throughout the course of any given year and across the life of the Project. Based on the information provided by Aera Energy, there would be approximately 720 working days (approximately 20 working days per month X 36 months of construction) over the life of the Project. The Project would generate an average of 1.5

construction equipment trips per day if the 1,088 ADT is spread out equally over 720 working days. However, for the purpose of this analysis and assuming that there would be ten times the average 1.5 trips per day during peak construction activity, the Project would generate 15 construction vehicles trips per day.

During construction, the number of workers on the site would vary daily. However, at the peak of construction, the number of workers on site would be 300 workers according to Aera Energy. Due to the rural nature of the Project, local labor would be used to the maximum extent practical. Workers would commute to and from the Project site daily from the nearby population centers. Workers employed in the rural areas of the County typically use strategies to reduce their reliance on single occupancy vehicles to reduce their commute costs, such as vanpools and carpools. Taking these factors into account, an assumption that 50 percent of the construction workers would carpool, there would be 300 trips (150 trips inbound during the AM peak hour and 150 trips outbound during the PM peak hour).

The construction trip generation for the Project is shown in Table 5. As shown, the Project is expected to generate a total volume of approximately 315 ADT, which includes 15 construction vehicle trips and 300 construction worker trips.

Table 5. Trip Generation During Peak Construction

Site	Construction Worker Trips	Construction Vehicle Trips	Total Trips
Aera Energy CCS	300	15	315

4.2 Operations Trip Generation

Based on information provided by Aera Energy, once constructed, the operational aspects of the Project would require a total of up to 10 employees. Assuming 10 employees per day, there would be approximately 25 trips per day based on an average trip rate of 2.5 trips per employee[1], which is generally considered not perceptible and would have no negative or undesirable effects to the surrounding roadway network.

4.3 Project Construction Trip Distribution

The geographic distribution of the Project-generated trips was determined based on the Project site location in relation to the surrounding uses while taking into account proposed driveway location, existing flow patterns and engineering judgement. A conservative scenario for each roadway segment is evaluated by assuming 100% of the Project construction trips assigned to each roadway segment

[1] The average trip rate of 2.5 trips per employee assumes that employee work during the day shift is two trips (one trip in and one trip out). In addition, some employees may travel an extra trip in between (e.g., lunch, errand), and there may be occasional deliveries to the site. Therefore, an average of 2.5 trips per employee is assumed.



individually as a worst-case scenario, i.e., 100% of the Project trips could travel on SR 33 either north or south of Seventh Standard Road.

4.4 Existing Plus Project Construction Conditions

This section describes the potential effects of the Project on traffic and transportation during construction. Project-generated construction traffic was added to existing conditions to represent "existing plus Project construction conditions." Similar to the analysis of the existing traffic conditions, the existing plus Project construction conditions for the roadway segments were evaluated based on the LOS and AADT thresholds for uninterrupted flow rural highways, shown in Table 3. The roadway capacities for the target LOS D were compared to the existing plus Project construction conditions traffic volumes.

As shown in Table 6, all the roadway segments continue to operate at LOS ≤B, even with the addition of construction traffic and are below the target threshold of LOS D.

Table 6. Existing Plus Project Construction Conditions Level of Service of Study Segments

Roadway Segment	Facility Type	Allowable Daily Service Volume (LOS D)	Project Trips	Average Annual Daily Traffic	LOS
1. SR 33 south of Junction Route 46	Two-lane Rural Highway	14,000	315	2,265	≤B
2. SR 33 south of Lost Hills Road (County Road P213)	Two-lane Rural Highway	14,000	315	2,215	≤B
3. SR 33 north of Lokern Road (County Road P208)	Two-lane Rural Highway	14,000	315	2,215	≤B

5 Vehicle Miles Traveled Analysis

The following analysis evaluates Project-related vehicle miles traveled (VMT) and complies with the updated California Environmental Quality Act (CEQA) guidelines that incorporate the requirements of Senate Bill (SB) 743. SB 743 requires the Governor's Office of Planning and Research (OPR) to establish recommendations for identifying and mitigating transportation impacts under CEQA (OPR, 2018). Generally, SB 743 moves away from using delay-based LOS as the metric for identifying Project impacts and uses VMT instead. The final OPR Technical Advisory, released in December 2018, provides guidance on evaluating transportation impacts and VMT and is the guidance on which this analysis is based.

Prior to undertaking a detailed VMT analysis, the OPR Technical Advisory recommends that lead agencies conduct a screening process "to quickly identify when a project should be expected to cause a less-than-significant impact without conducting a detailed study." The OPR Technical Advisory suggests that lead agencies may screen out VMT impacts using project size criteria, maps of low VMT areas,

transit availability, and provision of affordable housing. For this Project, the screening criteria related to project size is applicable in regard to the amount of traffic that is generated.

The OPR Technical Advisory recommends that absent substantial evidence indicating that a project would generate a potentially significant level of VMT or inconsistency with a sustainable communities strategy (SCS) or general plan, projects that generate or attract fewer than 110 trips per day may generally be assumed to cause a less-than-significant transportation impact.

The Project is consistent with the County's General Plan and SCS because the proposed Project would not change the current or planned County roadway system. As discussed in Section 4.2, a conservative estimate of the Project's daily operational trip generation is approximately 25 trips per day based on an average trip rate of 2.5 trips per employee. Therefore, the Project would generate substantially fewer than the 110 trips per day threshold and would result in a less-than-significant transportation impact.

Construction-related VMT is addressed in the context of air quality and greenhouse gas as part of a separate study. Construction VMT is temporary and is not applicable to the transportation thresholds of significance recommended in the OPR Technical Advisory, which are based on a measurement of the operational average VMT per capita.

6 Cumulative Conditions

Cumulative conditions have been considered, as construction of other developments in the vicinity during the same construction timeframe as the Project could have a temporary negative cumulative impact on traffic conditions. Current environmental documents listed on the Kern County website were reviewed to ascertain whether they would be constructed in a similar timeframe and would affect the same roadways as the Project. See Appendix A for the list of cumulative projects in Kern County found on the Kern County Planning website (Kern County, 2023). The list shows that most of the projects are solar farm projects. The traffic from these related projects would have a nominal effect on traffic volumes on the surrounding roadway network due to the remote location of the related project sites as well as due to the fact that the construction trips are short-term and temporary. On this basis, there will be no additional traffic impacts under cumulative conditions.

7 Conclusion

Under existing traffic conditions, all roadway study segments currently operate at LOS ≤B, which meets the target threshold of LOS D. As described in the Project description, construction equipment and vehicles would access the Project site from Main Camp Road, either from private Oasis Road off Seventh Standard Road or directly from Seventh Standard Road, west of SR 33. During the peak construction, the number of trips generated by the construction workers would be 300 trips per day. Construction vehicles would generate a total of 15 ADT. The overall daily trip generation during peak construction is estimated to be 315 ADT.



During construction, with the addition of construction traffic on the study area roadway segments, the ADT for each affected roadway would be below LOS D thresholds, which indicates that there would be no negative or undesirable effects on the roadway segments. Therefore, construction of the Project is not expected to cause any negative effects to the surrounding transportation network.

After construction, the Project would have up to 10 full-time employees that would generate up to approximately 25 trips per day, which is not perceptible and, therefore, would be considered to have no negative effect to the surrounding roadway network.

The Project is consistent with the County's General Plan and SCS and generates substantially fewer daily operational trips than the 110 trips per day threshold of significance for VMT impact. Therefore, based on the OPR recommended screening criteria, the Project would have a less-than-significant transportation impact.

VMT associated with construction of the Project is addressed in the context of air quality and greenhouse gas as part of a separate study. Construction VMT is temporary and is not applicable to the transportation impact thresholds of significance.

8 References

Caltrans (California Department of Transportation). 2021. Traffic Volumes on California State Highways. Available at: Traffic Census Program | Caltrans. Accessed August 1, 2023.

Highway Capacity Manual. Sixth Edition. 2016. Transportation Research Board, National Research Council.

Kern County. 2023. Environmental Documents. Available at: Environmental Documents - Kern County Planning & Natural Resources Dept. (kernplanning.com) Accessed August 14, 2023.

OPR (Governor's Office of Planning and Research). 2018. Technical Advisory on Evaluating Transportation Impacts in CEQA.

Appendix A Kern County Cumulative Project List

Board of Supervisors Planning Items (https://kernplanning.com/hearings/kern-county-board-supervisors-planning-items/)

– Planning Items Archive (https://kernplanning.com/hearings/kern-county-board-supervisors-planning-items/archive/)

Environmental Documents

See also: Notices of Preparation (https://kernplanning.com/planning/notices-of-preparation/) to view notices stating that Environmental Impact Reports will be prepared for various major projects. For additional help in viewing a PDF within your browser click here (http://helpx.adobe.com/acrobat/using/display-pdf-browser-acrobat-xi.html).

IMPORTANT - PDF File Linking Issue (https://kernplanning.com/planning/pdf-file-errors/)

Environmental Documents Archive (https://kernplanning.com/planning/environmental-documents/eda/)

Projects

Aratina Solar Project (https://kernplanning.com/environmental-doc/aratina-solar-project/)	Posted On: 2021-05-28 09:09	Last Updated: 2021-05-28 09:09	learn more (https://kernplanning.com/environmental-doc/aratina-solar-project/)
AV Apollo Solar Project (https://kernplanning.com/environmental-doc/av-apollo-solar-project/)	Posted On: 12/23/2019	Last Updated: 05/29/2020	learn more (https://kernplanning.com/environmental-doc/av-apollo-solar-project/)
AVEP Solar Project (https://kernplanning.com/environmental-doc/avep-solar-project/)	Posted On: 2021-01-11 03:17	Last Updated: 2022-05-20 01:13	learn more (https://kernplanning.com/environmental-doc/avep-solar-project/)
Azalea Solar Project (https://kernplanning.com/environmental-doc/azalea-solar-project/)	Posted On: 2022-09-02 03:54	Last Updated: 2023-03-14 02:12	learn more (https://kernplanning.com/environmental-doc/azalea-solar-project/)
Bellefield Solar Project (https://kernplanning.com/environmental-doc/bellefield-solar-project/)	Posted On: 2021-07-02 09:04	Last Updated: 2021-07-02 09:04	learn more (https://kernplanning.com/environmental-doc/bellefield-solar-project/)

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Boron Commercial Development Project (https://kernplanning.com/environmental-doc/boron-eir/)	Posted On: 2018-07-24 04:21	Last Updated: 2018-10-11 03:51	learn more (https://kernplanning.com/environmental-doc/boron-eir/)
Cal Centre (https://kernplanning.com/environmental-doc/cal-centre/)	Posted On: 2023-05-22 04:28	Last Updated: 2023-08-01 11:05	learn more (https://kernplanning.com/environmental-doc/cal-centre/)
Camino Solar Project (https://kernplanning.com/environmental-doc/camino-solar-project/)	Posted On: 02/13/2020	Last Updated: 02/13/2020	learn more (https://kernplanning.com/environmental-doc/camino-solar-project/)
Chalan Solar and Storage Project (https://kernplanning.com/environmental-doc/chalan-solar-and-storage-project/)	Posted On: 2023-06-15 02:51	Last Updated: 2023-06-15 02:52	learn more (https://kernplanning.com/environmental-doc/chalan-solar-and-storage-project/)
Clean Harbors Hazardous Waste Disposal Facility Project (https://kernplanning.com/environmental-doc/clean-harbors-hazardous-waste-disposal-facility-project/)	Posted On: 07/02/2012	Last Updated: 07/02/2012	learn more (https://kernplanning.com/environmental-doc/clean-harbors-hazardous-waste-disposal-facility-project/)
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Gem Hill Quarry Project (https://kernplanning.com/environmental-doc/gem-hill-quarry-project/)	Posted On: 2022-08-24 04:40	Last Updated: 2023-02-10 05:07	learn more (https://kernplanning.com/environmental-doc/gem-hill-quarry-project/)

Grapevine Specific and Community Plan (2019) (https://kernplanning.com/environmental-doc/grapevine-specific-community-plan-2019/)	Posted On: 2019-08-29 04:18	Last Updated: 2020-01-14 04:47	learn more (https://kernplanning.com/environmental-doc/grapevine-specific-community-plan-2019/)
Highway 46 Warehouse Project (https://kernplanning.com/environmental-doc/highway-46-warehouse-project/)	Posted On: 2018-02-22 04:47	Last Updated: 2018-09-14 09:30	learn more (https://kernplanning.com/environmental-doc/highway-46-warehouse-project/)
Johe Ranch Mining Project (https://kernplanning.com/environmental-doc/johe-ranch/)	Posted On: 2020-11-06 12:04	Last Updated: 2020-12-15 06:22	learn more (https://kernplanning.com/environmental-doc/johe-ranch/)
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Recology Blossom Valley Organics – South (https://kernplanning.com/environmental-doc/recology_eir/)	Posted On: 2018-05-22 02:00	Last Updated: 2018-08-10 03:17	learn more (https://kernplanning.com/environmental-doc/recology_eir/)
Reina Ranch Project (https://kernplanning.com/environmental-doc/reina-ranch-project/)	Posted On: 08/29/2014	Last Updated: 01/20/2023	learn more (https://kernplanning.com/environmental-doc/reina-ranch-project/)
Rosamond South Solar Project (https://kernplanning.com/environmental-doc/rosamond-south-solar-project/)	Posted On: 2022-07-13 03:27	Last Updated: 2022-12-08 02:36	learn more (https://kernplanning.com/environmental-doc/rosamond-south-solar-project/)
Sandrini Solar Project (https://kernplanning.com/environmental-doc/sandrini-solar-project/)	Posted On: 2021-09-17 07:54	Last Updated: 2021-09-17 07:57	learn more (https://kernplanning.com/environmental-doc/sandrini-solar-project/)
Soledad Mountain Project (https://kernplanning.com/environmental-doc/soledad-mountain-project/)	Posted On: 08/29/2014	Last Updated: 07/09/2020	learn more (https://kernplanning.com/environmental-doc/soledad-mountain-project/)
South Kern Compost Manufacturing Facility Project (Synagro) (https://kernplanning.com/environmental-doc/south-kern-compost-manufacturing-facility-project-synagro/)	Posted On: 2021-10-07 09:40	Last Updated: 2022-02-04 08:50	learn more (https://kernplanning.com/environmental-doc/south-kern-compost-manufacturing-facility-project-synagro/)

Supplemental Recirculated Environmental Impact Report (2020/2021) for Revisions to the Kern County Zoning Ordinance – 2020 A, focused on Oil and Gas Local Permitting (https://kernplanning.com/environmental-doc/oil-and-gas-sreir/)	Posted On: 2020-04-20 06:59	Last Updated: 2023-08-03 10:15	learn more (https://kernplanning.com/environmental-doc/oil-and-gas-sreir/)
Windhub Solar Project (https://kernplanning.com/environmental-doc/windhub-solar-project/)	Posted On: 2018-08-22 04:19	Last Updated: 2019-04-25 11:08	learn more (https://kernplanning.com/environmental-doc/windhub-solar-project/)

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Appendix J
Tribal Cultural AB-52 Outreach

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J.1 AB52 Consult Letters

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Lorelei H. Oviatt, AICP, Director
2700 "M" Street, Suite 100
Bakersfield, CA 93301-2323
Phone: (661) 862-8600
Fax: (661) 862-8601 TTY Relay 1-800-735-2929
Email: planning@co.kern.ca.us
Web Address: http://pcd.kerndsa.com/

PLANNING AND NATURAL RESOURCES DEPARTMENT

Planning
Community Development
Administrative Operations

Certified Mail 7019 2280 0000 9385 1478

April 14, 2022

FILE: ZCC 4, Map 51; ZCC 3, Map 74
ZCC 4, Map 75; CUP 9, Map 51
CUP 7, Map 74; CUP 7, Map 75
CUP 9, Map 96
PLN22-00137

San Manuel Band of Mission Indians
Attn: Jessica Mauck
Cultural Resources Analyst
26569 Community Center Drive
Highland, CA 92346

RE: AB 52 Tribal Consultation – Applications for Zone Classification Changes and Conditional Use Permits to allow Carbon dioxide (CO_2) capture and sequestration (CCS) on approximately 13,229-acres within the North and South Belridge Oilfields in the San Joaquin Valley of unincorporated Kern County (PP23402).

Dear Mrs. Mauck,

The Kern County Planning and Natural Resources Department is in receipt of a request to process applications for a proposed CCS field on approximately 13,229 acres located in Sections 20, 21, 22, 26, 27, 28, 34, 35, 36 of Township 27 South Range 20 East; Section 1, 2, and 12 of Township 28 South Range 20 East; Section 6, 7, 17, 18, 20, 27, 28, 29, 32, 33, and 34 of Township 28 South Range 21 East; and Section 2, 3, and 4 of Township 29 South Range 21 East. The proposed project, CarbonFrontier by Aera Energy, LLC. would include the installation of up to nine (9) EPA Class VI injection wells, the conversion of four (4) existing wells to CO_2 monitoring wells, amine-based capture equipment at existing facilities within the oilfields, approximately 10 miles of pipeline, and internal access roads. The proposed project would allow for the capture and sequestration of up to 42.6 million metric tons (MM Mt) of CO_2 within a geographically confined underground mineral formation for storage of CO_2 in perpetuity and would contribute to California's goal for carbon neutrality by 2045 (Executive Order B-55-18) by reducing industrial CO_2 emissions.

In compliance with California Assembly Bill No. 52 (AB-52), this Department is requesting your review and comments on the potential impacts on cultural places associated with your tribe by this proposal. Your participation is important at this early stage of processing to ensure that cultural places important to your tribe are identified, and the potential impacts associated with implementation of the project are mitigated.

If you have not responded by **May 15, 2023**, this Department will assume your tribe has declined consultation as per Public Resources Code (PRC) 21080.3.1. Please contact me at (661) 862-5015 or by email at AlvidrezK@kerncounty.com if you have any questions, comments, or request for consultation regarding this proposal.

Sincerely,

Keith Alvidrez
Planner I – Plan Development & Special Projects
Kern County Planning and Natural Resources Department

Enclosure: Vicinity Map

Lorelei H. Oviatt, AICP, Director
2700 "M" Street, Suite 100
Bakersfield, CA 93301-2323
Phone: (661) 862-8600
Fax: (661) 862-8601 TTY Relay 1-800-735-2929
Email: planning@co.kern.ca.us
Web Address: http://pcd.kerndsa.com/

PLANNING AND NATURAL RESOURCES DEPARTMENT

Planning
Community Development
Administrative Operations

Certified Mail 7019 2280 0000 9385 1331

April 14, 2022

FILE: ZCC 4, Map 51; ZCC 3, Map 74
ZCC 4, Map 75; CUP 9, Map 51
CUP 7, Map 74; CUP 7, Map 75
CUP 9, Map 96
PLN22-00137

Tejon Indian Tribe
Attn: Collin Rambo
Cultural Resource Management Technician
1731 Hasti Acres Dr., Suite 108
Bakersfield, CA 93309

RE: AB 52 Tribal Consultation – Applications for Zone Classification Changes and Conditional Use Permits to allow Carbon dioxide (CO_2) capture and sequestration (CCS) on approximately 13,229-acres within the North and South Belridge Oilfields in the San Joaquin Valley of unincorporated Kern County (PP23402).

Dear Mr. Rambo,

The Kern County Planning and Natural Resources Department is in receipt of a request to process applications for a proposed CCS field on approximately 13,229 acres located in Sections 20, 21, 22, 26, 27, 28, 34, 35, 36 of Township 27 South Range 20 East; Section 1, 2, and 12 of Township 28 South Range 20 East; Section 6, 7, 17, 18, 20, 27, 28, 29, 32, 33, and 34 of Township 28 South Range 21 East; and Section 2, 3, and 4 of Township 29 South Range 21 East. The proposed project, CarbonFrontier by Aera Energy, LLC. would include the installation of up to nine (9) EPA Class VI injection wells, the conversion of four (4) existing wells to CO_2 monitoring wells, amine-based capture equipment at existing facilities within the oilfields, approximately 10 miles of pipeline, and internal access roads. The proposed project would allow for the capture and sequestration of up to 42.6 million metric tons (MM Mt) of CO_2 within a geographically confined underground mineral formation for storage of CO_2 in perpetuity and would contribute to California's goal for carbon neutrality by 2045 (Executive Order B-55-18) by reducing industrial CO_2 emissions.

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Sincerely,

Keith Alvidrez
Planner I – Plan Development & Special Projects
Kern County Planning and Natural Resources Department

Enclosure: Vicinity Map

Lorelei H. Oviatt, AICP, Director
2700 "M" Street, Suite 100
Bakersfield, CA 93301-2323
Phone: (661) 862-8600
Fax: (661) 862-8601 TTY Relay 1-800-735-2929
Email: planning@co.kern.ca.us
Web Address: http://pcd.kerndsa.com/

PLANNING AND NATURAL RESOURCES DEPARTMENT

Planning
Community Development
Administrative Operations

Certified Mail 7019 2280 0000 9385 1485

April 14, 2022

FILE: ZCC 4, Map 51; ZCC 3, Map 74
ZCC 4, Map 75; CUP 9, Map 51
CUP 7, Map 74; CUP 7, Map 75
CUP 9, Map 96
PLN22-00137

Twenty-Nine Palms Band of Mission Indians
Attn: Anthony Madrigal Jr.
Tribal Grants Administrator
46-200 Harrison Place
Coachella, CA 92236

RE: AB 52 Tribal Consultation – Applications for Zone Classification Changes and Conditional Use Permits to allow Carbon dioxide (CO_2) capture and sequestration (CCS) on approximately 13,229-acres within the North and South Belridge Oilfields in the San Joaquin Valley of unincorporated Kern County (PP23402).

Dear Mr. Madrigal,

The Kern County Planning and Natural Resources Department is in receipt of a request to process applications for a proposed CCS field on approximately 13,229 acres located in Sections 20, 21, 22, 26, 27, 28, 34, 35, 36 of Township 27 South Range 20 East; Section 1, 2, and 12 of Township 28 South Range 20 East; Section 6, 7, 17, 18, 20, 27, 28, 29, 32, 33, and 34 of Township 28 South Range 21 East; and Section 2, 3, and 4 of Township 29 South Range 21 East. The proposed project, CarbonFrontier by Aera Energy, LLC. would include the installation of up to nine (9) EPA Class VI injection wells, the conversion of four (4) existing wells to CO_2 monitoring wells, amine-based capture equipment at existing facilities within the oilfields, approximately 10 miles of pipeline, and internal access roads. The proposed project would allow for the capture and sequestration of up to 42.6 million metric tons (MM Mt) of CO_2 within a geographically confined underground mineral formation for storage of CO_2 in perpetuity and would contribute to California's goal for carbon neutrality by 2045 (Executive Order B-55-18) by reducing industrial CO_2 emissions.

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Sincerely,

Keith Alvidrez
Planner I – Plan Development & Special Projects
Kern County Planning and Natural Resources Department

Enclosure: Vicinity Map

Lorelei H. Oviatt, AICP, Director
2700 "M" Street, Suite 100
Bakersfield, CA 93301-2323
Phone: (661) 862-8600
Fax: (661) 862-8601 TTY Relay 1-800-735-2929
Email: planning@co.kern.ca.us
Web Address: http://pcd.kerndsa.com/

PLANNING AND NATURAL RESOURCES DEPARTMENT

Planning
Community Development
Administrative Operations

Certified Mail 7019 2280 0000 9385 1461

April 14, 2022

FILE: ZCC 4, Map 51; ZCC 3, Map 74
ZCC 4, Map 75; CUP 9, Map 51
CUP 7, Map 74; CUP 7, Map 75
CUP 9, Map 96
PLN22-00137

Twenty-Nine Palms Band of Mission Indians
Attn: Darrell Mike
Tribal Chairman
46-200 Harrison Place
Coachella, CA 92236

RE: AB 52 Tribal Consultation – Applications for Zone Classification Changes and Conditional Use Permits to allow Carbon dioxide (CO_2) capture and sequestration (CCS) on approximately 13,229-acres within the North and South Belridge Oilfields in the San Joaquin Valley of unincorporated Kern County (PP23402).

Dear Mr. Mike,

The Kern County Planning and Natural Resources Department is in receipt of a request to process applications for a proposed CCS field on approximately 13,229 acres located in Sections 20, 21, 22, 26, 27, 28, 34, 35, 36 of Township 27 South Range 20 East; Section 1, 2, and 12 of Township 28 South Range 20 East; Section 6, 7, 17, 18, 20, 27, 28, 29, 32, 33, and 34 of Township 28 South Range 21 East; and Section 2, 3, and 4 of Township 29 South Range 21 East. The proposed project, CarbonFrontier by Aera Energy, LLC. would include the installation of up to nine (9) EPA Class VI injection wells, the conversion of four (4) existing wells to CO_2 monitoring wells, amine-based capture equipment at existing facilities within the oilfields, approximately 10 miles of pipeline, and internal access roads. The proposed project would allow for the capture and sequestration of up to 42.6 million metric tons (MM Mt) of CO_2 within a geographically confined underground mineral formation for storage of CO_2 in perpetuity and would contribute to California's goal for carbon neutrality by 2045 (Executive Order B-55-18) by reducing industrial CO_2 emissions.

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Sincerely,

Keith Alvidrez
Planner I – Plan Development & Special Projects
Kern County Planning and Natural Resources Department

Enclosure: Vicinity Map

Lorelei H. Oviatt, AICP, Director
2700 "M" Street, Suite 100
Bakersfield, CA 93301-2323
Phone: (661) 862-8600
Fax: (661) 862-8601 TTY Relay 1-800-735-2929
Email: planning@co.kern.ca.us
Web Address: http://pcd.kerndsa.com/

PLANNING AND NATURAL RESOURCES DEPARTMENT

Planning
Community Development
Administrative Operations

April 14, 2022

FILE: ZCC 4, Map 51; ZCC 3, Map 74
ZCC 4, Map 75; CUP 9, Map 51
CUP 7, Map 74; CUP 7, Map 75
CUP 9, Map 96
PLN22-00137

Torres Martinez Desert Cahuilla Indians
Attn: Michael Mirelez
Cultural Resources Coordinator
P.O. Box 1160
Thermal, CA 92274

RE: AB 52 Tribal Consultation – Applications for Zone Classification Changes and Conditional Use Permits to allow Carbon dioxide (CO_2) capture and sequestration (CCS) on approximately 13,229-acres within the North and South Belridge Oilfields in the San Joaquin Valley of unincorporated Kern County (PP23402).

Dear Mr. Mirelez,

The Kern County Planning and Natural Resources Department is in receipt of a request to process applications for a proposed CCS field on approximately 13,229 acres located in Sections 20, 21, 22, 26, 27, 28, 34, 35, 36 of Township 27 South Range 20 East; Section 1, 2, and 12 of Township 28 South Range 20 East; Section 6, 7, 17, 18, 20, 27, 28, 29, 32, 33, and 34 of Township 28 South Range 21 East; and Section 2, 3, and 4 of Township 29 South Range 21 East. The proposed project, CarbonFrontier by Aera Energy, LLC. would include the installation of up to nine (9) EPA Class VI injection wells, the conversion of four (4) existing wells to CO_2 monitoring wells, amine-based capture equipment at existing facilities within the oilfields, approximately 10 miles of pipeline, and internal access roads. The proposed project would allow for the capture and sequestration of up to 42.6 million metric tons (MM Mt) of CO_2 within a geographically confined underground mineral formation for storage of CO_2 in perpetuity and would contribute to California's goal for carbon neutrality by 2045 (Executive Order B-55-18) by reducing industrial CO_2 emissions.

In compliance with California Assembly Bill No. 52 (AB-52), this Department is requesting your review and comments on the potential impacts on cultural places associated with your tribe by this proposal. Your participation is important at this early stage of processing to ensure that cultural places important to your tribe are identified, and the potential impacts associated with implementation of the project are mitigated.

If you have not responded by **May 15, 2023**, this Department will assume your tribe has declined consultation as per Public Resources Code (PRC) 21080.3.1. Please contact me at (661) 862-5015 or by email at AlvidrezK@kerncounty.com if you have any questions, comments, or request for consultation regarding this proposal.

Sincerely,

Keith Alvidrez
Planner I – Plan Development & Special Projects
Kern County Planning and Natural Resources Department

Enclosure: Vicinity Map

J.2 AB52 Comment Letter

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Keith Alvidrez

From: Ryan Nordness <Ryan.Nordness@sanmanuel-nsn.gov>
Sent: Tuesday, May 16, 2023 10:51 AM
To: Keith Alvidrez
Subject: Zone Classification Changes and CUPs to allow CO2 capture and sequestration (CCS) on approx 13,229-acres within the North and South Belridge Oilfields in the San Joaquin Valley of unincorporated Kern County (PP23402) (PLN22-00137)

CAUTION: This email originated from outside of the organization. Do not click links, open attachments, or provide information unless you recognize the sender and know the content is safe.

Dear Keith,

Thank you for contacting the Yuhaaviatam of San Manuel Nation (formerly known as the San Manuel Band of Mission Indians) regarding the above-referenced project. YSMN appreciates the opportunity to review the project documentation, which was received by the Cultural Resources Management Department on April 18th 2023. The proposed project is located outside of Serrano ancestral territory and, as such, YSMN will not be requesting to receive consulting party status with the lead agency or to participate in the scoping, development, or review of documents created pursuant to legal and regulatory mandates.

Kind regards,
Ryan Nordness
Cultural Resource Analyst
Yuhaaviatam of San Manuel Nation

Ryan Nordness
Cultural Res Analyst
Ryan.Nordness@sanmanuel-nsn.gov
O:(909) 864-8933 Ext 50-2022
M:(909) 838-4053
26569 Community Center Dr Highland, California 92346



Appendix K
Other References

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K.1 Energy Utilization Study

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CarbonFrontier Project

Energy Utilization Study

September 28, 2023

Prepared for:
Aera Energy LLC
10000 Ming Avenue
Bakersfield, CA 93311

Prepared by:
Stantec Consulting Services, Inc.
555 Capitol Mall Suite 650
Sacramento, CA 95814

Project No.
185805372

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Appendix A: Energy Calculations

ABBREVIATIONS

AB	Assembly Bill
CAFE	Corporate Average Fuel Economy
CalEEMod	California Emissions Estimator Model
CARB	California Air Resources Board
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CFR	Code of Federal Regulations
CCR	California Code of Regulations
CO_2	Carbon Dioxide
Cogen	Co-generation Facility
County	Kern County
CPUC	California Public Utilities Commission
DEIR	Draft Environmental Impact Report
EISA	Energy Independence & Security Act
EO	Executive Order
EPCA	Energy Policy and Conservation Act
GHG	Greenhouse Gases
GP	Gas Plant
GW	Gigawatts
GWh	Gigawatt-hour
IRA	Inflation Reduction Act
kV	Kilovolt
LCFS	Low Carbon Fuel Standard
MMBtu	million British thermal units
MW	Megawatts
MWh	Megawatt-hour
NHTSA	National Highway Traffic Safety Administration
PG&E	Pacific Gas & Electric
Post-C	Post-Combustion
PRC	Public Resources Code
Pre-C	Pre-Combustion
Project	CarbonFrontier Project
RFS	Renewable Fuel Standard
RPS	Renewable Portfolio Standard
SAFE	Safer Affordable Fuel-Efficient
SB	Senate Bill
SGS	Steam Generator Setting
SR	State Route
USC	United States Code
USEPA	United States Environmental Protection Agency
UIC	Underground Injection Control



1.0 EXECUTIVE SUMMARY

This Energy Utilization Study is intended to support the preparation of the Draft Environmental Impact Report (DEIR) for the CarbonFrontier Project (Project). This technical analysis has been prepared to evaluate the Project's energy use during construction and operation.

1.1 PROJECT UNDERSTANDING

Aera Energy LLC (Aera Energy) has proposed a carbon capture and sequestration Project which would capture carbon dioxide (CO_2) from existing produced gas streams (pre-combustion [Pre-C]) and emissions from existing stationary sources (post-combustion [Post-C]) within the South Belridge Oil Field and transport the CO_2 through a pipeline to the North Belridge Oil Field for injection at dedicated Underground Injection Control (UIC) Class VI injection wells. The proposed underground CO_2 sequestration field would be located within the North Belridge Oil Field. Oil and gas production activities within the North Belridge 64 zone would cease as a result of the Project. It is anticipated that the Project would have a maximum forecasted capacity to sequester up to 1.6 million metric tons of CO_2 per year beginning in 2027 and contribute to California's goal of carbon net-neutrality by 2045 (Governor's Executive Order B-55-18) by reducing industrial CO_2 emissions.

1.2 SUMMARY OF ANALYSIS

This section provides a summary of each impact statement and the conclusion of the analysis.

Impact ENG-1: The Project would not result in potentially significant environmental impact due to wasteful, inefficient, or unnecessary consumption of energy resources. **Less Than Significant Impact.**

Impact ENG-2: The Project would not conflict with or obstruct a state or local plan for renewable energy or energy efficiency. **Less Than Significant Impact.**

2.0 INTRODUCTION

2.1 PURPOSE OF ANALYSIS

The purpose of this Energy Utilization Study is to determine the potential energy use, primarily in the form of petroleum fuel, associated with construction and operation of the Project. This evaluation is consistent with the air quality and greenhouse gas (GHG) emissions modelling prepared for the Project by Trinity Consultants (Trinity, 2023).

2.2 PROJECT DESCRIPTION

The Project would include the construction and operation of a carbon capture and sequestration system, with the CO_2 capture facilities located within the South Belridge Oil Field. The CO_2 would be transported by pipeline to the North Belridge Oil Field for permanent sequestration via CO_2 injection wells into a designated underground sequestration zone, known as the 64 Zone, at depths of approximately 8,000 feet below ground surface.

New processing facilities and field systems would be constructed. Processing facilities would include: 1) carbon capture facilities constructed adjacent to existing oil field equipment within the South Belridge Oil Field, 2) pipelines to transport the CO_2 stream to the North Belridge Oil Field, and 3) dedicated injection wells within North Belridge to inject CO_2 into the dedicated CO_2 sequestration zone. Existing oil wells that penetrate the dedicated CO_2 sequestration zone would be permanently plugged and abandoned (including the removal of surface wellheads) in accordance with applicable laws and regulations or repurposed for injection or monitoring activities.

Field systems would include additional pipelines to convey produced gas, water, and steam within South Belridge, as well as electrical power distribution and supervisory control and data acquisition networks and control rooms. Monitoring systems would be constructed, including re-purposing of existing wells, to monitor the CO_2 injection operations in accordance with state and federal requirements.

Electrical system upgrades would be required to supply electricity to the new facilities. This includes approximately 5,700 feet (1.1 mile) of 115 kilovolt (kV) overhead transmission lines from the existing electrical supply grid to two new electrical substations located near the CO_2 capture facilities. Additionally, approximately 13,000 feet of new 12 kV overhead distribution power lines would extend from the proposed electrical substations to each CO_2 capture facility.

Project construction would occur over an approximately 3-year time period starting in 2025. The Project is anticipated to operate for a period of up to 20 years. Following the completion of CO_2 injection operations, decommissioning would occur, which would involve a period of post-injection monitoring, plugging of injection wells, and post-closure site care.



2.2.1 Project Location and Surrounding Land Uses

The Project site is located within the Central Valley portion of western Kern County. The South Belridge and North Belridge oil fields are contiguous and located approximately six miles southwest of the community of Lost Hills and west of State Route (SR) 33. Together, the two Belridge oil fields cover an area of approximately 13 miles long and three miles wide. The proposed CO_2 capture facilities would be located within the developed portion of the South Belridge Oil Field. The proposed CO_2 sequestration field, which is located approximately 10 miles to the northwest in the North Belridge Oil Field, is made up of privately owned parcels totaling approximately 2,636 acres of land, predominately developed with oil and gas production and accessory facilities and infrastructure. Existing land use in the vicinity of the Project site generally includes oil and gas exploration and production, grazing, and agricultural lands.



3.0 ENERGY BACKGROUND

3.1 ENVIRONMENTAL SETTING

Pacific Gas and Electric (PG&E) provides natural gas and electric service to approximately 16 million people throughout a 70,000-square-mile service area in northern and central California, including Kern County (PG&E 2023). In February 2018, PG&E announced that it had reached California's 2020 renewable energy goal three years ahead of schedule (PGE 2018). In 2021, approximately 48 percent of PG&E's electricity came from renewable resources including solar, wind, geothermal, biomass and small hydroelectric sources. Additionally, approximately 91 percent of PG&E's total electric power mix is from GHG-free sources, which includes nuclear and large hydroelectric sources of energy (CEC 2023).

The California Energy Commission (CEC) tracks electricity and natural gas consumption across the state for residential and non-residential sources. In 2021, Kern County used a total of 15,009 GWh of electricity and 1,866 millions of therms of natural gas. Approximately 82 percent of the electricity usage and 95 percent of the natural gas use in the County came from non-residential sources (CEC 2016a, CEC 2016b).

The South Belridge Oil Field is powered by the Co-Generation (Cogen) Plant 32, which was constructed from 1985 to 1986. Cogen 32 is composed of three turbine-driven generator sets, each able to make 20 megawatts (MW) of power. The Cogen 32's output is backed up with a connection to PG&E in the event that any or all of the three Cogen 32 turbines are down for maintenance or temporary outage. The Project would pull available power from Cogen 32 within its existing capacity, and any additional electrical load would be provided by PG&E.

3.2 REGULATORY SETTING

The following includes the key federal, state, and local regulations related to energy resources that are applicable to the Project.

3.2.1 Federal

Federal Energy Regulatory Commission

The Federal Energy Regulatory Commission is an independent agency that regulates the interstate transmission of electricity, natural gas, and oil. The Federal Energy Regulatory Commission also reviews proposals to build liquefied natural gas terminals and interstate natural gas pipelines as well as licensing hydropower projects. Licensing of hydroelectric facilities under the authority of the Federal Energy Regulatory Commission includes input from state and federal energy and power generation, environmental protection, fish and wildlife, and water quality agencies.



National Energy Conservation Policy Act

The National Energy Conservation Policy Act (42 U.S. Code [USC] §8201 et seq.) serves as the underlying authority for federal energy management goals and requirements and is the foundation of most federal energy requirements. The National Energy Conservation Policy Act also established fuel economy standards for on-road motor vehicles in the United States. The National Highway Traffic Safety Administration (NHTSA) is responsible for establishing additional vehicle standards and for revising existing standards. NHTSA and the U.S. Environmental Protection Agency (USEPA) are taking coordinated steps to enable the production of clean energy vehicles with improved fuel efficiency. NHTSA sets the Corporate Average Fuel Economy (CAFE) levels, which are rapidly increasing over the next several years to improve energy security and reduce fuel consumption. In March 2022, the NHTSA finalized CAFE standards for model years 2024 to 2026. The standards require an industry-wide fleet average of approximately 49 miles per gallon for passenger cars and light trucks by model year 2026. The NHTSA projects that the foregoing standards will avoid the consumption of approximately 234 billion gallons of gasoline between model years 2030 to 2050 (NHTSA 2022).

Energy Independence and Security Act of 2007

The Energy Independence and Security Act (EISA) aimed to increase U.S. energy security, increased CAFE standards for motor vehicles, and included provisions related to energy efficiency, such as renewable fuel standards (RFS), appliance and lighting efficiency standards; and building energy efficiency standards. The EISA required increasing levels of renewable fuels to replace petroleum. The USEPA is responsible for developing and implementing regulations to ensure transportation fuel sold into the U.S. contains a minimum volume of renewable fuel.

The RFS programs regulations were developed in collaboration with refiners, renewable fuel products, and other stakeholders and were created under the Energy Policy Act of 2005. The RFS program established the first renewable fuel volume mandate in the U.S. As required under the EISA, the original RFS program required 7.5 billion gallons of renewable fuel to be blended into gasoline by 2012. The RFS program was expanded in several ways that laid the foundation for achieving significant reductions of GHG emissions through the use of renewable fuels, for reducing imported petroleum, and for encouraging the development and expansion of the nation's renewable fuels sector. The updated program is referred to as RFS2, and includes the following:

- EISA expanded the RFS program to include diesel, in addition to gasoline;
- EISA increased the volume of renewable fuel required to be blended into transportation fuel from 9 billion gallons in 2008 to 36 billion gallons by 2022;
- EISA established new categories of renewable fuel and set separate volume requirements for each one; and
- EISA required by the USEPA to apply lifecycle GHG performance threshold standards to ensure that each category of renewable fuel emits fewer GHGs than the petroleum fuel it replaces.

Additional provisions of the EISA address energy savings in government and public institutions, promoting research for alternate energy, additional research in carbon capture, international energy programs, and the creation of "green jobs."



Federal Vehicle Standards

The Energy Policy and Conservation Act of 1975 (EPCA) mandated that the NHTSA establish and implement a regulatory program for motor vehicle fuel economy, known as the CAFE program, to reduce national energy consumption. As codified in Chapter 329 of Title 49 of the USC, as amended by the EISA, EPCA sets forth specific requirements concerning the establishment of average fuel economy standards for passenger cars and light trucks. The EISA, discussed above, amended the EPCA CAFE program requirements by providing the Department of Transportation additional rulemaking authority and responsibilities.

Consistent with its statutory authority in rulemaking to establish CAFE standards for model year 2017 and beyond, NHTSA developed two phases of standards. The first phase included final standards for model years 2017–2021. The second phase, covering model years 2022–2025, included standards that were not final, due to the statutory requirement that NHTSA set average fuel economy standards not more than five model years at a time. Rather, NHTSA wrote that those standards were augural, meaning that they represented its best estimate, based on the information available at that time, of what levels of stringency might be maximum feasible in those model years. In 2012, the agencies jointly adopted more stringent Phase 2 standards for light duty cars and trucks, which would cover model years 2017 through 2025. In August of 2016, the agencies adopted more stringent Phase 2 standards for medium- and heavy-duty vehicles, which would cover model years 2018 through 2027 for certain trailers and model years 2021 through 2027 for semi-trucks, large pickup trucks, vans, and all types and sizes of buses and work trucks.

On March 31, 2020, NHTSA and the USEPA released a new rule, the final Safer Affordable Fuel-Efficient (SAFE) Vehicles Rule, setting CAFE and carbon dioxide emissions standards for model years 2021 through 2026 passenger cars and light trucks. The rule rolls back the 2012 standards for model years 2021 through 2026 for passenger cars and light trucks, which had required an average fleetwide fuel economy equivalent of 54.5 miles per gallon in model year 2025 with a 5 percent annual increase to an average fuel economy of about 40 miles per gallon in model year 2025 with annual increases of 1.5 percent starting in 2021. As a part of issuing the new SAFE rule, NHTSA issued a Final Environmental Impact Statement which found that the relaxed standards would result in increased petroleum consumption which in turn would result in increases to GHG and criteria pollutant emissions known to contribute to adverse health impacts (NHTSA 2020). The estimated increases from the roll back of the 2012 standards are expected to result in more than a billion metric tons additional climate pollution through 2040 as determined by calculating the difference from the reduction of 2 billion metric tons the 2012 rule was expected to accomplish compared to the standards of the 2020 rule (NHTSA 2020). On January 20, 2021, an Executive Order was issued on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis, which includes review of the Part One Rule by April 2021 and review of the Part Two Rule by July 2021. In response to the Part One Rule, in December 2021, the Department of Transportation withdrew its portions of the SAFE rule. As a result, states are now allowed to issue their own GHG emissions standards and zero-emissions vehicle mandates. In addition, the Part Two Rule was adopted to revise the existing national GHG emission standards for passenger cars and light trucks through model year 2026. These standards are the strongest vehicle emissions standards



ever established for the light-duty vehicle sector and will result in avoiding more than three billion tons of GHG emissions through 2050.

Inflation Reduction Act of 2022

The Inflation Reduction Act (IRA) of 2022 is considered the most ambitious climate law in U.S. history, and is intended to reduce GHG emissions, help build a clean economy, reduce energy costs for Americans, and advance environmental justice. With funding from the IRA, the USEPA has launched a network of clean energy financing and provided grant funding for climate pollution reduction programs (USEPA 2023). The IRA increases the 45Q tax credit to $85 per ton for geologic sequestration of CO_2 from industrial sources.

3.2.2 State

California Public Utilities Commission

The California Public Utilities Commission (CPUC) is a state agency created by a constitutional amendment to regulate privately-owned utilities providing telecommunications, electric, natural gas, water, railroad, rail transit, and passenger transportation services and in-state moving companies. The CPUC is responsible for ensuring that California utility customers have safe, reliable utility services at reasonable rates, while protecting utility customers from fraud. The CPUC regulates the planning and approval for the physical construction of electric generation, transmission, or distribution facilities, and local distribution pipelines of natural gas.

California Energy Code

Compliance with the California Energy Code (CCR Title 24, Part 6, California's Energy Efficiency Standards) and Title 20, Public Utilities and Energy, standards must occur for all new buildings constructed in California. These efficiency standards apply to new construction of both residential and nonresidential (i.e., maintenance buildings and pump station buildings associated with the Program) buildings, and they regulate energy consumed for heating, cooling, ventilation, water heating, and lighting. The building efficiency standards are enforced through the local building permit processes, and local government agencies may adopt and enforce energy standards for new buildings provided that these standards meet or exceed those provided in the Title 24 guidelines.

Warren-Alquist Energy Resources Conservation and Development Act

Initially passed in 1974 and amended since, the Warren-Alquist Energy Resources Conservation and Development Act (Warren-Alquist Act) created the CEC, California's primary energy and planning agency. The seven responsibilities of the CEC are forecasting future energy needs, promoting energy efficiency and conservation through setting standards, supporting energy-related research, developing renewable energy resources, advancing alternative and renewable transportation fuels and technologies, certifying thermal power plants 50 MW or larger, and planning for and directing state response to energy emergencies. The CEC regulates energy resources by encouraging and coordinating research into energy supply and demand problems to reduce the rate of growth of energy consumption. Additionally,



the Warren-Alquist Act acknowledges the need for renewable energy resources and encourages the CEC to explore renewable energy options that would be in line with environmental and public safety goals (Public Resources Code (PRC) Section 25000 et seq.)

California Integrated Energy Policy

Senate Bill (SB) 1389 requires the CEC to "conduct assessments and forecasts of all aspects of energy industry supply, production, transportation, delivery and distribution, demand, and prices. The Energy Commission shall use these assessments and forecasts to develop energy policies that conserve resources, protect the environment, ensure energy reliability, enhance the state's economy, and protect public health and safety." (PRC Section 25301(a)). The CEC adopts an Integrated Energy Policy Report every two years and an update every other year. The most recent version is the 2022 Integrated Energy Policy Report Update (CEC 2022).

California Renewables Portfolio Standard

California's Renewables Portfolio Standard (RPS) was initially established in 2002 by SB 1078, with the initial requirement that 20 percent of electricity retail sales be served by renewable resources by 2017. The program was accelerated in 2006 under SB 107, which required that the 20 percent mandate be met by 2010. In April 2011, SB 2 was signed into law, requiring electricity retailers in the state to procure 33 percent of their energy sources from renewable energy sources by the end of 2020 (CPUC 2021). In addition, SB 350, passed in 2015, directs California utilities to further increase the amount of renewable energy delivered to customers to 50 percent by 2030.

CPUC implements and administers RPS compliance rules for California's retail sellers of electricity, which include large and small investor-owned utilities, publicly owned utilities, electric service providers, and community choice aggregators. The CEC is responsible for the certification of electrical generation facilities as eligible renewable energy resources and adopting regulations for the enforcement of RPS procurement requirements of public owned utilities.

Low Carbon Fuel Standard

In 2007, Executive Order S-01-07 established the Low Carbon Fuel Standard (LCFS) and directed the Secretary for Environmental Protection to coordinate the actions of the CEC, the California Air Resources Board (CARB), the University of California, and other agencies to develop and propose protocols for measuring the "life-cycle carbon intensity" of transportation fuels. CARB adopted the LCFS on April 23, 2009.

The LCFS was subject to legal challenge in 2011. Ultimately, CARB was required to bring a new LCFS regulation for consideration in February 2015. The proposed LCFS regulation was required to contain revisions to the 2010 LCFS and new provisions designed to foster investments in the production of the low-carbon fuels, offer additional flexibility to regulated parties, update critical technical information, simplify and streamline program operations, and enhance enforcement. The regulation was last amended in 2018. The 2018 amendments strengthen the carbon intensive fuel reduction targets beyond 2020 to support the climate goals established in SB 32. Other major changes to the 2018 amendments include



expanding the fuel types and eligible activities to participate in the LCFS (CARB 2018a). One of the specific regulations added in 2018 is the Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard (CARB 2018b). The Carbon Capture and Sequestration Protocol establishes methodology for quantifying geological CO_2 sequestration, and permanence requirements related to site characteristics, plume extent evaluation, testing and monitoring, well operation, post-injection site care, and more.

2022 Scoping Plan for Achieving Carbon Neutrality

The 2022 Scoping Plan for Achieving Carbon Neutrality (2022 Scoping Plan) was approved by the CARB in December 2022 and assesses progress toward achieving the state's GHG reduction goals and establishes a path to achieve carbon neutrality no later than 2045. The 2022 Scoping Plan focuses on outcomes needed to achieve carbon neutrality by assessing paths for advancing transportation technology, clean energy deployment, maintenance and preservation of natural and working lands, and others, and is designed to meet the State's long-term climate objectives. Specifically, the 2022 Scoping Plan identifies carbon negative technologies, including nature-based and mechanical carbon sequestration projects, as an essential component in achieving state-wide carbon neutrality (CARB 2022).

3.2.3 Local

Kern County General Plan

The Kern County General Plan, initially adopted in 2004, includes an Energy Element.[1] The following goals and policies from the Energy Element of the Kern County General Plan are applicable to the Project (Kern County 2009):

- **Section 5.2 – Importance of Energy to Kern County**
    - **Policy 1.** Kern County should assert and promote its role as the State's leading energy County.
    - **Policy 4.** The County should actively seek State and federal energy grants and projects to assist in energy planning and development.
    - **Policy 5.** The County shall work with other agencies to define regulatory responsibility concerning energy-related issues, and shall seek to eliminate, insofar as possible, duplicative regulations.
    - **Policy 6.** The County should encourage discussion and mutual cooperation of various energy industries within the County to establish mutual understanding of common needs and issues.

[1] It is noted that Kern County is currently undergoing an update to the General Plan. However, the General Plan Update has not yet been finalized or adopted by the County Board of Supervisors.

  - **Policy 7.** The processing of all discretionary energy project proposals shall comply with California Environmental Quality Act (CEQA) Guidelines directing that the environmental effects of a project must be taken into account as part of project consideration.
  - **Policy 8.** The County should work closely with local, State, and federal agencies to assure that energy projects (both discretionary and ministerial) avoid or minimize direct impacts to fish, wildlife, and botanical resources, wherever practical.
  - **Policy 9.** The County should develop and implement measures which result in long-term compensation for wildlife habitat, which is unavoidably damaged by energy exploration and development activities.

- **Section 5.3.2 – Kern County's Economic Dependence on the Oil Marketplace**
  - **Policy 3.** The County shall encourage the conversion of existing petroleum-related facilities to other productive uses when they are no longer needed or productive.
  - **Policy 4.** The County should encourage the development of renewable energy industries to diversify the energy economy in Kern County.
- **Section 5.4.1 – Cogeneration**
  - **Policy 1.** The County shall allow the continued development of cogeneration facilities in primary oil resource areas and industrial areas.



4.0 MODELING INPUTS AND PARAMETERS

The following discussion explains the methodology and modeling parameters that will be used to estimate the energy demand associated with construction and operations of the Project.

4.1 ENERGY CALCULATION METHODOLOGY

Project energy demand during construction and operations was determined based on Project-specific information and using vehicle and equipment emission factors from the CARB's EMFAC2021 (v1.0.2) and EMFAC OFFROAD2021 (v1.0.4). The energy calculations are included as Appendix A.

The Project's energy consumption and demand were evaluated in comparison to the California Environmental Quality Act (CEQA) thresholds of significance to determine whether the Project would result in a significant impact related to energy.

4.1.1 Construction Assumptions

Construction Schedule

Project construction would require various tasks including facility pad grading, well drilling, pipeline construction, and others. Table 1 shows the anticipated construction components and timing per component.

Table 1: Project Construction Components

Project Component	Construction Days per Component
Facilities Pad Grading	80
Repurposed Injection Well Site Preparation	20
Repurposed Injection Well Drilling	100
Repurposed Monitoring Well Site Preparation	26
Repurposed Monitoring Well Drilling[1]	80
New Well Site Preparation	40
New Well Drilling[1]	60
CO_2 Capture Facilities (4 facilities)	522 days per facility
Compressor Station Construction	80
CO_2 Main Pipeline	390
Distribution Pipelines	260
Electrical Transmission Line	60
Intra-Field Electrical Distribution	60



Project Component	Construction Days per Component
Onsite Electrical Substations	130
Water Pipelines	87
Natural Gas Pipelines	120
Steam Pipeline	88
Demolition	40
On-Site Roads	15-20 Per Well

Notes:
1. The Well Hookup phase timing and equipment is included within the "Well Drilling" phases.

Construction of the components would overlap, and several components would begin construction at the same time. Construction of most components is anticipated to begin in 2025, except construction of the Intra-Field Electrical Distribution system would begin in 2026. The most time-consuming component, construction of the CO_2 Capture Facilities, is expected to finish in 2028.

For this analysis, all construction activity was assumed to occur in the year 2025, except Intra-Field Electrical Distribution, which was assumed to occur in 2026. The construction schedule utilized in the analysis represents a "worst-case" analysis scenario because fuel efficiency for construction equipment increases as the analysis year increases, due to improvements in technology and more stringent regulatory requirements. Therefore, the construction energy demand would be less if the construction schedule is adjusted to occur in later years.

Off-Road Equipment

The off-road equipment fleet and associated horsepower per piece of equipment for each Project component was provided by Aera Energy. The load factor for each piece of equipment was derived from Table G-12 of the California Emissions Estimator Model (CalEEMod) User Guide Appendix G. Consistent with the air quality and GHG emissions modeling, each piece of equipment was assumed to be in use for 8 hours per day, with the exception of drill rigs, which were assumed to operate for 24 hours per day. Off-road equipment energy demand was estimated based on the equipment usage (horsepower-hours) and fuel efficiency (gallons/horsepower-hour), as provided by the EMFAC OFFROAD2021 database. The comprehensive list of off-road equipment is available in Appendix A.

On-Road Vehicle Trips

Table 2 provides a summary of the construction-related vehicle trips.

Table 2: Construction Vehicle Trips

Project Component	Worker Trips per Day	Vendor Trips per Day	Heavy-Duty Truck Trips per Day
Facilities Pad Grading	30	9	0
Repurposed Injection Well Site Preparation	28	9	0

Project Component	Worker Trips per Day	Vendor Trips per Day	Heavy-Duty Truck Trips per Day
Repurposed Injection Well Drilling	34	10	0
Repurposed Monitoring Well Site Preparation	28	9	0
Repurposed Monitoring Well Drilling[1]	34	10	0
New Well Site Preparation	28	9	0
New Well Drilling[1]	34	10	0
CO_2 Capture Facilities	192	56	0
Compressor Station Construction	56	22	0
CO_2 Main Pipeline	58	20	2
Distribution Pipelines	46	17	2
Electrical Transmission Line	24	12	1
Intra-Field Electrical Distribution	24	12	1
Onsite Electrical Substations	36	10	0
Water Pipelines	40	16	2
Natural Gas Pipelines	40	16	2
Steam Pipeline	40	16	2
Demolition	24	8	0
On-Site Roads	16	5	0

Notes:
1. The Well Hookup phase timing and equipment is included within the “Well Drilling” phases.

The number of daily worker trips were based on Aera Energy’s estimate of the average number of daily workers required for each Project component, and assuming two one-way trips per worker per day. Consistent with the air quality and GHG emissions modeling, the worker trip length was estimated at 45 miles per one-way trip. The fleet mix for worker trips was composed of a mixture of passenger cars, light-duty trucks, and medium-duty vehicles.

The number of daily vendor trips were estimated as 0.4 vendor trips per construction worker, in addition to the on-road vehicles that were included in Aera Energy’s provided construction equipment list (i.e., flatbed trucks, mechanic trucks, SUVs, etc.). Consistent with the air quality and GHG emissions modeling, the vendor trip length was estimated at 45 miles per one-way trip. The fleet mix for vendor trips was composed of a mixture of light heavy-duty trucks, medium heavy-duty trucks, and heavy heavy-duty trucks.

The number of heavy-duty truck trips were based on information provided by Aera Energy. The trip length was assumed to be 45 miles, and the fleet mix was composed entirely of heavy-duty trucks.



4.1.2 Operational Assumptions

Operational energy use refers to the energy demand that would occur during operation of the Project. The sources are summarized below.

Motor Vehicles

During the years of peak Project operation, the Project is anticipated to generate approximately 12 average vehicle trips per day. Two of the daily trips would be bulk material and waste deliveries, and 10 would be employee vehicle trips. Consistent with the air quality and GHG emissions modeling, the trip lengths were assumed to be 45 miles per one-way trip. The fleet mix for employees was determined based on Kern County data from EMFAC2021, and the delivery trip fleet mix was assumed to be light-heavy to heavy-heavy duty trucks. Vehicle fuel efficiency was provided by the EMFAC OFFROAD2021 database for an assumed operational year of 2027. Although Project construction would be entirely completed in 2028, operations at the finished facilities may begin in 2027.

Processing Equipment

Most on-site equipment would be powered by electricity, with the exception of those presented in Table 3. Each steam generator would consume between 65 and 90 MMBtu/hr and was assumed to operate 24 hours per day and 365 days per year. The Project may alternatively use existing steam generation from Cogen 32, SGS 2868, or SGS 2972, as capacity is available.

Table 3: Operational Natural Gas-Powered Equipment

Process	Facility	Equipment	Annual Natural Gas Demand (MMBtu)
Pre-C	GP 32	Utility Steam Generator 1	569,400
		Utility Steam Generator 2	569,400
	Cogen 32	Utility Steam Generator 1	648,240
		Utility Steam Generator 2	648,240
		Utility Steam Generator 3	648,240
Post-C	SGS 2868	Utility Steam Generator 1	709,560
		Utility Steam Generator 2	709,560
		Utility Steam Generator 3	709,560
	SGS 2972	Utility Steam Generator 1	788,400
		Utility Steam Generator 2	788,400
		Utility Steam Generator 3	788,400
Natural Gas Compression	Del Sur Compressors	S-1548-433	15,941
		S-1548-434	15,941
		S-1548-435	15,941



5.0 ENERGY ANALYSIS

This section discusses potential energy impacts associated with the Project and provides mitigation measures where necessary.

5.1 CEQA GUIDELINES

The CEQA Guidelines define a significant effect on the environment as "a substantial, or potentially substantial, adverse change in the environment." To determine if a project would have a significant impact on energy the following must be evaluated.

Would the project:

a) Result in potentially significant environmental impact due to wasteful, inefficient, or unnecessary consumption of energy resources, during project construction or operation?

b) Conflict with or obstruct a state or local plan for renewable energy or energy efficiency?

5.2 ENERGY IMPACT ANALYSIS

Impact ENG-1	**Result in potentially significant environmental impact due to wasteful, inefficient, or unnecessary consumption of energy resources, during project construction or operation?**

Impact Analysis

The energy requirements for the Project were determined using the construction and operational estimates generated from the calculation worksheets for energy consumption (Appendix A). This impact addresses the energy consumption from both construction and operations, discussed separately below.

Construction Energy Demand

During construction of the Project, energy resources would be consumed in the form of diesel and gasoline fuel from the use of off-road equipment (i.e., tractors, excavators, cranes) and on-road vehicles (i.e., construction employee commutes, vendor, haul trucks).

Temporary electricity may be required to provide as-necessary lighting and electric equipment; such electricity demand would be met by portable generator sets and, possibly, local distribution. Fuel demand associated with portable generators is incorporated in the off-road equipment estimate provided below. The amount of electricity used during construction would be minimal. Natural gas is not anticipated to be required during construction of the Project.

Off-Road Equipment

Construction activities associated with the Project were estimated to consume 1,240,200 gallons of diesel fuel from the use of off-road equipment. For comparison, in 2021, approximately 3.7 billion gallons of diesel fuel was consumed within California (USEIA 2023). Thus, the diesel fuel required to power the off-road equipment during construction of the Project would represent approximately 0.03 percent of the state's annual diesel demand.

On-Road Vehicles

On-road vehicles for construction workers, vendors, and haulers would require fuel for travel to and from the site during construction. Table 4 provides an estimate of the total on-road vehicle fuel usage during construction.

Table 4: Construction On-Road Vehicle Fuel Consumption

Project Component	Average Fuel Economy (miles/gallon)	Total VMT	Total Fuel Consumption (gallons)
Worker Trips	26.33	21,202,380	805,193
Vendor Trips	7.72	6,407,316	829,718
Haul Trips	6.20	85,050	13,725
Total Construction On-Road Trips		**27,675,666**	**1,647,483**

Notes:
Calculations use unrounded numbers; totals may not appear to sum exactly due to rounding.
VMT = vehicle miles traveled
Source: Appendix A.

As shown above, construction of the Project was estimated to consume 1,647,483 gallons of a combination of gasoline and diesel fuel from on-road vehicles. For comparison, in 2021, approximately 10.2 billion gallons of gasoline for motor vehicles was consumed within California (USEIA 2023). Thus, the fuel required to power the on-road motor vehicles during construction of the Project would represent approximately 0.02 percent of the state's annual gasoline demand.

Conclusion

Overall, construction activities associated with the proposed Project would result in the consumption of petroleum-based fuels. However, there are no unusual Project characteristics that would necessitate the use of construction equipment or vehicles that would be less energy efficient than at comparable construction sites in other parts of the state. Therefore, it is expected that construction fuel consumption associated with the proposed Project would not be any more inefficient, wasteful, or unnecessary than at other construction sites in the region.



Operational Energy Demand

During operations of the Project, energy would be required to fuel the vehicles travelling to and from the site and to power the proposed equipment, pumps, and facility processes.

Transportation Energy Demand

Table 5 provides an estimate of the annual fuel consumed by vehicles traveling to and from the Project site. As shown in the table, annual vehicular fuel consumption is estimated to be 9,479 gallons of a combination of gasoline and diesel fuel.

Table 5: Operational Vehicle Fuel Consumption

Trip Type	Vehicle Type	Percent of Vehicle Trips	Annual VMT	Average Fuel Economy (miles/gallon)	Total Annual Fuel Consumption (gallons)
Employee Trips	Passenger Cars (LDA)	38.53	45,075	31.44	1,434
	Light Trucks and Medium Duty Vehicles (LDT1, LDT2, MDV)	40.69	47,602	23.77	2,003
	Light-Heavy to Heavy-Heavy Diesel Trucks (LHD1, LHD2, MHDT, HHDT)	20.17	23,596	7.83	3,013
	Motorcycles (MCY)	0.32	371	41.98	9
	Other (OBUS, UBUS, SBUS, MH)	0.30	356	7.02	51
	Employee Trip Subtotal	--	*117,000*	--	*6,509*
Delivery Trips	Light-Heavy to Heavy-Heavy Diesel Trucks (LHD1, LHD2, MHDT, HHDT)	--	23,400	7.83	2,988
Total		**--**		**--**	9,479

Notes:
Calculations use unrounded numbers; totals may not appear to sum exactly due to rounding.
VMT = vehicle miles traveled
"Other" consists of buses and motor homes.
Source: Appendix A.

As noted previously, in 2021, California consumed approximately 10.2 billion gallons of gasoline (USEIA 2023). The Project's anticipated consumption of 9,479 gallons of fuel per year represents approximately 0.00009 percent of the state's annual demand for gasoline. Further, over the lifetime of the Project, the fuel efficiency of the vehicles being used by the employees and delivery vehicles is expected to increase. As such, the amount of petroleum consumed as a result of vehicular trips to and from the Project site during operation would decrease over time.



Processing Equipment Energy Demand

Most on-site equipment (i.e., pumps, maintenance, monitoring, communications, etc.) would be powered by electricity from the on-site co-generation facility and supplemented by PG&E, as needed. The expected maximum electric load of the Project is approximately 49 MW. As noted previously, Kern County consumed a total of 15,009 GWh of electricity in 2021 (1.71 GW, or 1,710 MW). The Project's electricity demand would constitute approximately 2.87 percent of the County's annual electricity demand.

The Pre-C process would share the new substation and electrical distribution system that was included for Cogen 32. Post-C facilities would be constructed at the following three existing facilities: Cogen 32, Steam Generator Setting (SGS) 2868, and SGS 2972. The Pre-C facility would have two natural gas-powered steam generators. Each Post-C facility would have three natural gas-powered steam generators, with carbon capture from those steam generators. The Project may alternatively use existing steam generation from Cogen 32, SGS 2868, or SGS 2972, as capacity is available. The total annual natural gas usage was estimated to be 76.3 million therms. Compared to the County's annual usage from 2021 (1,866 million therms), the Project's natural gas use would represent approximately 4.1 percent of the County's natural gas demand.

Although the Project would result in increased demand for energy resources, the energy would be consumed efficiently and would be typical of industrial carbon capture projects. In addition, carbon capture and sequestration projects, such as the proposed Project, are essential to achieve the state's climate goals (CARB 2022); as a result, any energy consumed by the Project is not considered to be wasteful or unnecessary.

Conclusion

Based on the analysis above, the Project would consume energy resources during construction and operations. However, the energy consumption associated with the proposed Project would not be inefficient, wasteful, or unnecessary, and a less-than-significant impact would occur.

Impact ENG-2 Conflict with or obstruct a state or local plan for renewable energy or energy efficiency?

Impact Analysis

The following discussion evaluates Project consistency with applicable plans for renewable energy or energy efficiency during construction and operations.

Construction

During construction, off-road equipment and on-road vehicles would comply with all applicable federal and state requirements. For example, all off-road equipment would be subject to the most recent In-Use Off-Road Diesel-Fueled Fleets Regulations adopted by the CARB, which establish engine efficiency requirements, among other requirements (CARB 2023). Off-road engines are categorized per engine tier,



with Tier 0 being the least efficient and Tier 4 Final being the cleanest and most efficient. Compliance with the In-Use Off-Road Diesel-Fueled Fleets Regulations would ensure that the Project construction fleet would consist of energy-efficient engines. With respect to the on-road vehicle fleet operations, the USEPA and NHTSA have adopted Federal Vehicle Standards with which the Project would comply. The on-road construction fleet would incorporate these standards as they purchase newer model trucks and turn over their fleet. As such, these regulations would have an overall beneficial effect on reducing nationwide fuel consumption over time as older trucks are replaced. Moreover, heavy-duty trucks would be required to comply with CARB's 5-minute idling limits which would reduce fuel consumption. Although the foregoing regulations were primarily designed to reduce air quality emissions, they would also result in an increase in energy efficiency during construction.

Operation

California adopted the RPS in order to increase the amount of renewable energy supplied by utilities within the state. As noted previously, the Project would use electricity from PG&E during operations. PG&E will continue to be subject to state RPS requirements, and the Project would not preclude achievement of the RPS goals. In addition, any new structures developed as part of the Project would comply with federal, state, and local regulations aimed at reducing energy consumption, including the Building Energy Efficiency Standards (California Code of Regulations Title 24, Part 6) the CALGreen Code (California Code of Regulations Title 24, Part 11). Moreover, the Project directly supports the goals laid out in CARB's 2022 Scoping Plan, including the measures related to carbon capture and sequestration. Finally, the Project would be subject to the CARB's Carbon Capture and Sequestration Protocol under the LCFS (CARB 2018b). The LCFS requirements are designed to decrease the carbon intensity of fuels and increase the range of renewable alternatives; therefore, the Project's compliance with the CARB's Carbon Capture and Sequestration Protocol would indirectly support the state plan for renewable energy.

Conclusion

The Project would not conflict with or obstruct a state or local plan for renewable energy or energy efficiency; therefore, the impact would be less than significant.



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Appendix A. Energy Calculations

Aera CarbonFrontier Project—Energy Consumption Summary

Date of Last Revision: August 31, 2023

Summary of Energy Use During Construction		(Annually)
Construction On-Road Vehicle Fuel	1,647,483	gallons (gasoline, diesel)
Construction Off-Road Equipment Fuel	1,240,200	gallons (diesel)

Summary of Energy Use During Operations		(Annually)
Vehicle Fuel	9,497	gallons (gasoline, diesel)
Natural Gas	76,252,220	therms

Construction On-Road Vehicle Fuel Calculations

Aera Energy Project

Construction Schedule

Phase Name	Number of Days	Number of Staff	Default Vendor Trips (0.4/staff)	Additional Vendor Trips from Equipment List
Facilities Pad Grading	80	15	6	3
Injection Well Site Prep	20	14	6	3
Injection Well Drilling	100	17	7	3
Monitoring Well Site Prep	26	14	6	3
Monitoring Well Drilling	80	17	7	3
New Well Site Preparation	40	14	6	3
New Well Drilling	60	17	7	3
CO2 Capture Facilities	2088	96	38	18
Compressor Station Construction	80	28	11	11
CO2 Main Pipeline	390	29	12	8
Distribution Pipelines	260	23	9	8
Electrical Transmission Line	60	12	5	7
Intra-Field Electrical Distribution	60	12	5	7
On-site Electrical Substations	130	18	7	3
Water Pipeline	87	20	8	8
Natural Gas Pipelines	60	20	8	8
Steam Pipeline	88	20	8	8
Demolition	40	12	5	3
On-Site Roads	20	8	3	2

Construction Trips and VMT

	Trips per Day			Construction Trip Length in Miles				Trips per Phase			VMT per Phase			Fuel Consumption (gallons)		
Phase Name	Worker Trip Number	Total Vendor Trip Number	Hauling Trip Number	Worker Trip Length	Vendor Trip Length	Hauling Trip Length	Number of Days per Phase	Worker Trip Number	Vendor Trip Number	Hauling Trip Number	Worker Trips	Vendor Trips	Hauling Trips	Worker Trips	Vendor Trips	Hauling Trips
Facilities Pad Grading	30	9	0	45	45	45	80	2,400	720	0	108,000	32,400	0	4,101.46	4,195.65	0.00
Injection Well Site Prep	28	9	0	45	45	45	20	560	172	0	25,200	7,740	0	957.01	1,002.29	0.00
Injection Well Drilling	34	10	0	45	45	45	100	3,400	980	0	153,000	44,100	0	5,810.41	5,710.75	0.00
Monitoring Well Site Prep	28	9	0	45	45	45	26	728	224	0	32,760	10,062	0	1,244.11	1,302.98	0.00
Monitoring Well Drilling	34	10	0	45	45	45	80	2,720	784	0	122,400	35,280	0	4,648.33	4,568.60	0.00
New Well Site Preparation	28	9	0	45	45	45	40	1,120	344	0	50,400	15,480	0	1,914.02	2,004.59	0.00
New Well Drilling	34	10	0	45	45	45	60	2,040	588	0	91,800	26,460	0	3,486.24	3,426.45	0.00
CO2 Capture Facilities	192	56	0	45	45	45	2088	400,896	117,763	0	18,040,320	5,299,344	0	685,108.60	686,240.64	0.00
Compressor Station Construction	56	22	0	45	45	45	80	4,480	1,776	0	201,600	79,920	0	7,656.07	10,349.27	0.00
CO2 Main Pipeline	58	20	2	45	45	45	390	22,620	7,644	780	1,017,900	343,980	35,100	38,656.30	44,543.83	5,664.45
Distribution Pipelines	46	17	2	45	45	45	260	11,960	4,472	520	538,200	201,240	23,400	20,438.96	26,059.65	3,776.30
Electrical Transmission Line	24	12	1	45	45	45	60	1,440	708	60	64,800	31,860	2,700	2,460.88	4,125.72	435.73
Intra-Field Electrical Distribution	24	12	1	45	45	45	60	1,440	708	60	64,800	31,860	2,700	2,460.88	4,125.72	435.73
On-site Electrical Substations	36	10	0	45	45	45	130	4,680	1,326	0	210,600	59,670	0	7,997.86	7,726.99	0.00
Water Pipeline	40	16	2	45	45	45	87	3,480	1,392	174	156,600	62,640	7,830	5,947.12	8,111.59	1,263.61
Natural Gas Pipelines	40	16	2	45	45	45	60	2,400	960	120	108,000	43,200	5,400	4,101.46	5,594.20	871.45
Steam Pipeline	40	16	2	45	45	45	88	3,520	1,408	176	158,400	63,360	7,920	6,015.48	8,204.83	1,278.13
Demolition	24	8	0	45	45	45	40	960	312	0	43,200	14,040	0	1,640.59	1,818.12	0.00
On-Site Roads	16	5	0	45	45	45	20	320	104	0	14400	4680	0	546.86191	606.038447	0
											21,202,380	6,407,316	85,050	805,193	829,718	13,725

Total Project Construction VMT (miles)

27,675,666

Total Project Fuel Consumption (gallons)

1,647,483 0.016151795

Source: EMFAC2021 (v1.0.2) Emissions Inventory
Region Type: County
Region: Kern
Calendar Year: 2025
Season: Annual
Vehicle Classification: EMFAC2007 Categories
Units: miles/day for CVMT and EVMT, trips/day for Trips, kWh/day for Energy Consumption, tons/day for Emissions, 1000 gallons/day for Fuel Consumption

VMT = Vehicle Miles Traveled
FE = Fuel Economy

						Given			*Calculations*	
Region	Calendar Year	Vehicle Category	Model Year	Speed	Fuel	Population	VMT (mi/day)	Fuel Consumption (1000 gallons/day)	FE (mi/gallon)	VMT*FE
Kern	2025	HHDT	Aggregate	Aggregate	Gasoline	3.30133965	187.92696	0.052508952	3.57895086	672.5814
Kern	2025	HHDT	Aggregate	Aggregate	Diesel	29354.5932	4652574	750.8210931	6.19664803	28830364
Kern	2025	LDA	Aggregate	Aggregate	Gasoline	333250.856	12949542	429.9992316	30.115267	3.9E+08
Kern	2025	LDA	Aggregate	Aggregate	Diesel	965.347545	30782.41	0.692689876	44.4389496	1367938
Kern	2025	LDT1	Aggregate	Aggregate	Gasoline	33207.4274	1106340.5	44.33730087	24.9528163	27606312
Kern	2025	LDT1	Aggregate	Aggregate	Diesel	13.664457	180.80271	0.007407831	24.4069718	4412.847
Kern	2025	LDT2	Aggregate	Aggregate	Gasoline	170926.876	6807624.8	276.0045355	24.6649018	1.68E+08
Kern	2025	LDT2	Aggregate	Aggregate	Diesel	530.50566	22653.893	0.654638579	34.6051904	783942.3
Kern	2025	LHDT1	Aggregate	Aggregate	Gasoline	16471.7242	594831.17	61.67599769	9.64445153	5736820
Kern	2025	LHDT1	Aggregate	Aggregate	Diesel	14983.0012	532115.71	33.67693917	15.800596	8407745
Kern	2025	LHDT2	Aggregate	Aggregate	Gasoline	2978.90601	101664.12	12.0003499	8.47176266	861274.3
Kern	2025	LHDT2	Aggregate	Aggregate	Diesel	6687.09321	239840.12	18.42419173	13.0176741	3122161
Kern	2025	MDV	Aggregate	Aggregate	Gasoline	152842.847	5491589.3	279.5348482	19.6454551	1.08E+08
Kern	2025	MDV	Aggregate	Aggregate	Diesel	2414.83315	89081.304	3.597529867	24.761797	2205813
Kern	2025	MHDT	Aggregate	Aggregate	Gasoline	1228.03433	77887.576	16.39454601	4.75082236	370030
Kern	2025	MHDT	Aggregate	Aggregate	Diesel	10138.3783	495356.92	56.18379217	8.81672274	4367425

Worker

Sum of VMT*FE (Column BI)	**6.98E+08**
Total VMT	**26497795**
Weighted Average Fuel Economy	**26.33206**

Vendor

Sum of VMT*FE (Column BI)	**51696492**
Total VMT	**6694458**
Weighted Average Fuel Economy	**7.722282**

Haul

Sum of VMT*FE (Column BI)	**28831036**
Total VMT	**4652762**
Weighted Average Fuel Economy	**6.196542**

Construction Off-Road Equipment Fuel Calculation

Aera Energy Project

Construction Schedule

Phase Name	Number of Days
Facilities Pad Grading	80
Injection Well Site Prep	20
Injection Well Drilling	100
Monitoring Well Site Prep	26
Monitoring Well Drilling	80
New Well Site Preparation	40
New Well Drilling	60
CO2 Capture Facilities	2088
Compressor Station Construction	80
CO2 Main Pipeline	390
Distribution Pipelines	260
Electrical Transmission Line	60
Intra-Field Electrical Distribution	60
On-site Electrical Substations	130
Water Pipeline	87
Natural Gas Pipelines	120
Steam Pipeline	88
On-Site Roads	20
Demolition	40

Construction Equipment

Phase Name	Offroad Equipment Name	Standardized Equipment Type	Equipment Type + HP	Amount	Use Hours per Day	Horse Power	Load Factor	Number of Days	HP Hours	Fuel (gallons/HP-hour)	Diesel Fuel Usage
Facilities Pad Grading	Cat 14 Grader	Graders	Graders 300	2	8	259	0.41	80	135,923.20	0.021132035	2872.333765
Facilities Pad Grading	Cat 623 Water Wagon	Off-Highway Trucks	Off-Highway Trucks 600	2	8	407	0.38	80	197,964.80	0.019779292	3915.60354
Facilities Pad Grading	Cat 815 Compactor	Rubber Tired Dozers	Rubber Tired Dozers 300	2	8	232	0.4	80	118,784.00	0.020472256	2431.776509
Facilities Pad Grading	Cat 875 Challenger	Tractors/Loaders/Backhoes	Tractors/Loaders/Backhoes 600	2	8	585	0.37	80	277,056.00	0.018986932	5260.443333
Facilities Pad Grading	Cat D6	Rubber Tired Dozers	Rubber Tired Dozers 300	2	8	207	0.4	80	105,984.00	0.020472256	2169.731627
Facilities Pad Grading	GENERATOR,6-10KW,DIESEL	Generator Sets	Generators 25	2	8	18	0.74	80	17,049.60	0.015990265	272.6276275
Injection Well Site Prep	Cat 14 Grader	Graders	Graders 300	1	8	259	0.41	20	16,990.40	0.021132035	359.0417206
Injection Well Site Prep	Cat 623 Water Wagon	Off-Highway Trucks	Off-Highway Trucks 600	1	8	407	0.38	20	24,745.60	0.019779292	489.4504425
Injection Well Site Prep	Cat 815 Compactor	Rubber Tired Dozers	Rubber Tired Dozers 300	1	8	232	0.4	20	14,848.00	0.020472256	303.9720637
Injection Well Site Prep	Cat 875 Challenger	Tractors/Loaders/Backhoes	Tractors/Loaders/Backhoes 600	2	8	585	0.37	20	69,264.00	0.018986932	1315.110833
Injection Well Site Prep	Cat D6	Rubber Tired Dozers	Rubber Tired Dozers 300	2	8	207	0.4	20	26,496.00	0.020472256	542.4329067
Injection Well Site Prep	Vacuum Truck/Hydro-excavator	Off-Highway Trucks	Off-Highway Trucks 600	2	8	425	0.38	20	51,680.00	0.019779292	1022.193799
Injection Well Site Prep	GENERATOR,6-10KW,DIESEL	Generator Sets	Generators 25	2	8	18	0.74	20	4,262.40	0.015609438	66.53366925
Injection Well Drilling	Cat 14 Grader	Graders	Graders 300	1	8	259	0.41	100	84,952.00	0.021132035	1795.208603
Injection Well Drilling	Cat 623 Water Wagon	Off-Highway Trucks	Off-Highway Trucks 600	1	8	407	0.38	100	123,728.00	0.019779292	2447.252212
Injection Well Drilling	Cat 815 Compactor	Rubber Tired Dozers	Rubber Tired Dozers 300	1	8	232	0.4	100	74,240.00	0.020472256	1519.860318
Injection Well Drilling	Cat 875 Challenger	Tractors/Loaders/Backhoes	Tractors/Loaders/Backhoes 600	2	8	585	0.37	100	346,320.00	0.018986932	6575.554166
Injection Well Drilling	Cat D6	Rubber Tired Dozers	Rubber Tired Dozers 300	2	8	207	0.4	100	132,480.00	0.020472256	2712.164534
Injection Well Drilling	GENERATOR,6-10KW,DIESEL	Generator Sets	Generators 25	2	8	18	0.74	100	21,312.00	0.015609438	332.6683463
Injection Well Drilling	GENERATOR,DIESEL	Generator Sets	Generators 750	1	24	714	0.74	100	1,268,064.00	0.015990265	20276.67979
Injection Well Drilling	MUD PUMP ENGINE	Bore/Drill Rigs	Bore/Drill Rigs 600	1	24	529	0.5	100	634,800.00	0.025654741	16285.6298
Injection Well Drilling	CEMENT PUMP TRUCK	Off-Highway Trucks	Off-Highway Trucks 75	1	8	63	0.38	100	19,152.00	0.019551261	374.4457442
Injection Well Drilling	WIRELINE TRUCK	Off-Highway Trucks	Off-Highway Trucks 75	1	8	63	0.38	100	19,152.00	0.019551261	374.4457442
Injection Well Drilling	VACUUM TRUCK	Off-Highway Trucks	Off-Highway Trucks 600	1	8	425	0.38	100	129,200.00	0.019779292	2555.484497
Monitoring Well Site Prep	Cat 14 Grader	Graders	Graders 300	1	8	259	0.41	26	22,087.52	0.021132035	466.7542368
Monitoring Well Site Prep	Cat 623 Water Wagon	Off-Highway Trucks	Off-Highway Trucks 600	1	8	407	0.38	26	32,169.28	0.019779292	636.2855752
Monitoring Well Site Prep	Cat 815 Compactor	Rubber Tired Dozers	Rubber Tired Dozers 300	1	8	232	0.4	26	19,302.40	0.020472256	395.1636828
Monitoring Well Site Prep	Cat 875 Challenger	Tractors/Loaders/Backhoes	Tractors/Loaders/Backhoes 600	2	8	585	0.37	26	90,043.20	0.018986932	1709.644083
Monitoring Well Site Prep	Cat D6	Rubber Tired Dozers	Rubber Tired Dozers 300	2	8	207	0.4	26	34,444.80	0.020472256	705.1627787
Monitoring Well Site Prep	Vacuum Truck/Hydro-excavator	Off-Highway Trucks	Off-Highway Trucks 600	2	8	425	0.38	26	67,184.00	0.019779292	1328.851938
Monitoring Well Site Prep	GENERATOR,6-10KW,DIESEL	Generator Sets	Generators 25	2	8	18	0.74	26	5,541.12	0.025956408	143.8275708
Monitoring Well Drilling	Cat 14 Grader	Graders	Graders 300	1	8	259	0.41	80	67,961.60	0.021132035	1436.166882
Monitoring Well Drilling	Cat 623 Water Wagon	Off-Highway Trucks	Off-Highway Trucks 600	1	8	407	0.38	80	98,982.40	0.019779292	1957.80177
Monitoring Well Drilling	Cat 815 Compactor	Rubber Tired Dozers	Rubber Tired Dozers 300	1	8	232	0.4	80	59,392.00	0.020472256	1215.888255
Monitoring Well Drilling	Cat 875 Challenger	Tractors/Loaders/Backhoes	Tractors/Loaders/Backhoes 600	2	8	585	0.37	80	277,056.00	0.018986932	5260.443333
Monitoring Well Drilling	Cat D6	Rubber Tired Dozers	Rubber Tired Dozers 300	2	8	207	0.4	80	105,984.00	0.020472256	2169.731627
Monitoring Well Drilling	GENERATOR,6-10KW,DIESEL	Generator Sets	Generators 25	2	8	18	0.74	80	17,049.60	0.025956408	442.5463717
Monitoring Well Drilling	GENERATOR,DIESEL	Generator Sets	Generators 750	1	24	714	0.74	80	1,014,451.20	0.015990265	16221.34383
Monitoring Well Drilling	MUD PUMP ENGINE	Bore/Drill Rigs	Bore/Drill Rigs 600	1	24	529	0.5	80	507,840.00	0.025654741	13028.50384
Monitoring Well Drilling	CEMENT PUMP TRUCK	Off-Highway Trucks	Off-Highway Trucks 75	1	8	63	0.38	80	15,321.60	0.019551261	299.5565954
Monitoring Well Drilling	WIRELINE TRUCK	Off-Highway Trucks	Off-Highway Trucks 75	1	8	63	0.38	80	15,321.60	0.019551261	299.5565954
Monitoring Well Drilling	VACUUM TRUCK	Off-Highway Trucks	Off-Highway Trucks 600	1	8	425	0.38	80	103,360.00	0.019779292	2044.387598
New Well Site Preparation	Cat 14 Grader	Graders	Graders 300	1	8	259	0.41	40	33,980.80	0.021132035	718.0834412
New Well Site Preparation	Cat 623 Water Wagon	Off-Highway Trucks	Off-Highway Trucks 600	1	8	407	0.38	40	49,491.20	0.019779292	978.900885
New Well Site Preparation	Cat 815 Compactor	Rubber Tired Dozers	Rubber Tired Dozers 300	1	8	232	0.4	40	29,696.00	0.020472256	607.9441273
New Well Site Preparation	Cat 875 Challenger	Tractors/Loaders/Backhoes	Tractors/Loaders/Backhoes 600	2	8	585	0.37	40	138,528.00	0.018986932	2630.221666

New Well Site Preparation	Cat D6	Rubber Tired Dozers	Rubber Tired Dozers 300	2	8	207	0.4	40	52,992.00	0.020472256	1084.865813	
New Well Site Preparation	Vacuum Truck/Hydro-excavator	Off-Highway Trucks	Off-Highway Trucks 600	2	8	425	0.38	40	103,360.00	0.019779292	2044.387598	
New Well Site Preparation	GENERATOR,6-10KW,DIESEL	Generator Sets	Generators 25	2	8	18	0.74	40	8,524.80	0.015990265	136.3138137	
New Well Drilling	Cat 14 Grader	Graders	Graders 300	1	8	259	0.41	60	50,971.20	0.021132035	1077.125162	
New Well Drilling	Cat 623 Water Wagon	Off-Highway Trucks	Off-Highway Trucks 600	1	8	407	0.38	60	74,236.80	0.019779292	1468.351327	
New Well Drilling	Cat 815 Compactor	Rubber Tired Dozers	Rubber Tired Dozers 300	1	8	232	0.4	60	44,544.00	0.020472256	911.916191	
New Well Drilling	Cat 875 Challenger	Tractors/Loaders/Backhoes	Tractors/Loaders/Backhoes 600	2	8	585	0.37	60	207,792.00	0.018986932	3945.3325	
New Well Drilling	Cat D6	Rubber Tired Dozers	Rubber Tired Dozers 300	2	8	207	0.4	60	79,488.00	0.020472256	1627.29872	
New Well Drilling	GENERATOR,6-10KW,DIESEL	Generator Sets	Generators 25	2	8	18	0.74	60	12,787.20	0.015990265	204.4707206	
New Well Drilling	GENERATOR,DIESEL	Generator Sets	Generators 750	1	24	714	0.74	60	760,838.40	0.015990265	12166.00788	associated w drilling rig
New Well Drilling	MUD PUMP ENGINE	Bore/Drill Rigs	Bore/Drill Rigs 600	1	24	529	0.5	60	380,880.00	0.025654741	9771.377883	associated w drilling rig
New Well Drilling	CEMENT PUMP TRUCK	Off-Highway Trucks	Off-Highway Trucks 75	1	8	63	0.38	60	11,491.20	0.019551261	224.6674465	
New Well Drilling	WIRELINE TRUCK	Off-Highway Trucks	Off-Highway Trucks 75	1	8	63	0.38	60	11,491.20	0.019551261	224.6674465	
New Well Drilling	VACUUM TRUCK	Off-Highway Trucks	Off-Highway Trucks 600	1	8	425	0.38	60	77,520.00	0.019779292	1533.290698	
CO2 Capture Facilities	BACKHOE/LOADER,.75-1CY	Tractors/Loaders/Backhoes	Tractors/Loaders/Backhoes 75	6	8	67	0.37	2088	2,484,552.96	0.019036063	47296.10787	
CO2 Capture Facilities	COMPACTOR,ROLLER,24-33"	Rollers	Rollers 15	3	8	8	0.38	2088	152,340.48	0.021560654	3284.560392	
CO2 Capture Facilities	COMPRESSOR,100-200 CFM,DIESI	Air Compressors	Air Compressors 50	6	8	50	0.48	2088	2,405,376.00	0.027586816	66356.66625	
CO2 Capture Facilities	CRANE,10-14 TON,HYDRAULIC,RT	Cranes	Cranes 25	3	8	6	0.29	2088	87,194.88	0.016559033	1443.862927	
CO2 Capture Facilities	FORKLIFT,7-9K#,YARD	Rough Terrain Forklifts	Rough Terrain Forklifts 300	3	8	300	0.4	2088	6,013,440.00	0.020808964	125133.4565	
CO2 Capture Facilities	FORKLIFT,8-9K# RT TELE BOOM	Rough Terrain Forklifts	Rough Terrain Forklifts 75	6	8	73	0.4	2088	2,926,540.80	0.02087573	61093.67418	
CO2 Capture Facilities	FUEL/LUBE TRUCK,2 TON,2X4	Off-Highway Trucks	Off-Highway Trucks 75	1	8	73	0.38	2088	463,368.96	0.019551261	9059.44732	
CO2 Capture Facilities	GENERATOR,6-10KW,DIESEL	Generator Sets	Generators 25	6	8	18	0.74	2088	1,334,983.68	0.015990265	21346.74323	
CO2 Capture Facilities	LOADER,SKIDSTEER 36-45HP	Skid Steer Loaders	Skid Steer Loaders 50	1	8	45	0.37	2088	278,121.60	0.021273911	5916.734242	
CO2 Capture Facilities	MANLIFT,40-50',ELECTRIC	Other Construction Equipment	Other 75	3	8	60	0.42	2088	1,262,822.40	0.021260365	26848.06524	
CO2 Capture Facilities	PEOPLE MOVER,16-30 PASS	Other Construction Equipment	Other 175	3	8	150	0.42	2088	3,157,056.00	0.021428753	67651.77246	
CO2 Capture Facilities	SCISSOR LIFT,<20'	Other Construction Equipment	Other 600	6	8	475	0.42	2088	19,994,688.00	0.021507485	430035.4595	
CO2 Capture Facilities	TAMPER,100-150#	Other Construction Equipment	Other 50	3	8	45	0.42	2088	947,116.80	0.024074284	22801.15895	
CO2 Capture Facilities	TRUCK,1.5 TON,2X4,W/CRANE	Cranes	Cranes 25	3	8	8	0.29	2088	116,259.84	0.016559033	1925.15057	
CO2 Capture Facilities	WELDER,400-500 AMP DIESEL	Welders	Welders 25	9	8	18	0.45	2088	1,217,721.60	0	0	
CO2 Capture Facilities	WHEEL LOADER,2.5-3.0CY	Tractors/Loaders/Backhoes	Tractors/Loaders/Backhoes 50	3	8	42	0.37	2088	778,740.48	0.020959418	16321.94742	
Compressor Station Construction	BACKHOE/LOADER,.75-1CY	Tractors/Loaders/Backhoes	Tractors/Loaders/Backhoes 75	2	8	67	0.37	80	31,731.20	0.019036063	604.0371375	
Compressor Station Construction	COMPACTOR,ROLLER,24-33"	Rollers	Rollers 15	1	8	8	0.38	80	1,945.60	0.021560654	41.94840859	
Compressor Station Construction	COMPRESSOR,100-200 CFM,DIESI	Air Compressors	Air Compressors 50	3	8	50	0.48	80	46,080.00	0.027586816	1271.200503	
Compressor Station Construction	CRANE,10-14 TON,HYDRAULIC,RT	Cranes	Cranes 25	1	8	6	0.29	80	1,113.60	0.016559033	18.44013956	
Compressor Station Construction	FORKLIFT,7-9K#,YARD	Rough Terrain Forklifts	Rough Terrain Forklifts 300	1	8	300	0.4	80	76,800.00	0.020808964	1598.128436	
Compressor Station Construction	FORKLIFT,8-9K# RT TELE BOOM	Rough Terrain Forklifts	Rough Terrain Forklifts 75	2	8	73	0.4	80	37,376.00	0.02087573	780.2512666	
Compressor Station Construction	FUEL/LUBE TRUCK,2 TON,2X4	Off-Highway Trucks	Off-Highway Trucks 75	1	8	73	0.38	80	17,753.60	0.019551261	347.1052613	
Compressor Station Construction	GENERATOR,6-10KW,DIESEL	Generator Sets	Generators 25	2	8	18	0.74	80	17,049.60	0.015990265	272.6276275	
Compressor Station Construction	LOADER,SKIDSTEER 36-45HP	Skid Steer Loaders	Skid Steer Loaders 50	1	8	45	0.37	80	10,656.00	0.021273911	226.6947985	
Compressor Station Construction	MANLIFT,40-50',ELECTRIC	Other Construction Equipment	Other 75	1	8	60	0.42	80	16,128.00	0.021260365	342.8871678	
Compressor Station Construction	PEOPLE MOVER,16-30 PASS	Other Construction Equipment	Other 175	5	8	150	0.42	80	201,600.00	0.021428753	4320.036556	
Compressor Station Construction	SCISSOR LIFT,<20'	Other Construction Equipment	Other 600	2	8	475	0.42	80	255,360.00	0.021507485	5492.151463	
Compressor Station Construction	TAMPER,100-150#	Other Construction Equipment	Other 50	1	8	45	0.42	80	12,096.00	0.024074284	291.2025408	
Compressor Station Construction	TRUCK,1.5 TON,2X4,W/CRANE	Cranes	Cranes 25	1	8	8	0.29	80	1,484.80	0.016559033	24.58685274	
Compressor Station Construction	WELDER,400-500 AMP DIESEL	Welders	Welders 25	3	8	18	0.45	80	15,552.00	0	0	
Compressor Station Construction	WHEEL LOADER,2.5-3.0CY	Tractors/Loaders/Backhoes	Tractors/Loaders/Backhoes 50	2	8	42	0.37	80	19,891.20	0.020959418	416.9079801	
CO2 Main Pipeline	BACKHOE/LOADER,.75-1CY	Tractors/Loaders/Backhoes	Tractors/Loaders/Backhoes 100	3	8	84	0.37	390	290,908.80	0.019131329	5565.472082	
CO2 Main Pipeline	CAT 325 Excavator	Excavators	Excavators 175	3	8	172	0.38	390	611,769.60	0.019760537	12088.89562	
CO2 Main Pipeline	CAT 815 COMPACTOR	Rubber Tired Dozers	Rubber Tired Dozers 300	1	8	232	0.4	390	289,536.00	0.020472256	5927.455241	
CO2 Main Pipeline	COMPACTOR,40-66" ROLLER,RIDE	Rollers	Rollers 50	1	8	33	0.38	390	39,124.80	0.021576102	844.1606739	
CO2 Main Pipeline	WELDER,500-800 AMP DIESEL MU	Welders	Welders 50	4	8	48	0.45	390	269,568.00	0.025838887	6965.337138	
CO2 Main Pipeline	WHEEL LOADER,3.0-3.5CY	Tractors/Loaders/Backhoes	Tractors/Loaders/Backhoes 175	1	8	125	0.37	390	144,300.00	0.018991739	2740.508006	
CO2 Main Pipeline	Vacuum Truck/Hydro-excavator	Off-Highway Trucks	Off-Highway Trucks 600	1	8	425	0.38	390	503,880.00	0.019779292	9966.389539	
CO2 Main Pipeline	SIDEBOOM, 14OK#,300HP (583)	Crawler Tractors	Crawler Tractors 300	4	8	300	0.43	390	1,609,920.00	0.022153745	35665.75733	
CO2 Main Pipeline	CRANE,10-14 TON,HYDRAULIC,RT	Cranes	Cranes 75	1	8	62	0.29	390	56,097.60	0.014831616	832.0180471	
Distribution Pipelines	BACKHOE/LOADER,.75-1CY	Tractors/Loaders/Backhoes	Tractors/Loaders/Backhoes 75	2	8	67	0.37	260	103,126.40	0.019036063	1963.120697	
Distribution Pipelines	CAT 325 Excavator	Excavators	Excavators 175	3	8	172	0.38	260	407,846.40	0.019760537	8059.263746	
Distribution Pipelines	CAT 815 COMPACTOR	Rubber Tired Dozers	Rubber Tired Dozers 300	1	8	232	0.4	260	193,024.00	0.020472256	3951.636828	
Distribution Pipelines	COMPACTOR,40-66" ROLLER,RIDE	Rollers	Rollers 50	1	8	33	0.38	260	26,083.20	0.021576102	562.7737826	
Distribution Pipelines	WELDER,500-800 AMP DIESEL MU	Welders	Welders 50	3	8	48	0.45	260	134,784.00	0.025838887	3482.668569	
Distribution Pipelines	Vacuum Truck/Hydro-excavator	Off-Highway Trucks	Off-Highway Trucks 600	1	8	425	0.38	260	335,920.00	0.019779292	6644.259692	
Distribution Pipelines	WHEEL LOADER,3.0-3.5CY	Tractors/Loaders/Backhoes	Tractors/Loaders/Backhoes 175	1	8	125	0.37	260	96,200.00	0.018991739	1827.005337	
Distribution Pipelines	CRANE,10-14 TON,HYDRAULIC,RT	Cranes	Cranes 75	1	8	62	0.29	260	37,398.40	0.014831616	554.6786981	
Electrical Transmission Line	Cat D6	Rubber Tired Dozers	Rubber Tired Dozers 300	1	8	207	0.4	60	39,744.00	0.020472256	813.6493601	
Electrical Transmission Line	Cat 623 Water Wagon	Off-Highway Trucks	Off-Highway Trucks 600	1	8	407	0.38	60	74,236.80	0.019779292	1468.351327	
Electrical Transmission Line	TRAILER,CABLE PULLER,20-30K P	Other Construction Equipment	Other 100	1	8	82	0.42	60	16,531.20	0.021479935	355.089106	
Intra-Field Electrical Distribution	Cat D6	Rubber Tired Dozers	Rubber Tired Dozers 300	1	8	207	0.4	60	39,744.00	0.020469494	813.5395565	Use 2026 emission factors
Intra-Field Electrical Distribution	Cat 623 Water Wagon	Off-Highway Trucks	Off-Highway Trucks 600	1	8	407	0.38	60	74,236.80	0.019801016	1469.96408	Use 2026 emission factors
Intra-Field Electrical Distribution	TRAILER,CABLE PULLER,20-30K P	Other Construction Equipment	Other 100	1	8	82	0.42	60	16,531.20	0.021471738	354.9535895	Use 2026 emission factors
On-site Electrical Substations	BACKHOE/LOADER,1-1.25CY	Tractors/Loaders/Backhoes	Tractors/Loaders/Backhoes 100	3	8	92	0.37	130	106,204.80	0.019131329	2031.839014	
On-site Electrical Substations	BORING SYSTEM,30-36",AUGER,D	Bore/Drill Rigs	Bore/Drill Rigs 75	1	24	68	0.5	130	106,080.00	0.024508842	2599.898011	
On-site Electrical Substations	COMPACTOR,24-33" ROLLER,WAL	Rollers	Rollers 15	1	8	8	0.38	130	3,161.60	0.021560654	68.16616395	
On-site Electrical Substations	COMPRESSOR,100-200 CFM,DIESI	Air Compressors	Air Compressors 50	1	8	50	0.48	130	24,960.00	0.027586816	688.566939	
On-site Electrical Substations	CONCRETE VIBRATOR,HEAVY DU	Concrete/Industrial Saws	Concrete/Industrial Saws 15	1	8	6	0.73	130	4,555.20	0.041924095	190.972639	

On-site Electrical Substations	CRANE,70-79 TON,HYDRAULIC,RT	Cranes	Cranes 300	1	8	250	0.29	130	75,400.00	0.014892329	1122.881615
On-site Electrical Substations	FORKLIFT,7-9K#,YARD	Rough Terrain Forklifts	Rough Terrain Forklifts 75	1	8	73	0.4	130	30,368.00	0.02087573	633.9541541
On-site Electrical Substations	LOADER,SKIDSTEER 36-45HP	Skid Steer Loaders	Skid Steer Loaders 50	1	8	45	0.37	130	17,316.00	0.021273911	368.3790476
On-site Electrical Substations	MANLIFT,40' RT,GAS OR DSL	Other Construction Equipment	Other 75	1	8	60	0.42	130	26,208.00	0.021260365	557.1916477
On-site Electrical Substations	MANLIFT,60' RT,GAS OR DSL	Other Construction Equipment	Other 75	1	8	60	0.42	130	26,208.00	0.021260365	557.1916477
On-site Electrical Substations	MORTAR MIXER,6-9 CU FT	Cement and Mortar Mixers	Cement and Mortar Mixers 15	1	8	7	0.56	130	4,076.80	0	0
On-site Electrical Substations	TRENCHER,3-5'	Trenchers	Trenchers 100	1	8	80	0.5	130	41,600.00	0.026102425	1085.860897
Water Pipeline	BACKHOE/LOADER,.75-1CY	Tractors/Loaders/Backhoes	Tractors/Loaders/Backhoes 75	2	8	67	0.37	87	34,507.68	0.019036063	656.8903871
Water Pipeline	CAT 325 Excavator	Excavators	Excavators 175	2	8	172	0.38	87	90,981.12	0.019760537	1797.835759
Water Pipeline	CAT 815 COMPACTOR	Rubber Tired Dozers	Rubber Tired Dozers 300	1	8	232	0.4	87	64,588.80	0.020472256	1322.278477
Water Pipeline	COMPACTOR,40-66" ROLLER,RIDE	Rollers	Rollers 50	1	8	33	0.38	87	8,727.84	0.021576102	188.3127657
Water Pipeline	WELDER,500-800 AMP DIESEL MU	Welders	Welders 50	3	8	48	0.45	87	45,100.80	0.025838887	1165.354483
Water Pipeline	WHEEL LOADER,3.0-3.5CY	Tractors/Loaders/Backhoes	Tractors/Loaders/Backhoes 175	1	8	125	0.37	87	32,190.00	0.018991739	611.3440936
Natural Gas Pipelines	BACKHOE/LOADER,.75-1CY	Tractors/Loaders/Backhoes	Tractors/Loaders/Backhoes 75	2	8	67	0.37	120	47,596.80	0.019036063	906.0557063
Natural Gas Pipelines	CAT 325 Excavator	Excavators	Excavators 175	2	8	172	0.38	120	125,491.20	0.019760537	2479.77346
Natural Gas Pipelines	CAT 815 COMPACTOR	Rubber Tired Dozers	Rubber Tired Dozers 300	1	8	232	0.4	120	89,088.00	0.020472256	1823.832382
Natural Gas Pipelines	COMPACTOR,40-66" ROLLER,RIDE	Rollers	Rollers 50	1	8	33	0.38	120	12,038.40	0.021576102	259.7417458
Natural Gas Pipelines	WELDER,500-800 AMP DIESEL MU	Welders	Welders 50	3	8	48	0.45	120	62,208.00	0.025838887	1607.385493
Natural Gas Pipelines	WHEEL LOADER,3.0-3.5CY	Tractors/Loaders/Backhoes	Tractors/Loaders/Backhoes 175	1	8	125	0.37	120	44,400.00	0.018991739	843.2332325
Steam Pipeline	BACKHOE/LOADER,.75-1CY	Tractors/Loaders/Backhoes	Tractors/Loaders/Backhoes 75	2	8	67	0.37	88	34,904.32	0.019036063	664.4408513
Steam Pipeline	CAT 325 Excavator	Excavators	Excavators 175	2	8	172	0.38	88	92,026.88	0.019760537	1818.500538
Steam Pipeline	CAT 815 COMPACTOR	Rubber Tired Dozers	Rubber Tired Dozers 300	1	8	232	0.4	88	65,331.20	0.020472256	1337.47708
Steam Pipeline	COMPACTOR,40-66" ROLLER,RIDE	Rollers	Rollers 50	1	8	33	0.38	88	8,828.16	0.021576102	190.4772803
Steam Pipeline	WELDER,500-800 AMP DIESEL MU	Welders	Welders 50	3	8	48	0.45	88	45,619.20	0.025838887	1178.749362
Steam Pipeline	WHEEL LOADER,3.0-3.5CY	Tractors/Loaders/Backhoes	Tractors/Loaders/Backhoes 175	1	8	125	0.37	88	32,560.00	0.018991739	618.3710372
Demolition	Cat 14 Grader	Graders	Graders 300	1	8	259	0.41	40	33,980.80	0.021132035	718.0834412
Demolition	Cat 623 Water Wagon	Off-Highway Trucks	Off-Highway Trucks 600	1	8	407	0.38	40	49,491.20	0.019779292	978.900885
Demolition	Cat 815 Compactor	Rubber Tired Dozers	Rubber Tired Dozers 300	1	8	232	0.4	40	29,696.00	0.020472256	607.9441273
Demolition	Cat 875 Challenger	Tractors/Loaders/Backhoes	Tractors/Loaders/Backhoes 600	1	8	585	0.37	40	69,264.00	0.018986932	1315.110833
Demolition	CAT 325 Excavator	Excavators	Excavators 175	1	8	172	0.38	40	20,915.20	0.019760537	413.2955767
Demolition	Excavator with Shear	Excavators	Excavators 175	1	8	172	0.38	40	20,915.20	0.019760537	413.2955767
Demolition	Vacuum Truck/Hydro-excavator	Off-Highway Trucks	Off-Highway Trucks 600	1	8	425	0.38	40	51,680.00	0.019779292	1022.193799
Demolition	GENERATOR,6-10KW,DIESEL	Generator Sets	Generators 25	2	8	18	0.74	40	8,524.80	0.015990265	136.3138137
On-Site Roads	Cat 14 Grader	Graders	Graders 300	1	8	259	0.41	20	16,990.40	0.021132035	359.0417206
On-Site Roads	Cat 623 Water Wagon	Off-Highway Trucks	Off-Highway Trucks 600	1	8	407	0.38	20	24,745.60	0.019779292	489.4504425
On-Site Roads	Cat 815 Compactor	Rubber Tired Dozers	Rubber Tired Dozers 300	1	8	232	0.4	20	14,848.00	0.020472256	303.9720637
On-Site Roads	Cat 875 Challenger	Tractors/Loaders/Backhoes	Tractors/Loaders/Backhoes 600	1	8	585	0.37	20	34,632.00	0.018986932	657.5554166
On-Site Roads	Cat D6	Rubber Tired Dozers	Rubber Tired Dozers 300	2	8	207	0.4	20	26,496.00	0.020472256	542.4329067

1,240,199.99

Notes:
Source of usage estimates: California Air Resource Board (CARB). 2023. OFFROAD2021 (v1.0.4) Emissions Inventory
Website: https://arb.ca.gov/emfac/emissions-inventory/. Accessed May 26, 2023.

0.03

Table G-12. Horsepower and Load Factors for Construction Equipm	Fuel	Load Factor
Aerial Lifts	Diesel	0.31
Air Compressors	Diesel	0.48
Bore/Drill Rigs	Diesel	0.5
Cement and Mortar Mixers	Diesel	0.56
Concrete/Industrial Saws	Diesel	0.73
Cranes	Diesel	0.29
Crawler Tractors	Diesel	0.43
Dumpers/Tenders	Diesel	0.38
Excavators	Diesel	0.38
Forklifts	Diesel	0.2
Generator Sets	Diesel	0.74
Graders	Diesel	0.41
Off-Highway Tractors	Diesel	0.44
Off-Highway Trucks	Diesel	0.38
Other Construction Equipment	Diesel	0.42
Other General Industrial Equipment	Diesel	0.34
Other Material Handling Equipment	Diesel	0.4
Pavers	Diesel	0.42
Paving Equipment	Diesel	0.36
Plate Compactors	Diesel	0.43
Pressure Washers	Diesel	0.3
Pumps	Diesel	0.74
Rollers	Diesel	0.38
Rough Terrain Forklifts	Diesel	0.4
Rubber Tired Dozers	Diesel	0.4
Rubber Tired Loaders	Diesel	0.36
Scrapers	Diesel	0.48
Signal Boards	Diesel	0.82
Skid Steer Loaders	Diesel	0.37
Surfacing Equipment	Diesel	0.3
Sweepers/Scrubbers	Diesel	0.46
Tractors/Loaders/Backhoes	Diesel	0.37
Trenchers	Diesel	0.5
Welders	Diesel	0.45
Sources: California Air Resources Board (CARB). 2021. OFFROAD2017 - ORION. Available: https://www.arb.ca		

Source: Table G-12 of CalEEMod Use Guide Appendix G

a.gov/orion/. Accessed: March 2021.; California Air Resources Board (CARB). 2017. 2017 Emission Factor

rs. Available: https://ww3.arb.ca.gov/msei/ordiesel/ordas_ef_fcf_2017_v7.xlsx. Accessed: March 2021.

Model Output: OFFROAD2021 (v1.0.4) Emissions Inventory
Region Type: County
Region: Kern
Calendar Year: 2025
Scenario: All Adopted Rules - Exhaust
Vehicle Classification: OFFROAD2021 Equipment Types
Units: tons/day for Emissions, gallons/year for Fuel, hours/year for Activity, Horsepower-hours/y

Region	CalYr	Vehicle Class + HP Bin	Model Year	Fuel
Kern	2025	Bore/Drill Rigs 100	Aggregate	Diesel
Kern	2025	Bore/Drill Rigs 15	Aggregate	Diesel
Kern	2025	Bore/Drill Rigs 175	Aggregate	Diesel
Kern	2025	Bore/Drill Rigs 25	Aggregate	Diesel
Kern	2025	Bore/Drill Rigs 300	Aggregate	Diesel
Kern	2025	Bore/Drill Rigs 50	Aggregate	Diesel
Kern	2025	Bore/Drill Rigs 600	Aggregate	Diesel
Kern	2025	Bore/Drill Rigs 75	Aggregate	Diesel
Kern	2025	Bore/Drill Rigs 750	Aggregate	Diesel
Kern	2025	Bore/Drill Rigs 9999	Aggregate	Diesel
Kern	2025	Cement And Mortar Mixers 15	Aggregate	Diesel
Kern	2025	Cement And Mortar Mixers 25	Aggregate	Diesel
Kern	2025	Concrete/Industrial Saws 25	Aggregate	Diesel
Kern	2025	Concrete/Industrial Saws 50	Aggregate	Diesel
Kern	2025	Cranes 100	Aggregate	Diesel
Kern	2025	Cranes 175	Aggregate	Diesel
Kern	2025	Cranes 25	Aggregate	Diesel
Kern	2025	Cranes 300	Aggregate	Diesel
Kern	2025	Cranes 50	Aggregate	Diesel
Kern	2025	Cranes 600	Aggregate	Diesel
Kern	2025	Cranes 75	Aggregate	Diesel
Kern	2025	Cranes 750	Aggregate	Diesel
Kern	2025	Cranes 9999	Aggregate	Diesel
Kern	2025	Crawler Tractors 100	Aggregate	Diesel
Kern	2025	Crawler Tractors 175	Aggregate	Diesel
Kern	2025	Crawler Tractors 300	Aggregate	Diesel
Kern	2025	Crawler Tractors 50	Aggregate	Diesel
Kern	2025	Crawler Tractors 600	Aggregate	Diesel
Kern	2025	Crawler Tractors 75	Aggregate	Diesel
Kern	2025	Crawler Tractors 750	Aggregate	Diesel
Kern	2025	Crawler Tractors 9999	Aggregate	Diesel
Kern	2025	Dumpers/Tenders 25	Aggregate	Diesel
Kern	2025	Excavators 100	Aggregate	Diesel
Kern	2025	Excavators 175	Aggregate	Diesel
Kern	2025	Excavators 25	Aggregate	Diesel
Kern	2025	Excavators 300	Aggregate	Diesel
Kern	2025	Excavators 50	Aggregate	Diesel

Kern	2025	Excavators 600	Aggregate	Diesel
Kern	2025	Excavators 75	Aggregate	Diesel
Kern	2025	Excavators 750	Aggregate	Diesel
Kern	2025	Excavators 9999	Aggregate	Diesel
Kern	2025	Graders 100	Aggregate	Diesel
Kern	2025	Graders 175	Aggregate	Diesel
Kern	2025	Graders 25	Aggregate	Diesel
Kern	2025	Graders 300	Aggregate	Diesel
Kern	2025	Graders 50	Aggregate	Diesel
Kern	2025	Graders 600	Aggregate	Diesel
Kern	2025	Graders 75	Aggregate	Diesel
Kern	2025	Graders 9999	Aggregate	Diesel
Kern	2025	Off-Highway Tractors 100	Aggregate	Diesel
Kern	2025	Off-Highway Tractors 175	Aggregate	Diesel
Kern	2025	Off-Highway Tractors 25	Aggregate	Diesel
Kern	2025	Off-Highway Tractors 300	Aggregate	Diesel
Kern	2025	Off-Highway Tractors 50	Aggregate	Diesel
Kern	2025	Off-Highway Tractors 600	Aggregate	Diesel
Kern	2025	Off-Highway Tractors 75	Aggregate	Diesel
Kern	2025	Off-Highway Tractors 750	Aggregate	Diesel
Kern	2025	Off-Highway Tractors 9999	Aggregate	Diesel
Kern	2025	Off-Highway Trucks 100	Aggregate	Diesel
Kern	2025	Off-Highway Trucks 175	Aggregate	Diesel
Kern	2025	Off-Highway Trucks 300	Aggregate	Diesel
Kern	2025	Off-Highway Trucks 50	Aggregate	Diesel
Kern	2025	Off-Highway Trucks 600	Aggregate	Diesel
Kern	2025	Off-Highway Trucks 75	Aggregate	Diesel
Kern	2025	Off-Highway Trucks 750	Aggregate	Diesel
Kern	2025	Off-Highway Trucks 9999	Aggregate	Diesel
Kern	2025	Other 100	Aggregate	Diesel
Kern	2025	Other 15	Aggregate	Diesel
Kern	2025	Other 175	Aggregate	Diesel
Kern	2025	Other 25	Aggregate	Diesel
Kern	2025	Other 300	Aggregate	Diesel
Kern	2025	Other 50	Aggregate	Diesel
Kern	2025	Other 600	Aggregate	Diesel
Kern	2025	Other 75	Aggregate	Diesel
Kern	2025	Other 750	Aggregate	Diesel
Kern	2025	Other 9999	Aggregate	Diesel
Kern	2025	Pavers 100	Aggregate	Diesel
Kern	2025	Pavers 175	Aggregate	Diesel
Kern	2025	Pavers 25	Aggregate	Diesel
Kern	2025	Pavers 300	Aggregate	Diesel
Kern	2025	Pavers 50	Aggregate	Diesel
Kern	2025	Pavers 600	Aggregate	Diesel
Kern	2025	Pavers 75	Aggregate	Diesel
Kern	2025	Pavers 750	Aggregate	Diesel

Kern	2025	Paving Equipment 100	Aggregate	Diesel
Kern	2025	Paving Equipment 175	Aggregate	Diesel
Kern	2025	Paving Equipment 25	Aggregate	Diesel
Kern	2025	Paving Equipment 300	Aggregate	Diesel
Kern	2025	Paving Equipment 50	Aggregate	Diesel
Kern	2025	Paving Equipment 600	Aggregate	Diesel
Kern	2025	Paving Equipment 75	Aggregate	Diesel
Kern	2025	Paving Equipment 750	Aggregate	Diesel
Kern	2025	Paving Equipment 9999	Aggregate	Diesel
Kern	2025	Plate Compactors 15	Aggregate	Diesel
Kern	2025	Rollers 100	Aggregate	Diesel
Kern	2025	Rollers 15	Aggregate	Diesel
Kern	2025	Rollers 175	Aggregate	Diesel
Kern	2025	Rollers 25	Aggregate	Diesel
Kern	2025	Rollers 300	Aggregate	Diesel
Kern	2025	Rollers 50	Aggregate	Diesel
Kern	2025	Rollers 600	Aggregate	Diesel
Kern	2025	Rollers 75	Aggregate	Diesel
Kern	2025	Rough Terrain Forklifts 100	Aggregate	Diesel
Kern	2025	Rough Terrain Forklifts 175	Aggregate	Diesel
Kern	2025	Rough Terrain Forklifts 25	Aggregate	Diesel
Kern	2025	Rough Terrain Forklifts 300	Aggregate	Diesel
Kern	2025	Rough Terrain Forklifts 50	Aggregate	Diesel
Kern	2025	Rough Terrain Forklifts 600	Aggregate	Diesel
Kern	2025	Rough Terrain Forklifts 75	Aggregate	Diesel
Kern	2025	Rough Terrain Forklifts 750	Aggregate	Diesel
Kern	2025	Rubber Tired Dozers 100	Aggregate	Diesel
Kern	2025	Rubber Tired Dozers 175	Aggregate	Diesel
Kern	2025	Rubber Tired Dozers 300	Aggregate	Diesel
Kern	2025	Rubber Tired Dozers 50	Aggregate	Diesel
Kern	2025	Rubber Tired Dozers 600	Aggregate	Diesel
Kern	2025	Rubber Tired Dozers 75	Aggregate	Diesel
Kern	2025	Rubber Tired Dozers 750	Aggregate	Diesel
Kern	2025	Rubber Tired Loaders 100	Aggregate	Diesel
Kern	2025	Rubber Tired Loaders 175	Aggregate	Diesel
Kern	2025	Rubber Tired Loaders 25	Aggregate	Diesel
Kern	2025	Rubber Tired Loaders 300	Aggregate	Diesel
Kern	2025	Rubber Tired Loaders 50	Aggregate	Diesel
Kern	2025	Rubber Tired Loaders 600	Aggregate	Diesel
Kern	2025	Rubber Tired Loaders 75	Aggregate	Diesel
Kern	2025	Rubber Tired Loaders 750	Aggregate	Diesel
Kern	2025	Rubber Tired Loaders 9999	Aggregate	Diesel
Kern	2025	Scrapers 100	Aggregate	Diesel
Kern	2025	Scrapers 175	Aggregate	Diesel
Kern	2025	Scrapers 25	Aggregate	Diesel
Kern	2025	Scrapers 300	Aggregate	Diesel
Kern	2025	Scrapers 50	Aggregate	Diesel

Kern	2025	Scrapers 600	Aggregate	Diesel
Kern	2025	Scrapers 75	Aggregate	Diesel
Kern	2025	Scrapers 750	Aggregate	Diesel
Kern	2025	Scrapers 9999	Aggregate	Diesel
Kern	2025	Signal Boards 15	Aggregate	Diesel
Kern	2025	Signal Boards 50	Aggregate	Diesel
Kern	2025	Skid Steer Loaders 100	Aggregate	Diesel
Kern	2025	Skid Steer Loaders 175	Aggregate	Diesel
Kern	2025	Skid Steer Loaders 25	Aggregate	Diesel
Kern	2025	Skid Steer Loaders 300	Aggregate	Diesel
Kern	2025	Skid Steer Loaders 50	Aggregate	Diesel
Kern	2025	Skid Steer Loaders 600	Aggregate	Diesel
Kern	2025	Skid Steer Loaders 75	Aggregate	Diesel
Kern	2025	Skid Steer Loaders 9999	Aggregate	Diesel
Kern	2025	Surfacing Equipment 100	Aggregate	Diesel
Kern	2025	Surfacing Equipment 175	Aggregate	Diesel
Kern	2025	Surfacing Equipment 300	Aggregate	Diesel
Kern	2025	Surfacing Equipment 50	Aggregate	Diesel
Kern	2025	Surfacing Equipment 600	Aggregate	Diesel
Kern	2025	Surfacing Equipment 75	Aggregate	Diesel
Kern	2025	Surfacing Equipment 750	Aggregate	Diesel
Kern	2025	Surfacing Equipment 9999	Aggregate	Diesel
Kern	2025	Tractors/Loaders/Backhoes 100	Aggregate	Diesel
Kern	2025	Tractors/Loaders/Backhoes 175	Aggregate	Diesel
Kern	2025	Tractors/Loaders/Backhoes 25	Aggregate	Diesel
Kern	2025	Tractors/Loaders/Backhoes 300	Aggregate	Diesel
Kern	2025	Tractors/Loaders/Backhoes 50	Aggregate	Diesel
Kern	2025	Tractors/Loaders/Backhoes 600	Aggregate	Diesel
Kern	2025	Tractors/Loaders/Backhoes 75	Aggregate	Diesel
Kern	2025	Tractors/Loaders/Backhoes 750	Aggregate	Diesel
Kern	2025	Tractors/Loaders/Backhoes 9999	Aggregate	Diesel
Kern	2025	Trenchers 100	Aggregate	Diesel
Kern	2025	Trenchers 15	Aggregate	Diesel
Kern	2025	Trenchers 175	Aggregate	Diesel
Kern	2025	Trenchers 25	Aggregate	Diesel
Kern	2025	Trenchers 300	Aggregate	Diesel
Kern	2025	Trenchers 50	Aggregate	Diesel
Kern	2025	Trenchers 600	Aggregate	Diesel
Kern	2025	Trenchers 75	Aggregate	Diesel
Kern	2025	Trenchers 750	Aggregate	Diesel
Kern	2025	Trenchers 9999	Aggregate	Diesel
Kern	2025	Air Compressors 15	Aggregate	Diesel
Kern	2025	Air Compressors 25	Aggregate	Diesel
Kern	2025	Air Compressors 50	Aggregate	Diesel
Kern	2025	Welders 15	Aggregate	Diesel
Kern	2025	Welders 25	Aggregate	Diesel
Kern	2025	Welders 50	Aggregate	Diesel

Kern	2025	Generators 100	Aggregate	Diesel
Kern	2025	Generators 175	Aggregate	Diesel
Kern	2025	Generators 300	Aggregate	Diesel
Kern	2025	Generators 600	Aggregate	Diesel
Kern	2025	Generators 75	Aggregate	Diesel
Kern	2025	Generators 750	Aggregate	Diesel
Kern	2025	Generators 9999	Aggregate	Diesel
Kern	2025	Concrete/Industrial Saws 50	Aggregate	Diesel

ear for Horsepower-hours

Fuel Consumption (gallons/year)	Horsepower Hours (HP-hours/year)	Fuel (gallons/HP-hour)
15529.68913	603587.5599	0.025728975
3.253088934	0	0
19658.94153	752483.9345	0.026125397
15.06546036	0	0
28297.33583	1093459.441	0.025878725
2703.50607	91520.353	0.029539944
40745.00673	1588205.712	0.025654741
1224.27365	49952.32439	0.024508842
32694.98262	1252202.982	0.02610997
14684.74782	566011.7223	0.025944247
22.44281871	0	0
4.381395233	0	0
3.005397669	0	0
1040.25	24812.7	0.041924095
19863.7734	1336684.208	0.014860483
57263.10821	3837002.819	0.014923916
51.9411339	3136.724998	0.016559033
97644.68183	6556709.904	0.014892329
841.5314361	50352.07939	0.016712943
177808.1248	11939111.14	0.014892911
459.2641049	30965.2106	0.014831616
3457.402355	232316.8244	0.014882273
9665.121375	649144.1911	0.014889021
119929.064	5401371.252	0.022203448
131339.6726	5926409.14	0.022161763
137627.1204	6212363.631	0.022153745
2725.432486	111276.1938	0.024492503
481455.0475	21699337	0.022187546
472.5383559	21306.95808	0.022177655
4851.944933	220224.5204	0.022031811
27969.65656	1246941.168	0.022430614
2.162741271	0	0
132918.3633	6767644.544	0.01964027
298669.071	15114421.02	0.019760537
21.3231597	971.2233189	0.02195495
380413.3428	19244300.78	0.019767585
109061.0925	4964047.048	0.021970197

675234.5583	34242052.91	0.019719453
8347.880591	423143.5834	0.019728246
9860.864065	496815.0531	0.019848159
18820.80122	940273.8466	0.020016298
16321.66228	779398.7276	0.020941351
182037.9133	8557749.701	0.021271703
20.95198491	891.3105703	0.023506941
376668.4129	17824521.87	0.021132035
700.6643661	29845.13336	0.023476671
23682.12193	1124935.059	0.02105199
241.3256984	11075.85595	0.021788447
13051.91302	617150.9259	0.021148657
34489.35024	1526112.265	0.022599484
49135.82309	2183131.747	0.022507035
21.90309024	875.1564895	0.025027627
41414.6291	1838938.542	0.022520942
45091.7103	1802824.375	0.025011704
138997.0715	6185195.816	0.022472542
23260.24234	1035118.089	0.0224711
5814.578497	259977.3415	0.022365713
7327.497178	325446.6316	0.022515204
3163.245806	159465.2461	0.019836584
103360.2793	5244977.943	0.019706523
210487.899	10689681.28	0.019690755
4369.398734	200626.4238	0.02177878
902293.5083	45618089.8	0.019779292
1208.160464	61794.50444	0.019551261
308782.8095	15608377.1	0.019783146
543248.6729	27689031.58	0.019619634
71957.19512	3349972.623	0.021479935
49.44246463	0	0
41684.63068	1945266.304	0.021428753
8.080746781	0	0
56433.17671	2622991.994	0.021514811
24423.26311	1014495.923	0.024074284
216968.5278	10088047.21	0.021507485
4604.637338	216583.1736	0.021260365
33704.4968	1566035.891	0.021522174
13486.63658	628095.909	0.021472257
23894.61427	1114961.773	0.021430882
39443.69369	1833691.909	0.021510535
4.060411418	0	0
29983.72402	1394325.084	0.021504113
2989.133275	125020.7163	0.023909104
6501.780298	302728.9386	0.021477234
4928.011473	230843.145	0.021347879
1156.186682	53816.87928	0.021483718

15904.41	866256.9115	0.018359923
16486.84171	899260.7955	0.018333771
6.900977069	0	0
10896.53008	592471.0645	0.018391666
3724.345478	182729.6094	0.02038173
12492.0937	681275.1537	0.018336341
429.8708491	23580.39324	0.018230012
2312.140456	125850.3972	0.018372135
1092.284464	59446.87786	0.018374127
19.30442893	0	0
95252.98824	4906931.393	0.019411926
70.0094452	0	0
99138.6451	5112733.861	0.019390535
9.598231	445.173461	0.021560654
16761.56068	863382.365	0.019413833
61378.95882	2844765.887	0.021576102
9256.453247	475323.3055	0.019474015
612.6475567	31589.50879	0.01939402
245693.8976	11797588.45	0.020825773
52084.2697	2505535.657	0.020787678
32.08412403	1387.098886	0.02313038
4069.273114	195553.8542	0.020808964
3090.396857	133624.8859	0.023127405
1340.24573	64467.21884	0.02078957
103.7604401	4970.386302	0.02087573
252.1322716	12137.11526	0.020773657
8068.026143	391818.6364	0.020591226
12237.64018	598259.6497	0.0204554
12526.92322	611897.5333	0.020472256
2706.451285	119042.1525	0.022735235
137082.7259	6650584.071	0.020612133
3351.216913	163894.8237	0.020447363
5073.974007	248167.618	0.020445754
207336.9627	11185677.4	0.018535933
492157.0763	26385941.09	0.018652246
2.80960788	0	0
714980.9662	38294718.82	0.018670485
8515.012881	407982.4986	0.020871025
928438.0784	49684168.71	0.018686799
20.82358004	1112.472937	0.01871828
81419.94753	4364924.345	0.018653232
63792.42358	3401718.838	0.018752997
7174.199417	286340.8208	0.025054756
82320.96543	3274869.031	0.025137178
21.79753357	785.6787661	0.02774357
120223.4208	4825076.698	0.024916375
173.4916495	6359.720421	0.02727976

1347186.329	53884978.68	0.025001148
1580.84749	62954.61355	0.025110908
32703.00322	1310631.351	0.024952099
31418.79239	1259600.198	0.024943464
301.7551424	0	0
452.6	10263.8	0.044096728
87.29261	4578.704412	0.019064915
1667.215029	87606.3284	0.01903076
796.0059189	0	0
1549.065018	81253.70652	0.019064546
46446.38667	2183255.635	0.021273911
447.2766653	23437.9192	0.019083463
246566.4925	12924407.77	0.019077585
605.4506469	31816.58774	0.019029402
2678.26595	170270.9178	0.015729439
2192.232524	140442.7565	0.015609438
4222.611691	270513.9426	0.01560959
430.2537388	24630.0751	0.017468633
15109.78891	970323.9068	0.015571902
262.1906673	16737.69188	0.015664685
6635.313086	425683.8507	0.01558742
2576.479869	165187.7352	0.015597283
1469212.102	76796132.18	0.019131329
256181.8955	13489122.25	0.018991739
73.92187748	0	0
158940.0566	8355447.389	0.019022327
91508.83568	4366000.747	0.020959418
209277.6465	11022194.13	0.018986932
11675.79703	613351.4444	0.019036063
7702.110036	423313.5908	0.018194809
71748.91495	3762517.353	0.019069391
20692.64419	792747.9484	0.026102425
27.72138295	0	0
5432.485559	209292.6566	0.025956408
71.80497594	0	0
10913.10747	418381.1031	0.026084131
32494.98342	1122528.384	0.028948028
16830.25255	645404.2723	0.02607707
2264.973309	88073.81833	0.025716761
4738.396974	182295.2932	0.025992975
423.9361103	16306.7332	0.025997611
323.2082791	0	0
1289.895112	0	0
10252.85	371657.6	0.027586816
7400.764802	0	0
11810.24692	0	0
47066.75	1821547.1	0.025838887

141976.0248	8878903.637	0.015990265
167980.289	10505159.59	0.015990265
201352.9306	12592219.5	0.015990265
274071.737	17139911.79	0.015990265
44386.80023	2775863.9	0.015990265
36893.07579	2307220.992	0.015990265
223498.1413	13977137.77	0.015990265
1040.25	24812.7	0.041924095

Model Output: OFFROAD2021 (v1.0.4) Emissions Inventory
Region Type: County
Region: Kern
Calendar Year: 2026
Scenario: All Adopted Rules - Exhaust
Vehicle Classification: OFFROAD2021 Equipment Types
Units: tons/day for Emissions, gallons/year for Fuel, hours/year for Activity, Horsepower-hours/year for

Region	CalYr	Vehicle Class + HP Bin	Model Year	Fuel
Kern	2026	Off-Highway Trucks 100	Aggregate	Diesel
Kern	2026	Off-Highway Trucks 175	Aggregate	Diesel
Kern	2026	Off-Highway Trucks 25	Aggregate	Diesel
Kern	2026	Off-Highway Trucks 300	Aggregate	Diesel
Kern	2026	Off-Highway Trucks 50	Aggregate	Diesel
Kern	2026	Off-Highway Trucks 600	Aggregate	Diesel
Kern	2026	Off-Highway Trucks 75	Aggregate	Diesel
Kern	2026	Off-Highway Trucks 750	Aggregate	Diesel
Kern	2026	Off-Highway Trucks 9999	Aggregate	Diesel
Kern	2026	Other 15	Aggregate	Diesel
Kern	2026	Other 25	Aggregate	Diesel
Kern	2026	Other 100	Aggregate	Diesel
Kern	2026	Other 175	Aggregate	Diesel
Kern	2026	Other 25	Aggregate	Diesel
Kern	2026	Other 300	Aggregate	Diesel
Kern	2026	Other 50	Aggregate	Diesel
Kern	2026	Other 600	Aggregate	Diesel
Kern	2026	Other 75	Aggregate	Diesel
Kern	2026	Other 750	Aggregate	Diesel
Kern	2026	Other 9999	Aggregate	Diesel
Kern	2026	Rubber Tired Dozers 100	Aggregate	Diesel
Kern	2026	Rubber Tired Dozers 175	Aggregate	Diesel
Kern	2026	Rubber Tired Dozers 300	Aggregate	Diesel
Kern	2026	Rubber Tired Dozers 50	Aggregate	Diesel
Kern	2026	Rubber Tired Dozers 600	Aggregate	Diesel
Kern	2026	Rubber Tired Dozers 75	Aggregate	Diesel
Kern	2026	Rubber Tired Dozers 750	Aggregate	Diesel

Horsepower-hours

Fuel Consumption (gallons/year)	Horsepower Hours (HP-hours/year)	Fuel (gallons/HP-hour)
4790.727336	243273.4506	0.019692767
105682.2756	5360500.445	0.019715002
215.6116345	9825.905113	0.021943183
216443.9859	10993492.33	0.019688374
4278.605957	196172.7791	0.021810396
930224.8911	46978643.99	0.019801016
436.3269322	21739.70351	0.02007051
317225.2468	16032802.26	0.019786014
559254.84	28540841.99	0.019594896
50.13122194	0	0
8.194417415	0	0
75125.53101	3498810.027	0.021471738
42932.41696	2001013.407	0.021455337
0	0	0
57759.38192	2681291.302	0.021541629
25122.66493	1047113.199	0.02399231
225712.8702	10492598.41	0.021511628
3604.421373	169429.5285	0.021273868
32373.64708	1503165.637	0.021536979
13856.03242	645341.6789	0.021470847
8958.241799	433097.4675	0.020684124
12006.50261	587062.6908	0.020451824
14146.72453	691112.5777	0.020469494
2785.398101	122525.8077	0.022733154
139573.8993	6766634.987	0.020626781
3388.576801	165720.823	0.020447502
5222.243493	255419.4654	0.020445754

Operational Fuel Calculation—Project-Generated Trips

Daily Trips (Staff)	Daily Trips (Deliveries)	Trip Length	Annual VMT (Staff)	Annual VMT (Deliveries)	Total Annual VMT
10	2	45	117000	23400	140,400.00

Note: this assumes 260 working days per year, and two one-way trips per employee

Staff Trips						
Vehicle Type	Proportion of Fleet	Annual VMT	Daily VMT	Average Fuel Economy (miles/gallon)	Total Daily Fuel Consumption (gallons)	Total Annual Fuel Consumption (gallons)
Passenger Cars (LDA)	0.3853	45,075	173	31.44	5.5	1,434
Light Trucks and Medium Vehicles	0.4069	47,602	183	23.77	7.7	2,003
Light-Heavy to Heavy-Heavy Diese	0.2017	23,596	91	7.83	11.6	3,013
Motorcycles	0.0032	371	1	41.98	0.0	9
Other	0.0030	356	1	7.02	0.2	51
Total	*1.0000*	*117000*	*450*		*25.0*	*6,509*

Delivery Trips						
Vehicle Type	Proportion of Fleet	Annual VMT	Daily VMT	Average Fuel Economy (miles/gallon)	Total Daily Fuel Consumption (gallons)	Total Annual Fuel Consumption (gallons)
Light-Heavy to Heavy-Heavy Diese	100	23400	90	7.83	11	2988

9,497 12158000000 0.00008

Operational Fuel Calculation—Project-Generated Trips

Source: EMFAC2021 (v1.0.2) Emissions Inventory
Region Type: County
Region: Kern
Calendar Year: 2027
Season: Annual
Vehicle Classification: EMFAC2007 Categories
Units: miles/day for CVMT and EVMT, trips/day for Trips, kWh/day for Energy Consumption, tons/day for Emissions, 1000 gallons/day for Fuel Consumption

VMT = Vehicle Miles Traveled
FE = Fuel Economy

				Given					*Calculations*	
Region	Calendar Year	Vehicle Class	Model Year	Speed	Fuel	Population	VMT	Fuel Consumption	FE	VMT*FE
Kern	2027	LDA	Aggregate	Aggregate	Gasoline	333593.3636	12978574.68	413.1932807	31.41042046	407662488
Kern	2027	LDA	Aggregate	Aggregate	Diesel	807.6592787	25320.87435	0.555719214	45.56415127	1153724.15
									Sum of VMT*FE	**408816212**
									Total VMT	**13003895.6**
									Weighted Average Fuel Economy	**31.4379803**
Kern	2027	LDT1	Aggregate	Aggregate	Gasoline	31897.96796	1076094.639	41.45689026	25.95695511	27932140.2
Kern	2027	LDT1	Aggregate	Aggregate	Diesel	5.522617736	72.36844777	0.002868906	25.22510517	1825.50171
Kern	2027	LDT2	Aggregate	Aggregate	Gasoline	180712.5463	7179071.597	277.9314131	25.8303713	185438085
Kern	2027	LDT2	Aggregate	Aggregate	Diesel	591.2364642	24814.929	0.688748725	36.02900173	894057.12
Kern	2027	MDV	Aggregate	Aggregate	Gasoline	150050.5824	5369653.829	262.1190036	20.48555715	110000350
Kern	2027	MDV	Aggregate	Aggregate	Diesel	2339.161124	83299.00656	3.268247002	25.48736571	2123072.24
									Sum of VMT*FE	**326389530**
									Total VMT	**13733006.4**
									Weighted Average Fuel Economy	**23.7667938**
Kern	2027	LHDT1	Aggregate	Aggregate	Gasoline	15808.04784	574210.963	57.76052636	9.941234942	5708366.09
Kern	2027	LHDT1	Aggregate	Aggregate	Diesel	14181.71631	494859.3724	31.17439911	15.87390251	7855349.44
Kern	2027	LHDT2	Aggregate	Aggregate	Gasoline	2783.351121	93512.49978	10.81319202	8.648001405	808696.229
Kern	2027	LHDT2	Aggregate	Aggregate	Diesel	6439.047477	225370.7104	17.14425861	13.14555009	2962621.96
Kern	2027	MHDT	Aggregate	Aggregate	Gasoline	1158.423339	73833.74401	15.22520972	4.849440196	358052.326
Kern	2027	MHDT	Aggregate	Aggregate	Diesel	10756.78878	515068.1921	57.6033819	8.941631119	4605549.78
Kern	2027	HHDT	Aggregate	Aggregate	Gasoline	1.573555049	155.2767002	0.038731317	4.009073556	622.515713
Kern	2027	HHDT	Aggregate	Aggregate	Diesel	31025.59963	4830454.916	752.446232	6.419667892	31009916.3
									Sum of VMT*FE	**53309174.7**
									Total VMT	**6807465.67**
									Weighted Average Fuel Economy	**7.83098692**
Kern	2027	MCY	Aggregate	Aggregate	Gasoline	19198.99683	107031.606	2.549384632	41.98331027	4493541.12
									Weighted Average Fuel Economy	**41.9833103**
Kern	2027	MH	Aggregate	Aggregate	Gasoline	2359.713174	20556.70041	4.658368429	4.412854141	90713.7205
Kern	2027	MH	Aggregate	Aggregate	Diesel	1234.276475	10392.08856	1.103934362	9.413683381	97827.8313
Kern	2027	OBUS	Aggregate	Aggregate	Gasoline	336.5943334	17695.51916	3.616228288	4.893363401	86590.6058
Kern	2027	OBUS	Aggregate	Aggregate	Diesel	162.8306497	11401.54495	1.656143243	6.884395415	78492.7438
Kern	2027	SBUS	Aggregate	Aggregate	Gasoline	173.2969541	11558.60677	1.157351837	9.98711576	115437.144
Kern	2027	SBUS	Aggregate	Aggregate	Diesel	1042.416539	22918.22224	2.793208505	8.204980829	188043.574
Kern	2027	UBUS	Aggregate	Aggregate	Gasoline	56.42116005	4269.522934	0.729056887	5.85622742	25003.2973
Kern	2027	UBUS	Aggregate	Aggregate	Diesel	35.72838478	3781.987564	0.376461233	10.04615412	37994.43
									Sum of VMT*FE	**720103.347**
									Total VMT	**102574.193**
									Weighted Average Fuel Economy	**7.02031699**

Process	Facility	Equipment	NG Demand (MMBTU)	NG Demand (Therms)
Pre-C	GP 32	Utility SG 1	569,400	5,694,000
		Utility SG 2	569,400	5,694,000
Post-C	Cogen 32	Utility SG 1	648,240	6,482,400
		Utility SG 2	648,240	6,482,400
		Utility SG 3	648,240	6,482,400
	SGS 2868	Utility SG 1	709,560	7,095,600
		Utility SG 2	709,560	7,095,600
		Utility SG 3	709,560	7,095,600
	SGS 2972	Utility SG 1	788,400	7,884,000
		Utility SG 2	788,400	7,884,000
		Utility SG 3	788,400	7,884,000
Natural Gas Compression	Del Sur	S-1548-433	23,858	238,580
		S-1548-434	23,964	239,640
		Totals	***7,625,222***	***76,252,220***

Kern County total	1,866,000,000
Project share	4.1%

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K.2 Carbon Management Business Park 2023 Report

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An exploration of carbon management and clean energy industries, and their potential benefits and impacts if developed within a Carbon Management Business Park sited in Kern County.

Technical Report | June 2023

PREPARED BY *BLUE* ***ENGINE***
FOR THE Kern County Planning and Natural Resources Department



ENVISIONING A CARBON MANAGEMENT BUSINESS PARK

This technical report supplements the informational website

cmbp.kernplanning.com

Technical report and website prepared for the
Kern County Planning and Natural Resources Department

by Blue Engine
and with Technical Assistance from the
U.S. Department of Energy Communities-Local Energy Action Program (C-LEAP)

JUNE 2023

Preface

What is a carbon management business park?

Carbon management industries are those that capture carbon dioxide (CO_2) for the purpose of removing it from the atmosphere or preventing its release to the atmosphere. The capture of CO_2 can be either the primary purpose of the industry – where a facility is built exclusively to capture gaseous CO_2 from the atmosphere, or a secondary goal – where CO_2 that is a byproduct of a primary industry process is captured. The Kern County Planning and Natural Resources Department has envisioned a conceptual Carbon Management Business Park, which could be developed as a large industrial park where one or several carbon management industries are located, with the aim of capturing CO_2 at the scale of millions of tons per year. Clean energy industries that support carbon management could be co-located within the park.

About Kern County Planning and Natural Resources Department

The Planning and Natural Resources Department (the Department) provides consolidated land use planning and community development programs for Kern County's residents, landowners and businesses. The Department's mission is to balance the county's economic vitality and resource conservation with the diverse needs of Kern County at large by preparing and implementing programs that are aligned with the county's General Plan. In 2021, with approval from the Kern County Board of Supervisors, the Planning and Natural Resource Department applied for the U.S. Department of Energy's (U.S. DOE) Communities Local Energy Action Plan (C-LEAP) Pilot Initiative. The Department's aim was

to secure expert technical assistance in order to better understand the nascent carbon management sector – what industries are involved, how they work, what they look like, and the potential benefits and impacts those industries could have if developed at a large scale in Kern County. The proposal was successful, and in 2022 Kern County became one of the 24 communities nationwide to be awarded a C-LEAP grant.

About the U.S. DOE Communities-Local Energy Action Program

C-LEAP is a pilot program developed by the U.S. Department of Energy (U.S. DOE) that is designed to facilitate community-driven clean energy transitions by providing supportive services valued at up to $16 million USD. The program partners specifically with communities that are experiencing either direct environmental justice impacts, or direct economic impacts from a shift away from historical reliance on fossil fuels. Kern County faces both of these challenges. C-LEAP recipients are awarded up to 18 months of high-quality technical assistance from a network of national experts in order to help build community clean-energy related economic development action plans.

About Blue Engine

Blue Engine provides advisory services to local governments, communities, and companies or other organizations seeking to develop decarbonization strategies, with particular focus on identifying opportunities and mitigating impacts of the ongoing energy transformation. The team at Blue Engine works closely with its sister company, Climate Now, a multimedia educational resource that produces accessible, expert-driven content – including a weekly podcast, videos, and events across the United States – about how and why the climate is changing, the clean energy technologies available to address and mitigate climate change, and the role of policies, markets, and stakeholder communities in driving the transition to a net-zero emissions global economy. The combined capabilities of Climate Now and Blue Engine allow the team to manage projects that are highly interdisciplinary in nature, and to act as a communication bridge between project experts and stakeholder communities.

About this report

Kern County Planning and Natural Resources Department, in partnership with an executive committee of community leaders who represent the diverse stakeholders of Kern County, was awarded the C-LEAP grant to perform a pre-feasibility analysis for a conceptual carbon management industrial park that could serve as a Clean Energy and Carbon Management Hub for all of California. The envisioned park would comprise 30 million square feet of development on 4,000 acres, and could be supported by over 30,000 acres of solar power. The goal of the pre-feasibility analysis was to understand how much carbon could be

captured in such a facility, what kinds of industries would locate there, and how such a park might impact the surrounding community and environment of Kern County. This report, in conjunction with the website cmbp.kernplanning.com, addresses each of those questions. The website serves as an executive summary of this report, which is meant to provide a comprehensive review of the state of the art of carbon management technologies, and of the clean energy technologies most likely to support them in an industrial park situated in Kern County.

Disclaimer

This document was prepared by Blue Engine for the Kern County Planning and Natural Resources Department, and with support from the U.S. DOE Technical Assistance Team and other academic and industry experts. The purpose of the report is not to endorse or advise a specific strategy of development of a carbon management business park, but to provide a sufficient summary of publicly available information on these industries to allow area property owners, private investors, and the broader community to make their own well-informed strategic development plans. Any content or opinions expressed herein do not reflect the views of the U.S. Department of Energy or members of the U.S. DOE Technical Assistance Team, nor any of the other subject matter and industry experts who so generously contributed their time and knowledge.

Additionally, the research summarized within this report includes results that are experimental in nature, and neither Blue Engine, the Kern County Planning and Natural Resources Department, or any employees of either entity make any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information herein. Reference to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not constitute or imply an endorsement or recommendation by Blue Engine or the Kern County Planning and Natural Resources Department.

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Suggested citation:

E. Pope, S. Colbourn, V. Farid, S. Dasgupta, J. Lawler. Envisioning a Carbon Management Business Park. Technical Report, Blue Engine. June 2023.

Kern County Planning and Natural Resources Department Team Members

Lorelei H. Oviatt, AICP, Department Director

Cindi Hoover, AICP, Division Chief of Plan Development and Special Projects

Mark Tolentino, Staff Planner, Plan Development and Special Projects

Julie Williams, Supervising Planner, GIS, Map Updates and Addressing

Blue Engine Team Members

Emily Pope, Project Manager and Lead Author

Sarah Colbourn, Co-author and Research Analyst

Vania Farid, Research Analyst

Sukanya Dasgupta, Research Analyst

Alison Bloom, Website Design

Zura Kobakhidze, Website Development

James Lawler, CEO

U.S. DOE Technical Assistance Team Members

Darin Damiani, Technical Assistance Team Coordinator, U.S. DOE Office of Fossil Energy and Carbon Management

George Peridas, Lawrence Livermore National Laboratory

Jose Benitez, U.S. DOE Office of Fossil Energy and Carbon Management

Jeff Hoffmann, U.S. DOE Office of Fossil Energy and Carbon Management

Brian McPherson, Energy and Geoscience Institute, University of Utah

Anhar Karimjee, U.S. DOE Office of Fossil Energy and Carbon Management

Holly Buck, U.S. DOE Office of Fossil Energy and Carbon Management

Robert Balch, New Mexico Tech University

Community Stakeholder Executive Committee Team Members

Richard Chapman, Kern Economic Development Corporation

Camila Chavez, Dolores Huerta Foundation

Babatunde Deru, Bakersfield College

Shannon Eddy, Large Scale Solar Association

Aaron Ellis, Kern County Administrative Office

Susan Houghton, Lawrence Livermore Foundation

Suzanne Noble, Western States Petroleum Association

Reyna Olaguez, South Kern Sol

Nicole Parra, Kern Community College District

Lori Pesante, Dolores Huerta Foundation

Liz Rozell, Kern Community College District

Kristen Watson, California State University, Bakersfield

Acknowledgments

This document was prepared with the additional support of over 25 subject matter and industry experts, who through interviews, email correspondence, site tours, feedback from interim progress updates, and reviews of early drafts of this report have substantively expanded and improved the content herein. We thank all the contributors who have volunteered their time and expertise to support this work, with particular acknowledgement of the time and efforts of Drs. Roger Aines, Kimberly Mayfield and Simon Pang of Lawrence Livermore National Laboratory, and Ann Hayden and Anna Schiller of Environmental Defense Fund.

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1. Introduction

It is not an overstatement to say that Kern County is integral to feeding and fueling the state of California, and by extension, the United States. Since the discovery of oil in the Kern River Field in 1899, Kern County has led California in oil and gas production.[1] Currently, it produces about 70% of the state's oil,[2] and is host to four of the top seven producing oil fields in the nation.[3] As the southernmost county of California's Central Valley, which produces a quarter of the nation's food,[4] Kern also leads California in the agricultural sector, producing over $8 billion USD in goods from livestock and crops annually.[5]

These industries are important not only for what they export to the rest of the state and the nation, but for what they provide to the residents of Kern County. Nearly 1 in 5 county jobs are directly tied to the agriculture sector.[6] Oil and gas also provides about 2% of jobs in the region,[7] but more significantly, the sector is an important source of county tax revenue. The top ten property tax payers of Kern County are associated with either the extractive or energy sectors,[8] and in total, the oil and gas industry accounts for about a quarter of the county's annual tax revenue.[9] However, as policies are implemented to address climate

[1] Takahashi,K., D.L. Gautier (2007) A brief history of oil and gas in San Joaquin Valley. [12]
[2] Karlamangla (2022) If oil drilling ends in California, what happens to oil country? [7]
[3] U.S. Bureau of Land Management (no date) California Oil and Gas. [1]
[4] U.S. Geological Survey (no date) California's Central Valley. [17]
[5] California Department of Food and Agriculture (no date) County crop reports. [2]
[6] State of California Employment Development Department (no date) Kern County, California Labor Market Information Resources and Data. [11]
[7] State of California Employment Development Department (no date) Kern County, California Labor Market Information Resources and Data. [11]
[8] U.S. Department of the Interior (no date) Natural Resources Revenue Data: Kern County. [10]
[9] Karlamangla (2022) If oil drilling ends in California, what happens to oil country? [7]

change, regional water supplies and global energy use patterns are evolving. As a result, the agriculture and oil and gas sectors of Kern County are also anticipating an evolution.

Decades of drought in the southwestern United States have led to increasing dependence on groundwater resources for irrigation of agricultural lands, resulting in over-depletion of subsurface aquifers and subsidence of the land in the Central Valley. It is anticipated that by 2040, average annual water supplies in the San Joaquin Valley (the southern portion of the Central Valley, where Kern is located) may need to decline by as much as 20%, as climate change drives increasing aridity and as policies such as the Sustainable Groundwater Management Act mandate reduced consumption of water from aquifers.[10] The Public Policy Institute of California estimates that as much as 900,000 acres of farmland could be fallowed in the San Joaquin Valley in the next two decades. Landowners will need viable economic alternatives for creating revenue from their lands, and communities will need new industries that can provide alternative jobs and tax revenue.

The oil and gas industry is also experiencing a shift, as solar and wind become increasingly competitive energy markets,[11] and as focus grows among global, national and regional institutions to reduce the emission of greenhouse gases like carbon dioxide (CO_2). But the oil and gas industry, and in particular, the oil and gas industry *in Kern County*, is uniquely equipped to take the lead in a new market that has incredible growth potential: carbon dioxide removal.

The National Academy of Sciences, Engineering and Medicine estimates that by mid-century it will be necessary to remove 10 billion metric tons of CO_2 from the atmosphere every year to prevent global average temperatures from rising above 2°C.[12] Carbon dioxide removal can be accomplished in a variety of ways – such as through significant re-forestation efforts, through changing agricultural practices to enhance the drawdown and storage of CO_2 in soils, or through restoring wetlands and mangroves along coastal habitats, to name a few.[13] Among the most effective methods of CO_2 removal however, is carbon capture and sequestration (CCS), or the process of trapping CO_2 from the atmosphere and from point sources of CO_2 emissions (like chimney stacks of large industrial facilities) and then pumping the CO_2 deep underground, into geologic layers in the subsurface that trap and hold the CO_2, much like it trapped and held the fossil fuels from which that CO_2 was derived. This technique is effective for two reasons: first, it is much easier to account for how much CO_2 is captured and sequestered via CCS than to estimate CO_2 drawdown from nature-based solutions like reforestation or soil re-generation, because gas pressures and flow rates of the CO_2 being pumped underground can be measured. Second, CO_2 that is pumped into well-characterized geologic layers of

[10] Escriva-Bou, *et al.* (2023) The future of agriculture in the San Joaquin Valley. [6]
[11] Lazard (2021) Levelized cost of energy. [8]
[12] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 9. [9]
[13] Climate Now (2021) Carbon Dioxide Removal (CDR). [3]

the subsurface is effectively trapped there indefinitely – it will be hundreds or thousands of years, at least, before that CO_2 returns to the atmosphere.[14]

CCS is a nascent industry – less than 100 million metric tons of CO_2 is injected in the subsurface globally, and almost all of that injection is for the purpose of enhanced oil recovery (in which injected CO_2 pressurizes oil-filled cracks and pore spaces, helping push oil out of the ground) rather than permanent underground storage.[15] But new federal and state policies are incentivizing growth in CCS for the purpose of permanent CO_2 storage in the United States, and Kern County is extremely well positioned to benefit from those incentives. The geologic layers beneath Kern County that have allowed it to be such a prolific producer of oil and gas are the same kinds of layers that are perfectly suited for CO_2 storage. In fact, sediments underlying California's Central Valley have been identified as having among the highest CO_2 storage capacity in the nation, with storage potential of billions of tons of CO_2.[16] Additionally, companies and employees within the oil and gas industry who have been established in Kern County for decades have the requisite knowledge to safely and effectively drill injection wells, transport CO_2 from sources of capture to injection sites, and sequester CO_2 underground. Kern County is home to more than 7,000 direct employees of the oil and gas sector,[17] who already have the skillsets needed for carbon capture and storage. As of this report's publication, three companies in Kern County have begun the permitting process through the U.S. Environmental Protection Agency to develop the types of wells needed (called EPA Class VI wells) for CO_2 injection and permanent geologic storage.[18] For those wells to be cost effective, there will need to be a significant source of CO_2 – on the scale of millions of metric tons annually – available for injection. Where all that CO_2 could come from has yet to be determined, but one possibility is a dedicated carbon management park, which would locate existing and new industries that capture or produce CO_2 in close proximity to the injection sites.

1.1 What is a carbon management park?

In Spring 2022, Kern County was among the inaugural group of recipients for the Communities LEAP (Local Energy Action Program, or C-LEAP) technical assistance grant from the U.S. Department of Energy.[19] The Kern County Planning and Natural Resources Department's goal in obtaining this C-LEAP grant was to answer a question: could repurposing challenged agricultural lands with the development of one or several large-scale industrial parks designed for the express purpose of capturing CO_2 be an economically viable source of new jobs and revenue to Kern County over the coming

[14] Climate Now (2021) Carbon Dioxide Removal: Carbon Capture and Storage, Part II. [5]
[15] Climate Now (2021) Carbon Dioxide Removal: Carbon Capture and Storage, Part I. [4]
[16] Teletzke, G. (2018) Evaluation of Practicable Subsurface CO2 Storage. [13]
[17] U.S. Department of the Interior (no date) Natural Resources Revenue Data: Kern County. [10]
[18] EPA (last updated May 19, 2023) Class VI wells permitted by EPA. [16]
[19] U.S. Department of Energy (no date) Communities LEAP Pilot. [15]

decades? If so, what types of industries would be best suited for such a park, and what considerations should be taken in whether, where and how much to develop?

With technical assistance from the C-LEAP program, these questions are addressed through a Carbon Management Business Park pre-feasibility analysis, presented in the form of an interactive website hosted by the Kern County Planning and Natural Resources Department, and accompanied by this report. The analysis is designed to clarify the costs and benefits of a variety of emerging carbon management and clean energy industries, and based on these costs and benefits, to provide the necessary information for local residents and decision-makers to determine which carbon management technologies might be best suited for the region.

As principal investigator for the C-LEAP award, the Kern County Planning and Natural Resources Department developed a hypothetical framework for the carbon management park, envisioning a 30 million square foot park on 4,000 acres, with another 30,000 acres dedicated to solar power, that would be sited far from urban areas, in fallowed farmlands that are no longer viable for agriculture. The park would be closely situated to areas where EPA Class VI well permits for deep CO_2 storage are already being processed,[20] allowing regional infrastructure to work together. A variety of carbon management and clean energy technologies could be co-located within the park, and proximity to rail and interstate highways would provide connections with nearby transportation hubs like Los Angeles and Stockton that would expand the potential feedstock supply chains for the industrial park and potential end users for clean energy production.

Blue Engine Strategies was contracted by the Kern County Planning and Natural Resources Department to complete the pre-feasibility analysis, by gathering and synthesizing information about a suite of industries that could potentially be co-located on such a park. Each industry type was examined through a set of 4 lenses: technological, societal, environmental and economic. Information was collected through the following methods:

- Continuous research support and technical assistance from a team of experts from the U.S. Department of Energy through the C-LEAP Program
- Interviews with research experts at universities and national research laboratories, and with industry representatives
- Consultation with an Executive Committee of regional leaders, organized by the Planning and Natural Resources Department
- Independent scholarship of the latest published research, policies and regional data relevant to these technologies

This report provides a detailed summary of the pre-feasibility analysis. In addition, Blue Engine constructed a website, cmbp.kernplanning.com, that serves as an Executive Summary for this report. The website provides an interactive site map that can help users envision what such a park might look like, and explores a variety of the technologies that

[20] EPA (last updated May 19, 2023) Class VI wells permitted by EPA. [16]

could feasibly be incorporated into a carbon management and clean energy business park. The website provides an overview of how each technology investigated in this report works, how it might benefit from co-location with other technologies in a shared industrial space, and what impacts and benefits such a technology would have on the regional community and environment.

Please note, the purpose of this analysis is not to endorse any carbon management technology or specific business park configuration for development in Kern County. The purpose of the website and report is to provide a useful synthesis of relevant information about carbon management and clean energy to stakeholders, developers and planners in the Kern County community, to ensure that they have a holistic understanding of these novel industries. With such a resource, private investors and local stakeholders will be better equipped to plan how the region's energy economy should grow in a well-informed and transparent manner.

Any development of a carbon management business park in Kern County would be facilitated by private investors. Those investors would be required to submit a proposal to the Kern Planning and Natural Resources Department that would include a specified location and a Specific Plan designating the industries and land uses to be built. An Environmental Impact Report (EIR) would be required and the EIR and Specific Plan would go through a full public process.

1.2 How to read this report

This report is laid out in ten sections subsequent to this introduction. The first section (Section 2) provides a summary of the federal and state policy landscape that is relevant to all the carbon management industries examined here, and is intended as a general resource that is referred to in subsequent sections. Sections 3 through 5 examine industries whose primary or secondary purpose is to capture CO_2 for permanent underground storage, and Sections 6 through 10 examine industries that could support carbon management industries (e.g. energy storage or water treatment), could benefit from co-location with carbon management industries (e.g. hydrogen via electrolysis), and/or are tangential to carbon management industries (e.g. CO_2 transport and CO_2 utilization). The use of CO_2 for enhanced oil recovery is not examined in this report. Finally, Section 11 provides a brief examination of how carbon management industries might take advantage of partnerships with (and be a benefit for) the dominant regional industry of agriculture.

This report represents a synthesis of information derived from academic literature, publicly available data and subject matter and industry expertise. For each factor of analysis, the aim is to provide as quantitative an assessment of the state of the industry as possible. Where specific estimates of a variable were available (such as land use, energy or water use requirements) a specific value or range of values is given, with the range encompassing all published estimates that could be verified as reasonable based on corroborating reports or expert discussions. Because carbon management industries are novel and in a phase of

rapid growth and innovation, it is expected that all systems will become more efficient, smaller and less expensive in the coming decades than the technologies described here.

All costs listed in this report are given in U.S. dollars, and are reported as the dollar value used in the source material, unless explicitly noted otherwise in the text. That is, except for references in which cost estimates were older than 10 years or reported in a non-U.S. currency (noted in text), the dollar amount reported is the same as that reported in the referenced material and is not adjusted for inflation since the year of reference publication. This approach was taken for three reasons: (1) To maximize transparency with regards to how all calculations in this report were made and from where all information was obtained, and thus we avoided inflation corrections to reduce the possibility of confusion or miscalculation; (2) Most cost estimates are derived from references published within the last 5 years, which means inflation would increase the cost estimates by less than 20%.[21] Nearly all technologies examined in this report have cost uncertainties much greater than 20%, and we report the full range of cost estimates aggregated from multiple sources; (3) Given the rapidity with which carbon management industries are growing, cost reductions that have likely occurred in the last 1-5 years from "learning by doing" may partially or completely offset the cost increases resulting from inflation.

A detailed techno-economic analysis of potential fiscal and economic benefits of the carbon management industry to Kern County was completed in parallel to the construction of this report by the Natelson Dale Group, Inc., and is appended at the end of the report.

[21] U.S. Bureau of Labor Statistics (no date) CPI Inflation Calculator. [14]

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3. Climate Now. Carbon Dioxide Removal (CDR). Published online August 9, 2021. Accessed May 21, 2023 from https://climatenow.com/video/carbon-dioxide-removal-cdr/.

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5. Climate Now. Carbon Dioxide Removal: Carbon Capture and Storage, Part II. Published online December 6, 2021. Accessed May 31, 2023 from https://climatenow.com/video/cdr-carbon-capture-and-storage-part-ii/.

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13. Teletzke, G., *et al.* (2018) Evaluation of Practicable Subsurface CO2 Storage Capacity and Potential CO2 Transportation Networks, Onshore North America. *14th Greenhouse Gas Control Technologies Conference*, Melbourne, October 2018, 21–26. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3366176.

14. U.S. Bureau of Labor Statistics. CPI Inflation Calculator. Published online (no date). Accessed May 31, 2023 from https://www.bls.gov/data/inflation_calculator.htm.

15. U.S. Department of Energy. Communities LEAP (Local Energy Action Program) Pilot. Published online (no date) Accessed May 31, 2023 from https://www.energy.gov/communitiesLEAP/communities-leap.

16. U.S. Environmental Protection Agency (EPA). Class VI wells permitted by EPA. Published online (last updated May 19, 2023). Accessed May 31, 2023 from https://www.epa.gov/uic/class-vi-wells-permitted-epa.

17. U.S. Geological Survey. California's Central Valley. Published online (no date). Accessed March 4, 2023 from https://ca.water.usgs.gov/projects/central-valley/about-central-valley.html.

2. Policy Brief

International pressure to address climate change is spurring significant public and private interest in the development of carbon management technologies, and a variety national and state policies that enhance the benefits of deploying these technologies are making them particularly viable for development in Kern County. However, the building and operating of these technologies still must adhere to environmental, land use, and other existing policies if deployed.

In this report section, we endeavor to outline the topline general policy items that would impact carbon management implementation within Kern County. Thus, this section does not adhere to the lenses of analysis used throughout the rest of this report—this is intended as an informational addendum to the report at large.

- The first section explores the international case for limiting greenhouse gas concentrations in the atmosphere, as well as the natural and technological pathways available to remove carbon dioxide (CO_2) from the atmosphere.
- The second section outlines the United States' federal climate goals and California's state climate goals.
- The third section outlines the permitting and environmental requirements that projects looking to site in Kern County would need to adhere to in designing and constructing a carbon management facility, like the hypothetical carbon management business park.
- The fourth and final section outlines the subsidies and incentives available for implementing carbon management practices and related monetary benefits for emissions reduction.

2.1 International goals and the case for CCS

According to the IPCC, limiting global warming to 1.5°C is imperative to preserving the well-being of people and natural ecosystems.[1] It is considered a crucial target by the international community because climatic and environmental changes past that point become more drastic and unpredictable.[2] For example, limiting warming to 1.5°C is expected to lead to declines in coral reefs of 70-90% globally; however, warming of 2°C would lead to a near-total loss of coral reefs.[3]

Based upon the potential future pathways seen in Figure 2.1, meeting the future on the best possible terms relies upon not only rapidly lowering global emissions, but also removing more CO_2 from the atmosphere that we generate. The gray band at the bottom of the illustration demonstrates scenarios of net CO_2 removal. There are both natural and technological pathways to remove CO_2 from the atmosphere.

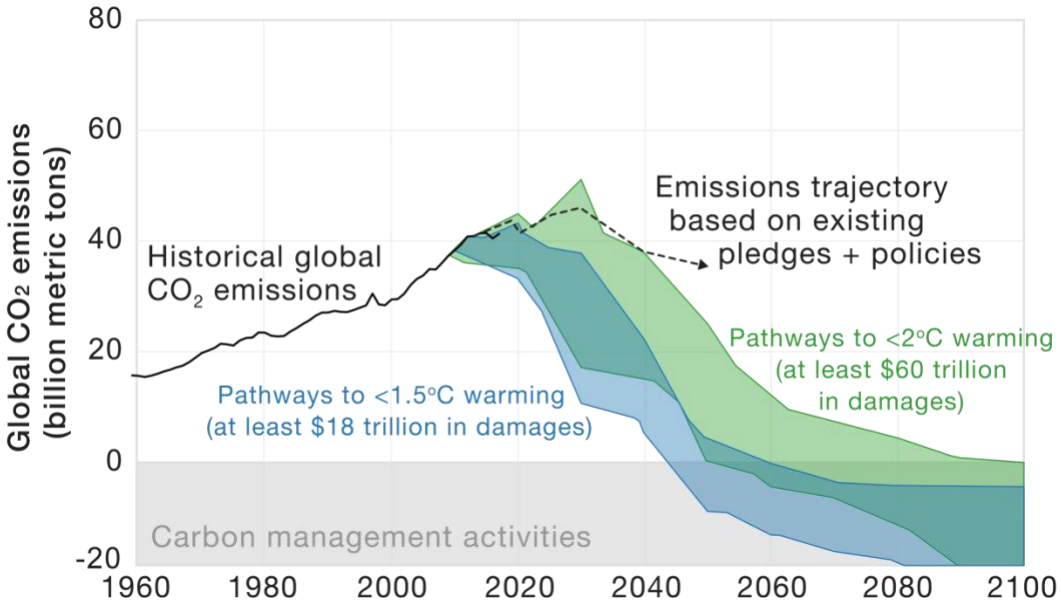


Figure 2.1. Illustration of CO_2 emissions pathways that could be employed to ensure global average temperatures remain below 2°C (green shaded region) or 1.5°C (blue shaded region). As temperatures rise, the cost of mitigating damages from extreme weather events like heat waves, floods and droughts will rise at a disproportionately higher rate.[4] Each region represents an aggregate of multiple modeled pathways that could maintain the desired temperature limits. Nearly all pathways require global CO_2 emissions to become net-negative by mid- or end-century, which will require the employment of carbon management activities to remove CO_2 from the atmosphere.[5] Adapted from Wikimedia commons: Mitigation Pathways.

[1] IPCC (October 8, 2018) Summary for Policymakers. [26]
[2] Nandi (August 9, 2021) World fails to meet key climate goal: IPCC. [32]
[3] IPCC (October 8, 2018) Summary for Policymakers. [26]
[4] Nuccitelli (September 19, 2021) Can the economy afford NOT to fight climate change? [34]
[5] Rogelj, *et al.* (2018) Scenarios limiting global mean temperature increase below 1.5°C. [41]

Natural processes, such as plant growth in forests and wetlands or ocean acidification, serve to sequester atmospheric carbon, but can also have undesirable effects once they pass natural thresholds.[6] For example, ocean acidification impacts the biodiversity of the ocean as it makes it difficult for coral and oysters to form their robust shells.[7] Plant-based solutions—like afforestation and wetland restoration—are promising because they are not only beneficial for sequestering CO_2, but also serve to support climate resilience and ecosystem health in the region.[8] However, these natural solutions – even when environmentally beneficial – can be problematic from a carbon management perspective, because it is difficult to assess how much CO_2 is being removed from the atmosphere from such interventions, and how long it will remain trapped in these organic reservoirs.[9]

Technological processes can also assist in removing CO_2 from the atmosphere and are generally termed carbon capture and storage (CCS). Many of the technological options available for capture—including DAC, BiCRS/BECCS, and point-source capture (with steel as an example industry)—are explored within this report at large, in Sections 3, 4, and 5, respectively. The primary value of these technologies is that they can prevent CO_2 from entering the atmosphere or remove it directly from the air.[10] Furthermore, if scaled adequately, these systems have the potential to remove CO_2 at much faster rates than natural processes.[11] They also can remove CO_2 with a smaller land footprint than natural solutions like reforestation, though the costs are generally higher per ton of CO_2 removed for technological solutions.[12] Given the time-sensitive nature of climate change, technological processes may be necessary to slow the rise in atmospheric CO_2 before we reach critical tipping points.[13] Achieving a global warming of under 2°C likely requires the use of carbon removal technologies *in addition to* substantial reductions in standard greenhouse gas emissions.[14]

2.2 Federal and state climate goals

The U.S. federal government has set ambitious targets for climate action in the coming decades. By 2030, the goal is to reduce greenhouse gas emissions to 50% of 2005 levels—by 2050, the target is to reach net-zero emissions.[15]

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[6] Sustainability for All – Acciona (no date) What are carbon sinks? [44]

[7] NOAA (April 1, 2020) Ocean Acidification. [33]

[8] Pfister (June 19, 2018) Carbon Removal Strategies. [38]

[9] Climate Now (October 5, 2021) Carbon Dioxide Removal: Forests. [14]

[10] Pfister (June 19, 2018) Carbon Removal Strategies. [38]

[11] Pfister (June 19, 2018) Carbon Removal Strategies. [38]

[12] Lebling, Leslie-Bole, *et al*. (May 2, 2022) 6 Things to Know About Direct Air Capture. [30]

[13] Mayewski, Beal (September 29, 2022) We miscalculated our climate tipping points. [31]

[14] Pfister (June 19, 2018) Carbon Removal Strategies. [38]

[15] The White House (no date) National Climate Task Force. [47]

In recent years, federal action on climate change has been supported by the Bipartisan Infrastructure Law (BIL) and the Inflation Reduction Act (IRA).[16] The BIL package awarded funding for over 20,000 projects and supports efforts to modernize the electric grid, expand rail and other public transportation, as well as maintaining other key infrastructure like roads, bridges, and water treatment facilities.[17] The IRA tackles climate more directly, with consumer rebates to install energy efficient appliances, tax credits for solar or electric vehicle purchases, and measures to directly reduce pollution and implement community-scale clean energy solutions.[18] A full exploration of the IRA's climate-related provisions is included in the Subsidies & Incentives section below.

As a state, California has set goals that are more ambitious than federal goals. By 2045, California is aiming to be carbon neutral.[19] This includes a goal to reduce natural gas consumption by 94% and greenhouse gas emissions by 85%.[20] These goals also rely upon ramping up carbon capture and sequestration efforts within California. In the most recent scoping plan announced by the California Air Resources Board (CARB), California targets to remove "20 million metric tons CO_2 equivalent ($MMTCO_2e$) by 2030 and 100 $MMTCO_2e$ by 2045" from the atmosphere to meet its climate targets.[21] This is aligned with the findings of other recent California-specific reports on reaching carbon neutrality, like Lawrence Livermore National Laboratory's Getting to Neutral.

2.3 Permits

2.3.1 Local land use

- Applicable for facilities with CO_2 capture, transport, or storage that takes physical place within, or in certain parts, of city or county boundaries.
- Agency level: local government
- Turnaround timeline: more than 18 months

The authorization of land use encompasses the physical footprint of the facility, from the types of activities allowed in certain areas, to the detailed aspects of facilities such as building height, traffic, noise, and other environmental impacts. Any planned CCS facilities must follow the city or county's zoning and land-use ordinance.

Carbon management projects on sites previously developed for similar purposes (like establishing a BiCRS facility by retrofitting a retired bioenergy plant, see Section 4) might

[16] The White House (no date) National Climate Task Force. [47]
[17] The White House (no date) Building a Better America. [45]
[18] The White House (August 15, 2022) The Inflation Reduction Act. [46]
[19] Office of Governor Newsom (November 16, 2022) California Releases World's First Plan. [36]
[20] Office of Governor Newsom (November 16, 2022) California Releases World's First Plan. [36]
[21] Office of Governor Newsom (November 16, 2022) California Releases World's First Plan. [36]

face fewer hurdles, since some uses might have been allowed already for existing facilities—however, this is not always the case. For instance, the installation of tall columns for carbon capture solvent or a gas flare may face minimal review when placed at an existing refinery that would have been permitted for much taller distillation columns, but could face higher scrutiny at a former power plant site, where they might exceed specified height limits for the site.

Transportation via pipeline will likely face a high level of scrutiny and review, regardless of the existing right-of-ways (ROW) in place. One way to reach compliance is to seek amendment of a county's zoning map to allow uses or activities commonly related to carbon capture and storage.[22] Such a measure would likely only be appropriate if it is in the county's long-term interests and economic plan, as opposed to authorizing a single project.

2.3.2 CO_2 Pipelines — Easements and ROWs

- Applicable for CO_2 transport.
- More than one agency could be involved and projects would generally involve private parties (including the pipeline owner and landowners)
- Timeline: more than 18 months

Permitting pipelines is often difficult and time consuming because most pipelines are sited across land held by a variety of owners. Thus, it is more attractive to route pipelines in such a way that it crosses large land holdings in the hands of fewer owners. Surface ownership of a pipeline might cross private, local government, state, federal, and tribal, as well as existing third-party easements. Under an easement—a legal agreement conferring to the pipeline owner the right to site, construct and operate the pipeline on a landowner's property—the holder is granted the right to travel over another's property.[23]

Areas with existing pipelines run may offer potentially easier pathways to siting. Depending on the contract language, opportunities for new development may already exist under existing easements or ROW agreements. The success of this strategy hinges on how the existing easements are written and if they provide for addition of a new pipeline or for repurposing or modification of an existing one.

Regulation of any CO_2 pipelines constructed would fall under the purview of the Pipeline and Hazardous Materials Safety Administration (PHMSA) at the federal level[24] and the Office of the State Fire Marshal (OSFM) at the state level.[25] A full exploration of the permitting and regulatory requirements for CO_2 pipelines can be found in Section 9.

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[22] World Bank (no date) Zoning and Land Use Planning. [51]

[23] Transportation Research Board of the National Academies of Sciences, Engineering, and Medicine (2004) Transmission Pipelines and Land Use. p. 34. [49]

[24] FECM (May 27, 2022) Statement: DOE Welcomes New Carbon Dioxide Pipeline Safety Measures. [35]

[25] OSFM (no date) Pipeline Safety and CUPA. [37]

2.3.3 Title V Air Permit

- Applicable for facilities with CO_2 capture, especially those that emit pollutants into the air
- Agency level: local air district, and potentially U.S. EPA
- Timeline: approximately 1 year

In California, air districts are the local regulators that implement federal Clean Air Act requirements, as well as other state-level regulations regarding emissions, for pollution sources within the region.[26] Any CCS project would likely have to engage these local air districts to receive air permits. Eastern Kern Air Pollution District (EKACPD) is the local regulator for eastern Kern County, while western Kern County falls under the authority of the San Joaquin Valley Air Pollution Control District (SJVAPCD).[27]

To gain a Title V operating permit, an institution or person that is constructing, altering, replacing, or operating any source that emits, may emit, or may reduce emissions must obtain preconstruction permit authorization before commencing construction as well as a permit to operate from their local air district.[28] For projects built on Indian and tribal lands within the borders of the United States, the U.S. EPA is required to issue operating permits instead.[29] Exemptions are limited to very low-emitting, minor equipment, such as engines on compressors or emergency generators, but full requirements for non-major sources are laid out in Code 40 of Federal Regulations.[30] It's particularly applicable to carbon management industries that operate in the CO_2 capture stage, because these types of facilities may emit other air pollutants in addition to the CO_2 that they are capturing, such as NO_x or particulate emissions, and fugitive emissions from some kinds of amine-based CO_2 scrubbers could produce volatile organic compound (VOC) emissions.

California, as a state, is required to develop state implementation plans (SIPs) to achieve National Ambient Air Quality Standards (NAAQS), for six criteria pollutants: ground-level ozone, particulates, carbon monoxide, lead, sulfur dioxide and nitrogen dioxide.[31, 32] Whether or not a state has achieved NAAQS attainment goals in a given pollution type determines the type of permit process that a new facility must pursue.

- Attainment areas: Prevention of Significant Deterioration (PSD) permits are required for new major sources or for making a major modification.[33]

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[26] CARB (no date) Government Roles and Contracts. [10]
[27] CARB (no date) California Map for Local Air District Websites. [8]
[28] EPA (November 29, 2022) Air Emissions Monitoring. [16]
[29] EPA (November 29, 2022) Air Emissions Monitoring. [16]
[30] EPA (May 25, 2022) Who Has to Obtain a Title V Permit? [23]
[31] CARB (no date) California State Implementation Plans. [9]
[32] EPA (January 20, 2023) Basic Information about Air Quality SIPs. [17]
[33] EPA (January 24, 2023) Prevention of Significant Deterioration Basic Information. [20]

- Non-attainment areas: Non-Attainment New Source Review (NNSR) permits are required for new major sources or for major sources making substantial modifications.[34]

The required mitigation action is stricter in non-attainment areas and requires achieving the Lowest Achievable Emissions Rate (LAER), as well as the use of offsets to the extent allowed or available.[35] Offsets are specific to each pollutant category, but specialized cases outlined by the EPA allow offsets from alternate sources at a 2-to-1 ratio.[36] In attainment areas, the corresponding requirement is Best Available Control Technology (BACT) for any "major new or modified sources."[37]

Table 2.1. Air quality attainment data for Kern County

Pollutant	EKAPCD[a]		SJVAPCD[b]	
	Federal	**State**	**Federal**	**State**
Ozone (1 hour)	Attainment	Nonattainment	Attainment	Severe Nonattainment
Ozone (8 hour)	Severe Nonattainment	Nonattainment	Extreme Nonattainment	Nonattainment
PM10	Attainment	Nonattainment	Attainment	Nonattainment
PM2.5	Attainment	Unclassified	Nonattainment	Nonattainment
Carbon Monoxide	Attainment	Unclassified	Attainment	Attainment
Nitrogen Dioxide	Unclassified	Attainment	Attainment	Attainment
Sulfur Dioxide	Unclassified	Attainment	Attainment	Attainment
Lead Particulates	Attainment	Attainment	Unclassified	Attainment

a. Eastern Kern Air Pollution Control District
b. San Joaquin Valley Air Pollution Control District

The California Ambient Air Quality Standards (CAAQS) are typically stricter than NAAQS requirements, but NAAQS attainment takes precedence "due to federal penalties for failure to meet federal attainment deadlines."[38, 39] Both NAAQS and CAAQS use 'attainment' or 'unclassified' and 'non-attainment' designations—an attainment or unclassified designation means an area meets or exceeds the standard for that compound, whereas

[34] EPA (January 24, 2023) Nonattainment NSR Basic Information. [19]
[35] EPA (January 24, 2023) Nonattainment NSR Basic Information. [19]
[36] EPA (2013) The Clean Air Act in a Nutshell: How It Works. p. 7. [22]
[37] EPA (February 22, 2016) RACT/BACT/LAER Clearinghouse: Basic Information. [21]
[38] CARB (no date) Ambient Air Quality Standards. [6]
[39] CARB (no date) California Ambient Air Quality Standards. [7]

non-attainment is used for areas that fail to meet the standard.[40] Table 2.1 summarizes Kern County's current status for major pollutants.

In addition to PSD and NNSR permitting, installation of carbon management facilities and associated equipment will likely trigger additional Clean Air Act Title V permitting under the local air district. The Title requires major sources of air pollutants and certain other sources to obtain an operating permit, operate in compliance with it, and certify compliance at least annually.[41]

2.3.4 California Environmental Quality Act (CEQA) Guidelines

In California, CEQA requires a project to identify significant environmental impacts of their activities, and to avoid or mitigate those impacts.[42] A project that may cause direct physical changes to the environment or an anticipated indirect change must comply with CEQA.[43] Most proposals for physical development need to comply with CEQA, but other projects which do not immediately result in physical development (like adopting a general or community plan) need to comply as well.[44]

For every project, an initial review of potential environmental effects must be conducted.[45] Depending on the initial review of the potential impacts of a project, CEQA may require the project to conduct a full environmental impact report (EIR).[46] If there are feasible alternative options or mitigation strategies available for the project to notably reduce its environmental impact, then a project cannot be approved as originally submitted.[47]

CEQA requires that an initial review determine the significance of a project's expected greenhouse gas emissions.[48] Under CEQA's definitions, greenhouse gasses "includes but is not limited to: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride."[49]

Regulated air pollutants under CEQA include nitrogen oxides (NO_x) and volatile organic compounds (VOCs), ozone-depleting substances (CFC and HCFC), particulate matter, carbon monoxide (CO), sulfur dioxide (SO_2) and lead. CEQA also evaluates greenhouse gas (GHG) emissions,[50] in which project-specific GHG emissions must be analyzed for their

[40] EPA (November 29, 2022) NAAQS Designations Process. [18]
[41] EPA (May 25, 2022) Who Has to Obtain a Title V Permit? [23]
[42] Governor's Office of Planning and Research (no date) Getting Started with CEQA. [25]
[43] CNRA (no date) FAQ about CEQA. [13]
[44] CNRA (no date) FAQ about CEQA. [13]
[45] CNRA (no date) FAQ about CEQA. [13]
[46] CNRA (no date) FAQ about CEQA. [13]
[47] CNRA (no date) FAQ about CEQA. [13]
[48] AER (January 1, 2023) 2023 CEQA. p. 189. [1]
[49] AER (January 1, 2023) 2023 CEQA. p. 317. [1]
[50] Governor's Office of Planning and Research (no date) CEQA & Climate Change. [24]

ability to contribute globally to climate change,[51] unless the project is exempted from CEQA.

2.4 Subsidies & Incentives

2.4.1 California Low Carbon Fuel Standard (LCFS)

California's LCFS is a market-based policy, first adopted in 2009 and implemented in 2011, that aims to diversify California's energy mix by setting annual carbon intensity (CI) benchmarks and encouraging the adoption of low-CI fuels under the oversight of the California Air Resources Board (CARB).[52] In 2018, the LCFS was extended by CARB from 2020 to 2030, with a goal of reaching a 20% CI reduction target from 2010 levels by 2030.[53]

The system operates based on CI life cycle assessments conducted by CARB, which "examines the GHG emissions associated with the production, transportation, and use of a given fuel" along with notable indirect impacts, and then gives the fuel in question a CI score.[54] CARB's model does not rely just on carbon dioxide emissions, but also emissions of methane, nitrous oxide, and other greenhouse gases.[55] After each fuel is scored based on its lifetime emissions, it is compared to a CI benchmark set by CARB that declines each year.[56] Fuels with CI scores lower than the benchmark will generate LCFS credits that year, whilst fuels that exceed the CI benchmark generate deficits.[57]

In short, the system grades fuels based on their relationship with the annual target—fuels that have a CI lower than the target will produce LCFS credits, while fuels that have a CI higher than the target have a deficit that must be fulfilled to meet the standard.[58] This deficit can be remedied by either generating LCFS credits directly or purchasing LCFS credits from another supplier in order to meet the annual target.[59] LCFS applies only for fuels used for transportation, including gasoline, diesel, and their alternatives.[60]

Under the LCFS, all "petroleum importers, refiners, and wholesalers" selling fuels in the California market are regarded as Regulated Parties (RPs).[61] Providers of clean, alternative fuels that already meet the relevant 2030 carbon intensity benchmark are exempt from the

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[51] Governor's Office of Planning and Research (no date) CEQA & Climate Change. [24]
[52] CARB (no date) About - Low Carbon Fuel Standard. [5]
[53] UC Davis Institute of Transportation Studies (no date) Status Review. [50]
[54] CARB (no date) About - Low Carbon Fuel Standard. [5]
[55] CARB (no date) About - Low Carbon Fuel Standard. [5]
[56] CARB (no date) About - Low Carbon Fuel Standard. [5]
[57] Boutwell (February 28, 2017) A Beginner's Guide. [3]
[58] Boutwell (May 2, 2018) LCFS 101 - An Update. [4]
[59] Boutwell (May 2, 2018) LCFS 101 - An Update. [4]
[60] Boutwell (February 28, 2017) A Beginner's Guide. [3]
[61] Boutwell (February 28, 2017) A Beginner's Guide. [3]

LCFS, but may opt-in to the program as RPs to receive credits for the fuels they sell in California.[62] The LCFS system hinges on the LCFS Reporting Tool (LRT), which serves as a central database where RPs must record the transaction-level information anytime that "transportation fuels are imported, refined, or sold in California."[63] (The LRT may also be referred to as the LRT-CBTS, or the LCFS Reporting Tool and Credit Bank & Transfer System.)[64] The LRT serves to track all transactions, and also serves to sum the credits and deficits for a given RP to track their compliance status in relation to the annual CI target.[65] If credits are used in an annual compliance report to offset deficits for an RP, those credits are retired; otherwise, LCFS credits generated or acquired by an RP do not sunset or decline in value over time.[66] Owners of credits can only sell or trade credits to other RPs in the system currently at a deficit, and parties that are not recognized as RPs are forbidden from holding any LCFS credits.[67]

In addition to credit generating fuels, the LCFS has provisions to generate credits through approved non-fuel activities that can help reduce transportation emissions at large.[68] This includes what CARB refers to as project-based crediting and capacity-based crediting under LCFS.[69] Project-based credit opportunities can include using renewable hydrogen at a facility generating transportation fuels, developing a direct air capture (DAC) facility to capture historic transportation emissions, and investments that reduce an existing transportation fuel facility's emissions, like using renewable energy or adopting carbon capture and storage (CCS).[70] Capacity-based credits are attainable by RPs that own hydrogen fueling equipment or zero-emission vehicle infrastructure.[71]

Starting in 2019, the LCFS began allowing the use of CCS technologies to "reduce emissions associated with the production of transport fuels" in California to generate LCFS credits—this included DAC projects.[72] To qualify, projects must meet CCS Protocol requirements, which encompass a variety of carbon management projects, as long as they lead to storage of captured CO_2 in depleted oil and gas reservoirs or saline formations onshore *or* are used for enhanced oil recovery (EOR) in oil and gas reservoirs.[73] Table 2.2 shows different types of CCS projects that can qualify to generate credits under the LCFS.

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[62] Boutwell (May 2, 2018) LCFS 101 - An Update. [4]
[63] Boutwell (February 28, 2017) A Beginner's Guide. [3]
[64] CARB (no date) LCFS Registration and Reporting. [12]
[65] Boutwell (February 28, 2017) A Beginner's Guide. [3]
[66] Boutwell (February 28, 2017) A Beginner's Guide. [3]
[67] Boutwell (February 28, 2017) A Beginner's Guide. [3]
[68] CARB (no date) LCFS Basics with Notes. p. 11. [11]
[69] CARB (no date) LCFS Basics with Notes. p. 11. [11]
[70] CARB (no date) LCFS Basics with Notes. p. 28. [11]
[71] CARB (no date) LCFS Basics with Notes. p. 33-35. [11]
[72] Townsend, Havercroft (2019) The LCFS and CCS Protocol. p. 4. [48]
[73] Townsend, Havercroft (2019) The LCFS and CCS Protocol. p. 9. [48]

Table 2.2. Qualifications for CCS projects to meet LCFS standards.[74]

	Direct Air Capture Projects	CCS at Oil & Gas Production Facilities	CCS at Refineries Projects	All other CCS Projects (e.g. CCS with Ethanol)
Location of CCS project	Anywhere in the world	Anywhere, provided they sell the transportation fuel in California	Anywhere, provided they sell the transportation fuel in California	Anywhere, provided they sell the transportation fuel in California
Storage site	Onshore saline or depleted oil and gas reservoirs, or oil and gas reservoirs used for CO_2-EOR			
Credit method	Project-based	Project-based, under the Innovative Crude Provision	Project-based, under the Refinery Investment Credit Program	Project-based or fuel pathway
Earliest date which existing projects eligible	Any	2010	2016	Any
Requirements	Project must meet requirements specified in CCS Protocol			
Additional restrictions	None	Must achieve minimum CI or emission reduction	None	None

DAC facilities located anywhere in the world can generate LCFS credits by choosing to opt in to the LCFS program.[75] DAC projects are an exception to the general requirements of LCFS credits, as they are "not required to sell any transportation fuel into the California market to generate credits."[76] Even so, the rules around DAC project eligibility are tightly defined. If CO_2 captured by a DAC facility was used to create a synthetic fuel for sale in California, it wouldn't qualify for project-based crediting and would instead need to seek a separate fuel pathway in order to generate LCFS credits.[77]

California's LCFS credits can also be stacked with federal 45Q tax credits (Section 2.4.3).[78] There are no restrictions on obtaining both incentives as long as the responsible party adheres to the rules and regulations of both systems.

2.4.2 Inflation Reduction Act (IRA)

The Inflation Reduction Act (IRA) was signed into law on August 16, 2022 and encompasses a wide range of new policy directives spanning healthcare, tax compliance, and energy and

[74] Townsend, Havercroft (2019) The LCFS and CCS Protocol. p. 9. [48]
[75] Townsend, Havercroft (2019) The LCFS and CCS Protocol. p. 9. [48]
[76] Townsend, Havercroft (2019) The LCFS and CCS Protocol. p. 9. [48]
[77] Townsend, Havercroft (2019) The LCFS and CCS Protocol. p. 9. [48]
[78] Townsend, Havercroft (2019) The LCFS and CCS Protocol. p. 20. [48]

environment issues (Figure 2.2).[79] Here, only the energy and environment directives are explored; other policy items included in the IRA are outside of the scope of this report.

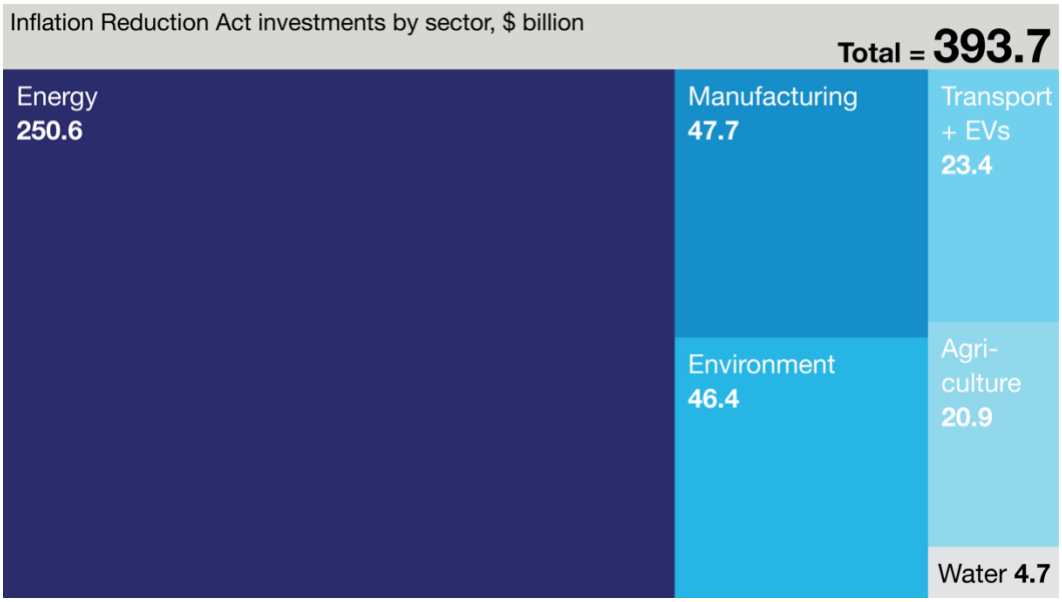


Figure 2.2. Scaled graphic indicating the amount of investment by sector, in billion USD, allocated under the Inflation Reduction Act.[80]

The diversity of climate investments in the IRA, as seen below, is extensive. Funding will be disbursed through grants, loan guarantees, and tax incentives, with tax incentives being the largest share of available funding under the IRA.[81] This includes tax credits for individuals associated with purchasing heat pumps and electric vehicles (new or used), as well as credits for businesses or utilities that are generating zero-carbon electricity, nuclear power, sustainable aviation fuels, or qualifying clean hydrogen.[82] It is worth noting that the time horizons and credit amounts differ based on sector.

The IRA also incorporates provisions aimed to bolster domestic production of goods. Facilities must "meet prevailing wage and apprenticeship requirements" to attain full eligibility under the IRA's tax credit system.[83] These requirements also impose specific requirements, as applicable, to specific initiatives. For example, attaining the full consumer EV tax credit is dependent on a sliding scale of how many of the materials in the battery

[79] Badlam, Cox, *et al*. (October 24, 2022) The Inflation Reduction Act. [2]
[80] Badlam, Cox, *et al*. (October 24, 2022) The Inflation Reduction Act. [2]
[81] Badlam, Cox, *et al*. (October 24, 2022) The Inflation Reduction Act. [2]
[82] Badlam, Cox, *et al*. (October 24, 2022) The Inflation Reduction Act. [2]
[83] Badlam, Cox, *et al*. (October 24, 2022) The Inflation Reduction Act. [2]

were recycled within North America or extracted in countries with whom the U.S. maintains free-trade agreements.[84]

Other provisions in the IRA are designed to aid in transitioning workers from fossil fuels to other energy industries. The IRA includes incentives for companies looking to develop solar or wind farms to locate in regions where coal facilities have recently discontinued operations.[85] It also includes some tailored worker benefits, like the development of a permanent federal trust aimed at supporting coal miners living with black lung disease.[86] Another angle of its transition-oriented policies is its expansion of support for hydrogen-based fuels and CCS, explored in the sections below.[87]

2.4.3 45Q Federal Tax Credits

The 45Q tax credit was introduced in 2008 as an incentive to develop carbon capture, use, and sequestration projects within the United States.[88] Over time, the credit's value has increased—as of the end of 2022, due to the Inflation Reduction Act (IRA), these credits were valued at \$85/ton CO_2 permanently stored and \$60/ton CO_2 used for enhanced oil recovery (EOR).[89] The values are higher for carbon captured via direct air capture (DAC) processes, where the values rise to \$180/ton CO_2 permanently stored and \$130/ton CO, for use in EOR.[90]

Changes in the IRA also extended the eligibility window for new projects to qualify.[91] Now, projects must begin construction by January 2033 in order to qualify for 45Q credits.[92] It also imposes updated minimums on the amount of CO_2 a facility must capture annually to qualify for credits: "18,750 tonnes per year for power plants (provided at least 75% of the CO2 is captured), 12,000 tonnes per year for other facilities, and 1,000 tonnes per year for DAC facilities."[93]

2.4.3 45V Federal Tax Credits

The hydrogen fuel benefits are dispensed through the new tax incentive 45V, in which producers of hydrogen with 'near-zero emissions' can earn \$3 per kilogram of hydrogen produced with no cap on the number of kilograms the producer can receive the incentive

[84] Badlam, Cox, *et al*. (October 24, 2022) The Inflation Reduction Act. [2]
[85] Plumer, Friedman (July 30, 2022) Democrats Got a Climate Bill. [39]
[86] Plumer, Friedman (July 30, 2022) Democrats Got a Climate Bill. [39]
[87] Plumer, Friedman (July 30, 2022) Democrats Got a Climate Bill. [39t]
[88] IEA (November 4, 2022) Section 45Q Credit. [29]
[89] IEA (November 4, 2022) Section 45Q Credit. [29]
[90] IEA (November 4, 2022) Section 45Q Credit. [29]
[91] IEA (November 4, 2022) Section 45Q Credit. [29]
[92] IEA (November 4, 2022) Section 45Q Credit. [29]
[93] IEA (November 4, 2022) Section 45Q Credit. [29]

for.[94] The exact structure of these benefits, however, will depend on rules that are still being written by the Treasury Department; until they have developed a clear definition for 'near-zero emissions,' it is difficult to guess what standards a producer would need to meet to be eligible for the $3/kilogram incentive.[95]

2.5 Additional California-Specific Policies

In California, there are some specific policies that will impact the avenues of carbon management activity that can be pursued, which are external to the permitting requirements outlined above, nor do they constitute as incentives, at least at this moment.

First, a recent package of climate bills that was signed last fall by Governor Gavin Newsom included multiple state bills relevant to carbon management efforts. SB 1314 effectively bans the utilization of any captured CO_2 to be used for enhanced oil recovery (EOR) in the state.[96] As a result, carbon management entities will need to identify other avenues of utilization or storage for their captured CO_2. SB 905 requires that the California Air Resources Board (CARB) establishes a "Carbon Capture, Removal, Utilization, and Storage Program."[97] Under SB 905, CARB must also set up a unified permit for California-based carbon capture, utilization and storage (CCUS) projects, establish a centralized database for California-based carbon management projects, and implement financial responsibility regulations for CO_2 storage operators to retain responsibility for a minimum of 100 years following their most recent CO_2 injection at a well site.[98]

Other statewide policies are likely to have indirect effects on carbon management efforts. California's Sustainable Groundwater Management Act (SGMA) from 2014 requires that state groundwater supplies be brought back into long-term balance by 2040,[99] which may limit the availability of freshwater supplies to Kern County and neighboring areas, depending on the region's hydrology over the coming decades. SGMA requires the development of local groundwater sustainability agencies (GSAs), formed as partnerships between city and/or county governments, irrigation districts, water districts, or other local bodies.[100] Each GSA submits plans to the state to meet SGMA's objectives, with a focus on implementing responsible groundwater management for their region.[101] The California Department of Water Resources (DWR) oversees implementation, giving routine assessments and providing technical assistance, and the State Water Resources Control

[94] Pontecorvo (December 12, 2022) Subsidy for 'green hydrogen' could set off a carbon bomb. [40]
[95] Pontecorvo (December 12, 2022) Subsidy for 'green hydrogen' could set off a carbon bomb. [40]
[96] IEA (November 4, 2022) SB 1314. [28]
[97] IEA (November 4, 2022) SB 905. [27]
[98] IEA (November 4, 2022) SB 905. [27]
[99] SWRCB (no date) SGMA. [43]
[100] SWRCB (no date) SGMA. [43]
[101] SWRCB (no date) SGMA. [43]

Board is entrusted with intervening in a basin's management if its sustainability plans fail.[102] With regulations like SGMA in place to protect local water supplies, water-intensive industries—like liquid direct air capture (L-DAC) or hydrogen production via electrolysis—may find it more difficult to locate in water-stressed regions. Issues relating to available freshwater supplies in Kern County are explored more in Section 8.1.4.

[102] SWRCB (no date) SGMA. [43]

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CARBON MANAGEMENT TECHNOLOGIES

3. Direct Air Capture

TECHNOLOGY AT A GLANCE

- Industry is in early commercial stages: Globally, a cumulative ~10,000 metric tons CO_2 are captured each year by other projects[1]
- Current cost per metric ton CO_2 captured: $94-877 USD/ton CO_2
- Projected cost per metric ton CO_2 captured at scale: $60-200 USD/ton CO_2
- 200-240 acres of land use required per million metric tons CO_2 captured
- Key advantages of this technology in Kern County: minimal feedstock requirements or waste; solid-direct air capture (S-DAC) has the potential to capture water as well as CO_2
- Key concerns for this technology in Kern County: noise and vibration levels with large-scale projects, high energy demands, poor clarity on job creation potential

3.1 Technology Summary

Direct Air Capture (DAC) is a technology that captures carbon dioxide (CO_2) directly from the atmosphere, usually through a mechanical system, although some passive capture techniques are also being developed. In a mechanical system, fans or wind are used to drive ambient air through a contactor unit, where the air passes across a chemical sorbent

[1] Values in this section are summarized from the suite of references cited herein, and are explained in further detail in each subsequent section.

that selectively reacts with and traps CO_2, allowing the other components of the air to pass through and exit the system. Currently, the most developed adsorbent materials are in liquid or solid forms.[2]

3.1.1 Description: How it Works

DAC can be thought of as an engineered equivalent to photosynthesizing plants, except that DAC captures CO_2 from the atmosphere at a faster rate and with a much smaller land footprint than biomass. Furthermore, DAC delivers CO_2 in a pure, compressed form. Captured atmospheric CO_2 can be permanently and safely stored in geologic reservoirs to deliver negative emissions, or be used to produce low carbon intensity products, such as synthetic fuels that work in existing vehicles and infrastructure.[3]

Current DAC technologies are primarily distinguished by using one of two types of sorbent: liquid solvents (L-DAC) and solid sorbents (S-DAC). In both techniques, DAC pulls air from the atmosphere and passes it over the sorbent material. The sorbent material captures the carbon dioxide, and the rest of the air passes through and exits the DAC unit. L-DAC typically uses hydroxide solutions (a liquid solvent) as the bonding sorbent, whereas S-DAC relies on a CO_2 "filter" or dry amine-based chemical sorbents.[4] In both cases, the CO_2 from the air is chemically bound into a new compound, and then is subsequently broken down to release 1) a high-purity stream of CO_2 for storage, and 2) the original sorbent components for reuse. Figures 3.1 and 3.2 illustrate the multi-stage process of DAC's operational system, distinguished by the solid sorbent (S-DAC) and liquid solvent (L-DAC) technologies, respectively.

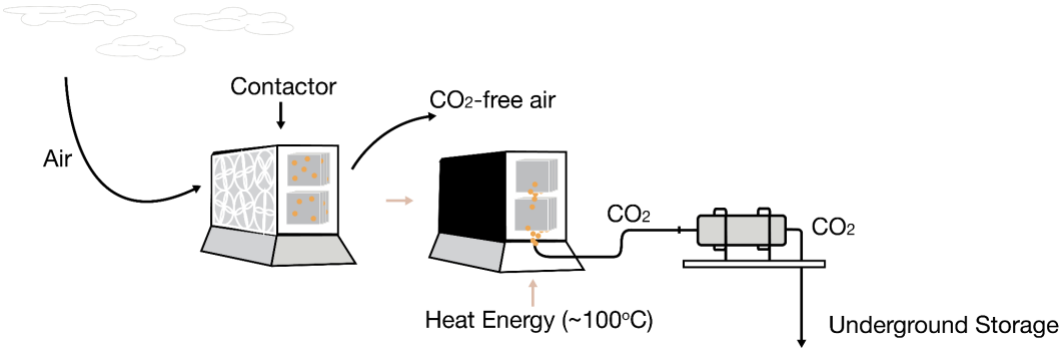


Figure 3.1. Schematic of S-DAC operation.[5] Step 1: ambient air enters the air contactor unit and CO_2 is absorbed onto a solid sorbent. Step 2: Heat exposure (± vacuum pressure) releases CO_2 from sorbent material and a concentrated stream of CO_2 is produced. Step 3: Sorbent is cooled, thereby reactivating it for reuse in the air contactor.

[2] IEA (2022) DAC Report. [40]

[3] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 149. [55]

[4] IEA (2020) CCUS in Clean Energy Transitions. p. 82. [41]

[5] Larsen *et al.* (2020) Capturing New Business. [44]

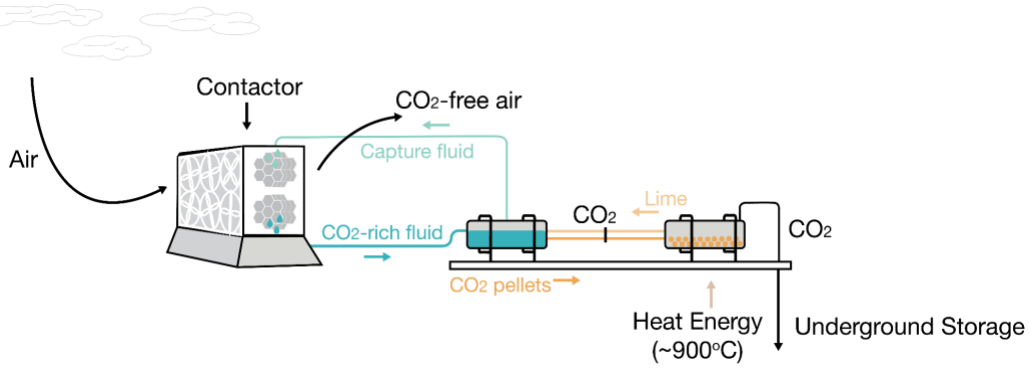


Figure 3.2. Schematic of L-DAC operation.[6] Step 1: ambient air enters the contactor and CO_2 reacts with capture fluid to produce carbonate. Step 2: Carbonate reacts with hydroxide to form small pellets. Step 3: Pellets are heated to produce lime and a concentrated stream of CO_2. Step 4: Lime from the calciner reactivates capture solution for reuse in contactor.

Both technologies require electricity and heat to operate; the electricity drives the fans and controls inlet systems, while the heat releases the trapped CO_2. However, S-DAC requires only temperatures of only ~100°C to break the chemical bonds linking the CO_2 to the sorbent material, whereas L-DAC requires temperatures around 900°C.[7,8] Such temperatures are difficult to reach using renewable energy sources like wind or solar. If natural gas is used to attain the necessary heat, the associated CO_2 released from the use of L-DAC technology would need to be recaptured and stored to avoid counteracting the benefit of DAC.[9]

3.1.2 State of Development

DAC is a relatively new industry that is still in the early stages of development.[10,11] As of the drafting of this report, large-scale commercial deployment of DAC does not exist, but several companies have developed pilot projects with limited commercialization that are capturing CO_2 on the scale of thousands of metric tons per year.[12] Some, but not all, of these pilot projects include geologic sequestration or utilization of the captured CO_2.[13] Because DAC technology is still in its infancy, there are few straightforward assessments of how the technology and business model of DAC will adapt to industrial scaling, although there is reason to expect that economies of scale and technological innovation will have

[6] Larsen *et al.* (2020) Capturing New Business. [44]
[7] IEA (2022) DAC Report. p. 10. [40]
[8] Ghiat, Al-Ansari (2021) A review of CCUS. p. 4. [31]
[9] IEA (2020) CCUS in Clean Energy Transitions. p. 82. [41]
[10] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 189. [55]
[11] IEA (2020) CCUS in Clean Energy Transitions. p. 83. [41]
[12] Ozkan *et al.* (2022) DAC Status Report. [59]
[13] IEA (2020) CCUS in Clean Energy Transitions. p. 83. [41]

positive effects.[14] The earliest breakthrough paper describing a working direct air capture system was written by Geoffrey Holmes and David Keith of Carbon Engineering in 2012, specifically discussing an L-DAC system.[15] The following year, the first pilot-scale deployment of DAC was launched by the Swiss company, Climeworks, which utilizes S-DAC technology.[16] With only about a decade since its early breakthroughs, DAC technology still needs research, innovation, and further technological breakthroughs to reach its maturity at scale.

As of April 2022, there are 18 DAC plants currently operating worldwide, capturing approximately 0.01 Mt CO_2/year.[17] Companies leading the industry with the most developed DAC technology are Climeworks, Carbon Engineering and Global Thermostat. These companies are primarily focused on developing megaton facilities: plants that will operate at the scale of capturing millions of metric tons of CO_2 annually (Mt CO_2/year), and have progressed the furthest towards opening commercial, large scale DAC plants.[18,19]

Two commercial plants, developed by Climeworks, are currently operating in Switzerland and selling CO_2 to greenhouses and beverage companies for carbonation.[20] The latest plant to come online from Climeworks is Orca, launched in 2021 and capturing 4,000 metric tons of CO_2 per year for storage in basalt formations in Iceland.[21] The Orca pilot plant is also a test facility for CO_2 mineralization, in which CO_2 is sequestered in porous basalt where it can react with host minerals and form the carbonate solid $CaCO_3$, precluding any risk of leakage.[22] In North America, both Carbon Engineering and Global Thermostat have been operating a number of pilot plants, with Carbon Engineering, in collaboration with Occidental (Oxy), currently designing what would be the world's first megaton DAC facility, called 1pointfive, in the Permian Basin region of west Texas anticipated to be operational in 2024.[23, 24]

[14] Industry representative, personal communication, August 29, 2022.

[15] Holmes, Keith (2012) Liquid DAC. [36]

[16] McQueen *et al.* (2021) DAC Review. [51]

[17] 1pointfive (n.d.) DAC Technology. [1]

[18] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 193. [55]

[19] Lebling *et al.* (May 2, 2022) 6 Things to Know about DAC. [49]

[20] Climeworks (2015) Capricorn. [20]

[21] Climeworks (2021) Orca. [23]

[22] Reuters (September 13, 2021) World's largest plant capturing carbon from air starts in Iceland.

[23] 1pointfive (no date) DAC Technology. [1]

[24] GlobalNewsWire (2022) Occidental, 1pointfive to begin construction. [32]

3.1.2.1 Operational projects - examples

Orca Facility, Climeworks, Iceland

Launched in September of 2021, the Orca plant (Figure 3.3a) is currently the largest DAC plant in the world.[25] Located in Hellisheidi, Iceland, the plant has a carbon removal capacity of 4,000 metric tons per year.[26] The plant was developed as a collaboration between Climeworks (using their S-DAC technology) and Carbfix, an industry-research consortium that is piloting the development of underground storage of CO_2 through mineralization.[27] The facility consists of eight collector containers, with an annual CO_2 capture capacity of 500 metric tons each.[28] The containers are arranged around a central process hall that accommodate electrical and processing equipment, allowing the company to operate and control the facility remotely.[29] The DAC plant is strategically located in proximity with the Hellisheidi Geothermal Power Plant, which supplies the heat and electricity required to run the direct air capture process at low cost.[30] The Orca footprint is 8,600 square feet, equivalent to the square footage of approximately four urban houses.[31] This translates to a per ton CO_2 land use requirement of 2.15 square feet per ton of CO_2 captured.



Figure 3.3. a) The four collectors of the Orca DAC facility in Hellisheidi, Iceland.[32] The capture technology is S-DAC, from Climeworks. b) Conceptual plan for the in-development Mammoth DAC facility, also S-DAC and expected to be operational in 2024. Mammoth is co-located with the Orca facility, and is a scaled up equivalent of the first pilot facility.[33] Image credit: Climeworks.

[25] Climeworks (2021) Orca. [23]
[26] Climeworks (2021) Orca. [23]
[27] Climeworks (December 2, 2020) The rapid construction of Climeworks' new DAC and storage plant Orca. [24]
[28] Climeworks (2021) Orca. [23]
[29] Climeworks (2021) Orca. [23]
[30] Climeworks (2021) Orca. [23]
[31] Ozkan *et al.* (2022) DAC Status Report. [59]
[32] Climeworks (2021) Orca. [23]
[33] Climeworks (June 28, 2022) Climeworks takes another major step. [22]

The capital and operational costs of the Orca plant are covered in part by the sale of carbon credits in the voluntary carbon offset marketplace, where private buyers can purchase the capture and storage of CO_2 on a per-metric ton basis to offset their own emissions.[34] The Orca plant sells the most expensive carbon offset credits in the world, costing as much as €1,000 per metric ton of CO_2 removed.[35] Climeworks' clientele for carbon offset credits includes Microsoft, Swiss Re, Shopify and Audi.[36] Jan Wurzbacher, co-chief of Climeworks, said commercial demand had been so high that the plant was nearly sold out of credits for its entire 12-year lifespan, prompting the accelerated development of their next plan: the Mammoth DAC facility (Figure 3.3b).[37] Mammoth uses the same technological design as Orca, will also be sited in Hellisheidi, Iceland, and will also sequester the CO_2 via mineralization in Iceland's basalt-rock subsurface, but will have a nominal CO_2 capture capacity of 36,000 tons per year. The plant is expected to be operational in 2024.[38]

DAC 1 Facility, Carbon Engineering, US

DAC 1 is a megaton DAC plant in development in west Texas by the companies 1pointfive and Carbon Engineering. Operation is expected to begin in 2024.[39] The plant will use Carbon Engineering's liquid solvent system (L-DAC), which uses a potassium hydroxide (KOH) solution as the sorbing fluid that binds the CO_2.[40] The facility will be assembled as "a scalable setup" consisting of modular contactors (Figure 3.4a, from Carbon Engineering's pilot facility in British Columbia) that will require a land size of 0.2 km^2, not including energy land use, to reach its 1 $MtCO_2$/yr capture target.[41] High-temperature release and separation of the CO_2 and regeneration of the liquid solvent will be performed using natural gas as the thermal energy source.[42] Because this facility will be sited in the Permian Basin region, which has ideal subsurface reservoirs for geological sequestration, transport of the separated CO_2 to a permanent storage site will be minimal.[43] The initial phase of DAC 1 is focused on a first capture train with a planned capture capacity of 0.5 $MtCO_2$/year; the total capacity of the project will subsequently increase to 1 $MtCO_2$/year.[44,45]

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[34] Favasuli, Sebastian (June 10, 2021) Voluntary carbon markets. [30]
[35] Hook (September 8, 2021) World's Biggest DAC Plant. [37]
[36] Milkywire (2022) The Climate Transformation Fund: Milkywire Progress Report 2022. p. 8. [53]
[37] Hook (September 8, 2021) World's Biggest DAC Plant. [37]
[38] Climeworks (June 28, 2022) Climeworks takes another major step. [22]
[39] GlobalNewsWire (2022) Occidental, 1pointfive to begin construction. [32]
[40] IEA (2021) DAC 1. [39]
[41] Ozkan *et al.* (2022) Current DAC Status. p. 8.
[42] Hook (September 8, 2021) World's Biggest DAC Plant. [37]
[43] Grover (July 8, 2021) Old oil fields may be ideal for carbon sequestration. [33]
[44] IEA (2022) DAC Report. p. 18. [40]
[45] IEA (2021) DAC 1. [39]

1pointfive and Carbon Engineering have raised money to cover the capital costs of this project from corporate sponsors, including a multi-million dollar direct investment from United Airlines, and hope to further offset costs by making the most of existing policy incentives, including the federal 45Q tax credit and California's Low Carbon Fuel Standard (LCFS) program.[46] More information about these policies and the incentives they provide for DAC can be found in Section 3.4 of this report.



Figure 3.4. a) Carbon Engineering Innovation Centre, R&D Facility, Squamish, British Columbia.[47] b) A conceptual aerial view of the megaton Carbon Engineering + 1pointfive facility, DAC 1 (in development).[48] Image credit: Carbon Engineering.

3.1.2.2. Technological innovations on the horizon

In terms of future development, technological designs that emphasize modular and relatively simple DAC approaches are generally favored because they allow for simplified mass production and can be scaled up easily for deployment.[49] Achieving economies of scale by producing large volumes of standard parts may also accelerate DAC's deployment and shorten technology learning curves, which will help to reduce costs. Additional technological trends that are being explored by many DAC startup companies include passive air contact and use of natural sorbents. Some notable start-ups in the DAC space that are indicative of these trends are Carbon Capture Inc, Sustaera, Mission Zero, and Noya. These companies are primarily in the design and development stage of their pilot projects.

Two startup companies are worth particular note for the innovative alternatives they are developing to traditional liquid-solvent or solid-sorbent based DAC systems, which may be

[46] IEA (2021) DAC 1. [39]

[47] Carbon Engineering (June 30, 2021) Carbon Engineering Innovation Centre Update. [13]

[48] 1pointfive (no date) DAC Technology. [1]

[49] Shayegh, Bosetti, Massimo (2021) Future Prospects of DAC Technologies. p. 3. [64]

critical for reducing the operational costs of DAC, and helping bring it to market more quickly.

Heirloom

Heirloom is a startup in the early phase of development. It has yet to deploy its first facility (slated for 2023), but is notable because it is attracting some of the largest investments in new carbon removal technologies from venture investment leaders like Microsoft co-founder Bill Gates's Breakthrough Energy Ventures, and because it has the lowest estimated cost of any direct air capture technology.[50,51] Heirloom had developed an approach that optimizes passive carbon capture absorption using one of the most abundant natural resources on the surface of the earth: limestone. Limestone is composed of calcium carbonate, and is the primary feedstock for cement production.[52] To produce cement, limestone is heated in the presence of water at high temperatures (~900°C) to form lime and a pure stream of CO_2, exactly the same process of solvent regeneration in L-DAC systems.[53,54] The lime is then hydrated to form calcium hydroxide or slaked lime—the slaked lime, when exposed to air, will naturally react with CO_2 to re-form calcium carbonate.[55] Heirloom's technological innovation is to optimize natural carbonation of the lime during passive exposure to air, eliminating the need for fans or high-cost solvents.[56] The primary (and extremely inexpensive) feedstock of limestone, once converted to lime, can be re-used multiple times in a process of calcification (CO_2 absorption) and lime regeneration (CO_2 release).[57] Given the nascent stage of this company's development, specific information regarding the technical and operational requirements of such a process are not yet available, but with the exception of the high-cost solvent chemicals and water requirements for L-DAC, are likely to be similar.

Verdox

Another company in the early stages of development, called Verdox, is exploring a different alternative approach to liquid-solvent or solid-sorbent based DAC (L-DAC and S-DAC). Their Electro-swing Adsorption (ESA) technology is composed of a large, specialized battery that absorbs carbon dioxide from the air, or other gas stream, as it passes over charged electrodes.[58] When the electrodes are discharged, they release the concentrated carbon dioxide gas.[59] The technology works by alternating between charging and

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[50] Cision PR Newswire (March 17, 2022) DAC startup Heirloom raises $53MM. [16]
[51] Olick (December 5, 2022) Heirloom uses limestone to capture CO2. [58]
[52] PubChem (no date) Limestone. [61]
[53] McQueen *et al.* (2022) A scalable DAC process. p. 3. [52]
[54] Larsen *et al.* (2020) Capturing New Business. [44]
[55] McQueen *et al.* (2022) A scalable DAC process. p. 3. [52]
[56] McQueen *et al.* (2022) A scalable DAC process. p. 4. [52]
[57] McQueen *et al.* (2022) A scalable DAC process. p. 4. [52]
[58] Verdox (no date) Breaking new ground. [72]
[59] Verdox (no date) Breaking new ground. [72]

discharging, thus relying on only electricity to run—the process has no heat or water needs.[60] ESA is able to capture carbon dioxide from any concentration, down to roughly 400 parts per million currently found in the atmosphere.[61] The technology is attractive for its high efficiency of raw materials and energy relative to more established direct air capture methods, using about 1GJ/tCO_2, or about 10-20% of the energy requirements for L-DAC and S-DAC (see Section 3.1.3.2).[62,63] Verdox is still in the testing phase of technology development, having been awarded a Department of Energy Advanced Research Projects-Energy (ARPA-E) research grant in 2020.[64] Anticipated capital and operational costs of a pilot-scale project, once deployed, are projected to be ~ $50-100 per metric ton of CO_2 captured.[65]

3.1.3 Operational Needs

This section provides a synopsis of the land use, energy, feedstock, waste disposal and other operational needs of the representative technologies for this industry, aggregated from literature review and interviews with industry experts. Because L-DAC and S-DAC are the most advanced direct air capture technologies, these are the only two DAC approaches considered here and in subsequent sections. Alternative DAC technologies, such as passive air capture or ESA, may be appropriate candidates for a research and development incubator facility.

3.1.3.1 Land use requirements

One of the key benefits of DAC as a carbon management technology is that it can be sited in any location that is economical, because unlike point-source carbon capture technologies, which require concentrated CO_2 streams (such as those emitted from CO_2-emitting industries like steel or concrete manufacturing, see Section 5 of this report) the source of CO_2 - ambient air - is accessible anywhere. Thus, a DAC plant could be co-located next to a plant which requires CO_2 as a feedstock or on top of a geological storage site to minimize costs and secondary emissions associated with transporting the CO_2 via truck, rail or pipeline.[66] DAC can also be co-located with other types of CO_2 capture facilities.[67]

A second benefit of DAC is that the direct land footprint of DAC is smaller than that of alternative carbon-removal processes. Land requirements for DAC are controlled by 1) the

[60] Verdox (no date) Breaking new ground. [72]
[61] Chandler (2019) New Technology: ESA. [15]
[62] Voskian, Hatton (2019) Faradaic electro-swing reactive adsorption for CO_2 capture. p. 3530. [73]
[63] Chandler (2019) New Technology: ESA. [15]
[64] ARPA-E (May 20, 2020) Electro-swing adsorption for high efficiency DAC. [2]
[65] Stauffer (September 2, 2020) Electro-swing cell. [67]
[66] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 189. [55]
[67] IEA (2020) CCUS in Clean Energy Transitions. p. 82. [41]

size of the contactor and 2) the spacing requirements of multiple contactors and contactor configuration.[68] Contactors are generally designed to be modular: easily transportable and stackable (e.g. Figures 3.3 and 3.5). Contactors from Carbon Engineering, a commercial L-DAC company, are about 23 ft long by 16 ft tall and 16 ft wide.[69] Climeworks, a commercial company with the largest existing capture capacity for S-DAC systems, has contactors the size of a standard shipping container, or about 40 ft long by 8 ft wide by 8.5 ft high.[70] Units cannot be too geographically concentrated within a site, as some units would be taking in air that has already been depleted in CO_2 by nearby contactor units.[71] Although the actual footprint required for the contactors is small, there would need to be ample space between sets of contactors to build an effective facility.

Figure 3.5 is a schematic representation of the physical footprint of a 1 $MTCO_2$/year DAC facility. The size, height and orientation of the contactor arrays is based off the original design of solvent-based L-DAC by the company Carbon Engineering, with the cross-sectional inlet of the contactor oriented normal to the land surface.[72] More recent designs from this company have a configuration in which fans are parallel to the land surface (Figure 3.4). The height of the pictured tower, with four vertically stacked units, is approximately 65 feet (20 meters) and over 650 feet long, and could capture 50,000-100,000 metric tons of CO_2 annually.[73] To capture 1 $MtCO_2$/year, process engineer and DAC expert Howard Herzog estimates that you would need 25-30 of Carbon Engineering's contactor rows in a facility, and they would have to be spread far enough apart to ensure that the exhaust of one row of units does not interfere with the inlet of another row.[74] Given that no DAC facilities exist at a scale above *thousands* of metric tons of annual CO_2 capture, no field tests exist to determine the optimal spacing between contactor rows. In a schematic representation of a 1 $MtCO_2$/yr facility developed by the American Physical Society, contactor rows were spaced 250 m (820 ft) apart, to ensure that CO_2-depleted air exiting one contactor would be replenished before reaching the next.[75] Using the APS's spacing estimate, the land footprint of Carbon Engineering's original design for a 1 $MtCO_2$ capture facility (25-30 contactor rows) would be about 300-360 acres, or 1.2-1.5 km^2. If we created the same framework for an S-DAC system modeled after Climeworks' Orca facility in Iceland, also creating 40-unit long rows, one contactor row would be able to capture ~40,000 metric tons of CO_2 annually.[76] Scaling accordingly, the footprint of a 1 $MtCO_2$/yr facility would be 190-230 acres, or 0.8-0.95 km^2, assuming the same 66-80% efficiency that

[68] IEA (2020) CCUS in Clean Energy Transitions. p. 87-88. [41]

[69] Heidel *et al.* (2011) Air contactor design. [34]

[70] Climeworks (no date) Capricorn. [18]

[71] Herzog (2021) DAC: A Process Engineer's View. 16:05-16:34. [35]

[72] Heidel *et al.* (2011) Air contactor design. p. 2865. [34]

[73] Heidel *et al.* (2011) Air contactor design. p. 2866. [34]

[74] Herzog (2021) DAC: A Process Engineer's View. 15:52-16:05. [35]

[75] APS (2011) DAC with Chemicals. p. 7. [3]

[76] The Orca facility in Iceland contains 4 units of 2 stacked contactors, each ~40 ft long on the air inlet side, and ~ 8 ft deep. The facility captures approximately 4,000 metric tons of CO_2 annually.

Dr. Herzog estimated for L-DAC systems.[77] These numbers are comparable to published estimates of L-DAC and S-DAC land use requirements, which range from 0.2-7 km^2 and 0.2-2 km^2, respectively (Table 3.1).[78,79,80,81] Further complicating land use estimates, DAC systems can make use of vertical space by stacking DAC contactors much higher than 2-4 units, and thus allowing for a far smaller footprint required for megaton-scale facilities.[82]

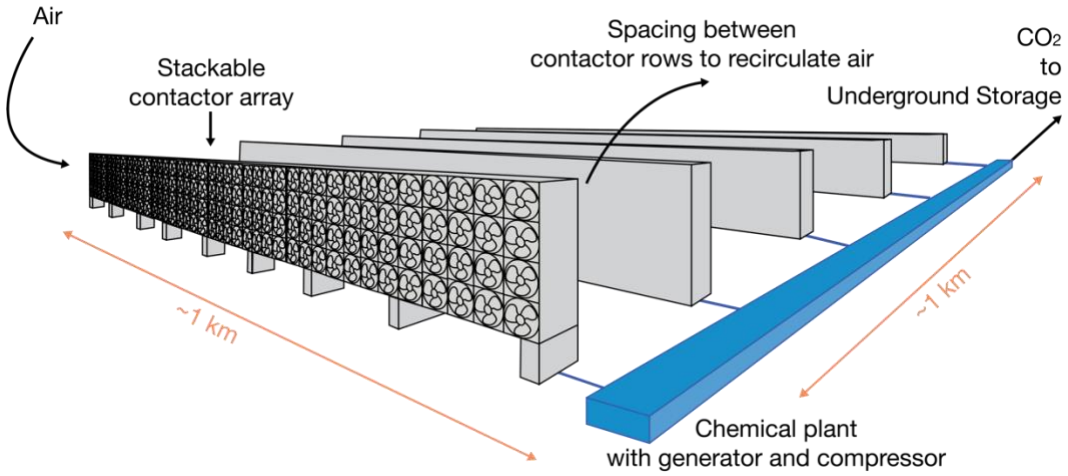


Figure 3.5. A conceptual drawing of a 1MtCO_2 DAC system, consisting of 10 m (33 ft) tall and 1 km (0.6 mile) long contactor structures and a facility for sorbent regeneration and CO_2 gas compression. Adapted from the American Physical Society[83] and Heidel et al. (2011).[84]

Indirect land use, resulting from the energy source needed to provide heat and electricity to a DAC facility, is generally much more significant than direct land use itself, but is dependent on the type of DAC sorbent (L-DAC or S-DAC) and the type of energy source in question.[85] For an L-DAC plant capturing one million tons of CO_2 annually powered entirely by solar PV, around 34 km^2 of land would be needed, whereas natural gas only requires 0.4 km^2.[86] However, L-DAC systems require heating temperatures of ~900°C (Table 3.1), and as of the publication of this report, there is not an at-market tool for converting solar or wind energy into process heat at those temperatures.[87] Thus, published land use estimates for

[77] Herzog (2021) DAC: A Process Engineer's View. 15:52-16:05. [35]
[78] Lebling *et al.*, WRI (2022) DAC: Assessing impacts to enable responsible scaling. p. 2. [48]
[79] IEA (2022) DAC Report. p. 39. [40]
[80] APS (2011) DAC with Chemicals. p. 7. [3]
[81] Lebling *et al.* (2022) Building DAC. [47]
[82] Aines, R. *Personal communication* (2022).
[83] APS (2011) DAC with Chemicals. p. 7. [3]
[84] Heidel *et al.* (2011) Air contactor design. p. 2865. [34]
[85] Baker *et al.* (2020) Getting to Neutral. p. 78. [6]
[86] Lebling *et al.* (2022) Building DAC. [47]
[87] McMillan *et al.*, NREL (2021) Opportunities for solar industrial process heat. p. vi. [50]

energy demand as a function of energy source for L-DAC have generally assumed that heat energy is derived from natural gas or geothermal sources, but that alternative renewable energy sources like wind and solar could provide the power needed for electricity.[88] In contrast, S-DAC requires maximum sorbent regeneration temperatures of only ~80-100°C (Table 3.1), and thus both heat and electrical energy can be supplied by existing at-market wind or solar energy technologies. For a 1 million metric ton S-DAC plant, energy sourced from natural gas would require a 0.26km^2 footprint, whereas solar requirements would be about 21km^2 (Table 3.1).[89]

Additional siting and footprint considerations

In addition to general land use considerations, attention needs to be paid to regional climate, dominant local airflows, and other meteorological conditions in the area, to identify preferred DAC technologies, optimal siting, and operational needs.[90] Humidity and average ambient temperatures are particularly important, because they can have large impacts on the capture productivity, energy efficiency, and water demands of DAC systems.

A recent study of S-DAC processes identified optimal capture productivity at low ambient temperatures, and much lower energy efficiency and capture productivity at higher ambient temperatures (Figure 3.6).[91] This is because solid sorbent materials not only absorb CO_2, but also water vapor from the air.[92] Although researchers agree that meteorological conditions will impact a DAC facility's effectiveness, findings are mixed as to these impacts. When looking specifically at Climeworks's S-DAC process, more water absorption from the atmosphere was found to reduce the sorbent's capacity for CO_2 sorption.[93] In overarching studies of amine-based solid sorbents for DAC, higher humidity was found to increase the sorbent's CO_2 capture capacity but increase the energy use of the chemical process, while higher temperatures led to both higher energy demand and lower productivity—and these effects interact with one another.[94] As seen in Figure 3.6, at ambient temperatures above ~20°C (68°F), increases in relative humidity also begins to negatively impact capture productivity and energy efficiency.[95] In water scarce regions, however, sorption of both water and CO_2 may be considered a technological benefit, as captured water could be put to new use. Similarly, the company Carbon Engineering, which employs L-DAC systems, is avoiding places with colder climates to avoid unwanted viscosity of the liquid solvent, while at the same time avoiding dry and hot places to

[88] Baker *et al.* (2020) Getting to Neutral. p. 78-79. [6]
[89] Baker *et al.* (2020) Getting to Neutral. p. 79. [6]
[90] Herzog (2021) DAC: A Process Engineer's View. 27:24-27:35. [35]
[91] Wiegner *et al.* (2022) S-DAC optimization. p. 12654. [75]
[92] Wiegner *et al.* (2022) S-DAC optimization. p. 12650. [75]
[93] Herzog (2021) DAC: A Process Engineer's View. 27:35-28:06. [35]
[94] Wiegner *et al.* (2022) S-DAC optimization. p. 12650. [75]
[95] Wiegner *et al.* (2022) S-DAC optimization. p. 12654. [75]

minimize evaporation of the liquid solvent, which leads to constant water loss and an increased possibility of leaking some of the captured CO_2.[96]

Table 3.1. Comparison of S-DAC and L-DAC key features.[a]

	S-DAC	L-DAC
CO_2 separation	Solid adsorbent	Liquid solvent
Specific energy consumption (GJ/tCO_2)	3.4-5.9	5.3-12.4
Share as heat consumption (%)	75-80%	80-100%
Share as electricity consumption (%)	20-25%	0-20%
Regeneration temperature	80-120°C	Around 900°C
Regeneration pressure	Vacuum	Ambient
Capture capacity	Modular (e.g. 50 tCO_2/yr per unit)	Large-scale (e.g. 0.5 to 1 $MtCO_2$/yr)
Net water requirement (tH_2O/tCO_2)	-2 to none	0-50
Life cycle emissions ($tCO_{2\text{-emitted}}/tCO_{2\text{-captured}}$)	0.03-0.91	0.1-0.4
Levelized cost of capture (USD/tCO_2)	Up to $540	Up to $340
Main advantages	• Possible net water production • Less capital-intensive • Modular • Operation can rely on low-carbon energy only • Novel and therefore more likely to see cost reduction	• Less energy-intensive • Large-scale capture • Operation relies on commercial solvents • Technology adapted from existing commercial units
Main trade-offs	• More energy-intensive • Manual maintenance required for adsorbent replacement	• More capital-intensive • Relies on natural gas combustion for solvent regeneration (with potential for full electrification in the future)
Land requirements	**S-DAC**	**L-DAC**
DAC footprint ($km^2/MtCO_2$)	0.2-2 (Median = 1.0)	0.2-7 (Median – 0.8)
Natural gas energy source ($km^2/MtCO_2$)	0.26	0.43
Solar energy source ($km^2/MtCO_2$) (with NG as a heat source – L-DAC only)	2	36 (5 + 0.37)
Wind energy source ($km^2/MtCO_2$) (with NG as a heat source – L-DAC only)	217	364 (51 + 0.37)

a. Data from: IEA (2021) DAC Report, p. 23-24, Baker *et al.* (2020) Getting to Neutral, p. 79, APS (2011) DAC with Chemicals, p. 7., Lebling *et al.* (2022) Building DAC, p. 12, Ozkan *et al.* (2022) Current DAC Status, p. 2-8, National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda, and this study.

[96] Herzog (2021) DAC: A Process Engineer's View. 28:06-29:59. [35]

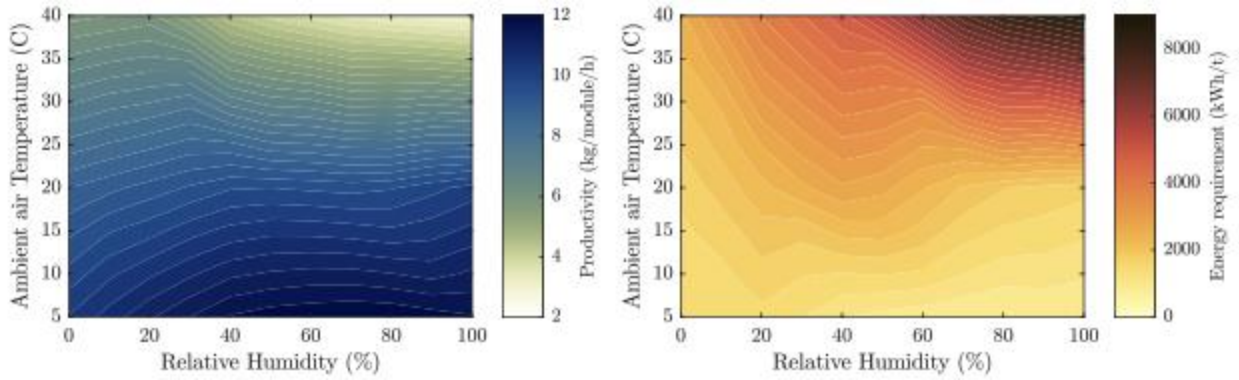


Figure 3.6. Productivity and specific energy requirements for S-DAC as a function of ambient temperature and humidity. Reproduced with permission from Wiegner et al. (2022)[97].

Land use estimates also have to anticipate less than 100% operational efficiency. H. Herzog estimated 66-80% of total DAC capacity would be operational at any given time, and a life-cycle assessment of Climeworks technologies estimated a carbon capture efficiency of 85-93%.[98,99] L-DAC contactors can "theoretically operate continuously at steady state without interruption" though they require regular maintenance.[100] However, S-DAC must operate using a batch operation which requires having multiple units in parallel.[101] At any one time, some contactor units will be in operation capturing CO_2, while the remaining contactor units are in their regeneration state, releasing CO_2 from the filters.[102]

3.1.3.2 Energy requirements

The energy requirement as well as per-ton cost of any carbon-dioxide removal technology is heavily influenced by the concentration of CO_2 in the main feedstock of the plant. For DAC, that feedstock is ambient air, which has CO_2 concentrations of a little over 400 parts per million, a small fraction of industrial-scale flue gas, which can be 5 to >90% CO_2.[103,104] The extremely dilute stream makes it difficult and energy-intensive to separate CO_2 from air relative to more established industrial point source carbon scrubbers.[105,106]

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[97] Wiegner *et al.* (2022) S-DAC optimization. [75]

[98] Herzog (2021) DAC: A Process Engineer's View. 15:52-16:05. [35]

[99] Deutz, Bardow (2021) Life-cycle assessment of an industrial DAC process. [25]

[100] IEA (2022) DAC Report. p. 22-23. [40]

[101] IEA (2022) DAC Report. p. 22-23. [40]

[102] IEA (2022) DAC Report. p. 22-23. [40]

[103] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 189. [55]

[104] IEA (2020) CCUS in Clean Energy Transitions. p. 101. [41]

[105] IEA (2022) DAC Report. p. 27. [40]

[106] IEA (2020) CCUS in Clean Energy Transitions. p. 82. [41]

The amount of energy needed for DAC also depends on the technology. For L-DAC, the most energy-intensive component of the capture process is the thermal regeneration step (Figure 3.2), in which the carbonate pellets holding the sorbed atmospheric CO_2 are combusted to release a stream of high-purity CO_2 and regenerate the lime solvent additive (CaO).[107] This process requires heating to temperatures up to 900°C.[108,109] In comparison, the regeneration step for S-DAC sorbent only requires a temperature of 80–120°C.[110,111] The result is that, while both technologies require about 80% of their energy for heating and 20% for electricity, estimates of the total energy need for L-DAC ranges from 5.3-10.7 gigajoules per ton of CO_2 captured (GJ/tCO_2), whereas S-DAC requires about 3.4 to 5.8 GJ/tCO_2 (Table 3.1), or 1.5-3.0 and 0.9-1.6 MWh/tCO_2, respectively.[112,113] In existing pilot facilities, energy sources include geothermal (the Orca facility in Iceland), waste heat (Climeworks' first pilot plant in Hinwil, Switzerland) or natural gas with carbon capture (Carbon Engineering).[114,115] Using solar power to supply both heat and electricity energy is a feasible option for S-DAC, given the lower required heat generation temperatures, but to deliver heat up to 900°C for L-DAC technologies, is not feasible unless paired with a high-temperature industrial battery solution (see Section 7 on energy storage industries).[116] Estimates of the scale of solar installation required to supply 100% of the heat and electrical energy needs of a $1MtCO_2/yr$ DAC facility (assuming industrial battery use as needed) are provided in Table 3.2. Installed capacity for the solar fields were calculated following the equation:

MWh (energy supplied) = MW (installed capacity of facility) x (8760 hours in a year) x Capacity factor (E3.1)

where the capacity factor for solar panels in Kern County is 32.8%.[117,118] Solar acreage is calculated on the basis of ~7 acres per MW installed solar capacity.[119,120] With these values,

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[107] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 203. [55]

[108] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 196. [55]

[109] IEA (2022) DAC Report. p. 10. [40]

[110] Beuttler *et al*. (2019) The role of DAC in mitigation. p. 2. [8]

[111] Ozkan *et al*. (2022) Current DAC Status. p. 2. [59]

[112] Baker *et al*. (2020) Getting to Neutral. p. 79. [6]

[113] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 222. [55]

[114] Climeworks (2021) Orca. [23]

[115] Climeworks (May 31, 2017) Climeworks makes history. [21]

[116] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 211. [55]

[117] Thomson Reuters Practical Law Glossary (no date) Capacity factor. [69]

[118] NREL (no date) Utility-Scale PV. [56]

[119] Lorelei Oviatt, Kern County Department of Planning and Natural Resources, personal communication, September 21, 2022.

[120] SEIA (no date) Land use and solar development. [65]

a megaton L-DAC facility would require on average 830 MW installed solar capacity (range = 508-1034 MW), or a ~5800 acre solar field. S-DAC would require an average of 420 MW installed solar capacity (range = 329-561 MW), or ~2900 acres of solar panels.

3.1.3.3 Other operational needs

Waste disposal requirements

Because the only feedstock for DAC systems is air, and the only output is CO_2, there are no significant waste streams from DAC plants.[121] Minor anticipated sources of waste are replacement of parts, and of the solid or liquid sorbent materials once their regenerative capacity has declined. It is not clear how many iterations of regeneration are possible before sorbents will need replacement, but may be on the scale of many dozens of capture cycles.[122] L-DAC sorbents are primarily composed of strong bases such as NaOH or KOH.[123,124] As standard industrial salts, these compounds have well established regulation and disposal procedures.[125,126] Sorbent materials currently being tested for S-DAC technologies include metal–organic frameworks (MOFs), zeolites, activated carbon, silica materials, carbon nanotubes, porous organic polymers, and carbon molecular sieves.[127] These are solid, non-reactive and non-hazardous materials that are common in many chemical laboratories, and do not pose a hazardous waste risk.

Warehousing requirements

Warehousing could be minimal for DAC, as there's no feedstock related to the capture other than ambient air, which does not require storage.

Transportation & pipeline requirements

Transportation and pipeline needs for a site should be minimal—adsorbents or solvents may need to be moved in and out of the plant at regular intervals to ensure the contactors remain in working order, a process that would likely rely on trucks for transport. The most likely pipeline needs for any site would be a pipeline to move the CO_2 to storage or, for L-DAC, pipelines to bring in natural gas, hydrogen, or other materials to support its high thermal energy needs. Please refer to Section 9 of the full report for more information on transportation requirements for more information about pipelines and other transportation options for safely moving CO_2 offsite for geologic storage.

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[121] Simon Pang, DOE C-LEAP Technical Assistance, personal communication, September 29, 2022.

[122] Industry representative, personal communication, November 11, 2022.

[123] McQueen *et al*. (2021) DAC Review. p. 3. [51]

[124] IEA (2021) DAC 1. [39]

[125] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. Research Agenda. p. 231. [55]

[126] EPA (no date) Substance Registry Service: Sodium hydroxide. [28]

[127] McQueen *et al*. (2021) DAC Review. p. 2. [51]

Table 3.2. Comparison of S-DAC and L-DAC energy requirements.[128]

	Energy Requirements:		Solar Requirements for a 1 $MtCO_2$/yr Facility:		
L-DAC	**GJ/t CO_2**	**MWh/t CO_2**	**Installed MW**	**Footprint (acres)**	**Footprint (km^2)**
minimum	5.3	1.46	508	3553	14
maximum	12.4	3.44	1199	8392	34
mean	9.2	2.55	889	6224	25
S-DAC					
minimum	3.4	0.94	329	2301	9
maximum	5.9	1.64	570	3993	16
mean	4.8	1.32	460	3223	13

3.2 Societal Impacts

3.2.1 Job creation potential

3.2.1.1 Number and types of jobs

The largest existing DAC project is 0.0004% the size of a megaton (million ton) capture facility, meaning that estimates of the job creation potential of this industry is highly speculative and must be based on growth trajectories of similar industries. The United Kingdom, which aims to capture 20-30 $MtCO_2$/yr by 2030, is anticipating 50,000 carbon capture-related jobs, translating to ~2,000 jobs per million tons of CO_2 sequestered.[129] The Rhodium Group estimated that construction, engineering and equipment manufacturing sectors combined could see at least 3,000 new jobs for every one million ton DAC plant, though the bulk of these jobs are in the initial plant investment period.[130] The breakdown of those jobs are as follows:

- >1500 jobs created from the equipment manufacturing process
- 657 jobs created from the engineering and design phase
- 721 jobs created from the construction phase
- 278 jobs created from operation and maintenance activities

[128] Data from: Baker *et al.* (2020) Getting to Neutral, p. 78, National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda, p. 222, and this study.
[129] United Kingdom Department for International Trade (2022) CCUS Investor Roadmap. p. 4. [71]
[130] Larsen *et al.* (2020) Capturing New Jobs. p. 15. [45]

- Additional job creation in supporting industries like the energy production sector.[131]

While it is not entirely clear how these estimates would scale, it is likely that some would grow more linearly than others. For example, operation and maintenance might not have significantly higher job creation potential at a 2 megaton DAC plant than a 1 megaton facility, but construction, manufacturing and supporting industries would.[132]

For the DAC 1 facility led by 1pointfive and Carbon Engineering, planned to capture 1 megaton per year, the reported permanent job estimate is about 75, with ~1,000 on-site construction jobs.[133] CarbonCapture Inc.'s Project Bison, a DAC hub planned for Wyoming with a goal of creating a 5 megaton DAC facility by 2030, is estimating the plant will support "more than 200 permanent jobs" in the state.[134] When compared to the Rhodium Group figure for a 1 megaton facility, these real facility estimates appear to reflect how permanent job potential is unlikely to scale proportionally for larger DAC facilities.

It is also critical to note that the job opportunities in several categories of the Rhodium Group estimate are not guaranteed to directly benefit local communities where a DAC facility is sited. This is particularly true for equipment manufacturing, engineering, and design. If a facility scale is large enough, it could provide an economic incentive to co-locate equipment manufacturing in the region.[135] However, it is recommended that concrete actions are taken to prepare both the industry and potential local workers for these new jobs to be sited in the region. One such action is to develop legally binding mechanisms ensuring that communities have the opportunity to benefit from available jobs and negotiate for other types of benefits beyond jobs. These agreements could take the form of a Community Benefit Agreement, a negotiated legal agreement between community groups and project developers that guarantees community benefits in exchange for a community's agreement to accept the project, or a Project Labor Agreement, an agreement between contractors and unions laying out the terms for a project. Project Labor Agreements can include Community Workforce Agreements, which require that the contractor hire a negotiated percentage of local, low-income or other marginalized workers, or that they collaborate with local organizations to provide job training programs and provide job quality specifications.[136]

3.2.2.2 Training pipelines

Direct jobs that would be based onsite—such as construction, operation and maintenance, and electricity generation and distribution—require skill sets that are transferable from

[131] Larsen *et al.* (2020) Capturing New Jobs. p. 15. [45]

[132] Roger Aines, DOE C-LEAP Technical Assistance, personal communication, September 28, 2022.

[133] Trendafilova, (August 26, 2022) Occidental Starts Construction Of Its First Large-Scale DAC Plant. [70]

[134] Arambel (October 7, 2022) CarbonCapture Inc. [5]

[135] Industry representative, personal communication, November 11, 2022.

[136] Lebling *et al.* (2022) Building DAC. [47]

other projects and industries, like fossil fuel and energy sectors.[137,138] As mentioned above, facility developers can work with local organizations and institutions to provide relevant training to take on these roles. This collaboration with local organizations to provide job training can be seen in Project Bison, where developers are already working with local community colleges in Wyoming to set up training programs for new positions at DAC facilities.[139]

3.2.2 Quality of Life

3.2.2.1 Location

The lack of dangerous feedstocks, waste streams or pollutants associated with DAC results in little to no health or environmental risk from the operation of DAC towards the local community. Key considerations that remain are:

1. Energy use: due to the enormous use of energy required to run DAC facilities, developers need to ensure that energy required for DAC doesn't compete with other existing uses, such as domestic and local industry.
2. Noise: a single DAC contactor unit operates much like a large fan or HVAC system, and thus is comparably loud.[140] One large HVAC air conditioner emits 50-70 decibels of sound, about the same as other home appliances (refrigerator, dishwasher, vacuum). This sound dissipates relatively quickly; 50 feet away from a unit the noise level would be about halved, to 25-45 decibels (comparable sounds are whispering, rustling leaves).[141] However, further research is warranted to assess how sound levels increase as multiple contactor units are combined.
3. Vibration: there is no clear data or discussion on the vibrational impact of DAC, but a megaton facility would have tens of thousands of contactors with rotating fan blades, it is a consideration. Several solutions exist to reduce the impacts of industrial vibration, including hardware, pads and mats designed to absorb vibration.[142]
4. Aesthetics: because DAC systems are modular, there is room for preference in whether towers are built very tall, to reduce the overall ground footprint, or kept low to minimize visual impact.

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[137] Larsen *et al.* (2020) Capturing New Jobs. p. 23-24. [45]

[138] Pollack (October 10, 2022) Firm has big plans for air capture. [60]

[139] Arambel (October 7, 2022) CarbonCapture Inc. [5]

[140] Simon Pang, DOE C-LEAP Technical Assistance, personal communication, September 28, 2022.

[141] WKC Group (no date) Sound attenuation - inverse square law. [76]

[142] Sorbothane Inc. (no date) Vibration Isolation in Industrial and Manufacturing Equipment. [66]

5. Commuting considerations: new roads and increased commuting for employees could increase traffic, and thus road noise and pollution for nearby residents.[143]

3.2.2.2 Multi-use potential

DAC contactors must be spaced far enough apart to prevent the CO_2-free exhaust from one contactor becoming the intake air for the next contactor.[144] The optimal configuration to prevent this is still in the design phase, and likely specific to the conditions of the facility site.[145] As a result, it is possible that there will be large swaths of available space between contactor rows that could have alternative uses, such as the siting of other facilities, part of the solar energy supply for the DAC units, or livestock grazing (depending on disruptiveness of noise and vibration of the contactor units).[146] Additionally, DAC can be placed on top of, or adjacent to other industrial facilities, as shown by Climeworks' DAC-1 plant, which is built on the roof of a municipal waste incinerator.[147]

3.3 Environmental Impacts

3.3.1 Water requirements

3.3.1.1 Minimum volume requirements

Water requirements for DAC are highly dependent on the chosen technology. While L-DAC requires significant amounts of water to dilute the hydroxide solution, some S-DAC technologies produce water as a byproduct of CO_2 absorption.[148, 149]

For L-DAC to capture one ton of CO_2, various sources estimate as little as 1 to more than 20 tons of water is needed to dilute the hydroxide solution that binds CO_2.[150,151,152] Water is not actually a feedstock in the L-DAC process, but is a component in the circulating solvent solution. Although that solution can be repeatedly regenerated, water must be regularly added to compensate for evaporation loss and, to a lesser degree, drift loss that occurs

[143] Lebling *et al.* (2022) Building DAC. [47]
[144] Herzog (February 4, 2021) DAC: A Process Engineer's View. 16:05-16:34. [35]
[145] APS (2011) DAC with Chemicals. p. 7. [3]
[146] Herzog (February 4, 2021) DAC: A Process Engineer's View. 32:05-32:32. [35]
[147] Evans (June 22, 2017) The Swiss company hoping to capture 1% of global CO2 emissions by 2025. [27]
[148] IEA (2020) CCUS in Clean Energy Transitions. p. 88. [41]
[149] Breyer *et al.* (2019) Direct air capture of CO_2. p. 2053. [9]
[150] Lebling *et al.* (May 2, 2022) 6 Things to Know about DAC. [49]
[151] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 199. [55]
[152] An et al. (2022) Impact of L-DAC. p. 7. [4]

during the sorbent-air contacting process.[153] The intensity of evaporation, and thus the H_2O needed for CO_2 captured, depends on the molarity of the hydroxide solvent and the relative humidity of ambient air. More concentrated solutions of hydroxide result in less water loss, as does higher ambient humidity.[154] For example, experiments conducted at relative humidity levels above 65%, for solutions with a concentration of 7.2 M NaOH or 2 M KOH effectively mitigated evaporative water loss.[155,156] In contrast, experiments conducted at ambient temperatures over 30°C and at relative humidity levels below 20%, water loss was higher than 20 metric tons of H_2O per ton CO_2 (Figure 3.7).[157]

In the case of S-DAC, water is used, but is contained and continuously recycled within closed-loop systems.[158] Under specific operating conditions, S-DAC can also *produce* fresh water as a byproduct of the CO_2 capture. Climeworks' solid sorbent system is an example, yielding approximately 0.8-2 metric tons of water per metric ton of CO_2 captured.[159] Other S-DAC technologies, like the process used by Global Thermostat, use steam condensation for sorbent regeneration.[160] These S-DAC systems are more water intensive, requiring up to 1.6 tons of water per metric ton of CO_2 captured.[161]

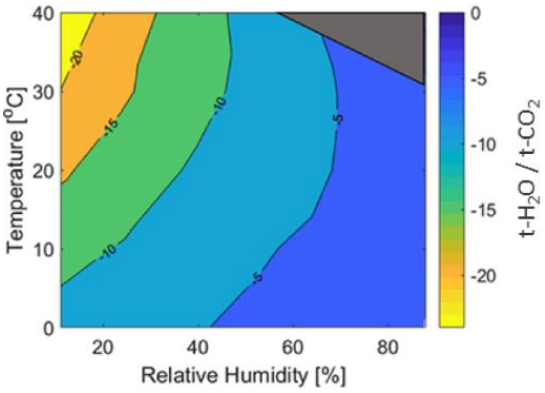


Figure 3.7. Net water consumption per metric ton of CO_2 capture using L-DAC technology, as a function of climate conditions. Reproduced with permission from An et al. (2022).[162] Kern County humidity and temperature highs in the summer and humidity and temperature lows in the winter winter are about 27% and 97°F (36°C), and 57% and 38°F (3°C), respectively,[163] meaning water consumption in Kern County would likely range from ~4-20 tons of water used per ton CO_2 captured.

[153] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 228. [55]
[154] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 199. [55]
[155] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 199. [55]
[156] Holmes, Keith (2012) Liquid DAC. p. 4395. [36]
[157] An *et al.* (2022) Impact of L-DAC. p. 7. [4]
[158] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 228-230. [55]
[159] Fasihi *et al.* (2019) Techno-economic DAC. [29]
[160] McQueen *et al.* (2021) DAC Review. p. 5. [51]
[161] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 230. [55]
[162] An *et al.* (2022) Impact of L-DAC. p. 7. [4]
[163] WeatherWX.com (no date) Kern County, California Climate Averages. [74]

3.3.2 Other potential impacts

DAC facilities are expected to produce zero or-near zero emissions onsite that could be hazardous to the environment or human health.[164] Hazardous waste is not a significant concern for DAC facilities, as reviewed in Section 3.1.3.2. Wastewater is also not generated in significant amounts in DAC processes, as the only water used is contained within close-loop systems. Solid waste buildup can occur in the CO_2 recovery equipment, as happens in traditional monoethanolamine (MEA) scrubbers that are used for point source carbon capture.[165] Similar environmental regulation and disposal guidelines would need to be followed. Chemicals used in sorbent plants would degrade over time as heat is applied to release captured CO_2, but those degradation products (e.g., ammonia) are expected to be contained within the DAC plant and not released into the environment, and have established regulation and disposal protocols (Section 3.1.3.2).[166]

3.4 Economic Impacts

3.4.1 Business Model

There are two primary revenue streams possible for a DAC development: private carbon credits or benefits from federal and state incentives.

Selling carbon credits to the voluntary carbon offset market

DAC developers can either seek private companies to invest in their carbon removal project, allow carbon credits to be purchased to offset their CO_2 emissions, or both. Companies such as Stripe, Shopify, and SwissRe have purchased carbon credits from DAC facilities to offset their CO_2 emissions.[167] Other companies are helping develop capture projects. United Airlines is investing in DAC directly via funding on the 1pointfive and Carbon Engineering project, in line with its commitment to become carbon neutral by 2050.[168] And Microsoft is both purchasing DAC removal carbon credits from Climeworks and, through its Climate Innovation Fund, is investing in the Climeworks Orca facility in Iceland.[169]

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[164] Lebling *et al.* (2022) Building DAC. [47]

[165] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 231. [55]

[166] Lebling *et al.* (2022) Building DAC. [47]

[167] Clancy (April 13, 2022) Stripe, Shopify, Alphabet, Meta and McKinsey will spend almost $1 billion on carbon removal. [17]

[168] Rucinski (December 10, 2020) United Airlines invests in a carbon-capture project. [63]

[169] Climeworks (July 13, 2022) Climeworks becomes first supplier of long-term, technology-based carbon removal. [19]

Utilizing federal and state incentives

A DAC plant that sequesters captured CO_2 into saline or other geologic formations is also eligible to take advantage of the 45Q tax credit, which, since the adoption of the U.S. Inflation Reduction Act, provides $180 per ton of CO_2 sequestered via DAC.[170] Moreover, DAC companies are eligible for the California Low Carbon Fuel Standard (LCFS) credit, which credits technologies that reduce transportation-derived greenhouse gas emissions.[171] DAC is eligible under the program because it removes CO_2 produced by gas-powered cars and trucks.[172] LCFS credits vary in price based on supply and demand within the credit marketplace, but from January 2018 to December 2022 ranged from $62 to $217 per metric ton CO_2.[173] 45Q and LCFS credits can be "stacked" (i.e. both credits given for one metric ton of carbon removed), such that, given historical LCFS prices, incentive revenue can be expected to be in the range of ~$242-$397 per metric ton CO_2.[174] Incentive credits cannot, however, be used in tandem with the voluntary carbon offset marketplace (for a summary of relevant policy and regulations pertaining to all carbon management industries, refer to Section 2 of this report).

3.4.2 Business Costs

Estimates of the current cost of carbon capture for DAC systems are highly variable, ranging in the published literature of the last decade from less than $100 per metric ton CO_2 captured to more than $1,000 per metric ton.[175] There are two reasons for the high variability. First, given the newness of the technology, all existing facilities are still in the testing or pilot scale. That means there are no large-scale facilities to directly assess cost, and ongoing research is continuously identifying lower-cost sorbent materials and optimal operating conditions.[176] Second, there are a large number of variables required for any techno-economic assessment of a new industry, and the assumptions used to determine each variable are different across different publications. In general, costs are assessed and reported through a 'Lifetime Cost Assessment' (LCA) model, or the summative cost per metric ton CO_2 of the capital costs (the prices of the equipment that make up the DAC facility), operational costs (including maintenance and labor), and energy costs (heat + electricity), normalized over the lifetime of the plant.[177,178] In some cases, costs related to

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[170] Carbon Capture Coalition (2022) The Inflation Reduction Act (IRA) of 2022. p. 2. [12]

[171] □□R□ □□□ d□□□□□□□□□□□□ □□r□□□ □□□□□□□□d□rd□□□□□

[172] CARB (no date) Low Carbon Fuel Standard Basics. □□□□□□□□□

[173] Neste (no date) California Low Carbon Fuel Standard Credit price. [57]

[174] Nagabhushan (November 10, 2018) California's CO2 reduction program opens doors to CCS. [54]

[175] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 190. [55]

[176] Ozkan *et al.* (2022) Current DAC Status. p. 9. [59]

[177] Fasihi *et al.* (2019) Techno-economic DAC. p. 965. [29]

[178] Carbonplan (no date) DAC cost calculator. [14]

the transport and permanent storage of captured CO_2 are also included (these are not accounted for here, but can be explored further in Section 9). Typically, the most significant drivers of cost uncertainty are the sorbent used and the source and cost of electricity.[179]

A summary of recent published estimates for DAC costs are presented in Tables 3.3 and 3.4, and a breakdown of how capital, operational and energy costs are estimated is detailed in the following sections. Current levelized costs for net CO_2 removed for the solid sorbent–based approach (S-DAC) range from \$89 to \$600/tCO_2, with the greatest variable being the type of adsorbent and energy source.[180] The cost range for the solvent-based approach (L-DAC) is \$156 to \$506/tCO_2, with the strongest control on price being the source of thermal energy.[181] Experts predict that these costs could fall significantly within the next decade, to ~\$100-200/tCO_2, and potentially as low as \$60/tCO_2 by 2040 or 2050, with the assumption that the technology will continue to grow and there will be cost reductions due to economies of scale (see Table 3.5, 'Future costs').[182,183]

3.4.2.1 Cost to build (upfront costs)

Capital cost consists mostly of the construction expenses needed to establish the facility from scratch, including the procuring equipment and construction materials and the cost of labor. For S-DAC systems, the equipment components that comprise capital expenditures (CapEx) are the adsorbent material (>90% of total capital costs), and the blower, vacuum pump, condenser and contactor.[184] Adsorbent materials range enormously in cost and efficacy, drive the greatest uncertainty in cost for S-DAC systems, and have the greatest potential to drop in cost due to further innovation.[185] L-DAC facilities are more capital-intensive, with necessary equipment including the contactor array (~30% of CapEx), the slacker, causticizer and clarificator (how the liquid solvent is produced and regenerated, ~20% of CapEx), the oxy-fired calciner (how the CO_2 is released and the lime regenerated, ~40% of CapEx) and the air separation unit and condenser (provides oxygen to the calciner, ~10% of CapEx).[186,187]

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[179] Ozkan *et al.* (2022) Current DAC Status. p. 11. [59]

[180] Ozkan *et al.* (2022) Current DAC Status. p. 7-8. [59]

[181] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 222. [55]

[182] Ozkan *et al.* (2022) Current DAC Status. p. 10. [59]

[183] Sutherland, B. R. (2019) Pricing CO_2 Direct Air Capture. p. 1572. [68]

[184] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 221. [55]

[185] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. Research Agenda. p. 219. [55]

[186] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 206. [55]

[187] Ozkan *et al.* (2022) Current DAC Status. p. 10. [59]

For an average L-DAC system with a capacity of 1 million metric tons per year CO_2 removal, estimated upfront capital costs range from $675 million to $1.255 billion, if the building of clean energy infrastructure is not included (Table 4). Existing pilot L-DAC facilities are run with natural gas, which releases CO_2 that must also be captured. A 2019 study from the National Academy of Sciences, Engineering and Medicine (NASEM) included a techno-economic analysis of co-locating a PV solar + battery system that supplied electricity directly to a putative million ton L-DAC facility and to an electrolyzer, which produces green hydrogen (H_2) via electrolysis (see Section 6) that can be combusted to drive the calciner operation. The added capital expense of these components leads to a net cost to build of $1,921-3,045 million for a 1 million metric ton CO_2 capture facility.[188]

An average S-DAC system with a 1 million metric ton CO_2 capture capacity is estimated to cost $630-1,700 million to build (Table 3.3).[189] This does not include the cost of building any energy-supplying infrastructure.

Annualizing the total capital costs to a per ton CO_2 cost allows us to better assess total costs of varying carbon management industries by making it possible to calculate the collective cost of capital, operations and energy. Annualizing costs requires assumptions about the lifetime of the plant (typically estimated to be in operation for 20-30 years), and the weighted average cost of capital (WACC), or discount rate, which are used in combination to determine the capital recovery factor (also called the fixed charge rate or annuity factor) - an assessment of the combined cost of equity and debt over the lifetime of the facility.

The capital recovery factor (crf) is determined based on the following equation, where N = the facility lifetime in years: [190,191]

$$crf = (WACC \cdot (1+WACC)^N)/((1+WACC)^N - 1). \quad \text{(E3.2)}$$

Levelized capital costs, in turn can then be calculated as:

$$CapEx (\$/ton\ CO_2) = (Cost\ to\ Build\ Facility/Capture\ Capacity\ of\ Facility) \cdot crf \quad \text{(E3.3)}$$

In Tables 3.3-3.5, capital recovery factors range from 7.5-12.5%. This leads to a levelized CapEx rate (or annualized rate) of $76-205 per ton CO_2 for S-DAC, and $52-365 per ton CO_2 for L-DAC.

[188] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. [55]
[189] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. 55]
[190] Fasihi *et al.* (2019) Techno-economic DAC. p. 958. [29]
[191] Carbonplan (no date) DAC cost calculator. [14]

Table 3.3. Estimated costs of S-DAC per metric ton CO_2 captured.

S-DAC				
Cost to build a facility capturing 1 million metric tons CO_2 annually				
$630-1700 million		NASEM (2019) Research Agenda. (Facility lifetime = 30 yrs, Capital Recovery Factor = 12%)		
~$820 million		Fasihi *et al.* (2019) Techno-economic DAC. (Facility lifetime = 20 yrs, Capital Recovery Factor = 9.4%)		
CapEx ($/ton CO_2)	**OpEx+Energy ($/ton CO_2)[a]**	**Energy Source**	**LCA Cost ($/ton CO_2)[b]**	**Reference**
$135	$93	Waste heat	$228	Baker *et al.* (2020) Getting to Neutral.
$191-196	$75-114	Geothermal	$266-310	Baker *et al.* (2020) Getting to Neutral.
$76-205	$11-22	Not included	$87-228[c]	NASEM (2019) Research Agenda.
		Waste heat	$600[d]	Ozkan *et al.* (2022) Current DAC Status.
		Geothermal	$205	McQueen et al. (2021) DAC Review.
		Natural gas	$223	McQueen et al. (2021) DAC Review.
$77	$57-96	Grid electricity ± waste heat	$134-174[e]	Fasihi *et al.* (2019) Techno-economic DAC
			$246	**MEAN Levelized Cost**

a. Energy costs are highly variable due to market fluctuations. The values here reflect energy cost estimates from the sited references at time of publication.
b. Some publications report only levelized cost analysis, without distinguishing capital and operational costs.
c. Some computational inconsistencies are due to rounding.
d. Reported operating cost of Climeworks pilot facility in Switzerland.
e. Costs originally reported in Euros. Converted to USD using the 2019 average exchange rate.[192]

[192] IRS (no date) Yearly average currency exchange rates. [38]

Table 3.4. Estimated costs of L-DAC per metric ton CO_2 captured.

L-DAC				
Cost to build a facility capturing 1 million metric tons CO_2 annually				
$694-1,146 million		Keith et al. (2018) LDAC.[193] (Facility lifetime = 25 yrs, Capital Recovery Factor = 7.5-12.5%)		
$675-1,255 million		NASEM (2019) Research Agenda. (Facility lifetime = 30 yrs, Capital Recovery Factor = 12%, Natural gas)		
$1,921-3,045 million		NASEM (2019) Research Agenda. (Facility lifetime = 30 yrs, Capital Recovery Factor = 12%, H_2, Solar + battery)		
~$910 million		Fasihi *et al.* (2019) Techno-economic DAC. (Facility lifetime = 25 yrs, Capital Recovery Factor = 9.4%)		
CapEx ($/ton CO_2)	**OpEx+Energy ($/ton CO_2)[a]**	**Energy Source**	**LCA Cost ($/ton CO_2)[b]**	**Reference**
$52-87	$61-76	Grid electricity + natural gas	$113-163	Keith et al. (2018) LDAC.
$56-143	$70-89	Natural gas	$126-232	Keith et al. (2018) LDAC.
$81-151	$66-113	Natural gas	$199-357[c]	NASEM (2019) Research Agenda.
$230-365	$87-136	Green H_2 + Solar + battery	$317-501	NASEM (2019) Research Agenda.
		Natural gas	$94-232[d]	Ozkan *et al.* (2022) Current DAC Status.
$87	$121	Grid electricity	$208[e]	Fasihi *et al.* (2019) Techno-economic DAC
			$231	**MEAN Levelized Cost**

a. Energy costs are highly variable due to market fluctuations. The values here reflect energy cost estimates from the sited references at time of publication.
b. Some publications report only levelized cost analysis, without distinguishing capital and operational costs.
c. LCA is higher than CapEx+OpEx+Energy because it incorporates the cost factor resulting from emitting CO_2 from the natural gas energy source (i.e. every ton CO_2 captured by the process is partially offset by CO_2 emitted, and thus the *net* cost per ton CO_2 removed is greater).
d. Reported operating cost of Carbon Engineering pilot facility in Canada.
e. Costs originally reported in Euros. Converted to USD using the 2019 average exchange rate.[194]

[193] Keith *et al.* (2018) A process for capturing CO_2 from the atmosphere. p. 1581. [42]
[194] IRS (no date) Yearly average currency exchange rates. [38]

Table 3.5. Anticipated change in cost of DAC[a] per metric ton CO_2 captured.

Anticipated Future LCA Cost ($/ton CO_2)		
2035	$100-200	Ozkan et al. (2022) Current DAC Status
2050	$60	Ozkan et al. (2022) Current DAC Status
2050	$60-80[b]	Ozkan et al. (2022) Current DAC Status

a. Includes both S-DAC and L-DAC.
b. Costs originally reported in Euros. Converted to USD using the 2019 average exchange rate.[195]

3.4.2.2 Operational costs

Operational costs involve the maintenance and labor for the various equipment pieces and the facility. NASEM (2019) provided a detailed breakdown of operational components for L-DAC facilities and Baker et al. (2020) does the same for S-DAC. Both are summarized in Table 3.6.

Table 3.6. Operational expenses for a 1 million ton CO_2 capture DAC facility.

L-DAC - from NASEM (2019)[196]		
Maintenance	$18-33 million/yr[a]	Estimated as ~3% of total capital requirement
Labor	$6-10 million/yr	Estimated as 30% of maintenance cost
Makeup and waste removal	$5-7 million/yr	Includes replacement of hydroxide solution (≥$500/ton KOH), lime (≥$250/t $Ca(OH)_2$), water (≥$0.30/t H_2O), waste disposal (≥$260/t)
Energy Supply	See Section 2.4.2.3	
S-DAC - Baker et al. (2020) Getting to Neutral.[197]		
Maintenance	~$22 million/yr	~10-17% of total capital requirement (from Baker et al., Fig. 41)
Labor	~$7 million/yr	~30% of maintenance cost (from Baker et al., Fig. 41)
Energy Supply	See Section 2.4.2.3	

a. For a megaton facility, this is equivalent to $18-33/t$CO_2$, and so forth for each cost estimate.

3.4.2.3 Energy costs

A critical variable, and perhaps the most poorly constrained for DAC, is the cost of energy. This is because there is uncertainty about the amount of energy necessary (1.5-3.0 MWh/tCO_2 and 0.9-1.6 MWh/tCO_2, for L-DAC and S-DAC, respectively, as shown in Table 1),

[195] IRS (no date) Yearly average currency exchange rates. [38]
[196] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 207. [55]
[197] Baker *et al.* (2020) Getting to Neutral. p. 86. [6]

how that energy could be sourced (published estimates consider a coal, natural gas, natural gas with CCS, solar, wind, nuclear, geothermal, waste heat or a combination of these), and then, for each of these, their local costs, given regional variability with capacity factor (particularly for solar and wind), and resource accessibility.

Existing pilot DAC facilities use natural gas (Carbon Engineering, L-DAC), geothermal heat (Climeworks Orca Facility, S-DAC) or waste heat (Climeworks pilot facility, S-DAC) as their energy source. With natural gas, or any fossil fuel, either the CO_2 emissions resulting from energy generation must be also captured - adding to the cost of the energy source, or the *net* CO_2 capture capacity of the facility decreases.[198] This is modeled by use of a cost factor, whereby:

$$\text{Cost factor} = 1/1\text{-}x \quad \text{(E3.4)}$$

And x is the amount of CO_2 emitted by the facility per ton of CO_2 captured. If x is near or greater than 1, and thus the cost factor approaches infinity, the facility can be considered uneconomical. If coal is the fuel source, the *net* capture capacity of a million ton facility drops to 0-0.11 million tons CO_2 per year ($MtCO_2$/yr), making it effectively useless. A natural gas facility has a net capacity of 0.11-0.42 $MtCO_2$/yr, and natural gas with CCS (as done by Carbon Engineering) has a net capacity of 0.49-0.99 $MtCO_2$/yr.[199] All non-fossil fuel sourced energy supplies (geothermal, waste heat, nuclear, green hydrogen, wind, solar) have a cost factor that approaches 1, and a net capacity that approaches its intended capacity.

To summarize the range of possibilities, Table 3.7 lists all energy sources considered in the references cited within Tables 3.3 and 3.4, and/or considered in this analysis. Note that for operations that use fossil fuels without carbon capture as their energy source, net capture capacity will be less than intended capacity.

Table 3.7. Energy expenses for a 1 million ton CO_2 capture DAC facility.

L-DAC						
Energy Type		**Energy Need (MWh/tCO_2)**		**Levelized Energy Cost ($/MWh)[a,b]**		**Total Energy Cost ($/$tCO_2$)**
Thermal	**Electric**	**Thermal**	**Electric**	**Thermal**	**Electric**	
Natural gas (NG)		2.1-3.0	0.2-0.5	$19-74		$45-257
NG + CCS (oxy-combustion)		2.1-3.0	0.2-0.5	$50		$117-174
NG+CCS (oxy-comb.)	Solar PV + battery (elec.)	2.1-3.0	0.2-0.5	$50	$28-37 + $15	$151-231
Green H_2	Solar PV + battery (elec.)	2.1-3.0	0.2-0.5	$48-108	$28-37 + $15	$109-350

[198] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 194. [55]
[199] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 203. [55]

S-DAC						
Energy Type		Energy Need (MWh/tCO_2)		Levelized Energy Cost ($/MWh)[a,b]		Total Energy Cost ($/$tCO_2$)
Thermal		Electric	Thermal	Electric	Thermal	
Grid electricity		0.9-1.3	0.15-0.3	$169[200]		$185-278
Waste heat		0.9-1.3	0.15-0.3	$0-29[201]		$0-48
Waste heat	Grid	0.9-1.3	0.15-0.3	$0-29	$169	$26-91
Geothermal		0.9-1.3	0.15-0.3	$56-93		$61-153
Natural gas (NG)		0.9-1.3	0.15-0.3	$45-74[202]		$49-122
NG + CCS (oxy-combustion)		0.9-1.3	0.15-0.3	$50		$55-82
Green H_2		0.9-1.3	0.15-0.3	$48-108		$50-173
Solar PV + battery (elec.)		0.9-1.3	0.15-0.3	$28-37 + $15		$47-86

a. Cost estimates from: 1) Levelized cost of energy analysis - Version 15.0. Lazard. Published online, October 2021. 2) Moch, J.M., *et al.* Carbon Capture, Utilization, and Storage: Technologies and Costs in the U.S. Context. Harvard Kennedy School Belfer Center for Science and International Affairs. Published online January 2022. 3) NASEM (2019) Research Agenda, p. 211. Energy costs are subject to significant market fluctuations. 4. This study (Section 4)
b. Energy costs are subject to significant market fluctuations.

3.4.3 Regional benefits

3.4.3.1 Land availability and renewable energy potential

While the DAC technology itself represents one of the most efficient carbon management techniques available in terms of CO_2-capture potential per acre, the enormous energy requirements of the technology will require a significant land footprint if energy is supplied entirely by renewable energy. Thus DAC facilities aiming to run entirely on fossil-free sources would benefit from locations with optimal solar potential and an abundance of available land (please see Section 3.1.1.2 for detailed analysis).

3.4.3.2 Proximity to optimal underground CO2 storage

For any carbon management technology, levelized cost per ton of CO_2 captured increases significantly as a function of distance from an underground storage site.[203] Being located in

[200] EIA (no date) Average price of electricity monthly. [26]
[201] Bertrand *et al.* (2019) Regional waste heat valorisation. p. 454-468. [7]
[202] Lazard (October 2021) Lazard's levelized cost of energy analysis. [46]
[203] [illegible]

close proximity with established Class VI EPA wells should reduce operational costs, decrease planning, permitting and construction time for extensive pipeline infrastructure, and increase the business viability of a DAC plant.

3.4.3.3 Co-location advantages

L-DAC requires water and a high-temperature heat source to operate. As such, it would benefit from co-location with energy storage companies designed to provide industrial heat from clean energy—for example, green or blue hydrogen (Section 6) or heat batteries (Section 7), and potentially, water generating industries, such as S-DAC (Section 3.3.1) or some forms of BiCRS technologies (Section 4).

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4. Biomass CO_2 Removal and Storage

TECHNOLOGY AT A GLANCE:

- 2.5 million metric tons CO_2 captured annually by other projects, globally[1]
- Estimated cost per metric ton CO_2 captured: $30-400 USD/ton CO_2
- Projected cost per metric ton CO_2 captured at scale: $61-288 USD/ton CO_2
- ~180-400 acres of land use required per million metric tons of CO_2 captured
- Key advantages of this technology in Kern County: around 470,000 tons of agricultural waste produced annually in Kern Co., close proximity to consumers of low-carbon fuels (including synthetic fuels and green hydrogen) due to California's Low Carbon Fuel Standard (LCFS).
- Key concerns for this technology in Kern County: Differences in potential air impacts from gasification/pyrolysis and combustion of biomass. Changes in biomass waste availability in the future due to climate change. Variable water requirements.

4.1 Technology Summary

Biomass Carbon Removal and Storage (BiCRS) encompasses a range of technologies that convert biomass into smaller molecular components, allowing CO_2 to be separated and sequestered, either through underground storage or in long-lived applications.[2] BiCRS is a

[1] Values in this section are summarized from the suite of references cited herein and are explained in further detail in each subsequent section.
[2] NETL (no date) Carbon Dioxide Removal Program. [64]

relatively new category of carbon management technologies,[3] and is an umbrella term for any technology making use of biomass for the purposes of carbon capture, including Bioenergy with Carbon Capture and Storage (BECCS), one of the longest-established carbon management industries.[4] BECCS is a distinct subcategory of BiCRS because it has a markedly different end goal, despite using the same technological processes. While the rest of BiCRS technologies prioritize CO_2 removal and storage as the primary technological aim, the focus of BECCS is fuel and energy production from biomass, and carbon capture and storage (CCS) represents an optional industrial component that neutralizes the carbon emissions of the primary commodity of power generation.

4.1.1 Description

BiCRS takes advantage of a natural mechanism of carbon dioxide removal: the storage of CO_2 in vegetation via photosynthesis. Rather than allowing stored CO_2 to return to the atmosphere as occurs when plants, trees and other organic matter die and decompose, these resources can be collected and chemically modified to produce clean CO_2 for underground storage ± biofuels. Biomass can be sourced from agricultural, forest, industrial or municipal waste, or from dedicated crops, forestry, or cultivated algae.[5] Generally, waste biomass is the preferred source of BiCRS feedstock because there are fewer competing uses (as in forestry and agriculture), and it typically costs less than biomass sources that require dedicated cultivation (like agriculture or algae).

There are a variety of processes used to convert biomass into CO_2 + other (potentially useful) organic compounds, which are generally divided into categories: biochemical and thermochemical conversion.[6] Biochemical conversion involves using living microorganisms — typically yeast or bacteria — to convert biomass into biofuels, and the most commonly used and simplest biomass-to-energy process in the U.S. is biochemical conversion of corn to ethanol via fermentation.[7] In fermentation, biomass feedstock is pretreated with an acid or base solution to break down biomass cell material into simple sugars.[8] Yeast or bacteria is added to drive fermentation reactions that produce ethanol + CO_2 + residue materials (including water, solvents and residual solids), which are then separated from each other for various uses or sequestration.[9]

A simplified version of the biomass conversion reaction: [10]

$$C_6H_{12}O_6 \text{ (glucose)} \rightarrow 2C_2H_5OH \text{ (ethanol)} + 2CO_2 \text{ (carbon dioxide)} \quad \text{(R4.1)}$$

[3] Sandalow *et al.* (2021) BiCRS Roadmap. p. v. [80]
[4] NETL (no date) Carbon Dioxide Removal Program. [64]
[5] Sandalow *et al.* (2021) BiCRS Roadmap. p. 14-15. [80]
[6] Sandalow *et al.* (2021) BiCRS Roadmap. p. 27-29. [80]
[7] Sanchez *et al.* (2018) Near-term deployment of CCS from biorefineries. p. 4875. [79]
[8] EERE (no date) Biochemical conversion. p. 2. [70]
[9] EERE (no date) Biochemical conversion. p. 2. [70]
[10] ETIP Bioenergy (no date) Ethanol fact sheet. [31]

Other biomass conversion processes add to or amend this process in order to utilize more complex plant structures, like agricultural residues (e.g. straw, corn stover, nut shells, fruit pits) or other lignocellulosic raw materials (e.g. wood chips, waste from forest management).[11] In low temperature deconstruction (also a form of biochemical conversion), enzymes or chemicals are used to break down the more starchy or woody materials into simple sugars in a process called hydrolysis (Figure 4.1).[12] High-temperature deconstruction comprises all *thermochemical* forms of biomass conversion, with the three primary methods being pyrolysis, gasification and hydrothermal liquefaction. Each of these methods use extreme heat and pressure to break down the biomass feedstocks into a suite of solid, liquid and gaseous components.

During pyrolysis, biomass is rapidly heated in an oxygen-free environment to temperatures of 500-700°C to produce gasses and a solid residue (biochar).[13] The biochar is removed, and the gasses are cooled, causing some of the vapor to condense into a liquid "bio-crude" oil. The remaining gas, called syngas (a combination of CO_2, CO, H_2, and light hydrocarbons) can be further distilled to separate the CO_2 from the combustible gasses, which can be used to provide heat for the reaction.[14]

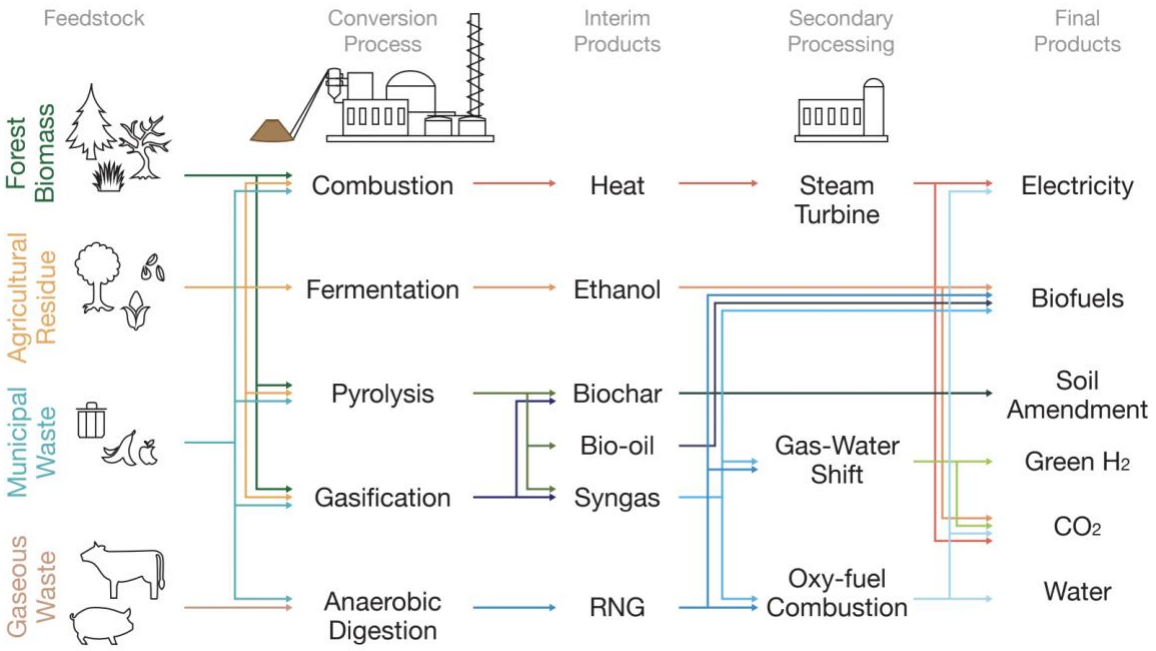


Figure 4.1. Summary of the potential feedstocks, processes, and products of biomass conversion. Adapted from Sandalow *et al.* (2021).[15]

[11] ETIP Bioenergy (no date) Biochemical value chains. [30]
[12] EERE (no date) Biofuel Basics. [71]
[13] EERE (no date) Biofuel Basics. [71]
[14] ARS (no date) What is pyrolysis? [2]
[15] Sandalow *et al.* (2021) BiCRS Roadmap. p. 28. [80]

Gasification occurs under even higher temperature conditions, above 700°C, and in the presence of some oxygen, but the reaction is controlled so that – like pyrolysis – combustion does not take place.[16] Instead, the biomass is converted into CO, H_2 and CO_2.[17] In a second step called a water-gas shift reaction, the carbon monoxide is reacted with water to form more hydrogen gas and carbon dioxide: $CO + H_2O \rightarrow CO_2 + H_2$.[18] The H_2 gas can then be sold as hydrogen fuel, known as green hydrogen.

Hydrothermal liquefaction is the preferred process when using wet feedstocks like algae[19] or municipal solid waste.[20] Thermal conversion takes place under moderate temperatures (200-300°C) and elevated pressures to form liquid bio-crude oil and biochar.

Finally, biomass can be directly combusted to create steam or heat to be used as a direct source of energy. These types of bioenergy power plants can be fitted with post-combustion carbon capture technology that scrubs CO_2 from gaseous byproducts to form a bioenergy with carbon capture and storage (BECCS) power station.[21] CO_2 capture rates can be as high as 90%[22] and it can be retrofitted onto existing power stations.

Post-capture combustion works similarly to point-source capture. An advantage of the technology is that it could easily be retrofitted to existing power plants[23] and is now considered ready for massive-scale deployment.[24] Amine absorption technology is the most common carbon dioxide binding chemical to be used in CCS, but other chemicals such as hot potassium carbonate (HPC) could be viable as well.[25]

Other capture technologies, such as oxy-fuel or pre-combustion technologies, are either relatively untested or inefficient.[26] Oxy-fuel combustion, as the name implies relies on combustion (rather than pyrolysis or gasification) in the presence of a pure or mostly-oxygen gas stream, rather than standard air.[27] The process relies on three primary components: an air separation unit to generate oxygen stream, an oxy-combustion boiler for the combustion itself, and then filtering the flue gas to remove pollutants and compress CO_2 for storage or use.[28] Compared to traditional combustion, oxy-fuel systems produce

[16] EERE (no date) Hydrogen Production: Biomass Gasification. [72]
[17] EERE (no date) Hydrogen Production: Biomass Gasification. [72]
[18] EERE (no date) Hydrogen Production: Biomass Gasification. [72]
[19] EERE (no date) Biofuel Basics. [71]
[20] Sandalow *et al.* (2021) BiCRS Roadmap. p. 28. [80]
[21] Donnison *et al.* (2020) BECCS win-wins. [21]
[22] Adams, Mac Dowell (2016) Off-design point modeling of a 420 MW CCGT power plant [1], as cited in Donnison *et al.* (2020) BECCS win-wins. [21]
[23] Mumford *et al.* (2015) Review of solvent based carbon-dioxide capture technologies. [60]
[24] Bui *et al.* (2018) Carbon capture and storage (CCS): the way forward. [12]
[25] Gustafsson *et al.* (2021) BECCS energy penalty. [43]
[26] Donnison *et al.* (2020) BECCS win-wins. [21]
[27] NETL (no date) Oxy-combustion. [65]
[28] NETL (no date) Oxy-combustion. [65]

about one-fourth the volume of flue gas emissions, making it easier to capture pollutants (including SO_x, NO_x, particulates, and mercury) from the gas, which is primarily composed of CO_2.[29] Furthermore, oxy-fuel pollution can reduce the amount of pollutants formed, such as NO_x.[30] This makes it far easier to purify and capture the CO_2 emissions to abate them.[31] However, challenges—high capital costs, energy usage, and difficulty with oxygen separation—have made it difficult for oxy-fuel combustion systems to be cost-competitive.[32]

4.1.2 State of Development

The key technological elements in BiCRS processes (biomass drying and pelletizing, gasification, anaerobic digestion, biomass boilers, CO_2 capture and separation, geologic storage and monitoring) are mature and commercially available at scale today in various industries, but have been combined for the explicit purpose of biomass carbon removal and storage in only a few instances.[33] 16 facilities are in operation at commercial-scale, though few are exercising their maximum capacity to store the carbon they are extracting from biomass.[34] However, several commercial-scale operations that emphasize carbon management are in the planning, development or pilot phase.[35,36]

4.1.2.1 Commercial Scale Examples

Illinois Basin Decatur Project, Decatur, Illinois

This five-year pilot project is a collaboration of the Illinois State Geological Society (ISGS), the Archer Daniels Midland Company (ADM), Schlumberger Carbon Services, and other subcontractors.[37] CO_2 is sourced as a byproduct of ADM's corn ethanol facility.[38] The pilot plant successfully injected approximately 1 million metric tons of CO_2 derived from biofuel production into a saline reservoir from November 2011 to November 2014. The success of this pilot led to a second commercial scale project, called IL-CCS project, which began operation in 2016.[39]

The IL-CCS project never met its stated aims of annually injecting one million tons of the carbon dioxide byproduct of the ethanol production process, to a depth of more than 7,000

[29] NETL (no date) Oxy-combustion. [65]
[30] NETL (no date) Oxy-combustion. [65]
[31] NETL (no date) Oxy-combustion. [65]
[32] NETL (no date) Oxy-combustion. [65]
[33] Sandalow *et al.* (2021) BiCRS Roadmap. p. 51. [80]
[34] EFI (2022) Surveying the BECCS Landscape. p. 3-4. [28]
[35] Sandalow *et al.* (2021) BiCRS Roadmap. p. 51. [80]
[36] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. p. 149. [62]
[37] Finley (2014) An overview of the Illinois Basin – Decatur Project. [33]
[38] Voegele (December 19, 2016) EC approves state aid for third Drax unit conversion. [93]
[39] Ahlberg (February 20, 2012) Innovation in CCS. [3]

feet in the Mt. Simon Sandstone saline aquifer of the Illinois basin.[40] According to the EPA, the plant's annual sequestered CO_2 emissions as of 2021 are less than 500 thousand tons,[41] which is significantly less than what was projected.[42] ADM receives tax credits of $20 per ton of carbon sequestered, and as of 2020, has received $281 million in total federal funding for both the Decatur and IL-CCS projects.[43,44]

Drax Power Stations, North Yorkshire, UK

The Drax Power Station is a biomass-to-power plant working to transition into a bioenergy + carbon capture and storage (BECCS) facility as part of the Zero Carbon Humber industrial cluster in northern England.[45] The project is supported by the UK Government, with the stated goal of being the first net zero carbon industrial cluster in the nation, with Drax aiming to be carbon-negative by 2030.[46]

Drax converted four out of six existing 645 MW coal power units to generate over 2.5 GW of electricity from biomass combustion.[47] They are in the process of piloting carbon capture and storage technologies to pair with the biomass facility, but cannot fully deploy CCS until transportation and storage infrastructure has been established and there is a policy framework or carbon marketplace in place that allows revenue generation for companies that produce negative emissions.[48] Drax uses wood pellets as the main feedstock of their power plant, primarily sourced from their factories in North America,[49] and estimates they will eventually be able to capture up to 8 million metric tons of carbon dioxide each year, starting with a first BECCS unit operational by 2027.[50]

Kore Infrastructure, Los Angeles, California

Kore Infrastructure has designed a proprietary pyrolyzer unit that can be added to existing installations.[51] Kore's process is a slow pyrolysis process operating at temperatures above 1000°F without oxygen, creating a biogas and carbon-rich biochar as products.[52] Most of the energy requirements are met using the biogas generated by the pyrolysis process, and

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[40] Ahlberg (February 20, 2012) Innovation in CCS. [3]
[41] GHG Data – EPA (no date) Archer Daniels Midland Co. [40]
[42] Hettinger (November 19, 2020) ADM's carbon capture program. [46]
[43] USASpending (no date, information through September 30, 2022) FAIN DEFE0001547 Grant Summary. [90]
[44] Hettinger (November 19, 2020) ADM's carbon capture program. [46]
[45] Drax (no date) BECCS and negative emissions. [23]
[46] Harris (2021) Deployment of bio-CCS: Drax. [45]
[47] Harris (2021) Deployment of bio-CCS: Drax. p. Summary-6. [45]
[48] Harris (2021) Deployment of bio-CCS: Drax. p. 6-7. [45]
[49] Drax (no date) Our History. [26]
[50] Frontier Economics (2021) Supporting BECCS. p. 4. [34]
[51] Kore Infrastructure (no date) A Fully Integrated System. [55]
[52] Kore Infrastructure (no date) A Fully Integrated System. [55]

the overall reaction generates more energy output than it consumes.[53] Once created, the generated biogas can be upgraded into renewable natural gas (RNG) or hydrogen.[54] Their business model is designed to meet multiple needs, either by setting up their system—along with biomass procurement and operation and maintenance assistance—for another company's onsite location, or by offering waste or energy services, by serving as waste disposal or as a source of natural gas, hydrogen, biogas, or biochar.[55] Currently, their largest operating facility is located in Los Angeles and serves SoCalGas, processing 24 tons of feedstock daily.[56] The SoCalGas facility opened in August 2021.[57]

Their process is rated at technology readiness level 7,[58] meaning it had a successful operating pilot at commercial-scale.[59] Given the approval of strict air quality districts in California and their eligibility for LCFS credits for biogas, RNG, or hydrogen gas,[60] it can be reasonably expected that Kore expects their operations to be scalable in the California market.

4.1.2.2 Development Phase Examples

Clean Energy Systems, multiple sites in California

Rather than building facilities from scratch, Clean Energy Systems (hereafter CES) has been purchasing old biomass power plants throughout California and retrofitting them to bring them back online as BiCRS facilities.[61] Within Kern County, CES has been running a biomass plant at Kimberlina as a 'proof of concept' facility,[62] a 40-acre site for R&D, sub-commercial, and commercial activities and currently the world's largest oxy-fuel combustion plant.[63] Their largest project currently in permitting is the Mendota BiCRS Project.[64] At Mendota, CES plans to set up a 20-year commercial facility that will convert biomass into carbon-negative grid electricity using oxy-fuel combustion.[65]

CES's oxy-fuel combustion system works by burning fuels (including, but not limited to, natural gas, gas generated on-site, synfuel, and landfill or bio-digester gas) alongside

[53] Kore Infrastructure (no date) A Fully Integrated System. [55]
[54] Kore Infrastructure (no date) A Fully Integrated System. [55]
[55] Kore Infrastructure (no date) A Fully Integrated System. [55]
[56] Kore Infrastructure (no date) A Fully Integrated System. [55]
[57] Kore Infrastructure (no date) A Fully Integrated System. [55]
[58] Kore Infrastructure (no date) A Fully Integrated System. [55]
[59] GAO (2020) Technology Readiness Assessment Guide. p. 11. [42]
[60] Kore Infrastructure (no date) A Fully Integrated System. [55]
[61] Industry representative, personal communication, October 4, 2022.
[62] Industry representative, personal communication, October 4, 2022.
[63] Clean Energy Systems (no date) Site Locations. [19]
[64] Clean Energy Systems (no date) Mendota BiCRS. [17]
[65] Clean Energy Systems (no date) Mendota BiCRS. [17]

oxygen gas and water "at near-stoichiometric conditions."[66*] Crucially, the water in question can be recycled or even untreated water without inhibiting the oxy-fuel combustion reaction.[67] The primary products of the reaction are CO_2 and steam, with CES reporting carbon capture rates of 100% for the produced CO_2.[68] However, how CES plans to store or use their captured CO_2 seems unclear. The EPA reports their Class VI well application was withdrawn,[69] and their website's suggestion of using captured CO_2 for enhanced oil recovery (EOR)[70] would violate language in California's SB 1314.[71]

Mote, Los Angeles, California

Mote, a Culver City-based cleantech startup, is planning to build a $100 million biomass to hydrogen energy plant with carbon sequestration on 5 acres of unincorporated land in Kern County, pending securing financing, government approval and permits.[72] The plant will extract carbon dioxide and hydrogen via gasification from wood waste from farms, forestry, and other resources.[73] The hydrogen gas will be sold to hydrogen fuel station operators, and the CO_2 will be sequestered into deep underground saline aquifers or retired oil wells.[74] Mote's first facility expects to produce approximately 60,000 kg of carbon-negative hydrogen (green hydrogen) per day, which translates to 450,000 tons of CO_2 captured per year from biomass and available for permanent sequestration.[75]

Mote's business model will provide cost-competitive green hydrogen and carbon removal credits to the wide economy and take advantage of rebates from the federal tax credit for CCS projects (45Q) as well as California's Low Carbon Fuel Standard (LCFS).[76] In May 2022, Mote announced that they had secured commitments for over 450 thousand tons of feedstock for their production.[77] Working with Fluor, an industry leading engineering, procurement and construction (EPC) firm, to execute the Front-End Loading 2 (FEL-2), Mote plans to begin construction in 2023 and be fully operational by 2025.[78]

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[66] Clean Energy Systems (no date) Oxy-Fuel Combustion. [18]
* Under stoichiometric conditions, the proportion of air (in this case, oxygen) to fuel is such that all of the combustible material will be completely combusted, leaving no oxygen remaining.
[67] Clean Energy Systems (no date) Oxy-Fuel Combustion. [18]
[68] Clean Energy Systems (no date) Oxy-Fuel Combustion. [18]
[69] EPA (April 24, 2023) Class VI Wells Permitted by EPA. [29]
[70] Clean Energy Systems (no date) Oxy-Fuel Combustion. [18]
[71] IEA (November 4, 2022) SB 1314. [47]
[72] Fine (January 3, 2022) Mote unveils plans for carbon capture plant. [32]
[73] Temple (February 15, 2022) Fuel plant will use agricultural waste to combat climate change. [87]
[74] Temple (February 15, 2022) Fuel plant will use agricultural waste to combat climate change. [87]
[75] Temple (February 15, 2022) Fuel plant will use agricultural waste to combat climate change. [87]
[76] Mote Hydrogen (no date) Mote. [59]
[77] BusinessWire (May 24, 2022) Mote Enters Advanced Stage of Engineering Design. [13]
[78] BusinessWire (May 24, 2022) Mote Enters Advanced Stage of Engineering Design. [13]



Figure 4.2. Digital rendering of a planned Mote Hydrogen facility in southern California, featuring a parking lot, office buildings, a gasifier building with conveyor belts for moving biomass, several large vertical tanks, and two evaporation ponds. Credit: Mote, Inc.

InterEarth, Australia

InterEarth is in the pilot phase of its operations, investigating the efficacy of shallow biomass burial. Their current model involves heavily trimming local trees, digging six-meter deep pits into salty groundwater, burying the tree matter and monitoring equipment, and refilling the pit to test if the salty water will successfully prevent the organic materials from releasing their stored carbon dioxide.[79*] Tests of the efficacy of their model are still ongoing, but they estimate that – if successful – the technology could be used to bury as much as 1 billion metric tons of carbon (nearly 4 billion metric tons of CO_2) annually, at a cost of less than $50 USD per ton.[80] At least 4-5 more years of monitoring the pilot projects are necessary to establish the efficacy of the technique. For reference, globally, about 140 billion tons of biomass waste is produced each year.[81]

Charm Industrial, San Francisco, California

Charm Industrial is a new start-up utilizing a two-part pyrolysis processing model, which should reduce the physical footprint required for a facility.[82] In general, pyrolysis generates biochar (or charcoal), bio-oil, and hydrogen gas, but the proportions of the products are dependent on the speed and heat of the pyrolysis process.[83] For their feedstock, Charm has

[79] Rathi (March 15, 2022) Carbon Pickling. [77]

* The 'salty groundwater' in question here is not naturally formed saline aquifers, which would be found much deeper than 6 meters below ground, but salty groundwater formed after farming practices in the region disturbed the groundwater table and accelerated the accumulation of salt. See Rathi (March 15, 2022) Carbon Pickling [77] for more information.

[80] Rathi (March 15, 2022) Carbon Pickling. [77]

[81] Tripathi *et al.* (2019) Biomass waste utilisation in low-carbon products. [88]

[82] Pontecorvo (May 18, 2021) Meet the startup producing oil to fight climate change. [76]

[83] Bolan *et al.* (2022) Applications of Biochar. p. 151. [9]

been utilizing agricultural wastes from central California.[84] Charm has experimented with yielding a variety of pyrolysis products in their efforts to sequester carbon dioxide—originally they looked at maximizing biochar yield, then pivoted to hydrogen production, and currently have found success in focusing on bio-oil.[85] Bio-oil is viscous and prone to solidifying, making it a weak fuel source but a promising candidate for carbon sequestration, as its tendency to solidify makes carbon dioxide leaks highly unlikely.[86] Furthermore, working with bio-oil has cost advantages over other forms of sequestration; bio-oil "would be cheaper to inject than CO2 gas captured from the air or from a power plant, since CO2 has to be compressed into a form that can be pumped underground."[87] However, financing larger projects using Charm's bio-oil process will likely rely on changes within the federal and state policy landscape. Bio-oil sequestration is currently not eligible for the federal 45Q tax credit program or recognized by California's Low Carbon Fuel Standard (LCFS), though Charm is pushing for policy changes to recognize the potential of bio-oil.[88] Charm is optimistic about scaling up their operations in the near future and Kern County could be a favorable location, as Charm indicates they are looking for new sites to operate with minimal transportation needs and available agricultural waste for feedstocks.[89]

4.1.2.3 Planning Phase Examples

San Joaquin Renewables Project, McFarland, California

The San Joaquin Renewables (hereafter SJR) project is a planned venture of Frontline Bioenergy, an Iowa-based company currently operating a commercial-scale gasification plant in Montana and a demonstration pyrolysis plant in Iowa.[90] According to SJR, the project will operate as a renewable natural gas (RNG) facility and could be considered either a BiCRS or BECCS project—they are aiming to maximize their potential bioenergy output from agricultural waste via gasification, but will also be sequestering carbon dioxide on-site "deep underground in an EPA class VI sequestration well."[91] The SJR project is in permitting with the City of McFarland, California and has secured up to $165 million in funding for development and construction from Cresta Fund Management and Silverpeak Energy Partners.[92] SJR is also seeking permitting to site their class VI well for carbon

[84] Pontecorvo (May 18, 2021) Meet the startup producing oil to fight climate change. [76]
[85] Pontecorvo (May 18, 2021) Meet the startup producing oil to fight climate change. [76]
[86] Pontecorvo (May 18, 2021) Meet the startup producing oil to fight climate change. [76]
[87] Pontecorvo (May 18, 2021) Meet the startup producing oil to fight climate change. [76]
[88] Pontecorvo (May 18, 2021) Meet the startup producing oil to fight climate change. [76]
[89] Reinhardt (October 21, 2021) Largest Permanent Carbon Removal Delivery of All Time. [78]
[90] Frontline Bioenergy (no date) Our Projects. [35]
[91] San Joaquin Renewables (no date) The Project. [81]
[92] NewsWire (October 27, 2021) San Joaquin Renewables Secures $165 Million. [69]

sequestration within the City of McFarland; their permit application is still undergoing review by the EPA.[93]

SGH2 Energy, Lancaster, California

SGH2 Energy is a producer of green hydrogen using a patented "plasma-enhanced thermal catalytic conversion process" of gasification which operates at temperatures of 3500°-4000°C and produces a clean stream of hydrogen and carbon dioxide with reportedly "no toxins or pollution."[94] A plan for permanent CO_2 storage has not yet been specified by the company. According to SGH2's technical overview, "Lawrence Berkeley National Lab has found that for every ton of hydrogen produced, our process displaces 23 to 31 tons of carbon dioxide. That's 13 to 19 tons more carbon dioxide avoided than other fossil-free hydrogen production processes, which rely on electrolysis from renewable energy."[95] Their process has yet to be tested at commercial scale. Costs per kilogram of hydrogen produced by this process are competitive relative to the existing hydrogen market, as they estimate a cost of $2-3/kg hydrogen for their process compared to a $10-13/kg hydrogen range for electrolysis-based blue hydrogen production.[96] SGH2 Energy is planning to build a facility in Lancaster, California, just south of Kern County's boundary with LA County. The Lancaster plant would generate 3.8 million kg of green hydrogen utilizing 42,000 tons of recyclable waste annually supplied by the City of Lancaster, saving the city an estimated $50 to $75 per ton of waste annually due to avoided landfill space and processing costs.[97] The City of Lancaster is required to sort and supply a feedstock of recyclables for use by SGH2 Energy, and in exchange, will receive co-ownership of the facility.[98] The Lancaster facility is designed for a 5-acre industrial lot scheduled to open in the first quarter of 2023, and is estimated to support the creation of 35 full-time positions once operational.[99]

4.1.3 Operational Needs

4.1.3.1 Land use requirements

A BiCRS facility designed for commercial scale will likely have a large physical footprint, as the volumes of biomass to be sorted and converted will be extensive and need appropriate space to be stored and treated.[100] The overall land footprint for BECCS is estimated at between 1,000 and 17,000 km^2 per million tons of CO_2 removed, depending on location and the source for the biomass (e.g. forest and agricultural residues, and purpose-grown

[93] EPA (April 24, 2023) Class VI Wells Permitted by EPA. [29]
[94] SGH2 Energy (no date) Technology. [83]
[95] SGH2 Energy (no date) Technology. [83]
[96] SGH2 Energy (no date) Technology. [83]
[97] SGH2 Energy (no date) World's Largest Green Hydrogen Project. [84]
[98] SGH2 Energy (no date) World's Largest Green Hydrogen Project. [84]
[99] SGH2 Energy (no date) World's Largest Green Hydrogen Project. [84]
[100] Koornneef *et al.* (2012). Global potential for biomass and carbon dioxide capture, transport and storage. [54]

energy crops).[101] Since we are focusing on scenarios where facilities could rely on existing waste biomass—rather than growing dedicated crops—we have chosen to emphasize the likely footprint of the facility itself where pyrolysis, gasification, or other biomass conversion would take place.

Based on scaling existing facility size estimates and interviews with industry representatives, the estimated physical footprint for a BiCRS facility capturing 1 million metric tons of CO_2 annually is 180 to 400 acres. The unscaled estimates, with their years indicated and estimated capture capacity represented by circle size, are illustrated in Figure 4.3. These estimated acreages do not account for land used to grow biomass for processing (as ideally, biomass will be sourced as waste from existing local agriculture and forestry partners) or external energy use needs, which will vary by plant design and efficiency.

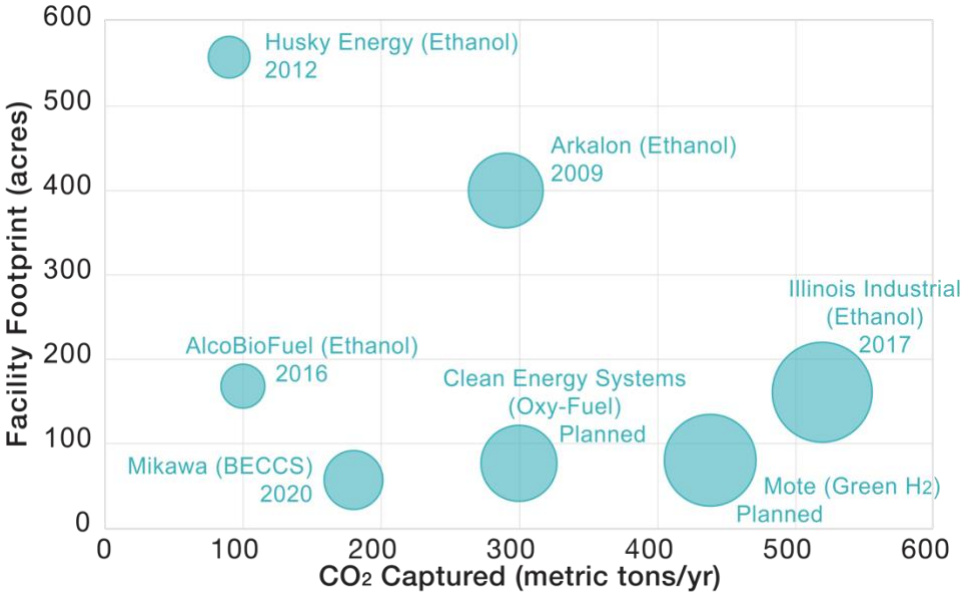


Figure 4.3. Land use requirements of existing and planned BiCRS/BECCS facilities as a function of their CO_2 capture potential. Footprint sizes were either reported directly from operator data or were measured digitally using publicly available satellite imagery.

The plant itself will typically involve a small handful of buildings (3-5) with a conveyor belt to bring in biomass from outdoors, as well as piles of biomass for processing and (depending on the facility) evaporation ponds for wastewater.[102] The tallest installation at a facility would be a gas flare, with an estimated height of 100 feet.[103] Typically, most of the acreage for a plant is dedicated to biomass storage and electricity generation.[104]

[101] IEA (2020) CCUS in Clean Energy Transitions. p. 87. [49]

[102] Industry representative, personal communication, September 8, 2022.

[103] Industry representative, personal communication, September 8, 2022.

[104] Industry representative, personal communication, September 8, 2022.

4.1.3.2 Energy requirements

The energy requirements of a BiCRS facility are opaque. Based upon the variety of conversion methods available and the lack of commercial-scale facilities operating with the goal of sequestration, rather than bioenergy, there is a wide error range for any estimates about energy usage. As such, it is best to evaluate projects billed as BECCS projects on their energy requirements, as there is a greater availability of information to analyze.

As bioenergy facilities, BECCS facilities will have an energy-positive process—meaning they produce more energy output than they consume to process the biomass via pyrolysis or gasification. This energy output can be producing electricity for the grid or generating synthetic fuels for consumers. For every metric ton of CO_2 captured at a BECCS facility, the estimated energy output is 0.83 MWh.[105] This is simply a representative example for a woody biomass-based facility but other estimates may differ substantially, as many bioenergy projects only report their energy output, not the total energy generated or the amount used to sustain their pyrolysis or gasification reactions, and the energy content of the biomass material may differ.

Due to the high temperatures needed for pyrolysis or gasification, facilities require an energy source for heat. For BiCRS/BECCS, this energy is typically supplied by the biomass itself, which contains energy, or by the fuels (syngas, hydrogen, or other products) that are produced on-site as products by breaking down biomass. Depending on the model, some pyrolyzers need external fuel to start the process,[106] which can be supplied from renewable sources like green hydrogen, renewable natural gas (RNG), or biodiesel.

For BECCS, energy requirements will also depend greatly on the plant's thermal efficiency.* Capturing carbon dioxide from the flue gas, which is commonly the source of carbon dioxide in post-combustion technology, of an energy conversion plant requires energy input.[107] As a result, the net energy efficiency of the plant is lowered. However, larger BECCS power stations are expected to have higher thermal efficiencies at 30% - 36%.[108] Higher thermal efficiency means the plant requires less energy to run the system, and subsequently lowering the cost of capital and operating expenses. Although current operational BECCS plants have yet to reach the million metric tons of CO_2 capture range, recent BECCS development shows that larger plant sizes are feasible.[109] For instance, Drax

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[105] NREL (2022) Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035. p. 13. [66] In this report, the finding is reported as net negative emissions of 1.2 metric tons of CO_2 per MWh—converting to be in terms of per metric ton of CO_2 gives the 0.83 MWh figure reported above.

[106] Industry representative, personal communication, September 21, 2022.

* Thermal efficiency is a performance measure of a device that uses thermal energy, which measures the ratio of the heat that becomes useful work.

[107] Bui *et al.* (2017) Bio-energy with CCS (BECCS) performance evaluation [11], as cited in Gustafsson *et al.*, (2021) BECCS energy penalty. [43]

[108] Austin (no date) Size matters [7], as cited in Donnison, *et al.* (2020) BECCS win-wins. [21]

[109] IEA (2020) CCUS in Clean Energy Transitions. [49]

Power Station has a capacity from biomass of 2,595 MW[110] and, as of 2018, operates with a thermal efficiency of 38% or more.[111] They estimate that the installation of CCS equipment in their power plant will decrease their thermal efficiency to 37%, so the change in efficiency due to the addition of carbon capture will be relatively small.[112]

4.1.3.3 Other operational requirements

Waste disposal requirements

The reaction products for biomass conversion and their disposal requirements will differ depending on the conversion process used by a given company. Reaction products outside of the main three—solid biochar, liquid bio-oil, and hydrogen gas—typically fall into the following categories.

Unless operating at extremely high temperatures, biomass processing generates ash and fine particulates, which can be accumulated and sold as a fertilizer product.[113] Water is often used in these processes for cooling or scrubbing, generating varied qualities of wastewater—some processes generate water clean enough for direct reuse in agricultural irrigation, whilst others hold wastewater and sludge in on-site evaporation ponds until it can be sent for proper treatment.[114, 115] Although some reaction products can be reused in other applications, non-hazardous industrial wastes will have to be landfilled. Items in this category include spent catalyst and any solid waste generated from spent material, like dolomite, silicates, or heavier ash.[116]

Of the standard three products generated via biomass pyrolysis, biochar is typically the least sought-after product, as bio-oil and hydrogen gas can both be upgraded into usable fuels. This means the solid biochar, or charcoal, generated by a pyrolysis-based biomass plant needs a designated end-of-life trajectory. Fortunately, biochar is both safe and more useful than most industrial waste products, and thus is less likely to be landfilled or otherwise discarded. A range of academic literature on biochar has identified uses including carbon storage, as a soil amendment, as a soil conditioner for contaminant immobilization, or as a catalyst for various uses.[117,118] Resale of biochar for agricultural uses is the most common existing use, as it can be added in livestock feed, used as a treatment for increased soil fertility, or mixed in with compost or other organic materials to prevent

[110] Drax (no date) Drax Power Station. [24]
[111] Drax (May 11, 2018) Tweet. [27]
[112] Donnison *et al.* (2020) BECCS win-wins. [21]
[113] Industry representative, personal communication, September 8, 2022.
[114] San Joaquin Renewables (no date) The Project. [81]
[115] Industry representative, personal communication, September 8, 2022.
[116] Industry representative, personal communication, September 8, 2022.
[117] Bolan *et al.* (2022) Applications of Biochar. p. 151. [9]
[118] Lee, Kim, Kwon (2017) Biochar as a Catalyst. p. 70. [58]

nutrient leaching.[119] Biochar can also be used to remediate sites contaminated by oil and gas or mining operations, as its high porosity makes it a promising material to sequester chemicals from heavy metals to volatile organic carbons (VOCs).[120] There have also been studies conducted regarding the viability of using biochar as a cover for landfill waste disposal.[121]

Warehousing requirements

Warehousing for a BiCRS operation will likely need to be extensive, as any commercial-scale facility would likely be dealing with thousands of tons of biomass daily for processing.[122] The source and quality of the feedstocks—for example, if it's delivered already dehydrated or in its raw form—will likely dictate the amount of space needed for biomass storage. There will also need to be ample space for storing byproducts like biochar before their sale or disposal. In interviews with experts,[123] facility size was estimated to require approximately 80 acres of land to accommodate the storage of feedstocks, on-site electricity generation, and evaporation pools for wastewater, as well as necessary buildings for processing. Gas-fired facilities would be 3 stories tall and processing is estimated to require 3 of these buildings, though figures on estimated square footage are unavailable. Other facilities have had much smaller warehousing requirements—SGH2 Energy's entire Lancaster hydrogen plant fits on a 5 acre industrial lot because their feedstocks are regularly replenished under their agreement with the city, reducing the need to store large amounts of feedstock on-site.[124] Based upon this wide range of warehousing needs and total acreage presented by biomass firms, this requirement is likely flexible depending on contract terms and the feedstocks being processed.

Transportation requirements

In capturing carbon dioxide from biomass for sequestration, the most preferred facility sites are either co-located with a viable biomass source to eliminate transporting biomass, or located on-site with a sequestration well, to avoid needing to transport carbon dioxide for storage.[125] Transporting biomass often requires some pre-processing and is conducted using trains or trucks. When possible, rail is preferable to trucking, as it has lower costs—especially over longer distances—and lower externalities, according to the Government Accountability Office (GAO).[126] Rail can require upfront investments to build new tracks,

[119] Usmani (August 25, 2021) Things You Should Know About the Different Uses of Biochar. [91]
[120] Simekin Inc. (no date) Biochar. [85]
[121] Bordoloi *et al.* (2021) Role of biochar as a cover material in landfill waste disposal system. [10]
[122] Approximately 1,000 tons per day biomass for a 400k CO_2/yr facility (According to data from an industry representative, personal communication, September 8, 2022).
[123] Industry representative, personal communication, September 8, 2022.
[124] SGH2 Energy (no date) World's Largest Green Hydrogen Project. [84]
[125] Stolaroff *et al.* (2021) Transport for Carbon Removal Projects. p. 3. [86]
[126] Stolaroff *et al.* (2021) Transport for Carbon Removal Projects. p. 3. [86]

depending on the region's existing infrastructure, so trucks are typically used for shorter distances.

Byproducts of BiCRS processes, from hydrocarbon fuels and grid electricity to biochar, would require transportation offsite to be used by customers. These transportation considerations should be taken seriously, as without proper planning, the carbon efficiencies of BiCRS could be lost in trying to sustain a market for related goods reliant on increased carbon emissions for transport.

Infrastructure & Pipeline requirements

Initial deployment of BiCRS should consider the availability of surrounding existing infrastructure to minimize the costs and complexities of long-distance transport of either carbon dioxide, biomass feedstock, and biofuel distributions.

Given that Kern County has appropriate geology for long-term carbon sequestration underground, any BiCRS facility should try to locate as close to an injection site as possible, limiting the need for extensive pipework to handle the supercritical carbon dioxide fluid. However, the pipeline requirements for carbon dioxide are not specialized—their requirements are well-understood due to decades of prior manufacturing and use in the U.S. For more details on carbon dioxide transport, particularly pipeline transport, please refer to Section 9 of this report.

Other requirements

Sequestering carbon underground requires clearing a number of legal and permitting hurdles. Although Kern County and other parts of California's Central Valley are seen as prime real estate for carbon sequestration from a geological perspective, it may be more complex to get all of the legal and regulatory matters aligned and have local landowners on board.[127]

Another hurdle comes into play when using hydrogen as fuel: "There is very little refueling infrastructure and even fewer fuel cell-powered heavy duty vehicles" already in existence.[128] Ensuring biomass-to-hydrogen production timelines match up with the development and scale of hydrogen-fueled technology will be critical to the success of a green hydrogen project. For further exploration of biomass-based green hydrogen considerations, please see Section 6 of this report.

4.1.4 Carbon Capture Potential

The carbon capture potential of BiCRS and BECCS is highly promising, though restricted regionally based on resource use constraints. On average, "biomass is roughly half carbon by weight," so if processed efficiently the carbon removed from biomass is substantial.[129]

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[127] Baker *et al.* (2020) Getting to Neutral. p. 7. [8]

[128] Hanley (May 22, 2020) Lancaster, California Will Be Home To World's Largest Renewable Hydrogen Plant. [44]

[129] Sandalow *et al.* (2021) BiCRS Roadmap. p. 7. [80]

However, biomass can also be utilized for other applications in agriculture and construction that also repurposes or stores its carbon content—often the local context will determine if the financial cost and carbon benefits balance out in favor of a BiCRS or BECCS facility, or repurposing products for other uses.

Based upon the best estimates in the literature, experts posit that "roughly 2.5 to 5.0 $GtCO_2$/year could be removed from the atmosphere and stored by 2050 using biomass produced with minimal environmental impact."[130] Here, 'minimal environmental impact' means without repurposing other productive landscapes, like agricultural lands or forests, to grow biomass dedicated crops or using other carbon-rich materials like forests for biomass feedstocks.

Furthermore, biomass that decays anaerobically in other settings, like landfills, produces methane in addition to carbon dioxide, thus contributing multiple greenhouse gas emissions into the atmosphere.[131] Thus for biomass-rich materials that are routinely landfilled, such as household organic wastes, the carbon removal potential could be even greater than expected as it would prevent the production of multiple forms of carbon-based pollutants.

However, quantifying the overall impacts of a BiCRS or BECCS facility will depend on the full life-cycle analysis (LCA) of a specific project. In a full LCA, it would be possible to identify how much carbon the plant material holds and the amount that could be captured in a given gasification or pyrolysis process, but also the carbon intensity of other steps, like transporting biomass, processing and/or dehydrating biomass, or sending finished products aside from CO_2 to market. Existing LCAs conducted for different BECCS models have indicated that net emissions can differ considerably depending upon the feedstock, conversion method, and carbon capture method used by a given facility.[132]

4.2 Societal Impacts

4.2.1 Job creation potential

4.2.1.1 Number and types of jobs

Because BiCRS facilities at commercial scale are quite rare, the most relevant data to approximate job creation is to examine commercial-scale BECCS operations using likely BiCRS feedstocks available in Kern County, namely agricultural waste and municipal organic waste.

[130] Sandalow *et al.* (2021) BiCRS Roadmap. p. vi. [80]

[131] LMOP (April 21, 2023) Basic Information About Landfill Gas. [56]

[132] Almena *et al.* (2022) Carbon dioxide removal potential from decentralised bioenergy. p. 9-11. [5]

Fulcrum Bioenergy's first commercial plant in Reno, NV, capable of processing 175,000 tons of landfill waste annually, supports over 100 permanent jobs.[133] Looking at estimates for upcoming projects under Fulcrum's umbrella, there is also a large requirement for construction workers to build these facilities—anywhere from 1,000 to 1,200 jobs created in the construction process, though these positions are not permanent.[134,135] San Joaquin Renewables, who is planning to sequester carbon on-site though at a smaller facility, predicts its operation will sustain 45-50 full-time employees.[136] In industry interviews, some operators estimated smaller staff needs—closer to 25 for a full facility, even for a facility processing up to 219,000 tons of biomass annually.[137] Given this wide range of jobs figures across different biomass facility models, it appears that permanent job creation is not clearly correlated with facility capacity.

The Drax plant in the UK, as it converts from bioenergy to BECCS, is estimated to generate over 4,000 direct jobs annually during the CCS construction phase from 2024 to 2028.[138] Once Drax has been fully converted to BECCS, it is expected to support an estimated operations and maintenance staff of up to 800 employees.[139] After the facility is operational, it could further generate 2,300 indirect and 4,100 induced jobs.[140] Given that Drax claims that full BECCS operations at their facility would result in the removal of about 8 million metric tons of CO_2 per year, which would make it the largest CO_2 capture and storage project globally,[141] it makes sense that these estimates are much higher than those of other BiCRS or BECCS facilities.

It is worth noting that scaled estimates for the million metric tons per year of CO_2 capture range for other facilities generate much smaller estimates, somewhere in the range of 45 to 150 full-time jobs created. Although some estimates range lower or higher, as seen in Table 4.1, the 45 to 150 range seems like the most consistent estimate based on both scaling existing facilities and any literature estimates, with an average of 102 jobs estimated per million metric tons of CO_2 captured annually. It is important to note that biomass facility jobs are not expected to necessarily scale linearly with plant size (in terms of CO_2 capture potential), as can be seen in the range of permanent jobs associated with already-existing facilities. Furthermore, the possibilities of increased automation and remote monitoring means that steps should be taken in the planning and permitting process to ensure jobs for any new carbon management facility benefits local communities.

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[133] Fulcrum BioEnergy (no date) Sierra BioFuels Plant & Feedstock Processing Facility. [37]

[134] Fulcrum BioEnergy (no date) Trinity Fuels Plant. [38]

[135] Fulcrum BioEnergy (no date) Centerpoint Biofuels Plant. [36]

[136] San Joaquin Renewables (no date) The Project. [81]

[137] Industry representative, personal communication, October 4, 2022.

[138] Vivid Economics (2020) Delivering Jobs at Drax. p. 18. [92]

[139] Vivid Economics (2020) Delivering Jobs at Drax. p. 19. [92]

[140] Vivid Economics (2020) Delivering Jobs at Drax. p. 25. [92]

[141] Drax (July 12, 2022) Drax submits plans to build world's largest carbon capture and storage project. [25]

Table 4.1. Job creation estimates for planned and current BiCRS/BECCS facilities, globally.

Facility Name[a]	Year Operational	Annual CO_2 Capture[b]	Reported Jobs		Scaled Employment (per 1MtCO_2/yr)	
			Perm.[c]	Const.[d]	Perm.[c]	Const.[d]
Drax Power Station, Humber, UK	2024-2028	8	800	4,000	100	500
Mendota BiCRS Project, Mendota, CA	Future	0.3	25		83	
Calgren Renewable Fuels, Pixley, CA	2015	0.15	20		133	
Mote, Los Angeles, CA	2024	0.438	100		228	
Stockholm Exergi, Stockholm, SE	2019	0.8	35		44	
Illinois Industrial CCS, Decatur, IL	2017	0.444	11		25	
AVERAGE					**102**	**500**

a. Facility details are fully outlined in Appendices A-C.
b. In million metric tons (Mt). Where actual figures are available, they are used, otherwise data reported correspond with press releases or projections.
c. Permanent jobs.
d. Construction jobs.

4.2.2.2 Training pipelines

In conversations with industry experts, we found that oftentimes, facilities like to recruit locally where possible, though local hiring can be dependent on the specific skills needed. Some facilities that specialize in retrofitting old power plants or other infrastructure into BiCRS or BECCS facilities have found that since existing employees already know the plant well, they can be easily kept on and retrained as necessary, keeping all workforce demands local.[142]

For the Drax plant, there are concerns regarding the challenges in labor and skills supply due to the lack of specialist skill in key manufacturing sectors as required by the plant.[143] This will need to be addressed with a combination of a direct apprenticeship scheme, early investment in the next generation of workers, and endorsement of vocational work at a local school.[144]

[142] Industry representative, personal communication, October 4, 2022.
[143] Vivid Economics (2020) Delivering Jobs at Drax. p. 29. [92]
[144] Vivid Economics (2020) Delivering Jobs at Drax. p. 29-30. [92]

4.2.2 Quality of Life

4.2.2.1 Location

At existing biomass-based plants, noise is a common concern for area residents. For example, a safety valve at the Drax Power Station, when opened, generates a sound so loud that residents 2.5 miles from the station reported that they were awoken by the noise.[145] It is anticipated that mitigation is possible with sound-dampening design within buildings.[146] Siting away from residential areas and incorporating sound dampening materials in construction would likely mitigate noise at nearby communities.

Given that burning is the traditional disposal method for agricultural and forestry wastes, moving to process agricultural waste at a BiCRS or BECCS facility could lead to lower emissions; potentially up to 95-99% lower than they would be if the biomass was burned instead.[147] Biomass-based facilities which produce emissions or pollutant discharge will need to adhere to a federal Title V operating permit. For Kern County, developers would need to obtain permit authorization to construct and operate before commencing construction, and a permit to operate from Eastern Kern Air Pollution Control District (EKAPCD) or San Joaquin Valley Air Pollution Control District (SJVAPCD).[148]

4.2.2.2 Multi-use potential

There is multi-use potential for BECCS and BiCRS facilities, although examples are limited. Feedstock generation from nearby agricultural waste can be considered a multi-use byproduct of the primary agriculture industry. For the facilities themselves, noise pollution generated by biomass processing would need to be addressed, but co-locating community facilities with processing plants is possible. A waste-to-energy plant located in central Copenhagen, Denmark – called Amager Bakke – was designed to be a public recreational facility as well as a power plant.[149] The building, which converts municipal waste to electricity, is topped with a hiking trail and artificial ski slope. While Amager Bakke does not capture CO_2, it sets a precedent for the possibility of innovative proposals that could integrate other businesses or community facilities with BiCRS/BECCS facilities.

[145] The York Press (January 26, 2008) Drax fault causes 'deafening' noise. [89]
[146] Doyle (2015) White Rose Carbon Capture and Storage (CCS) Project: Environmental Permit. [22]
[147] San Joaquin Renewables (no date) The Project. [81]
[148] CARB (no date) California Air Districts. [14]
[149] Crook (October 8, 2019) BIG opens Copenhill power plant topped with rooftop ski slope in Copenhagen. [20]

4.3 Environmental Impacts

4.3.1 Water requirements

4.3.1.1 Minimum volume requirements

Water requirements vary depending on the conversion process used to process the biomass intake, but is low under every well-understood conversion pathway. The largest lifetime intake of water in the BiCRS life-cycle is that required for actually growing the biomass in question. As long as dedicated feedstock crops are not being grown to sustain the facility (i.e. the biomass in question is agricultural or forestry waste), it is likely the water would have been used anyway. In fact, biomass is frequently 'de-watered' before conversion, aside from supercritical water extraction,[150] so it's actually likely that facilities will be generating some volume of wastewater in the process.

However, in case there needs to be a dedicated feedstock crop to feed the facility, sustainable agriculture practices which reduce water consumption could reduce the additional water withdrawal.[151] However, a study shows a potential tradeoff between land use pressure and water consumption. For instance, to reduce land use one might choose to grow crops with higher yields which require higher water volume. If we include the water consumption to grow the feedstock, the total amount of water to deliver 12 Gt carbon dioxide per year through BECCS would account for 3% of the total amount of water currently used by human activities.[152]

Information about San Joaquin Renewable's current process appears to corroborate these assumptions. Their method requires some water vapor to gasify biomass, but also produces "irrigation-quality water" as a product of its conversion process, resulting in a net gain in water.[153] A diagram illustrating their model is included below in Figure 4.4.[154] With that said, these are assumptions—the water demands of any project may differ based upon their conversion method, kinetics, biomass source, or other factors.

4.3.1.2 Minimum quality requirements

As discussed above, water is not a necessary component to most BiCRS conversion processes, with some BiCRS processes even generating a net gain of water in the process. However, water availability issues in future projections are still poorly understood.[155]

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[150] Lee, Conradie, Lester (2021) Review of supercritical water gasification. p. 1. [57]

[151] Ai *et al.* (2021) Global bioenergy with carbon capture and storage potential. [4]

[152] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. [62]

[153] San Joaquin Renewables (no date) The Project. [81]

[154] San Joaquin Renewables (no date) The Project. [81]

[155] Sandalow *et al.* (2021) BiCRS Roadmap. p. 18. [80]

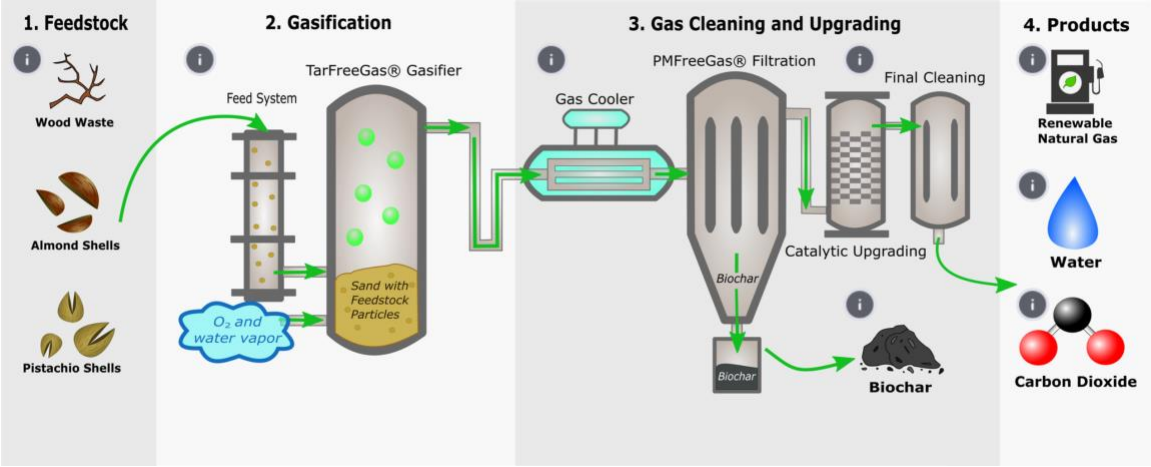


Figure 4.4. The biomass gasification process employed by San Joaquin Renewables.[156] Image credit: San Joaquin Renewables.

4.3.2 Air quality

Data availability for distinctions between biomass pyrolysis, gasification, and combustion with respect to emission impacts is limited, largely because most studies restrict themselves to a single type of biomass feedstock or single type of biomass conversion process, if not both. For this reason, we have chosen to highlight findings from coal, which is fossilized organic material from wetlands[157] and has clearly understood data due to decades of use with all three technologies. Although the comparison is imperfect, it provides useful insight into the differences between conversion types. The primary benefit of pyrolysis and gasification, from an emissions perspective, is the high temperatures and pressures of the biomass conversion generate a syngas stream of emissions that makes it simpler to separate out criteria air pollutants (including NO_x and SO_x) as well as trace contaminants including mercury, cadmium, arsenic, and selenium.[158]

4.3.3 Other potential impacts

Some types of biomass production damage ecosystems, hurt local farmers, or increase emissions.[159] The American ethanol industry has been a notable offender, as its push to grow biofuel crops has contributed to deforestation with little to no clear carbon reduction benefits.[160]

Any biomass plant will have to consider the land use impact associated with feedstock production. If there are no land use changes because biomass would be sourced from

[156] San Joaquin Renewables (no date) The Project. [81]
[157] Schweinfurth (November 23, 2016) Coal—A Complex Natural Resource. [82]
[158] NETL (no date) 6.5. EMISSIONS ADVANTAGES OF GASIFICATION. [63]
[159] Sandalow *et al.* (2021) BiCRS Roadmap. p. 12. [80]
[160] Sandalow *et al.* (2021) BiCRS Roadmap. p. 12. [80]

waste and residues from existing land uses, the impact will be little to zero.[161] If biomass feedstock needs are to come from dedicated agriculture soil, 380 to 700 Million hectares of land area is needed to deliver the global BiCRS sequestration potential of 12 GT per year carbon dioxide.[162] Change in local land cover, or extensive withdrawal of water from irrigation sources, will impact the climate in regions as far as a few hundred kilometers downwind.[163]

Land use change would also potentially cause indirect impacts, such as initiating new competition with other land uses, such as food-production, wood production, or residential land, which could lead to changes in the market for related commodity supplies and prices.[164] Given the abundance of potential biomass waste feedstocks in California in the form of agriculture waste, forest residues and municipal waste,[165] a significant volume of BiCRS facilities could be operational without the need to cultivate bioenergy crops – and their downstream effects – in the region.

4.4 Economic Impacts

4.4.1 Business Model

Whether a project defines itself as BiCRS or BECCS, the business model generally depends on the ability to outweigh fixed costs (i.e. levelized capital costs, labor expenses, taxes) and flexible costs (i.e. costs of energy use, biomass, transport) with income (i.e. selling products and/or carbon credits).

BiCRS and BECCS technologies have a number of revenue streams, depending on the outputs they prioritize in the gasification or pyrolysis process. All of these processes will generate CO_2 for permanent sequestration, and thus will be eligible for the 45Q federal tax credit.[166] As of 2022, the 45Q tax credit totaled $85/ton CO_2 for every ton permanently stored and $60/ton CO_2 for every ton used in enhanced oil recovery (EOR).[167] Due to California's SB 1314, captured CO_2 effectively cannot be used for EOR within the state.[168] Most biomass projects will also generate bioenergy products, which can be sold as electricity or fuel; BECCS processes will aim to maximize the potential bioenergy output. For gasification, the

[161] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. [62]
[162] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. [62]
[163] Jia *et al.* (2019) Land-climate interactions - Executive Summary. [51]
[164] National Academies of Sciences, Engineering, and Medicine (2019) Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. [62]
[165] Baker *et al.* (2020) Getting to Neutral. p. 4. [8]
[166] IEA (November 4, 2022) Section 45Q Credit. [48]
[167] IEA (November 4, 2022) Section 45Q Credit. [48]
[168] IEA (November 4, 2022) SB 1314. [47]

hydrogen gas created can be sold as a product—this economic opportunity is explored more in Section 6.4 of this report, which addresses the business of hydrogen production.

At the start of 2022, there were 16 operational facilities classified as BECCS facilities,[169] though some items on this list—like Charm Industrial—would likely be better described as BiCRS. An estimated 50 additional facilities are currently under development.[170] As for expanding the amount of BiCRS/BECCS facilities in the future, reduced costs in various technological pathways will help reduce the economic barriers, but the primary hurdle to scaling is anticipated to be generating new institutional arrangements and stakeholder consensus.[171] In short, most of the expected barriers are political and institutional in nature, rather than economic or technical.[172]

Most companies currently working on biomass facilities are working with large upfront capital investors and planning to fund their sequestration through a mixture of tax credits, selling carbon offsets, and/or selling byproducts (syngas, biochar, etc). Biomass conversion technologies can produce products aside from CO_2, including biochar and biofuels. As mentioned above, biochar can be used for a variety of agricultural and industrial applications. In recent years, biochar has sold for amounts ranging from $9 to $42 per cubic foot of biochar, with variations depending on the type, texture, quality, and sale venue.[173] Biofuels can vary considerably depending on the process in question: ethanol from fermentation,[174] hydrogen from gasification or fast pyrolysis,[175] or synthetic fuels generated by upgrading bio-oil.[176] For RNG and hydrogen fuel, the sale comes with additional benefits, as these fuels can often qualify for other state and federal subsidies.[177,178] More details about these economic incentives established via policy for various lower-carbon fuels can be found in Section 2, and specific information for hydrogen incentives can be found in Section 6.

The other avenue of revenue is the carbon credit market, of which there are both governmental and private options available. For the government carbon market, there are benefits at the federal and state level, with the 45Q tax credit and depending on the products and their intended market, can also be eligible for California's LCFS credits. For BiCRS or BECCS projects that generate alternative fuels for sale in California—including renewable natural gas, hydrogen, or electricity[179]—should be eligible for Low Carbon Fuel

[169] EFI (2022) Surveying the BECCS Landscape. p. 3-4. [28]
[170] GCCSI (no date) CO_2RE Facilities Database. [41] (See Appendices A-C).
[171] Sandalow *et al.* (2021) BiCRS Roadmap. p. 2. [80]
[172] Sandalow *et al.* (2021) BiCRS Roadmap. p. 2. [80]
[173] Pokharel, Comer (December 7, 2021) Economics of biochar. [75]
[174] Sanchez, *et al.* (2018) US Biorefineries. p. 4875. [79]
[175] Arregi *et al.* (2016) Hydrogen production from biomass by fast pyrolysis. p. 25975. [6]
[176] Nanda *et al.* (2021) Catalytic and Noncatalytic Upgrading of Bio-Oil to Synthetic Fuels. p. 2. [61]
[177] Natural Gas Intelligence (no date) How do you price RNG? [67]
[178] Piper, Krause, Janzow (February 27, 2023) The Hydrogen Credit Catalyst. [73]
[179] Casetext (April 14, 2023) Cal. Code Regs. tit. 17 § 95482. [16]

Standard (LCFS) credits, though uses like electricity would need to demonstrate their contribution to lowering state transportation carbon intensity.[180] LCFS credits between 2018 and 2022 varied between $62 and $218 per ton of CO_2 reduced.[181] The most recent price updates can be found on the California Air Resources Board LCFS credit dashboard, which posts LCFS price averages from the preceding week every Tuesday.

In speaking with industry experts, some BiCRS facilities have been selling their energy as electricity to the grid currently, but are planning to convert to more lucrative alternative energy sources, like selling hydrogen to consumers, once there is a sustained market and distribution network nearby.[182] This reflects the adaptivity of biomass-based energy facilities—depending on the current energy market, the biomass content can be converted into different materials to meet local needs.

4.4.2 Business Costs

Combining the estimated capital and operational costs—capital costs, feedstock costs, fixed and variable operating costs—of BiCRS/BECCS, outlined below, results in an estimated cost per ton CO_2 of $61-288, which aligns well with industry estimates of $88-288.[183]

4.4.2.1 Cost to build (upfront costs)

The estimated capital costs for constructing a BiCRS/BECCS facility capable of capturing 1 million metric tons of CO_2 annually ranges from $350 million to $1.2 billion, based on scaled estimates. This range has been corroborated by industry representatives. If a BiCRS/BECCS facility ran for 30 years, the average capital cost per metric ton of CO_2 would fall between $30-189. Given that estimates in the academic literature for BECCS typically range from $30 to $400 per metric ton of CO_2,[184] the scaled estimates calculated in this study appear quite reasonable.

Costs can also vary depending on the inputs a facility requires, and between BiCRS and BECCS processes, the largest differences typically originate from energy needs. Biomass pyrolysis or gasification will generate thermal heat, and many facilities can be largely or fully energy self-sufficient by utilizing this heat to meet the plant's energy needs. For BECCS facilities, the process is optimized to maximize the bioenergy output—whether it be heat, electricity, or fuel—leaving excess energy available to sell. However, this often requires upfront investment to reuse process heat or build off-grid renewables of heat-to-electricity equipment to support any on-site electricity needs.

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[180] CARB (October 2022) Carbon Capture and Sequestration Project Eligibility FAQ. [15]

[181] Neste (updated daily) California Low Carbon Fuel Standard Credit price. [68]

[182] Industry representative, personal communication, October 4, 2022.

[183] Kalra *et al*. Technical CO_2 Removals Market. p. 10. [52]

[184] Fuss *et al*. (2018) Negative emissions. p. 12. [39]

4.4.2.2 Operational costs

Operational costs on-site will involve maintenance and repairs, staff, monitoring, and any taxes. In terms of fueling their conversion processes, facilities will also need access to biomass feedstocks, which vary in terms of seasonal availability and cost. Not only do these materials need to be purchased (or obtained through another standing arrangement) and then chipped and dried, they also must be transported to the facility via train or truck.[185] Feedstock costs are often the largest estimated category in assessing a facility's operational costs. However, costs can vary widely—items like municipal solid waste (MSW) or some agricultural residues, like pistachio shells or almond hulls, are already collected and processed, making them easy to purchase at relatively low additional cost.[186] Other materials that require collection directly from the field, or processing steps like chipping or drying for forestry waste, can increase the cost of biomass feedstocks.[187] In general, placing facilities within close proximity of CO_2 storage sites and large quantities of biomass to use results in lower overall costs per ton CO_2 by reducing the transportation burden at both ends.[188]

Within the operational costs, there are fixed and variable expenses at play. Fixed operating costs—such as routine maintenance and labor costs—are typically estimated at 2-7% of the capital costs;[189] breaking down the estimated capital costs per ton CO_2 gives an estimated range from $1-13 per ton of CO_2 in fixed operating costs. Variable operational costs—such as unplanned maintenance, waste disposal, or non-biomass feedstocks—range from $10-27 per ton CO_2.[190] As mentioned above, biomass feedstock costs are typically the largest cost category, and can vary considerably depending on the type of biomass and the distance it needs to be moved. Based on the estimates available, a good range is approximately $20-60 per ton CO_2.[191,192] Combining these estimates, you would get a range of operating costs per ton CO_2 of $31-100.

4.4.3 Regional benefits

Businesses looking to start commercial-scale BECCS and BiCRS operations are drawn to southern California locations, including operations eyeing Kern County specifically. Due to the region's promising geography for underground carbon sequestration and relative abundance of agricultural waste feedstocks, there are clear assets to siting a BiCRS or BECCS facility in Kern County. These benefits would also extend beyond the county: in a

[185] Stolaroff *et al*. (2021) Transport for Carbon Removal Projects. p. 3. [86]
[186] Stolaroff *et al*. (2021) Transport for Carbon Removal Projects. p. 3. [86]
[187] Stolaroff *et al*. (2021) Transport for Carbon Removal Projects. p. 3. [86]
[188] Fuss *et al*. (2018) Negative emissions. p. 12. [39]
[189] IRENA (2012) Biomass for Power Generation. p. i. [50]
[190] IRENA (2012) Biomass for Power Generation. p. 35. [50]
[191] IRENA (2012) Biomass for Power Generation. p. 28. [50]
[192] NREL (2022) Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035. p. 109. [66]

study of CO_2 removal options for California at-large, experts found that "NNBFs [net-negative biofuels], and specifically biomass gasification to hydrogen, had the largest potential and among the lowest cost of carbon removal options for California."[193]

4.4.3.1 Proximate feedstocks

Feedstocks for biomass carbon capture are abundantly available in Kern County, and the available feedstocks are highly preferred from a climate perspective. Both the area's high concentration of agricultural waste and steady supply of municipal organic waste could be used to fuel a BiCRS facility in the region. Within California, there is an estimated 55 million tons (Mt) of biomass available annually for energy applications, not including energy crops.[194] Within Kern County, the 2019 County Crop Report determined that 237,000 tons of almond hulls and shells and 236,000 tons of biomass were produced from the local agriculture industry.[195] The collective ~470,000 tons of biomass would be enough to support a ~620,000 ton CO_2 capture BiCRS facility—see Section 11 for more details about these calculations in relation to local agricultural waste.

4.4.3.2 Proximate consumers

Depending on the process used to extract carbon from oven-dried biomass, a byproduct of BiCRS facilities using slow pyrolysis processing is biochar—a material which can be applied to crop fields to improve soil fertility.[196] Given agriculture's large footprint in the area, this could produce a symbiotic relationship, with farms supplying agricultural waste feedstock and consuming the carbon-rich biochar produced by a local BiCRS facility.

There may also be proximate consumers for other biofuel or carbon offsets given the relative closeness of both Los Angeles and the Bay Area. Regional leaders in the digital technology space, such as Stripe in San Francisco, have been key investors in start-ups working towards carbon removal strategies.[197]

4.4.3.3 Co-location advantages

The primary co-location advantage for biomass processing facilities is the ability to share infrastructure for common needs—CO_2 transport for sequestration or use, onsite water supplies, and the potential of using electricity from a shared solar array or other off-grid power source with other companies. Co-locating reduces the costs, and therefore risks, of each player within the carbon management park.

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[193] Stolaroff *et al.* (2021) Transport for Carbon Removal Projects. p. 2. [86]

[194] Stolaroff *et al.* (2021) Transport for Carbon Removal Projects. p. 2. [86]

[195] Kern County Department of Agriculture and Measurement Standards (2020) 2019 Kern County Agricultural Crop Report. p. 10. [53]

[196] Sandalow *et al.* (2021) BiCRS Roadmap. p. 1. [80]

[197] Plumer, Flavelle (January 18, 2021) Businesses Aim to Pull Greenhouse Gases From the Air. [74]

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Advanced-Stage-of-Engineering-Design-for-Southern-California-Carbon-Negative-Hydrogen-Facility.

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5. CO_2-emitting Industries

TECHNOLOGY AT A GLANCE:

- Point source carbon capture is a technique applied to industrial and energy facilities that emit large concentrations of CO_2. The technology is commercially available and used in over 30 energy plants and manufacturing facilities worldwide, but its cost (and thus level of deployment) varies as a function of facility type.[1]
- Of the many industries that could use point source carbon capture, the steel industry was the most practical to investigate for purposes of location in Kern county.
- Carbon capture in the steel industry is in an early commercial stage: globally, there is 1 steel mill operating with carbon capture.
- Several techniques for producing low carbon steel are in the pilot or demonstration phase, and are explored briefly here, although they would not involve capture and storage of CO_2, and thus would not qualify as a carbon management technology.
- Current cost per metric ton CO_2 captured from steel: \$68-114 USD/ton CO_2.
- Projected cost per metric ton CO_2 captured at scale: \$40-90 USD/ton CO_2.
- Key advantages of this technology in Kern County: steel mills can provide hundreds of high paying jobs, many of which do not require post-secondary education.
- Key concerns for this technology in Kern County: steel mills do produce emissions, wastewater and solid byproducts that will have to be mitigated to meet regional environmental and safety standards.

[1] Values in this section are summarized from the suite of references cited herein, and are explained in further detail in each subsequent section.

5.1 Technology Summary

5.1.1 Description: How it Works

5.1.1.1 Point Source Carbon Capture

Many industries and energy facilities produce CO_2 as a byproduct of their processing activities, collectively accounting for about half of global greenhouse gas emissions.[2,3] However, most of these industries and facilities can employ a technology called *point source carbon capture*, which scrubs CO_2 from significant points of exhaust before they are released to the atmosphere. In contrast to Direct Air Capture (DAC, Section 3) and Biomass with Carbon Removal and Storage (BiCRS, Section 4), which are designed to remove human-derived CO_2 emissions from the ambient air, point source capture prevents the release of CO_2 before it is emitted. Point source carbon capture is at an advanced state of technological development, and many techniques are commercially available today that can be used to trap CO_2 from the exhaust of coal and natural gas power plants and boilers, or in the industries of natural gas processing, petrochemical development, fertilizer development, iron and steel manufacture, cement production and paper mills.[4] Despite this, only about 230 million metric tons of CO_2 are captured annually,[5] less than 1% of the 28 billion metric tons of CO_2 emitted from these sectors globally each year.[6]

Of those facilities that do employ carbon capture, most in operation today use a solvent-based approach, illustrated in Figure 5.1.[7] Rather than directly emitting CO_2-bearing flue gas through exhaust chimneys of a plant or facility, the flue gas is diverted to a separate *absorption tower*, where it is mixed with a liquid solvent. The solvent has either chemical properties that cause the CO_2 to readily dissolve into the fluid (for example having a mildly basic pH),[8] or a component of the solvent physically attracts the CO_2, such that it is drawn out of the flue gas and sorbs onto the surface of the molecular component in the capture fluid.[9] The flue gas is returned to the chimney and released; the CO_2-rich capture fluid is transferred to a stripping tower (or capture tower), where the CO_2 is separated from the solvent. In chemical solvents, this is accomplished by increasing the temperature (making

[2] Ritchie, Roser, Rosado (February 15, 2023) CO_2 and Greenhouse Gas Emissions. [68]

[3] Ge *et al.* (February 6, 2020) GHG emissions by sector. [35]

[4] [illegible]. [5]

[5] IEA (2020) CCUS in clean energy transitions. p. 109. [41]

[6] Ge *et al.* (February 6, 2020) GHG emissions by sector. [35]

[7] Kearns *et al.* (2021) CCS readiness and costs. p. 11-12. [45]

[8] Carbon dioxide removal: Carbon capture and storage, Part I. Climate Now. Published online November 8, 2021. Accessed March 14, 2023 from https://climatenow.com/video/carbon-capture-and-storage-part-i/. 3:20.

[9] [illegible]. [5]

the CO_2 exolve as a gas). In physical solvents, pressure is decreased such that CO_2 is more stable as a gas than bound to the surface of the in-solvent physical adsorbents.[10]

A less common capture technique makes use of membranes (mostly used for natural gas processing). Membranes are permeable physical barriers that allow gasses to pass through at variable rates, effectively separating some gas molecules from others.[11] Like physical solvents, membranes are used in processes that have high concentrations of CO_2 in the flue gas stream, whereas chemical solvents are more efficient when CO_2 makes up less than 15% of the flue gas.[12]

The cost (and thus feasibility) of point source carbon capture is directly proportional to the concentration (or partial pressure) of CO_2 in the exhaust stream, and is therefore industry specific.[13] Carbon capture technology for gas streams with CO_2 concentrations higher than 25% have been used in industrial applications since the 1940s[14], and technologies currently exist that can capture CO_2 from gas streams with concentrations as low as hundreds of parts per million (as in the atmosphere). But to date, CO_2 point source capture has not been implemented on a large scale due to lack of financial or regulatory incentives.[15]

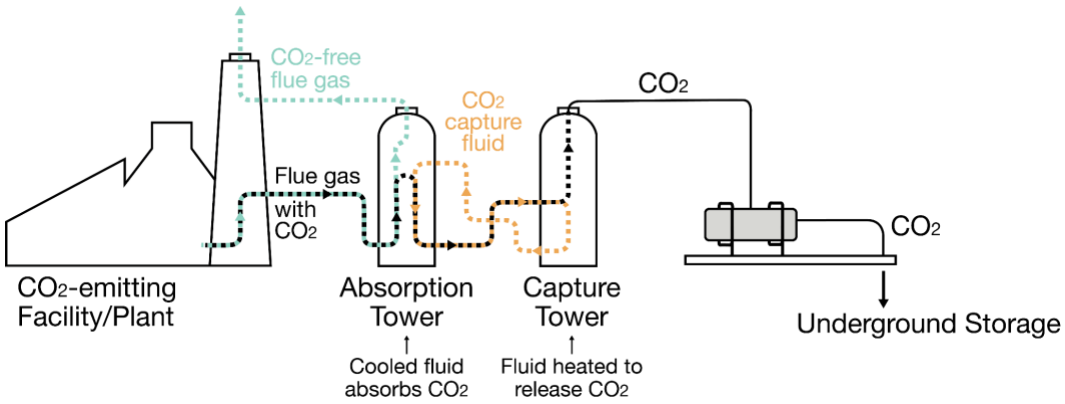


Figure 5.1. Generalized schematic of point source carbon capture. Adapted from Kearns et al. (2021).[16]

Industries for which point source capture is applicable for the purpose of carbon capture are summarized in Table 5.1. For the purposes of this analysis, our mandate was to explore industries for which there are existing or planned facilities in Kern County, and that might reasonably be included in a carbon management business park. According to the EPA

[10] Kearns *et al*. (2021) CCS readiness and costs. p. 15. [45]
[11] Kearns *et al*. (2021) CCS readiness and costs. p. 16. [45]
[12] [illegible]. [5]
[13] Kearns *et al*. (2021) CCS readiness and costs. p. 3. [45]
[14] Kearns *et al*. (2021) CCS readiness and costs. p. 10. [45]
[15] Kearns *et al*. (2021) CCS readiness and costs. [45]
[16] Kearns *et al*. (2021) CCS readiness and costs. p. 13. [45]

Facility Level Information on GreenHouse gases Tool (FLIGHT), Kern County has 44 facilities that reported significant CO_2 emissions in 2021,[17] and are divided into the following sectors:

- 15 Power plants
- 20 Petroleum and natural gas systems or refineries
- 4 Agriculture and/or food processing facilities
- 2 Waste facilities (Bakersfield and Clean Harbors landfills)
- 2 Cement facilities
- 1 Mine (Borax - boron mine and refinery)

Agricultural facilities and landfills - while sources of emissions - are not viable candidates for point source capture because greenhouse gas emissions are diffuse, rather than concentrated from a single or few point(s) of exhaust (although waste could be diverted from landfills to a BiCRS facility, see Section 4). The cement and borax facilities are site dependent, meaning that although point source carbon capture could be a viable carbon management option in these industries, facilities are located adjacent to the mine or quarry from which raw material is extracted, and thus are not likely candidates for development in a dedicated carbon management park. Finally, because the business park under consideration would utilize renewable energy sources and is intended to be complementary rather than additive to the existing oil and gas sectors of Kern County, we have excluded investigation of power plants, natural gas processing, and petroleum refineries from this analysis. For additional information on the potential of point source capture for these CO_2-emitting industries, the interested reader is referred to two recent reports from the International Energy Agency on carbon capture utilization and storage (CCUS) in clean energy transitions[18] and the role of CCUS in low-carbon power systems.[19]

Another CO_2-emitting industry is not yet operating in Kern County but may be in the future. The San Diego-based Pacific Steel Group announced in April 2022 that it plans to build a state-of-the-art steel plant in southeast Kern County, with construction beginning in 2025.[20] As of the publication of this report, Pacific Steel Group's proposal is under planning and permitting review by the county.

Steel mills are technologically diverse. Depending on the type of steel production employed, they can produce as much as 2.4 tons of CO_2 for every ton of steel produced (Table 5.2), or – with the most advanced technologies – no CO_2.[21] Here, we examine the

[17] EPA (no date) FLIGHT. [27]

[18] IEA (2020) CCUS in clean energy transitions. [41]

[19] IEA (2020) The role of CCUS in low-carbon power systems. [42]

[20] Cox (March 14, 2022) 'Green steel' plant proposed for Mojave. [21]

[21] Soderpalm (August 19, 2021) Sweden's HYBRIT delivers world's first fossil-free steel. [72]

steel industry both as a potential carbon management industry and as an emerging clean energy technology.

Table 5.1. Industrial sources of emissions with commercial carbon capture facilities, globally.

Industry	CO_2 Concentration in Exhaust[a]		Cost of Capture[b]	Commercial Facilities[c]	
	vol %	Partial Pressure[d]	(USD/mtCO_2)	Operational	In Development
Natural gas processing	2-65	0.05 - 5	$15-25	15	12 (9)[e]
Fertilizer (ammonia) production	18-40	0.3 - 2.5[f]	$25-40	4	1 (7)
Bioethanol production[g]	85-100	0.085 - 0.10	$15-30	4	35 (3)
Production of other chemicals	7-92	0.2 - 0.27	$25-40	4	2 (7)
Hydrogen production (Blue H_2)	15-20	0.3 - 0.5	$50-80	3	12 (18)
Power generation - coal	12-15	0.012 - 0.014	$45-100	3	7 (4)
Power generation - NG	3-5	0.003 - 0.005	$50-100	0	9 (14)
Waste to energy[g]	10-12	0.010 - 0.012	$15-85	0	3 (3)
Iron and steel production	4-35	0.004 - 0.060	$60-100	1	0 (1)
Cement production	14-33	0.014 - 0.033	$60-120	0	2 (7)
TOTAL				**34**	**83 (73)**

a. Gale *et al.* (2005) IPCC Sources of CO_2. p. 79-80., Kearns et al. (2021) CCS readiness and costs. p. 25.
b. Sources: Sanchez et al. (2017) CCS from biorefineries,[22] Fuss et al. (2018) Negative emissions,[23] IEA (2020) CCUS in clean energy transitions.
c. Global CCS Institute Facility Database.[24]
d. Units are in MPa. (0.1 MPa = 1 bar = 0.99 atmospheres of pressure)
e. Those in parentheses are in early development stages. All other facilities are in construction or advanced development. For details, see Appendices A-C.
f. Up to 25% of captured CO_2 is used to convert produced ammonia to urea to create fertilizer.[25]
g. These industries can are examples of BiCRS/BECCS, and are discussed further in Section 4.

5.1.1.2 Steel Production and Carbon Emissions

There are a variety of production routes for steel, which vary as a function of the iron source material being used. Source materials include iron ore, the raw material mined from geologic deposits, direct reduced iron (DRI), which is formed by reducing iron ore in the presence of natural gas or a coal derivative, and recycled scrap steel. Integrated steel plants

[22] Sanchez *et al.* (2017) Near-term deployment of CCS from biorefineries. [70]
[23] Fuss *et al.* (2018) Negative emissions. p. 20. [32]
[24] GCCSI (no date) CO_2RE Facilities Database. [36]
[25] TFI (no date) State of the fertilizer industry: Environment & Energy. [78]

can produce steel from any of these sources, typically using a *blast furnace* (BF) to convert iron ore to reduced iron, and using a *basic oxygen furnace* (BOF) to convert the reduced iron, DRI and/or scrap steel to new steel products.[26]

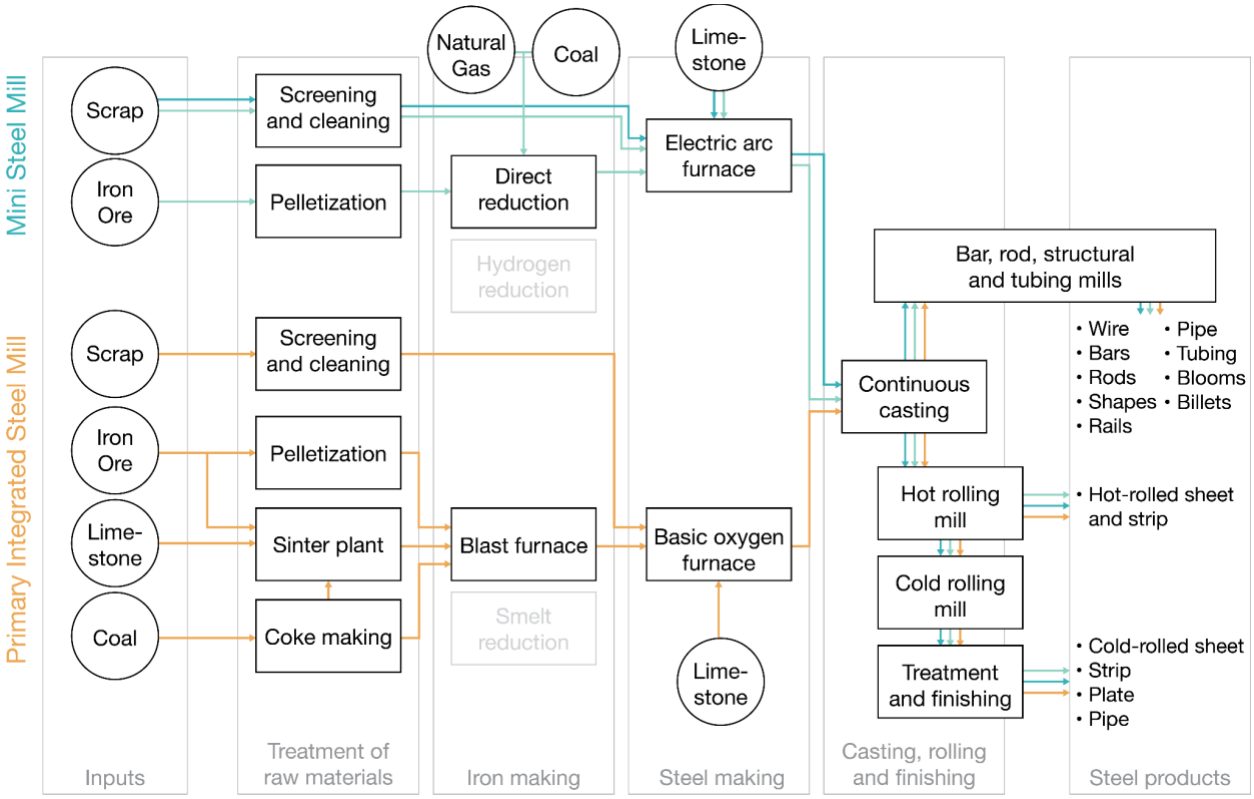


Figure 5.2. Process pathways for the two main methods of iron and steel production, blast furnace + basic oxygen furnace (BF-BOF, typical in integrated steel mills) and the electric arc furnace (typical in mini mills that use scrap ± direct reduced iron (DRI) as an iron source. Adapted from de Beer et al. (2003).[27]

These types of steel facilities currently account for over 70% of global steel production,[28] but since the 1960's[29] a new type of mill, called mini mills, are becoming increasingly common and are now the predominant mill type in the United States.[30] Mini mills (and even more recently, micro mills)[31] use a technology called *electric arc furnaces* to re-melt, refine and alloy scrap steel, or less commonly, DRI. Because they do not require the raw materials (iron sinter and/or pellets and coke) or extremely high heat needed to reduce iron ore in a

[26] de Beer *et al.* (2003) Emissions from iron and steel production. [24]
[27] de Beer *et al.* (2003) Emissions from iron and steel production. p. 14. [24]
[28] Kueppers *et al.* (2022) Iron and Steel. [49]
[29] Stubbles (2009) The minimill story. [76]
[30] CRU (2022) Steelmaking emissions analysis. [22]
[31] Anderton (August 6, 2015) Micro steel mills are competitive. [3]

blast furnace, these smaller mills are able to produce steel at cost-competitive rates with the significantly larger integrated steel mills. Their growth potential is simply limited by the availability of scrap steel or DRI.[32]

Table 5.2. CO_2-equivalent emissions as a function of steel-making process and process step.

Process Step	Direct CO_2 Emissions[a] (tCO_2/t steel)	Capture Eligible? (tCO_2/t steel)	Energy Use (GJ/t steel)	CO_2 from NG Energy Source[b] (tCO_2/t steel)
Electric Arc Furnace + Scrap (EAF)				
Treatment of raw materials	0	N/A	N/A	N/A
Iron making	N/A	N/A	N/A	N/A
Steel making	0.04-0.12	No	1.3-3.3	0.06-0.15
Casting rolling and finishing	0.07-0.22	No	0.02-2.2	0.00-0.10
TOTAL	**0.11-0.32**	**No**	**1.3-5.5**	**0.06-0.25**
Electric Arc Furnace + Direct Reduced Iron (DRI-EAF)				
Treatment of raw materials	0.02-0.05	No	1.9	0.09
Iron making	0.52-1.05	Yes	10.9-16.1	0.5-0.74
Steel making	0.04-0.12	No	1.3-3.3	0.06-0.15
Casting rolling and finishing	0.07-0.22	No	0.02-2.2	0.00-0.10
TOTAL	**0.65-1.44**	**0.42-0.84**	**14.1-23.5**	**0.65-1.08**
Blast Furnace + Basic Oxygen Furnace (BF-BOF)				
Treatment of raw materials	0.05-0.5	Some	1.75-3.2	0.08-0.15
Iron making	1.3-1.5	Yes	9.8-13.5	0.45-0.62
Steel making	0.13-0.21	Yes	7.9-11	0.36-0.51
Casting rolling and finishing	0.07-0.22	No	0.02-2.2	0.00-0.10
TOTAL	**1.55-2.43**	**0.92-1.12**	**19.5-29.9[c]**	**0.89-1.38**

a. Data from de Beer et al. (2003) Emissions from iron and steel production, CRU (2022) Steelmaking emissions analysis, and Fan and Friedmann (2021) Low-carbon production of iron and steel, Fruehan et al. (2000) Minimum energies to produce steel.

b. Natural gas CO_2 emission factor from Our World in Data.[33]

c. ~6 Gj of process heat are created per ton of steel produced, reducing this total value to ~13.5-24 Gj/ton of steel of net-energy requirements. (IEA (2020) Iron and Steel Roadmap.)

[32] de Beer *et al.* (2003) Emissions from iron and steel production. [24]

[33] Our World in Data (no date) Carbon dioxide emissions factor. [63]

The intensity of CO_2 emissions produced during the steelmaking process is dependent on the steelmaking route used, and thus integrated steel mills, mini mills, and scrap-specific mini mills have very different emissions profiles.[34] To break down the sources of CO_2 emissions associated with each type of steelmaking process, and its potential for capture or mitigation, in the following sections we examine each step of steelmaking systematically. A flow chart outlining each step in steel making, and how those steps vary by process, is provided in Figure 5.2, and a summary of the sources and volume of greenhouse gas emissions from each step is provided in Table 5.2.

Treatment of raw materials

To make new steel, raw iron ore (the oxidized iron material mined from geologic formations) must be reduced to metallic iron,[35] which must then be treated by the addition or removal of carbon and other trace metals to achieve an alloy with the desired properties (i.e. strength, hardness, ductility, or weldability).[36] Luckily, once made, steel is an excellent candidate for recycling. Scrap steel, which is the steel discarded as waste either during manufacture or from products at the end of their useful life, can be repeatedly turned back into new steel, while retaining its original properties.[37]

Every steel manufacturer uses some amount of scrap to produce new steel.[38] In dedicated scrap mini mills, scrap represents 100% of the raw material for steel production. In regions where scrap is scarce, mini mills will supplement scrap with metallic iron converted from ore via the direct reduction (direct reduced iron, or DRI) method.[39] In integrated steel mills, scrap is most commonly combined with pig iron, the material made from iron ore using a blast furnace (Figure 5.3).[40]



Figure 5.3. a. Hot iron pellets. Pellets are generally ~1cm in diameter. b. Iron sinter, on A4 size paper, for scale. Image credits: Wikimedia commons, RobSimmons 223311, CC BY-SA 4.0 and Borva53, CC BY-SA 4.0.

[34] de Beer *et al*. (2003) Emissions from iron and steel production. p. ii. [21]
[35] IIMA (no date) About Metallics. [43]
[36] Mar (September 28, 2017) Chemical composition of steel. [57]
[37] World Economic Forum (January 17, 2023) Steel scrap and how it can help reach net zero. [90]
[38] World Steel Association (2021) Scrap use in the steel industry. [91]
[39] de Beer *et al*. (2003) Emissions from iron and steel production. p. 21. [24]
[40] IIMA (no date) About Metallics. [43]

The preparation of scrap material for recycling into new steel products is relatively minimal - it involves collection, cleaning, and sorting.[41,42] However, creation of metallic iron (either DRI or pig iron) requires the conversion of iron ore into a form that can be fed into the smelter or furnace. Two conversion processes are used: pelletization (for DRI and pig iron) and sinter plants (for pig iron only).[43] Pelletization occurs in a pellet plant, which can be cited at the ore mine or steel mill, and involves first crushing and grinding iron ore, and then forming 'green balls' of material by aggregating the iron grounds with crushed limestone, clays, and water. The balls are hardened for transport and loading through an *induration process*; they are dried, fired in a kiln at temperatures up to 1350°C, and cooled.[44] Sinter plants prepare iron ore by combusting it at ~1300-1480°C with limestone and coke breeze (used as the fuel) to produce a carbon-rich, porous clinker.[45] Formation of raw iron (pig iron or DRI) is often measured in 'tons of hot metal.'[46] For each ton of hot metal, about 1.5-1.7 tons of pellets or sinter is required.[47,48]

In integrated mills, coke is another raw material that needs to be treated in preparation for iron making. Coking is the process of converting metallurgical coal to the porous, carbon-rich material 'coke.' Metallurgical coal is heated to temperatures up to 1125°C, melting and releasing any volatiles, and then re-solidifying as coke.[49] About 0.3-0.5 tons of metallurgical coal are used for each ton of hot metal produced.[50]

Pelletization, sintering and coking all emit CO_2 - about 0.02-0.05, 0.3-0.4, and 0.03-0.10 tons CO_2 per ton hot metal, respectively.[51,52] The combined impact of these emissions on the carbon intensity of final steel products derived from a given steel production pathway is detailed in Table 5.2.

Iron making

In integrated steel making, iron pellets, sinter, and coke are combined in a *blast furnace* (Figure 5.4) to form hot iron metal, or in its cooled form, pig iron. Coke is used as a fuel - combusting to help the furnace reach the melting temperatures of iron (as much as 2000°C[53]), as a reductant - accepting oxygen from the iron oxides in the ore material to

[41] Peters *et al.* (2021) Improve the EAF scrap route for a sustainable value chain. p. 10. [66]
[42] de Beer *et al.* (2003) Emissions from iron and steel production. p. 14. [24]
[43] de Beer *et al.* (2003) Emissions from iron and steel production. p. 38-40. [24]
[44] de Moraes *et al.* (2018) Iron ore pelletizing process: An overview. [25]
[45] de Beer *et al.* (2003) Emissions from iron and steel production. p. 13-15. [24]
[46] Fan, Friedmann (2021) Low-carbon production of iron and steel. [30]
[47] Uys, Kirkpatrick (1963) The beneficiation of raw materials in the steel industry. [84]
[48] Van Wortswinkel, Nijs (2010) ETSAP - Iron and Steel. [86]
[49] Kentucky Geological Survey (no date) Coal to make coke and steel. [46]
[50] de Beer *et al.* (2003) Emissions from iron and steel production. p. 16. [24]
[51] de Beer *et al.* (2003) Emissions from iron and steel production. p. 15-17. [24]
[52] Fan, Friedmann (2021) Low-carbon production of iron and steel. p. 833. [30]
[53] IIMA (no date) About Metallics. [43]

produce metallic iron and CO_2, and as a charger - increasing the carbon content of the iron, which is critical for processing to steel in the *basic oxygen furnace*.[54] Within the steel making process, blast furnaces represent the largest source of CO_2 emissions, about 70% of emissions in an integrated plant.[55] For each ton of steel produced,[56] about 1.3-1.4 tons of CO_2 are released.[57]

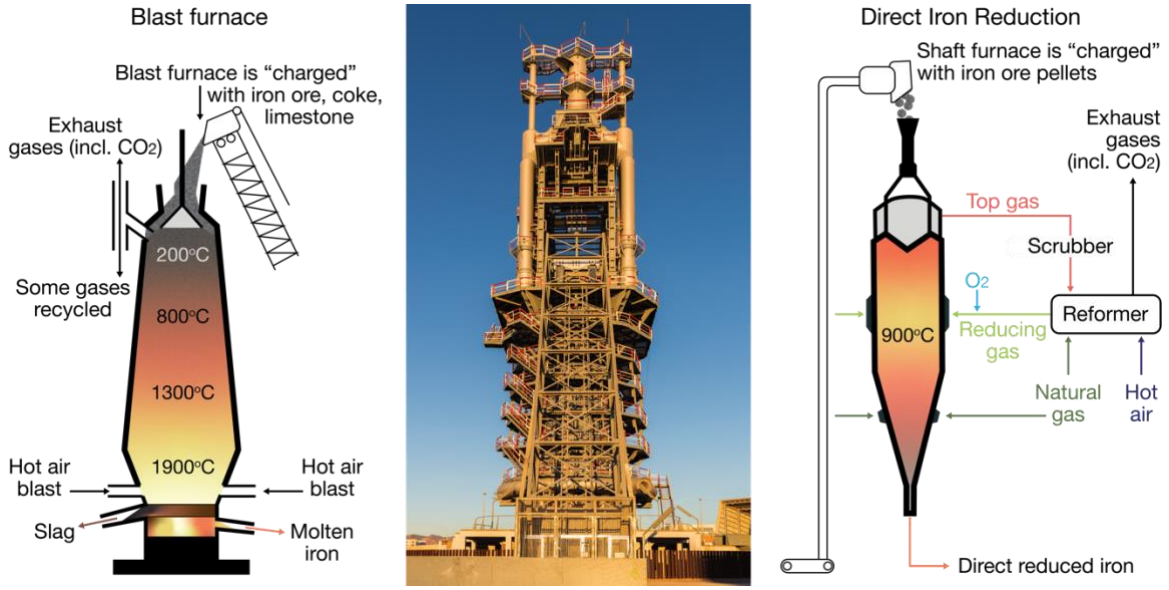


Figure 5.4. a. Schematic of iron production via blast furnace. b. Blast furnace, Port of Sagunto, Spain. Image credit: Wikimedia Commons, Diego Delso, CC BY-SA 4.0. c. Schematic of direct reduced iron production (modeled after the Midrex process, one of several flow processes for DRI). Adapted from International Iron Metallics Association. DRI facilities are of a similar scale to blast furnaces – the shaft furnace is a multi-story scaffolded building, with an attached conveying system for the iron ore pellet charge.

Direct reduced iron is an alternative to pig iron that can be used in *electric arc furnaces*. It has a significant advantage over the blast furnace in terms of emissions because it does not require coke as a fuel or additive. Rather, a natural gas- or coal-derived reducer, called syngas ($CO + H_2$), is used to remove oxygen from the pelletized iron ore. This process takes place in solid state; the ore never actually melts. Thus, required temperatures for the process are much lower, reaching only 900-1000°C. Because iron is not melted, impurities present in the ore are retained in the DRI product. This can mean additional additives will

[54] de Beer *et al.* (2003) Emissions from iron and steel production. p. 18-21. [24]

[55] Fan, Friedmann (2021) Low-carbon production of iron and steel. p. 831. [30]

[56] Some references report emissions in tons of hot metal (what emerges from the iron making process), whereas other references report emissions as a function of tons of steel. de Beer *et al.* (2003) Emissions from iron and steel production (p. 26) reports that hot metal comprises 65-90% of steel output, the balance being from scrap. To maintain continuity, we assume that 0.9 tons of hot metal are used to produce 1 ton of steel, with scrap steel comprising the remaining steel input.

[57] Fan, Friedmann (2021) Low-carbon production of iron and steel. p. 833. [30]

be needed in the steel-making step to extract unwanted impurities or to add under-represented elements, like carbon, that control desired steel properties.[58,59] The combustion of coal or natural gas to produce DRI emits between 0.5 and 1.0 tons of CO_2 per ton steel (Table 5.2).[60]

Two other processes are worth noting briefly here: smelt reduction and hydrogen steel production. Smelt reduction is an alternative mechanism for producing pig iron that employs direct reduction of iron ore fines (omitting the pelletization or sintering step) in the presence of coal.[61] The technology is mature, but has seen very little penetration in the global iron production market, likely because it is more expensive than conventional blast furnace-basic oxygen furnace (BF-BOF) production, but more carbon intensive than scrap-EAF or DRI-EAF processes.[62]

Hydrogen-blended, or hydrogen fueled steel production are clean-energy alternatives to existing steel production, that are still in the early development or demonstration stages of technological readiness. These technologies would adapt existing BF, DRI, and smelting reduction reactors to operate with H_2 as part or all of the reducing agent and fuel source for the ironmaking step of steel production, resulting in reduced or eliminated process emissions of CO_2.[63]

Steel making

Once crude iron has been produced, it is introduced into a furnace to further refine to steel. The purpose of this step is to remove any undesired impurities from the source iron, and to adjust the concentration of carbon and other desirable elements that imbue steel with specific properties optimized for its final intended use.[64] Basic oxygen furnaces (BOFs) are traditionally used in integrated mills, with iron sourced primarily from blast furnaces, with scrap and occasionally DRI to supplement.[65] The furnace is a large and pear-shaped reactor, where pure oxygen is blown into the vessel to react with the liquid iron metal. Carbon, and other impurities, are oxidized by the iron and separated, creating CO_2 gas and a metal-oxide-rich slag.[66] The molten and purified steel are separated and transported to a finishing facility for casting and rolling (Figure 5.2). BOFs are enormous, housed in buildings that can be as much as 80 meters (~260 feet) high. This is to accommodate the gravity feed equipment, oxygen lance and off-gas cooling systems.[67]

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[58] IIMA (no date) About Metallics. [43]
[59] de Beer *et al*. (2003) Emissions from iron and steel production. p. 21-23. [24]
[60] Fan, Friedmann (2021) Low-carbon production of iron and steel. p. 835. [30]
[61] IEA (2020) Iron and Steel Roadmap. p. 91. [40]
[62] IEA (2020) CCUS in clean energy transitions. p. 65. [41]
[63] IEA (2020) Iron and Steel Roadmap. p. 91. [40]
[64] de Beer *et al*. (2003) Emissions from iron and steel production. p. 26. [24]
[65] de Beer *et al*. (2003) Emissions from iron and steel production. p. 26-27. [24]
[66] Britannica.com (no date) Primary Steelmaking. [7]
[67] Britannica.com (no date) Primary Steelmaking. [7]

In mini steel mills (and some integrated mills), the electric arc furnace (EAF) is used in the steel making step. This process involves using a high-current electric arc to melt steel scrap (± DRI), which is chemically adjusted by varying the melting temperature and "charging" with DRI, pig iron and limestone (for slag formation). Because EAF is less oxidizing than BOF, steels made by this process typically have higher carbon contents than BOF steel, and CO_2 emissions from the EAF are lower - about 0.4 to 0.12 tons of CO_2 is released per ton of steel processed in an EAF, compared to 0.14 to 0.21 tons of CO_2 per ton steel in BOF processes (Table 5.2). An EAF furnace is much smaller than a BOF, with a shell diameter ranging from ~6-9 meters (20-30 feet), and able to process 100-300 tons of steel melt at a time.[68]



Figure 5.5. a. Basic oxygen furnace being charged at the ThyssenKrupp steel mill in Duisburg. Image credit: Wikimedia Commons, Katpatuka, CC BY-SA 3.0. b. Electric arc furnace of the Georgsmarienhütte GmbH steel plant in Germany. Wikimedia Commons, GMH official, CC BY-SA 3.0.

Casting, rolling and finishing

Most steel facilities use continuous casting (rather than ingot casting) to cool and prepare steel for shaping into a range of final products.[69] In this process, liquid steel is continuously fed into short, vertical water-cooled copper molds. The outer most shell of the steel 'strand' is solidified, allowing them to be rolled out of the copper molds, as the inside continues to cool and solidify. Once solidified, the steel is cut into billets, blooms or slabs (distinguished by size), which are then shaped into finished products.[70] Such shaping takes place through rolling and finishing operations - hot rolling (done immediately after the slabs have been cast) and cold rolling (done once the slabs are cooler than their recrystallization

[68] Britannica.com (no date) Primary Steelmaking. [7]

[69] de Beer *et al*. (2003) Emissions from iron and steel production. p. 63. [24]

[70] de Beer *et al*. (2003) Emissions from iron and steel production. p. 31. [24]

temperature) are used to reduce slab thickness and ensure thickness uniformity,[71] and further cutting to the preferred shape and size of the final steel product. An analysis performed for the Steel Manufacturers Association[72] estimated that high-temperature heat emissions related to this portion of the steel making process was between 0.07 and 0.22 tons CO_2 per ton steel (Table 5.2), with lower values being associated with younger, more efficient facilities.

5.1.1.3 Carbon Capture in the Steel Industry

Pilot studies and research on the application of carbon capture as a decarbonization solution in the steel industry has been most closely applied to integrated mills, where blast furnaces produce ~80% of the mill's emissions (Table 5.2).[73] Retrofitted carbon capture devices on the blast furnace could capture as much as 65% of CO_2 emissions, and an additional ~10-20% could be conserved by adding oxygen and combusting the exhaust stream (composed of CO + CO_2) to provide heat energy to the furnace or other plant facilities.[74,75] It is possible to apply commercially available carbon capture devices to other components of the integrated mill system (coke production, sinter production and the BOF), but as these produce a smaller fraction of total emissions, capturing CO_2 from these sources is likely not cost-effective for a globally-traded industry that must operate on tight profit margins.[76] For example, when blast furnace gas is combusted in the presence of air, the concentration of CO_2 in the exhaust is about 27 vol%. In contrast, the composition of off-gas from a basic oxygen furnace includes only about 16 vol% CO_2.[77] Thus, the basic oxygen furnace produces less CO_2 to capture, and does so at a higher price per ton CO_2 captured.

DRI can also be designed or retrofitted with carbon capture, with the possibility of capturing as much as 80% of CO_2 emissions, although the lower concentrations of carbon in the flue gas make this process more challenging and expensive than carbon capture for BF-BOF.[78] The only commercially operating steel mill with carbon capture in the world - in Abu Dhabi, U.A.E. - captures carbon from the DRI process (see Section 5.1.2.2). An alternative decarbonization approach for DRI is using green hydrogen (produced via electrolysis or gasification of biomass, see Sections 6 and 4, respectively) as a carbon-free replacement fuel, but adapting the EAF technology for this fuel is far from technologically ready, and could be prohibitively expensive until the cost of producing green hydrogen decreases.[79,80]

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[71] American Steel Products Company (January 5, 2017) What is a rolling mill? [2]

[72] CRU (2022) Steelmaking emissions analysis. [22]

[73] CRU (2022) Steelmaking emissions analysis. [22]

[74] de Beer *et al.* (2003) Emissions from iron and steel production. p. 71. [24]

[75] EPRS (2021) Carbon-free steel production. p. 15-16. [28]

[76] [illegible]

[77] Gale *et al.* (2005) Chapter 2: Sources of CO_2. p. 80. [33]

[78] EPRS (2021) Carbon-free steel production. p. 15-16. [28]

[79] Liberty Steel Group (no date) A direct reduced iron (DRI) plant. [53]

[80] [illegible]

EAF, like the blast furnace, emits an exhaust stream of CO + CO_2, which could be captured or re-used for its waste heat. However, even less CO_2 is emitted per ton of steel in this process than the BOF or raw material treatments (Table 5.2), making it unlikely that capture would ever be cost effective. In fact, for most EAFs, the emissions produced by creating the grid-sourced electricity needed to operate the facility are more than double the direct emissions from the furnace,[81] and thus supplying an EAF mini mill with off-grid, carbon-free electricity would be the most efficient decarbonization approach for these kinds of facilities. While such a facility would produce low-carbon steel, it would not be considered a carbon management industry, as no appreciable carbon capture could take place.

Some researchers have proposed powering the EAF with natural gas via oxy-fuel combustion, rather than grid or renewable-sourced electricity.[82] Oxy-fuel combustion combusts natural gas (or biomass-derived syngas, or renewable natural gas) in the presence of a pure oxygen stream, creating outputs of a pure stream of CO_2, water and electricity (see Section 4).[83] Thus, a mill could produce low-carbon steel and CO_2 for capture. If a scrap mini mill were powered entirely by natural gas with oxy-fuel combustion, approximately 0.06-0.25 (~0.15 on average) tons of CO_2 would be produced per ton of steel produced. Using oxy-fuel combustion from natural gas to power a DRI-EAF mini mill would produce about 0.65-1.08 tons of CO_2 per ton of steel, and for a BF-BOF mill it would produce about 0.89-1.38 tons of CO_2 per ton of steel (Table 5.2).[84]

5.1.2 State of Development

The technological readiness of carbon capture in the steel industry is a two-part problem: first, what is the state of development of point source carbon capture technology? Second, to what extent is such technology (or other decarbonization technologies) ready to be implemented within the steel sector? Here, we will give a brief summary of the state of development of point source carbon capture, with a focus on the most developed approach: chemical solvents. Then we will highlight global examples of decarbonization efforts in the steel industry, with a focus on carbon capture and green hydrogen substitution.

5.1.2.1 Point Source Carbon Capture

Chemical and physical solvents have been in commercial use for decades, and technological development in this space has been focused on reducing the costs of such solvents so that they can be used in industries that produce more diffuse gas streams, or where profit margins are tight.[85] Examples of cost-saving innovations include creation of water-lean solvents, which require a much lower energy input to regenerate the solvent (release the CO_2), simply because less water needs to be boiled. Ion Clean Energy is a

[81] CRU (2022) Steelmaking emissions analysis. [22]

[82] de Beer *et al*. (2003) Emissions from iron and steel production. p. 73. [24]

[83] [illegible]

[84] de Beer *et al*. (2003) Emissions from iron and steel production. p. 13-15. [24]

[85] Kearns *et al*. (2021) CCS readiness and costs. p. 12. [45]

commercial company that produces water-lean liquid solvent capture plants, and more recently, Pacific Northwest National Lab developed a technique that uses an oil-based instead of water based solvent, reducing water requirements by as much as 97%.[86,87] Another next-generation solvent technology comes from the company Saipem. They have identified a biologically-derived enzyme that speeds a naturally slow carbonate salt solvent. The increased capture efficiency allows more CO_2 to be captured with a smaller stripper (and thus smaller footprint and lower capital costs), and the carbonate salt technology has the added benefits of being able to regenerate with hot water, rather than steam (so waste heat can be used as an energy source), and producing no hazardous waste byproducts.[88,89]

Another company, Carbon Clean, is also driving cost savings by modularizing and reducing the physical footprint of their carbon capture technology. Their carbon capture system is the size of a shipping container, and can capture up to 35,000 metric tons of CO_2 annually. That is about one tenth the size of conventional carbon capture facilities.[90] Carbon Clean is developing a variety of projects in California, and globally. It is working with Cemex in Victorville, CA to capture carbon at a cement plant,[91] and with Chevron to create a pilot facility in Kern County that would capture CO_2 from a gas turbine at the Kern River Eastridge cogeneration plant.[92,93] They have also launched a demonstration facility in India, capturing 5 metric tons of CO_2 per day from the blast furnace of Tata Steel's Jamshedpur plant.[94]

5.1.2.2 Example Projects in the Steel Industry

In the steel industry, scrap-based mini mills powered by carbon-free energy are the optimal solution for decarbonizing the sector. However, although ~85% of steel waste is recycled as scrap, it is not enough to meet the global demand for steel.[95] In terms of carbon capture as a decarbonization solution for ore-sourced steel making, DRI is the most technologically advanced. Carbon capture applied to smelt reduction or blast furnace process gas is still in the development to demonstration stages.[96] Replacing hydrocarbons (coke, coal and natural gas) with hydrogen as the reduction agent and/or fuel, is also still in development stages.[97] Below is a sample of key leaders in each of these innovations.

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[86] Kearns *et al*. (2021) CCS readiness and costs. p. 13. [45]

[87] Clifford (January 24, 2023) New technique from U.S. national lab promises to strip carbon dioxide. [18]

[88] Kearns *et al*. (2021) CCS readiness and costs. p. 13. [45]

[89] Saipem (no date) CO_2 Solutions. [69]

[90] Clancy (May 18, 2022) Meet the startup shrinking industrial carbon capture. [16]

[91] Carbon Clean (February 9, 2021) CEMEX Awarded Grant from US Department of Energy. [12]

[92] Carbon Clean (February 24, 2022) Chevron announces investment in Carbon Clean. [13]

[93] Kumar (May 18, 2022) Chevron to launch carbon capture project in San Joaquin Valley. [50]

[94] Carbon Clean (September 14, 2021) India's first blast furnace carbon capture plant. [11]

[95] [illegible]

[96] [illegible]

[97] [illegible]

Al Reyadah CCUS Project, Abu Dhabi, U.A. Emirates

The first (and as of this report's publication, only) fully commercial carbon capture and storage facility for the iron and steel industry is at a DRI plant in Abu Dhabi, where an existing facility was retrofitted with traditional liquid solvent capture technology (using monoethanolamine, or MEA, which is the industry leading solvent). The project was launched in 2016, and captures 800,000 metric tons of CO_2 annually, for enhanced oil recovery use (EOR) in nearby onshore oil fields. $15 billion US of seed funding was supplied from the government of Abu Dhabi to launch the project.[98]

CO2 Ultimate Reduction in the Steelmaking Process (COURSE50), Japan

Since 2008, a consortium of Japan's steel manufacturers has been working on experimental technologies to reduce emissions in BF-BOF steel plants through hydrogen reduction of iron in the blast furnace and capture of blast furnace off-gas. The project was commissioned and financed by the New Energy and Industrial Technology Development Organization.[99] So far, the project has been able to reduce blast furnace emissions by ~10% through supplementing coke with hydrogen. Continuing work focuses on development of novel chemical absorbents and physical adsorption technologies for BF carbon capture.[100]

STEPWISE Project, Luleå, Sweden

Funded through the European Union's Horizon 2020 Low Carbon Energy programme, the STEPWISE Project aims to create a demonstration scale facility of sorption-enhanced water-gas shift (SEWGS) carbon capture for blast furnace gas. The pilot plant is a retrofit of the SSAB steel plant in Luleå, Sweden, and is able to capture 14 metric tons of CO_2 per day. The aim of the technology is to improve the efficiency of conversion of CO in the blast furnace off-gas to CO_2, which is currently a highly energy-intensive process. Such improvement has the potential to reduce BF emissions by 85%, reduce the energy requirement of capture by 60%, and the cost by 25%. While the pilot plant is operational, the extent to which these goals are achieved is still being investigated.[101,102]

HYBRIT Project, Luleå, Sweden

Launched by three private companies in 2016 (SSAB, LKAB and Vattenfall), the HYBRIT initiative aims to develop a completely fossil-free value chain for steel production, using fossil-free pelletization, electricity and hydrogen. A pilot facility for producing fossil-free sponge iron (the output of DRI) was commissioned in 2020, and a pilot facility for hydrogen storage in a rock cavern facility launched in September 2022.[103] In August 2021, SSAB

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[98] The University of Edinburgh (no date) Al Reyadah: Project Details. [79]

[99] Tonomura *et al.* (2016) Concept and current state of CO_2 Ultimate Reduction. [81]

[100] COURSE50 (no date) To the future of the low carbon blast furnace. [20]

[101] Stepwise (no date) STEPWISE: a H2020 Project. [75]

[102] van Dijk *et al.* (2017) Cost effective CO_2 reduction in the iron & steel industry. [85]

[103] HYBRIT (September 23, 2022) HYBRIT: Milestone reached. [39]

produced the world's first fossil-free steel using HYBRIT technology at its pilot facility - in which DRI is produced with 100% hydrogen as the fuel and reducing agent.[104]

Boston Metal, United States

Boston Metal, a steel startup company in the United States, is developing an alternative technique for direct reduction of iron that uses *electricity* as the reducing agent, rather than hydrocarbons or hydrogen. Called Molten Oxide Electrolysis (MOE), the technology works by heating iron in a cell to 1600°C, in the presence of an electrolyte solution (i.e. water containing dissolved salts). The iron ore becomes molten, and an inert anode placed in the electrolyte solution is electrified, driving an electrical current through the molten iron that splits the bonds between iron and oxygen in the ore:

$$Fe_2O_3 + e^- \rightarrow Fe + O_2 \qquad (R5.1)$$

The process is anticipated to be cost competitive with traditional BF-BOF steel production, but is still being validated in the industrial environment. Demonstration facilities are planned for 2024, with the aim of commercial operation by 2026.[105]

Rocky Mountain Steel, Colorado

Rocky Mountain Steel, based in Pueblo, Colorado was the first integrated steel mill built in the U.S. west of the Mississippi River, having been in operation since 1882.[106] Today, it no longer operates as an integrated mill, but rather a scrap steel mill - recycling scrap into rails for train tracks, pipes and re-bar.[107] In 2022, the company broke ground on developing the first steel mill to run almost entirely on solar power. Construction of the solar project that will power the mill is ongoing at the time of writing this report, but will use 750,000 solar panels, located on ~1,800 acres, to provide more than 90% of the mill's power needs.[108]

Mojave Micro Mill, Kern County, California

In May 2022, the Pacific Steel Group announced plans to develop a state-of-the-art 'green steel' micro mill in the Mojave Desert of Kern County. The mill would be a 100% scrap-EAF mill, modeled after a similar mill that is in development in Mesa, Arizona, that has an expected opening date in 2023. The Mojave facility would be powered at least partially by local renewable energy (solar), and would produce up to 380,000 tons of steel annually.[109] It would use MIDA-Micromill technology from the company Danieli, which also produced the Mesa, Arizona facility, and a similar plant in Durant, Oklahoma.[110] In terms of development status for the Mojave Micro Mill, the Pacific Steel Group has submitted a

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[104] HYBRIT (no date) HYBRIT Demonstration. [38]

[105] Boston Metal (no date) Molten Oxide Electrolysis for steel decarbonization. [6]

[106] The Center for Land Use Interpretation (no date) Rocky Mountain Steel, Colorado. [77]

[107] EVRAZ North America (no date) EVRAZ Rocky Mountain Steel. [29]

[108] Lawrence (March 2, 2022) World's largest solar-powered steel mill breaks ground in Colorado. [51]

[109] Cox (May 13, 2022) 'Green steel' plant proposed for Mojave. [21]

[110] Danieli (July 29, 2015) Danieli to supply second MIDA to CMC. [23]

development proposal for the project, and the project is currently undergoing the public environmental review process pursuant to the California Environmental Quality Act.[111]

5.1.3 Operational needs

This section provides a synopsis of the land use, energy, feedstock, waste disposal and other operational needs of the representative technologies for the steel industry that employs carbon management and/or clean energy technologies. Information was aggregated from literature review and interviews with industry experts.

Integrated steel mills that employ primarily BF-BOF steel making technology are quite distinct from mini mills in terms of their footprints, operational needs, and steel output. An integrated steel mill typically produces 3 million tons or more of steel annually, whereas mini mill production capacity is about 1 million tons per year.[112] Micro mills (and even nano mills), like the Mojave Micro Mill that is currently in development (see Section 5.1.2.2), produce even less - on the order of 200,000-500,000 tons of steel per year.[113] Additionally, integrated mills are dependent on primary ores (iron ore and metallurgical coal for coke), and so have traditionally been located close to these natural resources and/or along major waterways where transport of raw materials is possible.[114] Although located close to major rail and road transportation routes, Kern County is distantly located from any significant iron or coal natural resources, and is unlikely to be suitable for a large-scale integrated steel mill. Thus, for the purposes of this study, we will focus on the requirements and impacts of mini- and micro mills that use scrap as a primary feedstock, with DRI as a potential supplementary feedstock, if future regional demand outpaces the availability of scrap metal.

Considering that this industry is being evaluated in the context of its role as a carbon management industry, it is also worth noting the needs and impacts that such a facility will have in terms of its CO_2 output as well as its steel output. To this end, we considered three mini mill scenarios in the impact analyses that comprise the remainder of this report section. The scenarios are based on the direct and indirect (energy-sourced) CO_2 emissions profiles described in Table 5.2, and are as follows:

1. A scrap-based mini mill powered by solar energy, in which **0 tons of CO_2 can be captured per ton steel produced** (direct emissions are not easily captured, and the solar energy source is emission-free).
2. A scrap based mini mill that utilizes oxy-fuel combustion of natural gas, producing an average of **~0.15 tons CO_2 that can be captured per ton of steel** (full range is 0.06-0.25 tons CO_2 per ton steel).

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[111] Kern County Planning and Natural Resources Department (October 28, 2022) Notice of Preparation (NOP). [47]

[112] Fan, Friedmann (2021) Low-carbon production of iron and steel. p. 833. [30]

[113] Millennium Steel (May 25, 2017) Mini mills, micro mills, nano mills. [58]

[114] Anderton (August 6, 2015) Micro steel mills are competitive. [3]

3. A mini mill that utilizes DRI with point source capture for 100% of its iron source and oxyfuel combustion of natural gas as its energy source. Point source capture can capture up to 80% of DRI emissions,[115] or ~0.42-0.84 tons CO_2 per ton steel produced. Combined with the CO_2 produced from oxy-fuel combustion (0.65-1.08 tons CO_2 per ton steel), this method would produce, on average, **~1.3 tons CO_2 per ton steel produced** (full range is 1.07-1.50 tons CO_2 per ton steel).

A steel mill that utilized DRI and oxy-fuel combustion (the most emissions-intensive scenario) would need to produce about 770,000 tons of steel annually to emit 1 million tons of CO_2. The same size facility utilizing only scrap and solar energy, or scrap and oxy-fuel combustion, would emit 0 tons CO_2 and ~115,000 tons CO_2, respectively. For the purposes of understanding the impacts of a steel facility in Kern County, data from existing steel mills and published estimates are normalized both to a 1 million ton (Mton) steel production capacity (for consideration of impact per ton steel), and to a 770,000 ton (770 kton) steel production capacity (for consideration of impact per million tons CO_2, noting that such a value is a *maximum* CO_2 output estimate).

5.1.3.1 Land use requirement

There are myriad existing examples of mini steel mills that can be utilized to approximate the land use requirements for this industry. As of 2022, 71% of the domestic U.S. steel supply was produced in 101 mini mills across the country.[116] Table 5.3 provides a representative sampling of U.S. mini and micro mills, denoting their production capacity (in annual steel output) and land footprint. The footprint to steel output ratio for these facilities is diverse, suggesting flexibility in land use needs, depending on the cost and availability of land. The facilities investigated have annual steel outputs ranging from 350,000 tons to 1.2 million tons. For comparative purposes, the land use to output ratio was normalized, producing a range of 140 to 1,071 acres used per million tons (Mton) of steel production, with an average footprint of 663 acres/Mtons. Similarly, to a 770,000 ton steel mill, which could produce *up to* 1 million tons of CO_2 (see Section 5.1.3), would use 129 to 825 acres per million tons of CO_2 produced, with an average footprint of 510 acres per 770kton steel mill.

[115] EPRS (2021) Carbon-free steel production. p. 15-16. [28]

[116] Watson (2022) Domestic Steel Manufacturing. [88]

Table 5.3. Land use requirements for example mini- and micro-steel mills in the United States.

Facility Name[a]	Year Operational	Annual Steel Output	Facility Footprint		Normalized Footprint	
		(kton steel)	km^2	Acres	(acres/ Mton steel)	(acres/770 kton steel)
Mojave Micro Mill, CA (proposed)	2025+	380	0.70	174	458	353
CMC Mesa Plant (II), AZ	2023	500	0.34	84	168	129
HighBar LLC, Osceola, AK	2024	600	2.43	600	1000	770
Nucor Steel, Brandenburg, KY	2022	1,200	3.64	900	750	578
CMC Durant Plant, OK	2017	350	1.52	375	1071	825
Nucor Steel, Davidson Co, NC	2024	430	0.93	229	533	410
MEAN		**577**	**1.59**	**394**	**663**	**510**

a. These six mills will be used for comparative purposes throughout the multi-lens analysis of the steel industry. For this, and all future references to these sites, references are detailed in Table 5.7.

5.1.3.2 Energy Requirements

As detailed in Table 5.2, the primary energy needs for a scrap-based steel mill come from the electric arc furnace (EAF), which requires about 1.3-3.3 GJ (=0.4-0.9 MWh) of energy per ton of steel produced.[117,118] Casting, rolling and finishing the hot steel that is made in the EAF into usable products requires another ~0.02-2.2 GJ (0.01-0.6 MWh)/ton steel.[119] If DRI is made on site from pelletized iron ore feedstock, it would contribute an additional 10.9-16.1 GJ (3.0-4.5 MWh) of energy needs,[120] increasing the facility's energy requirements by an order of magnitude.[121] It is important to note that DRI requires temperatures of 900-1000°C to reduce the iron ore in the presence of a reduction agent like natural gas, syngas or hydrogen. Such high temperatures cannot be directly supplied by solar-derived electricity without also utilizing a heat battery (see our section on energy storage). Capturing carbon from DRI requires additional energy input: point source capture using advanced chemical solvent technologies demands about 2.5-3 GJ (0.7-0.8 MWh) of energy per ton of CO_2 captured, which translates to an additional energy demand of about 1.1-1.3 GJ (0.3-0.35 MWh) per ton steel produced via DRI-EAF.[122] Finally, Pelletization requires about 1.9 GJ (0.5 MWh) of energy per ton of steel, and while this step can be done at the

[117] Fruehan *et al.* (2000) Minimum energies to produce steel. p. iii. [31]

[118] Fan, Friedmann (2021) Low-carbon production of iron and steel. p. 835. [30]

[119] Fruehan *et al.* (2000) Minimum energies to produce steel. p. iii. [31]

[120] de Beer *et al.* (2003) Emissions from iron and steel production. p. 22. [24]

[121] [illegible] p. 29 + 42. [40]

[122] Kearns *et al.* (2021) CCS readiness and costs. p. 36. [45]

steel mill site, it is more commonly done at the mine where iron is sourced,[123,124] so is not included in the energy analysis here.

Estimates of the scale of solar installation required to supply 100% of the heat and electrical energy needs of a steel mill are calculated following the equation: [125]

MWh (energy supplied) = MW (installed capacity of facility) x (8760 hours in a year) x Capacity factor (E5.1)

where the capacity factor for solar panels in Kern County is 32.8%.[126] Solar acreage is calculated on the basis of ~7 acres per MW installed solar capacity.[127,128] With these values, a 770,000 ton steel mini mill utilizing only scrap and solar energy would need about 690-2,900 acres of solar fields to supply the electricity demand. A 770,000 ton DRI mini mill using solar energy and only capturing CO_2 from process emissions of iron reduction would need 6,400-11,255 acres of solar fields (with heat battery storage) to operate. However, in this scenario, only 320,000 tons of CO_2 could be captured annually. A mini mill using oxy-fuel combustion with carbon capture as the sole power supply would require no solar input.

In addition to solar energy, two other potential power supplies for mini mills are explored here: oxy-fuel combustion of natural gas (or alternatives like syngas or renewable natural gas) with carbon capture, and combustion of hydrogen gas.

Oxy-fuel Combustion

Oxy-fuel combustion is a process in which hydrocarbon-based fuels are combusted in a specialized chamber in the presence of a pure stream of oxygen (± an inert carrying agent, like purified CO_2). Normally, we combust fuels in the presence of air, which produces a series of partial reactions that convert the hydrocarbons to CO_2, CO, and a variety of unreacted residues that can be grouped as "volatile organic compounds" or VOCs. These products instantly mix with the surrounding air to produce a dilute stream of CO_2, making it difficult – and expensive – to separate the CO_2. In oxy-fuel combustion, the only inputs in the reaction are hydrocarbons and oxygen, and the reaction can be controlled so that the only products are H_2O (water) and CO_2. Because the reaction is taking place in a vacuum, rather than in the presence of air, the CO_2 product does not become diluted, and thus can easily (and cheaply) be separated for storage. Oxy-fuel combustion technology is generally at the large prototype or pre-demonstration stage of development.[129]

Two examples of companies developing oxy-fuel combustion technologies are Clean Energy Systems and NET Power. Clean Energy Systems designs oxy-fuel turbines (the

[123] Carlson (no date) Iron ore pellet production a bottleneck for steel producers. [14]

[124] Cision PR Newswire (October 21, 2021) Iron ore pellets demand to surpass 399 Mn tons in 2021. [15]

[125] Thomson Reuters Practical Law Glossary (no date) Capacity factor. [80]

[126] NREL (no date) Utility-Scale PV. [59]

[127] Lorelei Oviatt (Kern County), personal communication, September 21, 2022.

[128] SEIA (no date) Land use and solar development. [73]

[129] I□□ □□□□

reaction chambers for oxy-fuel combustion) using technology adapted from rocket engine design, to optimize the combustion reaction.[130] They have a pilot facility in Kern County and are in the process of converting several biomass power plants into Biomass Carbon Removal and Storage (BiCRS) facilities in California (see Section 4.1.2.4). NET Power has developed a form of oxy-fuel combustion called the Allam-Fetvedt power cycle, which uses the pure CO_2 produced from the combustion process as a streaming agent that carries heat energy and new pure CO_2 and H_2O streams, optimizing the efficiency of the process.[131,132]

Hydrogen Fuel

Green hydrogen, or hydrogen that is derived from non-CO_2 emitting processes, like electrolysis (see Section 6) or biomass gasification with carbon capture (see Section 4), has enormous potential in helping to decarbonize iron and steel production, because it can work both as a fuel source, powering high-temperature operation of the DRI and EAF, and as an iron reducing agent, further reducing the necessity of coke or natural gas in the iron-refining process.[133] One company, SSAB in Sweden, has successfully fossil-free steel, using green hydrogen in the production process. Their work is currently at the demonstration stage (see Section 5.1.2.2). If hydrogen is used to power steel production and act as a reducing agent, the steel made will be carbon emissions free (a clean technology), but would not be a source of CO_2 for carbon capture.

5.1.3.2 Other Operational Requirements

Waste disposal requirements

Steel production from EAFs produce a variety of byproducts, including metal dusts, slag, wastewater, and gaseous emissions,[134] each of which needs to be handled appropriately on- or offsite, following state and federal regulations. Slag is relatively inert, and can be repurposed in other industrial applications, like construction.[135] Dust creation is a bigger issue, as on average, EAFs produce about 10 kilograms of dust per metric ton of steel, which can have a variety of heavy metals in it: zinc, lead, cadmium, chromium, and nickel. However, there are a variety of available mitigation measures that can minimize the hazard of dust creation, including: locating operational facilities inside enclosed buildings, selecting a feed quality (steel scrap or iron pellets) that have low concentrations of impurities or heavy metals, use fabric filters and other dry dust collection methods[136].

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[130] Clean Energy Systems (no date) Oxy-fuel Combustion. [17]

[131] Kearns *et al.* (2021) CCS readiness and costs. p. 17. [45]

[132] Patel (November 10, 2022) NET Power's first Allam Cycle 300-MW gas-fired project. [64]

[133] Bartlett, Krupnick (February 18, 2021) The potential of hydrogen for decarbonization. [4]

[134] World Bank Group (1998) Mini Steel Mills. p. 341. [89]

[135] World Bank Group (1998) Mini Steel Mills. p. 342. [89]

[136] World Bank Group (1998) Mini Steel Mills. p. 342. [89]

In terms of wastewater, mini mills can produce up to 80 cubic meters (~21,000 gallons) of wastewater per metric ton of steel produced.[137] Like the dust, wastewater can have high concentrations of metals, totaling up to 3,000 milligrams per liter of water. That is about equivalent to 0.3% of the water being dissolved or suspended solids. These solids can be removed from settling, creating sludges that then need to be properly disposed of following environmental and safety guidelines. With proper treatment, the wastewater can be recycled to minimize the water demands of steel production.[138] Additionally, many of the metals that are concentrated in steel mill wastewater are of interest in development of clean energy technologies. Recovering critical metals from fluids, like waste waters of mining and industrial processes, is beginning to be explored,[139] and could warrant further investigation, both in its potential for an alternative revenue stream, and as a solution for waste mitigation.

The variety of methods described here (and for gas emissions, in Section 5.4.2) to manage and minimize waste from steel mills is not meant to be comprehensive, but is intended to illustrate that solutions already exist to address secondary products of steel production. Like any industrial facility hosted within a carbon management park, environmental and safety impacts of a steel mill would be assessed through a public process, and if approved, all facilities would be reviewed and mitigated in accordance with the California Environmental Quality Act (CEQA).

Warehousing requirements

Warehousing is a necessity at steel mills, both to hold a reserve of iron feedstock (whether steel scrap or iron pellets), and steel product. Although no explicit information could be found on storage requirements for feedstock or product, aerial and satellite imagery of existing steel mills suggests that whether storage is in enclosed warehouses or open air depends on regional preferences and regulation.

Transportation and pipeline requirements

Steel scrap and/or iron pellets will need to be delivered to a mini mill facility, and products will likely be sold nationally or internationally. Therefore, access to rail and shipping lanes are high priorities for steel industries. The availability of rail in Kern County, and its proximity to ports along the West Coast both make it an attractive site for steel production.

[137] World Bank Group (1998) Mini Steel Mills. p. 341. [89]

[138] World Bank Group (1998) Mini Steel Mills. p. 342. [89]

[139] Can Sener *et al.* (2021). Recovery of critical metals from aqueous sources. [9]

5.2 Societal Impacts

5.2.1 Job creation potential

5.2.1.1 Number and types of jobs

On average, it takes 1.5 man-hours to produce a ton of steel, with some mini mills able to produce a ton of steel with only 0.5 man-hours, due to increased efficiency and automation.[140] Given this range, a 770,000 ton steel mill could produce about 200-600 full-time equivalent jobs. This approximated range is consistent with job creation estimates reported from recently built U.S. micro mills, which, scaled to 770,000 ton steel production capacity, would produce on average ~400 permanent jobs. Details of these job estimates are given in Table 5.4.

Of the example steel mills examined in Table 5.4, two provide estimates of job growth in relation to facility construction. The 600,000 ton High Bar LLC steel mill in Arkansas, and the 430 thousand ton Nucor Steel mill being developed in North Carolina report generating 600 and 500 construction jobs, respectively. Scaled to a 770,000 ton facility, a steel mill could provide up to 900 short term jobs in construction. Additionally, such a facility would produce thousands of indirect jobs to support facility needs, such as solar and battery installation jobs.

According to a 2022 Congressional Research report,[141] the average annual wage of steel workers in 2020 was $88,325 USD, higher than both the national average in manufacturing ($73,397 USD), and the median national household income across all sectors ($71,186 USD)[142] for that year. Steel product manufacturing (casting, rolling, and finishing steel into final products) accounted for about 40% of the job market in 2020, and had an average annual wage of $68,585 USD.[143] Reported annual salary for the example steel micro mill manufacturing jobs support this average, with salaries ranging from $60,000-$140,000 plus benefits, with higher salaries associated with technical positions (see Appendix D for complete reference list).

5.2.2.2 Training pipelines

Most jobs in the iron and steel industry require a high school diploma or equivalent and may involve an apprenticeship training program. A significant amount of training is done on-the-job.[144] This is likely particularly true for steel product manufacturing. However, with sector wide goals of decarbonization and digital transformation, the steel industry is

[140] Perry (March 16, 2018) Increased productivity is eliminating steel industry jobs, not imports. [65]
[141] Watson (2022) Domestic Steel Manufacturing. p. 9. [88]
[142] U.S. Census Bureau (September 13, 2022) Income in the United States. [83]
[143] Watson (2022) Domestic Steel Manufacturing. p. 9. [88]
[144] Vault Firsthand (no date) Steel industry workers. [87]

increasingly looking for more trained or specialized workers.[145] The World Steel Association has a published fact sheet emphasizing the need for skilled workers in metallurgy, materials science, physics, chemistry, engineering, environment, mathematics, information technology and computer science, languages, business, and accountancy.[146]

Table 5.4. Reported job creation estimates for example mini- and micro-steel mills in the U.S.

Facility Name[a]	Year Operational	Annual Steel Output	Facility Footprint		Normalized Jobs (per 770 kton steel)	
		(kton steel)	Perm.[b]	Const.[c]	Perm.[b]	Const.[c]
Mojave Micro Mill, CA (proposed)	2025+	380	400		811	
CMC Mesa Plant (II), AZ	2023	500	186		286	
HighBar LLC, Osceola, AK	2024	600	200	600	257	770
Nucor Steel, Brandenburg, KY	2022	1,200	400		257	
CMC Durant Plant, OK	2017	350	225		495	
Nucor Steel, Davidson Co, NC	2024	430	200	500	358	895
MEAN		**577**			**411**	**833**

a. These six mills are used for comparative purposes throughout the multi-lens analysis of the steel industry. For this, and all other references to these sites, references are detailed in Table 5.7.
b. Permanent jobs
c. Construction jobs

5.2.2 Quality of Life

5.2.2.1 Location

Steel mills do emit fine materials and gasses that can have harmful health effects, like particulate matter, lead, nitrous oxides (NO_x), and sulfur oxides (SO_x), although there are techniques mills can use to trap matter and minimize emissions[147] (see Section 5.3.2). Any mill developed within the carbon management park would be required to submit an environmental impact report and undergo pre-development review and operational monitoring to ensure emissions impacts remain within federal and state determined safety standards.

[145] Maldonado-Mariscal *et al.* (2023) Skills intelligence in the steel sector. [56]
[146] World Steel Association (2021) Working in the steel industry. [94]
[147] World Bank Group (1998) Mini Steel Mills. [89]

Steel mill operations are also loud[148,149] – with most operational equipment emitting noise at levels that require hearing protection for workers.[150] It is possible to design steel mills in ways that diffuse noise levels to minimize noise pollution in the vicinity. One steel mill in New Zealand integrated several noise-minimizing solutions into their facility, and measured noise levels about 0.75 miles from the facility of ~45 decibels, a typical sound level for an urban neighborhood.[151]

5.2.2.2 Multi-use potential

Steel mills are among the most land intensive of the carbon management industries investigated in this report (Appendix D, Figure D.1), and as that land use involves warehousing of large volumes of feedstocks, enclosed buildings housing large manufacturing equipment, and warehousing (and treatment) of products and byproducts, it is unlikely that the land allocated to a steel mill would be well suited for multi-use potential. That being said, there is a plethora of opportunity in co-locating such an industry with other carbon management and clean energy technologies, explored in detail in Section 5.4.3.3.

5.3 Environmental Impacts

5.3.1 Water requirements

5.3.1.1 Minimum volume requirements

Steel mills require water to operate, primarily for cooling, but secondarily for equipment descaling, dust scrubbing and other processes. On average, steel mills that use electric arc furnaces require a water intake of 7,400 gallons of water per metric ton of steel produced, but discharge 7,000 gallons of water (about 94% of intake water), for a net water requirement of 400 gallons per metric ton of steel.[152] It is also notable that the range in water use from plant to plant varies widely, suggesting that there are a variety of process configurations that can minimize water use and water waste. The most comprehensive publicly available assessment of water use in the steel industry was a report published by the World Steel Association (WSA) in 2011.[153] They examined water usage in 8 EAF steel plants (and 17 integrated plants, not discussed here), whose water intake ranged from 290 gallons of water per metric ton of steel produced, to over 18,000 gallons of water per metric

[148] Hojati *et al.* (2016) Determining the noise exposure pattern in a steel company. [37]
[149] Nyarubeli *et al.* (2018) Variability and determinants of occupational noise exposure. [61]
[150] OSHA (no date) Occupational Noise Exposure. [62]
[151] New Zealand Steel (no date) Reducing noise. [60]
[152] World Steel Association (2020) Water management in the steel industry - Fact Sheet. [93]
[153] World Steel Association (2011) Water management in the steel industry - Full Report. [92]

ton of steel.[154] The strongest control on water use intensity was whether water used for cooling was circulated or merely used one time ("once-through cooling"). In regions where water resources are abundant, once-through cooling can have minimal environmental impact, while also being cost effective, but given that only 25% of EAF plants examined by the WSA report used once-through cooling, water-circulation cooling appears to be a well-established technique in the industry.[155]

Discharged water from steel mills can be treated and reused, or returned to the source.[156] The extent of treatment required will depend on the original water composition and its use in the steelmaking process. Water that is used for cooling never actually comes into contact with material or equipment, so does not require the same level of treatment as that used for descaling and dust scrubbing. Water used for these latter purposes could have a significant amount of dissolved solids, including metals and oil and gas residues,[157] that would need to be treated before water could be reused (see Section 8 for a summary of water treatment techniques and applications). If water is recirculated within the steel mill to minimize waste, it needs to be cooled and desalinated between uses. This could be energy and time intensive, but in the context of a carbon management business park, it is also a synergistic opportunity. If a thermal network were integrated into a carbon management park, waste heat in the form of hot process water from the steel mill could potentially supply heat energy to other co-located industries, and the cooled water could be circulated back to the steel mill for reuse.

5.3.1.2 Minimum quality requirements

Water for steel manufacturing can come from a variety of sources, with EAF mills examined by the World Steel Association using freshwater (potable water), groundwater, brackish water, seawater, and other non-potable water as sources.[158] Gray (reclaimed) water, of which there is an abundance in California (see Section 8), could be used similarly, minimizing the impact on local fresh water sources. Depending on the water source used, and its role in the steel making process, a variety of pre-treatment processes may be necessary, all of which are well established techniques. These include biological control or disinfection for reclaimed water, demineralization, desalination, distillation, filtration, reverse osmosis, and softening.[159] For further information, interested readers should refer to Section 8 of this report, as well as the WSA report on water use in the steel industry.

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[154] World Steel Association (2011) Water management in the steel industry - Full Report. p. 31. [92]
[155] World Steel Association (2011) Water management in the steel industry - Full Report. p. 32. [92]
[156] World Steel Association (2020) Water management in the steel industry - Fact Sheet. [93]
[157] World Bank Group (1998) Mini Steel Mills. p. 342. [89]
[158] World Steel Association (2011) Water management in the steel industry - Full Report. p. 32. [92]
[159] World Steel Association (2011) Water management in the steel industry - Full Report. p. 39-40. [92]

5.3.2 Other potential impacts

5.3.2.1 Criteria pollutants from operation

Two sources of atmospheric pollutants should be considered in the context of steel as a carbon management industry. First, there is the production of steel itself, and then there are emissions related to power generation for steel production, which - if it is in the form of oxy-fuel combustion with carbon capture, can have associated non-CO_2 emissions.

In the electric arc furnace (the steel making phase of production), scrap metal is "charged", or combined with DRI, pig iron (from integrated mills) and/or limestone, to add or remove impurities in the steel that control its properties (like strength and ductility). Elements that are separated out of the steel form a metal-oxide rich slag and small amounts of CO2 (not enough to be economically captured) and other gas or fine particulate emissions.[160] The slag is a waste byproduct that can typically be used in other industrial processes (see Section 5.1.3.2), and therefore poses little environmental risk.

Particulate emissions emitted from the EAF (and to a lesser degree from other steps in the steel making process) include particulate matter composed of iron and iron oxides, and depending on the composition of the source iron could also include heavy metals such as zinc, chromium, nickel, lead, and cadmium. Gaseous pollutants such as NO_x, CO, SO_2, and volatile organic compounds (VOCs) can also be emitted.[161,162] These emissions can be captured and scrubbed from facility exhaust streams, to keep facility emissions under regulated limits. Techniques for trapping emissions include locating the EAF in an enclosed building, using hoods to evacuate dust into dust arrestment equipment, using scrubbers to attract gasses, and using equipment like cyclones, baghouses, and electrostatic precipitators to further attract and trap dust. However, regular maintenance and monitoring of facilities is critical to prevent fugitive emissions.[163]

If natural gas (or synthetic natural gas or RNG) is used with oxy-fuel combustion and carbon capture and storage to power some or all of the steel-making processes, emissions associated with such combustion must also be considered. Thus far, this is difficult. There are few detailed studies of the emissions resulting from oxy-fuel combustion, and those emissions seem to be dependent on the fuel used (coal vs. natural gas vs. biomass), the oxygen/fuel ratio, and the combustion technique.[164] However, it appears that overall, gaseous emissions and particulate matter emissions from oxyfuel combustion are

[160] World Bank Group (1998) Mini Steel Mills. p. 342. [89]

[161] Environmental Protection Agency (EPA) (2009) Emission factor documentation. p. 5. [26]

[162] Van Wortswinkel, Nijs (2010) ETSAP - Iron and Steel. p. 6. [86]

[163] World Bank Group (1998) Mini Steel Mills. p. 342. [89]

[164] Senior *et al.* (2013) Emissions from oxyfuel combustion. [71]

considerably lower than emissions related to traditional air-fired combustion.[165,166] Integrating flue gas filtering processes into the oxy-fuel combustion process can also eliminate pollutants from any flue gas stream, as the Allam-Fedtvedt power cycle does for NO_x and SO_x.[167]

Ultimately, any project sited in Kern County, California, including those developed in a carbon management park like that examined here, would be considered through a public process, where the environmental impacts specific to the technologies and fuels being used in any given facility will be reviewed and mitigated in accordance with the California Environmental Quality Act (CEQA).

5.4 Economic Impacts

5.4.1 Business Model

Unlike other carbon management industries investigated in this report (DAC and BiCRS, in Sections 3 and 4, respectively), the capture and sequestration of CO_2 is not a primary objective or product of CO_2-emitting industries. Thus, the only motivations that a CO_2-emitting industry will have to capture and store carbon are financial (if the CO_2 can be sold as a product or for a financial credit), or through pressure, whether regulatory or from consumers. A 2021 feasibility analysis by the Global CCS Institute examined the factors common to commercially operating point source capture facilities, that made them economically viable.[168] At the time, there were 28 operational facilities in the world (as of the writing of this report there are 35, according to the GCCSI facilities database, see Appendix A). Every single one of those operations had at least one of the following characteristics, and all but 1 had at least two:

1. They were capturing CO_2 from the lowest-cost point sources: natural gas processing, fertilizer production, bioethanol production, chemical manufacturing (23 facilities)
2. They sold their CO_2 to enhanced oil recovery (EOR) operations to offset costs (23 facilities).
3. Their country of operation provided grant support, tax credits, or had a government provision for carbon capture (17 facilities.)
4. Their country of operation was Norway, the only nation that implements a carbon tax (2 facilities).

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[165] Senior *et al.* (2013) Emissions from oxyfuel combustion. [71]

[166] Kosowska-Golachowska, M. *et al.* (2022) Pollutant emissions during oxy-fuel combustion of biomass. [48]

[167] Allam, R. *et al.* (2017) Demonstration of the Allam Cycle. p. 5953-5954. [1]

[168] Rassool *et al.* (2021) CCS in the circular carbon economy. p. 7. [67]

Since the publication of GCCSI's report, the outlook for point source carbon capture has become more promising. Recent innovations in "water-lean" capture amine technology is helping the cost of capture decrease, even for industries with more dilute exhaust emissions.[169,170] Additionally, the 2022 Inflation Reduction Act raised the amount of the 45Q tax benefit for CO_2 capture and storage processes other than direct air capture (DAC) to $85 per ton stored,[171] meaning that even at the current state of technological development, every CO_2-emitting industry has the potential to entirely offset the cost of capture carbon with a tax credit (Table 5.1). This is particularly important for industries that are traded on international markets, like steel, in which the need to remain cost competitive allows for very low profit margins and little flexibility for added cost.[172] Additional policies that could further encourage the adoption of carbon capture in the steel industry, specifically, include those that encourage the purchase of low-carbon or clean energy products (e.g. Buy Clean incentives), thereby increasing their market demand, or those that would create a regulatory framework for allowable carbon-intensity of domestically manufactured or purchased products.[173]

5.4.2 Business Costs

For point source carbon capture facilities, capture equipment is most commonly retrofitted onto existing infrastructure, adding to the baseline cost of producing the primary industry output. As mentioned in Section 5.1, the concentration of CO_2 within the gas stream emitted from an industrial facility is proportionally related to the cost of capture. This is illustrated in occurs for two reasons:

1. More dilute streams require larger process equipment. This is because lower concentrations of CO_2 mean a higher total gas volume processed per ton of CO_2. Thus, the total size of equipment also needs to be larger to process the greater volume of gas. Additionally, higher CO_2 concentrations are more reactive - the CO_2 will transfer more rapidly from the source gas to the solvent than at low CO_2 partial pressures - thus speeding the time of the reaction. Faster reactions mean less necessary contact time between source gas and solvent, and thus smaller capture equipment, reducing capital costs.[174]
2. More energy is required to capture more dilute CO_2. At high partial pressures, CO_2 can be captured using "physical" solvents - those in which the CO2 is bound to the surface of the a substance via electro-magnetic attraction, forming a weak bond (called van der Waals bonds) that is easily broken by modestly decreasing the

[169] Jiang, Y. *et al.* (2023) Energy-effective and low-cost carbon capture from point-sources. [44]

[170] Clifford (January 24, 2023) New technique from U.S. national lab promises to strip carbon dioxide. [18]

[171] Carbon Capture Coalition (2022) IRA. p. 2. [10]

[172] I□□ □□□□

pressure or increasing the temperature of the system. In contrast, low-concentration CO_2 generally requires selective "chemical" solvents to be use - those which trap CO_2 by forming stronger chemical bonds, that can only be broken by increasing temperatures significantly. The higher temperatures needed for solvent regeneration directly translate to higher energy needs, and therefore higher cost.[175]

An additional relevant factor to the cost of carbon capture is the scale of deployment. An impact analysis by the Global Carbon Capture and Storage Institute determined that economies of scale could drive cost decreases considerably when moving from pilot scale (thousands of metric tons of capture annually) to commercial scale (hundreds of thousands of metric tons of capture annually), with costs reaching a minimum at capture rates above ~400 thousand metric tons of CO_2 capture per year.[176] In their analysis, economies of scale reduced carbon capture costs for natural gas and coal power generation by about 40% and 20%, respectively. Figure 5.6, adapted from the GCCSI report, illustrates both controls on the cost of point source carbon capture: the x-axis showing how increasing concentrations (partial pressures) of CO_2 in industry flue gas decreases the levelized cost of carbon capture, and the error bars reflecting the range in cost of capture at any given CO_2 concentration due to the scale of capture at any given facility.

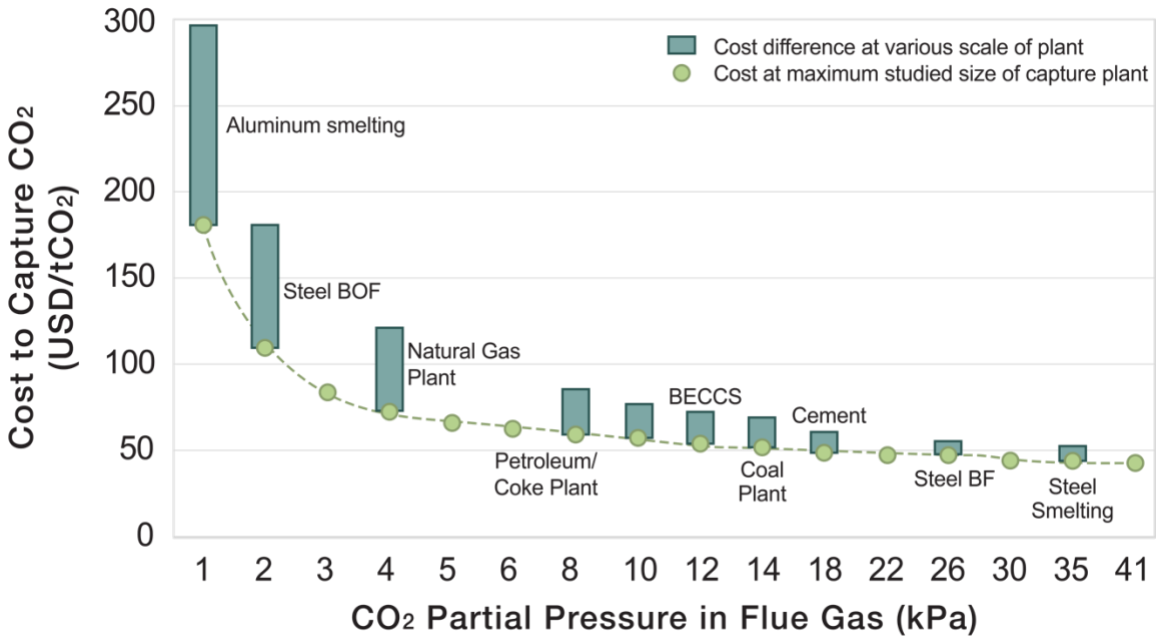


FIGURE 5.6. Levelized cost of carbon capture per metric ton CO_2 as a function of CO_2 partial pressure and operational scale, with the largest capacity capture facilities demonstrating the lowest cost at any given partial pressure. Adapted from Kearns et al. (2021) CCS readiness and costs.

[175] Kearns *et al.* (2021) CCS readiness and costs. p. 26-27. [45]

[176] Kearns *et al.* (2021) CCS readiness and costs. p. 31. [45]

To compare the relative costs of different carbon management industries (DAC, BiCRS, or point source capture), a 'Lifetime Cost Assessment' (LCA) model is used. The LCA is the total cost per metric ton CO_2 resulting from the cost of building the facility (capital costs), the cost of maintenance and labor (operational costs), and the cost of energy (heat + electricity), over the lifetime of the plant. However, for a micro steel mill, the cost of carbon capture is a comparatively small addition to the cost of building the mill. For simplicity, we assess the costs of creating the mill, and of capturing carbon from the mill separately. A micro steel mill that uses scrap and clean energy (0 tons CO_2 emissions per ton steel) would cost about $398-848 per ton steel produced. A scrap mill that used oxy-fuel combustion for energy would cost ~$407-903 per ton steel produced, with the added cost of CO_2 capture being ~$68-112 per ton CO_2. A mill that used direct reduced iron (DRI) with point source carbon capture and oxy-fuel combustion would cost ~$586-975 per ton steel produced, and the average cost of CO_2 capture would be $75-114 per ton CO_2. These estimated ranges are broken down in Table 5.5 and explained in detail below.

Table 5.5. Levelized cost per ton steel produced, by steel mill configuration.

Cost (USD per ton steel)[a]	Scrap-EAF + solar	Scrap-EAF + oxyfuel	DRI-EAF w. CCUS + oxyfuel	DRI-EAF + hydrogen
Cost to build steel mill (CapEx)	$88-125	$88-125	$88-125	$114-194
Feedstock (scrap steel or iron pellet)	$192-557	$192-557	$81-154	$157-267
Fixed operation & maintenance (OpEx)	$77-116	$77-116	$77-116	$90-153
Energy (solar, natural gas or green H_2)	$41-50	$40-88	$243-433	$226-508
Total Levelized Cost	**$398-848**	**$397-886**	**$489-828**	**$587-1,122**
Oxy-fuel combustion (Cap+OpEx)	--	$10-17	$59-97	--
DRI point source capture (Cap+OpEx)	--	--	$38-50	--
Total Levelized Cost Including Capture	**$398-848**	**$407-903**	**$586-975**	**$587-1,122**

a. See text for references for each estimated cost.

5.4.2.1 Cost to Build (upfront costs)

We can get a rough estimate of the capital expenditures, or cost to build a steel mini mill based on the six example mills listed in Table 5.5, which have been recently built, or are currently in development (detailed references for each of these sites is provided in Table 5.7). These mills, which produce between 350 and 1,200 thousand tons of steel annually, would cost $250 million to $1.7 billion dollars to construct. Normalizing those capital costs to the size of a steel mill that could capture up to 1 million tons of CO_2 annually (while producing ~770 thousand tons of steel), gives a range in capital costs between ~$460 million and $1.9 billion (average value is $680 million USD). If we annualized these costs, assuming a facility lifetime of 30 years and a capital recovery factor of 12.5% (see Section

3.4.2.1 for a detailed explanation of this calculation), the levelized capital cost of these normalized facilities ranges from ~$73-172 USD per ton steel produced. Such values closely approximate the estimated capital costs of DRI-EAF steel mills reported in the International Energy Agency (IEA)'s 2020 report on iron and steel technology.[177] They report a minimum CapEx for DRI-EAF of $88 USD per ton steel produced, but include an ~40% uncertainty to account for cost variability across regions, resulting in a CapEx range of $88-125. For the sake of consistency with the published literature, this is the CapEx range we employ in our levelized cost analysis (table 5.5). It is important to note that we approximate the same CapEx value for the scrap-EAF and DRI-EAF mills, and the added capital costs of CO_2 stemming from point source capture equipment (in the DRF-EAF with CCUS + oxy-fuel scenario) is accounted for separately.

Table 5.6. Reported capital expenditures for new or developing EAF mills.

Facility Name[a]	Year Operational	Annual Steel Output	Capital Costs (CapEx)	Normalized CapEx (per 770k tons steel)
		(kton steel)	million USD	million USD
Mojave Micro Mill, CA (proposed)	2025+	380	$350	$709
CMC Mesa Plant (II), AZ	2023	500	$300	$462
HighBar LLC, Osceola, AK	2024	600	$500	$642
Nucor Steel, Brandenburg, KY	2022	1,200	$1,700	$1,091
CMC Durant Plant, OK	2017	350	$250	$550
Nucor Steel, Davidson Co, NC	2024	430	$350	$627
MEAN		**577**		**$680**

a. These six mills are used for comparative purposes throughout the multi-lens analysis of the steel industry. For this, and all other references to these sites, references are detailed in Table 5.7.

5.4.2.2 Operational Costs

Operational costs fall into two categories: fixed costs (labor and maintenance) and variable costs (price of feedstocks). For scrap mills, the feedstock is steel scrap, which due to supply chain disruptions and the COVID-19 coronavirus, fluctuated significantly in recent years. Between January 2020 and March 2023, steel scrap ranged from $192-557 USD per ton.[178] Iron ore, the raw material feedstock for DRI-EAF, has also fluctuated, ranging from $81-154 USD in 2022 and 2023.[179] Reported fixed operational costs range from $77-116 USD.[180,181]

[177] [illegible]

[178] SteelBenchmarker (April 24, 2023) Price History: Tables and Charts. [74]

[179] Trading Economics (no date) Iron Ore. [82]

[180] [illegible]

[181] M'barek *et al.* (2022) Global steel production costs. [54]

5.4.2.3 Energy Costs

Scrap-EAF mills require ~0.95MWh of energy production per ton steel (see Table 5.2), and DRI-EAF mills with point source capture require about 5 MWh per ton steel (see Section 5.1.3.2). If powered by solar with industrial scale battery storage, energy costs are estimated to be $43-52 USD/MWh ($28-37/MWh for solar energy + $15/MWh for battery storage).[182] Natural gas prices, based on a three year average, range from $43-92/MWh.[183] Combining these rates, we obtain an estimated cost of energy of $41-50 USD per ton steel for a scrap-EAF mill powered by solar, $40-88 USD per ton for a scrap-EAF mill powered by natural gas, and $211-461 USD per ton for a DRI-EAF mill with point source capture powered by natural gas. A steel mill powered by hydrogen would produce would not require the infrastructure or additional energy demand needed for point source capture. Thus, a DRI-EAF mill would require only about 4.7 MWh per ton steel produced. Costs for fossil-free green hydrogen range from ~$1.60-3.60 USD per kg (Section 6), or about $48-108 per MWh. Thus, green hydrogen energy costs for a scrap-EAF mill would be about $46-103 USD per ton steel, and for a DRI-EAF mill would be about $226-508.

5.4.2.4 Carbon Capture Costs

Finally, for mini-mills that are emitting appreciable CO_2, the capital and operational costs of capture via oxy-fuel combustion and point-source capture from DRI are additive to the costs of simply operating the mill. If these costs can remain under the $85 USD federal tax credit 45Q,[184] then carbon capture can be cost-effective, or even serve as an additional form of revenue. In the IEA's 2020 economic analysis of steel production, they estimated the combined capital and operational costs of post-combustion point source carbon capture, when applied to a DRI-EAF mill, to range from $38 to 50 USD per ton of steel. Given that about 0.42 tons of CO_2 can be captured via DRI point source capture per ton of steel made, the capture cost per ton CO_2 is $90-119 USD, within the cost range reported by the GCCSI (Figure 5.6).[185] Separately, a 2017 European techno-economic study of oxy-fuel combustion provided an estimated cost range of €71-116 EUR per ton CO_2 captured in 2014 currency. Converting those values to 2023 USD,[186,187] equates to an oxy-fuel combustion cost per ton of CO_2 captured of $68-112 USD.

A scrap-EAF mill that uses oxy-fuel combustion with capture produces, on average, 0.15 tons of CO_2 per ton steel (Table 5.2). At a cost of $68-112 USD per ton of CO_2, there would be an added net levelized cost to steel production of $10-17 USD per ton of steel (Table 5.5). A DRI-EAF mill, which is much more energy-intensive, would produce, on average, 0.87 tons of CO_2 via oxyfuel combustion, resulting in an added levelized cost to steel

[182] Lazard (October 2021) Levelized cost of energy analysis. [52]

[183] Gamage *et al.* (March 9, 2023) Forging a clean steel economy in the United States. [34]

[184] Carbon Capture Coalition (2022) IRA. [10]

[185] Kearns *et al.* (2021) CCS readiness and costs. p. 31. [45]

[186] Macrotrends (no date) Euro Dollar Exchange Rate. [55]

[187] Bureau of Labor Statistics (no date) CPI Inflation Calculator. [8]

production of $59-97 USD per ton steel. The additional 0.42 tons of CO_2 captured via point source capture in a DRI-EAF mill add $38-50 USD per ton steel.[188] The total cost of carbon capture for a DRI-EAF mill with oxy-fuel combustion is $97-147 USD per ton of steel produced, and an average cost of CO_2 capture of $75-114 USD per ton CO_2.

5.4.3 Regional benefits

5.4.3.1 Proximate feedstocks

The primary feedstocks for mini mills are scrap steel or pelletized iron ore. Kern County, while not rich in geologic iron resources, has an advantage in its location along major rail and interstate routes, and adjacent to the Pacific Coast and associated shipping lanes. Abundant domestic and international steel scrap could be readily available for processing in this region. Pelletized iron could be similarly shipped along such routes. Additionally, because steel-making is such an energy-intensive, close proximity to abundant clean energy, whether in the form of solar energy, green hydrogen, or oxy-fuel combustion of RNG or biomass-derived syngas, Kern County (and a potential carbon management park) offer significant opportunities for accessible clean energy.

5.4.3.2 Proximate consumers

The same proximity to highly populated areas, as well as rail, interstate and shipping routes are also advantageous for the sale of steel, a product that is traded on an international marketplace.

5.4.3.3 Co-location advantages

Steel produces a relatively smaller amount of CO_2 emissions than BiCRS/DAC - and thus development of dedicated CCUS compression, transport and storage infrastructure may not be economically viable for a stand-alone facility.[189] Co-location and sharing infrastructure with other industries that produce larger amounts of CO_2 could allow for cost-effective capture of CO_2 from steelmaking, even in smaller plants that produce significantly less than 1 million tons of CO_2 annually.

[188] [illegible]

[189] [illegible]

Table 5.7. References for representative micromill facilities in the U.S.

Facility Name	Year Operational
Mojave Micro Mill, CA (proposed)	Cox (2022) 'Green steel' plant proposed for Mojave.
CMC Mesa Plant (II), AZ	SE Mesa plant double steel production. East Valley Tribune. Published online April 20, 2021. Accessed March 19, 2023 from https://www.eastvalleytribune.com/money/se-mesa-plant-double-steel-production/article_78424896- a137-11eb-816a-d787277d5d29.html.
	CMC Steel Arizona - Breaking Ground on the World's First Combination Micro Mill. Queen Creek Independent. Published online January 6, 2022. Accessed March 19, 2023 from https://www.yourvalley.net/queen-creek-independent/stories/cmc-steel-arizona-breaking-ground-on-the-worlds-first-combination-micro-mill,279239.
	CMC sees spring start for Arizona micro-mill. Association for Iron & Steel Technology. Published online January 12, 2023. Accessed March 30, 2023 from https://www.aist.org/news/steel-news/2023/january/9-13-january-2023/cmc-sees-spring-start-for-arizona-micro-mill.
HighBar LLC, Osceola, AK	Chen, I. US' HighBar plans to invest rebar mill in Arkansas. Published online November 3, 2022. Accessed March 19, 2023 from https://yieh.com/en/NewsItem/137424.
	Kamczyc, A. Highbar LLC announces site for first rebar mill. Recycling Today. Published online November 2, 2022. Accessed March 19, 2023 from https:// www.recyclingtoday.com/news/highbar-llc-announces-site-for-first-rebar-mill/.
Nucor Steel, Brandenburg, KY	Gregg, J. The New Steel City: Brandenburg Braces for Massive Steel Plant. Spectrum News 1. Published online July 19, 2019. Accessed March 19, 2023 from https://spectrumnews1.com/ky/louisville/news/2019/07/19/small-kentucky-town-ready-for-big-steel-plant.
	Otts, C., Ragsdale, T. Nucor starts work on Brandenburg, Ky. steel mill. WDRB.com. Published online Octobter 23, 2020. Accessed March 19, 2023 from https://www.wdrb.com/in-depth/nucor-starts-work-on-brandenburg-ky-steel-mill/article_68b6530c-156b-11eb-8d81-ffc75a1b85c1.html.
	New Nucor Steel Brandenburg Plate Mill Rolls First Plate. Nucor. Published online January 3, 2023. Accessed March 19, 2023 from https://nucor.com/news-release/19471.
CMC Durant Plant, OK	Ground broken for new steel mill in Durant. News On 6. Published online April 30, 2016. Accessed March 19, 2023 from https://www.newson6.com/story/ 5e360f752f69d76f62039b57/ground-broken-for-new-steel-mill-in-durant.
	Commercial Metals Co. receives air permit. The Journal Record. Published online February 4, 2016. Accessed March 19, 2023 from https://journalrecord. com/2016/02/04/commercial-metals-co-receives-air-permit/.
	Commercial Metals Company selects Durant, Okla., for new micro mill. Oklahoma Commerce. Published online July 30, 2015. Accessed March 19, 2023 from https://www.okcommerce.gov/commercial-metals-company-selects-durant-okla-for-new-micro-mill/.

Facility Name	Year Operational
Nucor Steel, Davidson Co, NC	Doss-Raines, J. Nucor Steel to host two town hall meetings to get to know the Davidson County. The Dispatch. Published online February 8, 2023. Accessed March 19, 2023 from https://www.the-dispatch.com/news/nucor-steel-to- host-two-town-hall-meetings-to-get-to-know-the-davidson-county/article_5165f657-eafe-56d5-a30e-eaa8d5d1e3b5.html.
	Nucor to build new $350 million micro mill in North Carolina. Industry Week. Published online April 11, 2022. Accessed March 19, 2023 from https://www.industryweek.com/leadership/growth-strategies/article/21238679/nucor-to-build-new-350-million-micro-mill-in-north-carolina.

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Clean Energy Technologies

6. Hydrogen Production

TECHNOLOGY AT A GLANCE

- There are many ways to produce hydrogen, which are at different degrees of technical readiness. Here we examine blue hydrogen (commercially operational), green hydrogen via electrolysis (commercial demonstration phase), and green hydrogen via biomass (pilot and early demonstration phase).[1]
- Current costs per kilogram H_2 produced: $1.30-10.60 USD/kg H_2
- Current cost of CO_2 capture: $125-257 USD/ton CO_2 (green hydrogen from biomass), ~$82 USD/ton CO_2 (blue hydrogen from steam methane reforming+carbon capture and storage [SMR+CCS])
- Projected costs reductions per kilogram H_2 produced at scale: 20-50%
- Key advantages of this technology in Kern County: close proximity to feedstocks for some production methods (agricultural waste for green hydrogen from biomass, natural gas for blue hydrogen from SMR+CCS), located within the largest hydrogen market in the U.S., abundant renewable energy can make green hydrogen via electrolysis cost-competitive with other techniques
- Key concerns for this technology in Kern County: high energy and water demands for green hydrogen via electrolysis, potential for air pollutants - particularly from blue hydrogen via SMR+CCS - warrants further investigation, the hydrogen market is still quite nascent and will require large infrastructure investments before it can scale significantly

[1] Values in this section are summarized from the suite of references cited herein, and are explained in further detail in each subsequent section.

6.1 Technology Summary

In looking for alternative fuels to traditional hydrocarbons (including gasoline and diesel), both scientific experts and policymakers have turned to hydrogen as a potential fuel of the future, as it does not generate carbon emissions when burned.[2] Hydrogen is highly abundant, but most commonly is chemically bound in the compounds of other familiar substances, like water (H_2O) or methane (CH_4, which is natural gas). To use hydrogen as a fuel, it must be isolated from those compounds.[3] In this section, we present a brief overview of the variety of processes available to generate hydrogen gas (H_2), with a focus on two forms of hydrogen that are considered to produce little or no CO_2 emissions in their production: green and blue hydrogen.

6.1.1 Methods of Hydrogen Production

Hydrogen can be produced via several different methods, which for short-hand discussions have been categorized into a color key system, with each color indicating the production technique. Understanding this system is useful for research and discussions about the hydrogen industry and when thinking about the viability and trade-offs of given production methods. (Note, hydrogen itself is a colorless gas; the color system is simply a convenient notation device, but describes only the difference in hydrogen generation technique. There is no difference in the visual, physical, or chemical properties of hydrogen gas derived from these different production methods).[4]

While most applications of this color key system use commonly agreed upon definitions for each color, there is not a regulatory or industry standard, so some sources may have differences in what processes they include under each color. In this section, we provide a brief overview of the hydrogen labeling system, giving the commonly agreed upon definitions of each color. Then, we will examine the three forms of hydrogen production that would be most relevant for consideration in a carbon management and clean energy industrial park: green hydrogen via electrolysis, green hydrogen via biomass, and blue hydrogen.

6.1.1.1 The Hydrogen Color System

Unless otherwise noted, all definitions of the hydrogen color key system are derived from National Grid, an electricity distribution company operating in the United States and United Kingdom.[5]

Green hydrogen production refers to production techniques that generate no greenhouse gas byproducts. Most commonly, this is achieved via a process known as electrolysis,

[2] FuelCellWorks (November 28, 2022) 'Gold Hydrogen' Is an Untapped Resource. [31]
[3] EPA (September 13, 2022) Green Vehicle Guide: Hydrogen Fuel Cell Vehicles. [28]
[4] National Grid (no date) Hydrogen Colour Spectrum. [50]
[5] National Grid (no date) Hydrogen Colour Spectrum. [50]

wherein clean energy (like solar or wind) is used in an electrochemical reaction to split water molecules into hydrogen and oxygen. However, other non-carbon emitting techniques, such as gasification of biomass to form pure streams of H_2 and CO_2 gasses, combined with carbon capture, also qualify as green hydrogen.[6]

Blue hydrogen production refers to the conversion of methane (natural gas) to hydrogen via a process called steam reforming, which – like gasification from biomass – generates both hydrogen and carbon dioxide. In blue hydrogen generation, generated CO_2 is captured via point source capture technologies (see Section 5) reducing the carbon-intensity of hydrogen generation.

Gray hydrogen production also refers to steam reforming methane (natural gas), but does not incorporate the carbon capture processes necessary to reduce emissions. Currently, gray hydrogen is the most commonly used production process to generate hydrogen.

Black and brown hydrogen production relies on using pure coal or lignite (brown coal) to generate hydrogen, by gasification of the coal resulting in hydrogen as a byproduct. This is understood to be one of the most environmentally harmful ways to produce hydrogen.

Pink hydrogen production refers to the process of electrolysis, where water is split into hydrogen and oxygen, akin to green hydrogen. Unlike green hydrogen, though, it relies on nuclear power to sustain the electrochemical reaction. Some sources refer to this with other similar colors, like purple or red.[7]

Turquoise hydrogen production involves a process called methane pyrolysis, which converts methane to hydrogen and solid carbon, called "carbon black."[8] Carbon black has many industrial uses, but this method of hydrogen production has yet to operate at a commercial scale.

Yellow hydrogen production is a less commonly used and newer term, referring specifically to hydrogen production via electrolysis fueled by solar power. As such, yellow hydrogen is a subcategory of green hydrogen.

White hydrogen refers to hydrogen that does not need to be produced, but that is naturally occurring in geologic formations and could be accessed via fracking. At present, there are no plans or strategies to mine hydrogen, and opinions are mixed as to whether naturally-occurring hydrogen gas even exists. The National Renewable Energy Laboratory (NREL) states that hydrogen gas is not naturally-occurring, but there is growing optimism from other scientists that naturally-occurring hydrogen may be abundant beneath the Earth's surface.[9]

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[6] Cormos (2023) Green hydrogen production from decarbonized biomass gasification. [20]

[7] Willige (July 28, 2022) The colors of hydrogen. [84]

[8] Willige (July 28, 2022) The colors of hydrogen. [84]

[9] Coy (February 27, 2023) A Gold Mine of Clean Energy May Be Hiding Under Our Feet. [21]

6.1.1.2 Envisioning hydrogen production in Kern County

Given the current economy, climate, and resources of Kern County, and the developmental objectives of a carbon management and clean energy industrial park, only some hydrogen production approaches were identified as warranting exploration in this study. The following production methods were ruled out:

- Black/brown and pink hydrogen production make little sense to explore at this juncture, given Kern County's current and anticipated energy mix.
- White hydrogen production is still within very early stages of technological development and will require significant further research before it is ready for commercial demonstration.
- Turquoise hydrogen is still within very early stages of development. Although it is not examined extensively here, production is very similar to other forms of biomass gasification and pyrolysis, which are described in detail in Section 4.
- Yellow hydrogen is a type of green hydrogen, and thus will be examined briefly in the discussion of hydrogen via electrolysis.
- Gray hydrogen production, given its large, unmitigated greenhouse gas emissions footprint, is incompatible with the park's guiding principle of hosting carbon management and clean energy industries.

Green hydrogen (via electrolysis or biomass gasification) and blue hydrogen production are potential clean energy or carbon management technologies that could feasibly be adopted in a Kern County carbon management park, and we explore each of these in this report. Given that more than one production method can be classified as 'green hydrogen,' the nomenclature used in this report will always specify both the color key and the process of production, to avoid ambiguity: hydrogen via electrolysis (green), hydrogen via biomass gasification (green), and hydrogen via steam methane reforming (SMR) + CCS (blue). Finally, because hydrogen production via biomass gasification with carbon capture is a form of Biomass with Carbon Dioxide Removal and Storage (BiCRS), most of the information on this method of hydrogen production is also contained in the BiCRS/BECCS section of this report (Section 4) and is cross-referenced accordingly.

6.1.2 Green and Blue Hydrogen Description: How it Works

6.1.2.1 Green hydrogen via Electrolysis

Hydrogen production via electrolysis involves using an electric current to drive an electrochemical reaction in which water is split into its constituent elements, hydrogen and oxygen:[10]

$$H_2O \rightarrow H_2 + \tfrac{1}{2}O_2 \qquad \text{(R6.1)}$$

[10] AFDC (no date) Hydrogen Production and Distribution. [6]

There are a variety of machines, called electrolyzers, that can sustain this electrochemical reaction to produce hydrogen, using varying techniques, which are reviewed here.

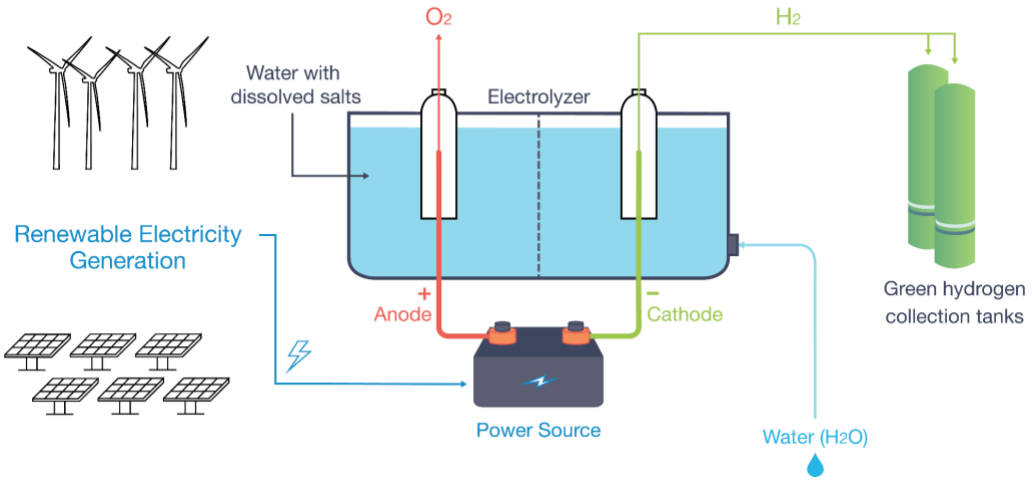


Figure 6.1. Schematic of the process of producing hydrogen via electrolysis: renewable energy provides electricity to power a cathode and anode placed in a water + dissolved salt solution. The electric current created breaks water (H_2O) molecules into hydrogen and oxygen.

The most well-established method, alkaline electrolysis, has existed for more than two centuries. Alkaline electrolysis uses an electrochemical cell, where a cathode and anode are placed in an electrolyte solution, which is a water-based solution with salts (Figure 6.1).[11] When voltage is applied to the cell, water molecules are reduced by electrons at the cathode to produce hydrogen gas and negatively charged hydroxide (OH^-). The hydroxide ions will be electrically attracted to the anode, and by placing a membrane between the anode and cathode, the hydrogen gas molecules can be separated from the negatively charged hydroxide ions. At the anode, the hydroxide ions are oxidized, producing oxygen gas, and releasing water molecules and electrons back to the electrolyte solution (see reactions R6.2 + R6.3):[12]

Cathode reaction: $2H_2O + 2e^- \rightarrow H_2 + 2OH^-$ (R6.2)

Anode reaction: $2OH^- \rightarrow \frac{1}{2}O_2 + H_2O + 2e^-$ (R6.3)

Hydrogen gas is separated from the electrolyte solution to be dried (removing any H_2O vapor), cleaned (involving the removal of oxygen impurities),[13] and depending on the end use, compressed.[14] The reactions in the electrolyte solution (R6.2 + R6.3) generate heat; if this heat is harnessed during the process, it can help improve the cell's overall energy

[11] Lichner (March 26, 2020) Electrolyzer overview. [47]
[12] Brauns, Turek (2020) Electrolysis review. [12]
[13] Brauns, Turek (2020) Electrolysis review. [12]
[14] Lichner (March 26, 2020) Electrolyzer overview. [47]

efficiency.[15] Alkaline electrolysis represents a *type* of electrochemical cell, which is often used as a kind of battery. For a general explanation of electrochemical cells and reduction-oxidation reactions, please see Section 7.1.1 of this report.

Most new hydrogen via electrolysis projects today use a different process that relies on a proton exchange membrane (PEM).[16] Here, instead of a liquid electrolyte solution, water is pressed through a stack of two electrodes with a polymer membrane in between (Figure 6.2). At the anode, the water reacts to form oxygen, hydrogen ions (H^+), and electrons; the hydrogen ions can then move selectively across the membrane, a specialty solid plastic material,[17] towards the cathode.[18] The electrons are moved to the cathode side as well through an external circuit, as they cannot pass through the membrane.[19] On the cathode side, the hydrogen ions and electrons combine, forming hydrogen gas.[20]

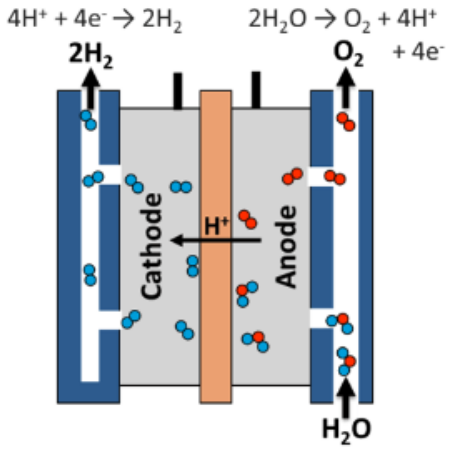


Figure 6.2. Schematic of a proton exchange membrane. Image credit: U.S. Department of Energy.[21]

There is a third electrolysis technology—solid oxide electrolysis (SOE)—that is rising in prominence, but alkaline and PEM systems are far more common for commercial applications. It is explored briefly here for comprehensiveness, but future sections on hydrogen via electrolysis primarily focus on alkaline and PEM systems. The electrolyte in these systems is a solid ceramic that selectively allows negatively charged ions to pass through at high temperatures—in this case, the negative ion is oxygen (O^{2-}).[22] Water enters at the cathode as steam, where it combines with negative ions brought in via the external

[15] Lichner (March 26, 2020) Electrolyzer overview. [47]
[16] Lichner (March 26, 2020) Electrolyzer overview. [47]
[17] EERE (no date) Hydrogen Production: Electrolysis. [58]
[18] EERE (no date) Hydrogen Production: Electrolysis. [58]
[19] EERE (no date) Hydrogen Production: Electrolysis. [58]
[20] EERE (no date) Hydrogen Production: Electrolysis. [58]
[21] EERE (no date) Hydrogen Production: Electrolysis. [58]
[22] EERE (no date) Hydrogen Production: Electrolysis. [58]

circuit to form hydrogen gas and O^{2-}.[23] Once formed, the oxygen ions pass through the solid ceramic membrane to the anion, where the oxygen ions react to form oxygen gas and electrons that will supply the external circuit.[24]

Many projects currently emphasize "power-to-hydrogen" or "power-to-gas" initiatives, where excess renewable energy—when it is available from the grid—is channeled to electrolyzers to create hydrogen.[25, 26]

6.1.2.2 Green Hydrogen via Biomass Gasification

There are a variety of ways to treat biomass in order to produce an energy-rich product and CO_2 byproduct that can be captured for permanent storage, which are detailed in Section 4 of this report. The most relevant in the context of hydrogen is a process called gasification, a two-step process in which first, biomass is reacted with steam and oxygen at high temperatures (>700°C) and pressure, converting it into gaseous components – primarily CO, CO_2, and H_2.[27] In the second step, called a water-gas shift reaction, the carbon monoxide (CO) is reacted with water to produce more CO_2 and H_2, along with a small amount of heat.[28] The resulting products are two streams of high-purity gasses: CO_2 for permanent storage, and H_2 for fuel use. Pyrolysis, the high-pressure and high-temperature process used to create turquoise hydrogen from methane, is a technique that can also be applied to biomass to produce CO_2 and a variety of hydrocarbon byproducts, and is also detailed further in Section 4.

6.1.2.3 Blue Hydrogen via Steam Methane Reforming (SMR) + CCS

Hydrogen via steam methane reforming (SMR) + CCS relies on an interconnected series of processes to transform methane (CH_4) and water (H_2O) into hydrogen (H_2) and CO_2. In the initial SMR reaction, steam reacts with methane in a high-pressure container with a catalyst to produce syngas, a mixture of hydrogen, carbon monoxide, and carbon dioxide.[29] As an endothermic reaction, SMR requires heat for the reaction to proceed—requiring about 206 kJ of heat energy per mol of methane.[30,31] (Steam reforming can be used to generate hydrogen from other hydrocarbon fuels, like propane or gasoline, but SMR is the most

[23] EERE (no date) Hydrogen Production: Electrolysis. [58]
[24] EERE (no date) Hydrogen Production: Electrolysis. [58]
[25] AFDC (no date) Hydrogen Production and Distribution. [6]
[26] Shibata (2015) Hydrogen Production from Variable Renewables. p. 27-28. [70]
[27] EERE (no date) Hydrogen Production: Biomass Gasification. [57]
[28] EERE (no date) Hydrogen Production: Biomass Gasification. [57]
[29] Student Energy (no date) Steam Methane Reforming. [74]
[30] Student Energy (no date) Steam Methane Reforming. [74]
[31] National Research Council and National Academy of Engineering (2004) The Hydrogen Economy. p. 199. [51]

common choice for hydrogen production, as it is the cheapest and most efficient.[32,33]) Like gasification, the next step is typically a water-gas shift reaction, where the carbon monoxide generated in SMR is reacted with more steam in the presence of a catalyst to form more hydrogen, carbon dioxide, and a small amount of heat.[34] The final step, pressure-swing adsorption, removes the carbon dioxide and other gasses from the final products, leaving a pure stream of hydrogen gas.[35]

Once separated from the hydrogen gas stream, the carbon dioxide generated in the SMR and water-gas shift steps can be purified, compressed, and transported for permanent underground storage, preventing it from entering the atmosphere and contributing to climate change. In gray hydrogen production (from SMR without CCS), for every kilogram of hydrogen produced, approximately 9 kilograms of CO_2 is generated.[36] With carbon capture and storage attached, the estimated emissions of SMR hydrogen production drops to 1-5 kilograms of CO_2 generated per kilogram of hydrogen.[37] Although this reduces the impacts of SMR, it does not make the process carbon-neutral—blue hydrogen still releases CO_2 into the atmosphere. This is explored in further detail in Section 6.3 on the environmental impacts of hydrogen production.

6.1.3 State of Development

Blue hydrogen via SMR + CCS, green hydrogen via electrolysis and green hydrogen from biomass are all commercially operational processes that are ready to be scaled up, but hydrogen production from electrolysis and biomass gasification in particular are currently deemed too costly to be competitive with less environmentally-friendly hydrogen production methods.

In addition to the hydrogen production methods detailed here, and in the color classification summary (Section 6.1.1.1), there are several emerging hydrogen production techniques that are still in the early research and development stage. It is beyond the scope of this study to detail each of these emerging technologies, but a list of their names is provided for the interested reader who would like to explore further. Hydrogen production techniques still in the experimental phase include processes like photo-electrochemical solar water splitting, solar high-temperature thermochemical cycles, high-temperature electrolysis, photo-biological conversion, bio-derived conversion, microbial conversion and generating hydrogen from aluminum scrap.[38]

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[32] Student Energy (no date) Steam Methane Reforming. [74]
[33] AFDC (no date) Hydrogen Production and Distribution. [6]
[34] Student Energy (no date) Steam Methane Reforming. [74]
[35] Student Energy (no date) Steam Methane Reforming. [74]cf
[36] Simon *et al.* (August 13, 2021) Economics of Hydrogen Energy. [71]
[37] Simon *et al.* (August 13, 2021) Economics of Hydrogen Energy. [71]
[38] Bezdek (2019) The hydrogen economy. [8]

Below, we provide brief summaries of extant companies or projects that are representative of the three hydrogen production techniques explored here.

6.1.3.1 Example projects

Electrolysis: Air Liquide, Bécancour, Québec

Air Liquide's facility in Bécancour is discussed at length in Section 6.1.4, as a case study for operational needs of electrolysis. This facility has the largest operating electrolyzer of its kind in the world—a 20 MW PEM electrolyzer developed with Cummins technology.[39] This 20 MW capacity was obtained by a four-module configuration of HyLYZER 1000-30 units, which are 5 MW each.[40] The facility is run using grid hydropower resources from Hydro-Québec, an almost-all renewable source of energy.[41]



Figure 6.3. Digital rendering of the planned alkaline electrolysis facility in Lancaster, California, under construction by Element Resources. Image credit: Element Resources.

Electrolysis: Element Resources, Lancaster, California

At the planned Lancaster Energy Center, Element Resources intends to set up an electrolysis site on 1,165 acres with an electrical capacity of 135 MW using alkaline electrolysis.[42] The primary reason for the large land footprint is the electricity demand, which will be met using solar photovoltaic (PV) panels installed on-site. Their estimated hydrogen output per year, once fully operational, is 18,750 metric tons per year.[43]

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[39] Air Liquide (February 8, 2021) World's Largest PEM Electrolyzer. [2]

[40] Collins (January 27, 2021) World's largest green-hydrogen plant inaugurated. [19]

[41] Air Liquide (February 8, 2021) World's Largest PEM Electrolyzer. [2]

[42] Element Resources (no date) Lancaster Energy Center. [24]

[43] Element Resources (no date) Lancaster Energy Center. [24]

Biomass Gasification: Mote, Los Angeles, California

Mote, a Culver City-based cleantech startup, is planning to build a $100 million biomass to hydrogen energy plant with carbon sequestration on 5 acres of unincorporated land in Kern County, pending securing financing, government approval and permits.[44] The plant will extract carbon dioxide and hydrogen via gasification from wood waste from farms, forestry, and other resources.[45] The hydrogen gas will be sold to hydrogen fuel station operators, and the CO_2 will be sequestered into deep underground saline aquifers or retired oil wells. Mote expects to produce approximately 7,000 metric tons of carbon-negative hydrogen (green hydrogen) annually, which translates to ~150,000 metric tons of CO_2 captured from biomass and available for permanent sequestration.[46]

Mote's business model will provide cost-competitive green hydrogen by partly offsetting their costs with income from the storage of CO_2. They will either take advantage of carbon removal credits in the voluntary carbon credit market, or of rebates from the federal tax credit for CCS projects (45Q) as well as California's Low Carbon Fuel Standard (LCFS).[47] In May 2022, Mote announced that they had secured commitments for over 450 thousand tons of feedstock for their production.[48] Working with Fluor, an industry leading engineering, procurement and construction (EPC) firm, to execute the Front-End Loading 2 (FEL-2), Mote plans to begin construction in 2023 and be fully operational by 2025.[49] A digital rendering of their planned facility is shown in Figure 6.4.

Steam Methane Reforming: Air Products, Texas & Louisiana

Air Products has deployed retrofitted carbon capture to two existing hydrogen via SMR facilities in Texas, and is now planning a more ambitious project: building the world's largest SMR + CCS facility in Louisiana, planned to go online in 2026.[50] The Louisiana Clean Energy Complex webpage states they expect to capture over 5 million tons of CO_2 annually from SMR + CCS hydrogen production, expecting that they'll capture 95% of the CO_2 generated during the process.[51] According to Air Products, this would position them to be the largest CCS plant in the world. If they can attain this 95% capture rate in practice, it would be a higher capture rate than any reported estimates for SMR with CCS found in the literature during the preparation of this report. Total planned investment for the project amounts to $4.5 billion, and the project would create an estimated 170 permanent jobs and another 2,000 positions during the construction phase.[52]

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[44] Fine (January 3, 2022) Clean tech startup Mote unveils plans for $100M plant. [30]
[45] Temple (February 15, 2022) Fuel plant will use agricultural waste to combat climate change. [76]
[46] Temple (February 15, 2022) Fuel plant will use agricultural waste to combat climate change. [76]
[47] Temple (February 15, 2022) Fuel plant will use agricultural waste to combat climate change. [76]
[48] BusinessWire (May 24, 2022) Mote Enters Advanced Stage of Engineering Design. [14]
[49] BusinessWire (May 24, 2022) Mote Enters Advanced Stage of Engineering Design. [14]
[50] Air Products (no date) Carbon Capture. [3]
[51] Air Products (no date) Louisiana Clean Energy Complex. [4]
[52] Air Products (no date) Louisiana Clean Energy Complex. [4]



Figure 6.4. Digital rendering of a planned Mote Hydrogen facility in southern California, featuring a parking lot, office buildings, a gasifier building with conveyor belts for moving biomass, several large vertical tanks, rows of biomass feedstock, and two evaporation ponds. Image credit: Mote, Inc.

6.1.4 Operational Needs

6.1.4.1 Land use requirement

The scale of a commercial hydrogen facility is generally described in terms of how much energy it is able to produce annually (its MW capacity), rather than the physical footprint that it would occupy, meaning published descriptions of land use needs from operators are rare. Furthermore, given the rapid rate of technological innovation and plans to scale up production in this sector, most existing facilities are significantly smaller than planned future facilities. As such, experts have largely been approximating facility footprints based "on engineering estimates, rather than plot optimization based on real experience."[53]

For hydrogen via electrolysis, the largest currently active site in the world is Air Liquide's site in Bécancour, Quebec, which began production in January 2021.[54] It has a capacity of 20 MW and can generate over 8.2 metric tons per day of hydrogen; their plant relies on hydropower from Hydro-Québec for its nearly-all renewable energy source.[55] The Bécancour facility relies on four proton exchange membrane (PEM) electrolyzers to generate its hydrogen, which are approximately the size and shape of very round water towers.[56]

Estimates aggregated by the International Renewable Energy Agency (IRENA) can help refine size estimates for future hydrogen facilities that would be larger than Bécancour, as

[53] IRENA (2020) Green Hydrogen Cost Reduction. p. 41. [38]
[54] Air Liquide (February 8, 2021) World's Largest PEM Electrolyzer. [2]
[55] Air Liquide (February 8, 2021) World's Largest PEM Electrolyzer. [2]
[56] Air Liquide (February 8, 2021) World's Largest PEM Electrolyzer. [2]

is expected to become common if hydrogen is to be a widely-used fuel in the future. In a 2014 study, IRENA estimated that a 100 MW capacity electrolyzer would require ~6,300 m^2 (1.55 acres) of land.[57] For reference, a 100 MW electrolyzer would produce about 50,000 kilograms of H_2 per day[58] (that is the equivalent to about 50,000 gallons of gasoline production per day[59]).

Later studies of 100 MW capacity facility designs generated smaller estimates than this initial figure, with a 2017 study estimating a footprint of 3,500 m^2 (0.86 acres) and a 2018 study estimating a footprint of 4,500 m^2 (1.11 acres).[60] In regards to even larger facilities, a 2017 study by Siemens predicted a 300 MW capacity electrolyzer facility would need 15,000 m^2 (3.71 acres).[61] Relative to other industrial energy facilities that produce electricity or fuel, these are relatively modest land use requirements.[62,63]

The accuracy of these estimates will be easier to determine moving forward, as companies have begun planning and constructing facilities in the hundreds of MW capacity range. A 100 MW hydrogen via electrolysis facility run by RWE Generation is planned for Lingen, Germany as part of the world's first publicly-accessible hydrogen network.[64]

6.1.4.2 Energy requirements

Hydrogen production is an extremely energy intensive process, particularly for electrolysis, because of the strength of the chemical bonds that need to be broken between the hydrogen and oxygen ions within a water molecule. For hydrogen production via electrolysis, the efficiency of the reaction generally ranges between 60-81%, depending on the technology used.[65] This means that for every 100 MW of electricity used to drive an electrolysis reaction, about 60-81 MW of energy value is produced in the form of hydrogen fuel. That is equal to a production rate of about 43,600-58,900 kg of H_2 produced each day,[66] with one kg of H_2 having about the same energy content as one gallon of gasoline. If all of the hydrogen currently produced in the world (about 69 million metric tons annually) was

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[57] IRENA (2020) Green Hydrogen Cost Reduction. p. 41. [38]

[58] EERE (August 2018) Global Electrolyzer Sales Reach 100 MW per Year. [55]
This DOE estimate assumes that the electrolyzer is running full-time with 50 kWh of electricity needed per kilogram of hydrogen produced to arrive at this estimate.

[59] Hydrogen Program (no date) Hydrogen Conversion Factors. p. 1. [35]

[60] IRENA (2020) Green Hydrogen Cost Reduction. p. 41. [38]

[61] IRENA (2020) Green Hydrogen Cost Reduction. p. 41. [38]

[62] Stevens *et al*. (2017) The Footprint of Energy. p. 1. [73]

[63] Boyett (January 27, 2023) Henderson history: Third time wasn't the charm for local synthetic fuel plants. [11]

[64] Celovic (March 19, 2020) First Publicly Accessible Hydrogen Network. [15]

[65] IEA (2019) The Future of Hydrogen. p. 43. [37]

[66] National Research Council and National Academy of Engineering (2004) The Hydrogen Economy. p. 240. [51]
*1kg of hydrogen has an energy value ("lower heating value") of about 33.3 kWh, and 60-81MW of energy value translates to 525,600-700,800 MWh of energy production in a year.

generated using electrolysis, it would require 3,600 terawatt hours (TWh) of electricity, more than the total annual electrical output of the European Union—a staggering energy demand.[67] To put that energy demand in a domestic perspective, if hydrogen were to replace US gasoline consumption (requiring about 135 million tons of hydrogen annually[68]), producing that hydrogen via electrolysis would use nearly twice the amount of electricity that currently powers the entire United States.[69,70,71]

A biomass gasification facility producing 1 million tons of CO_2 for capture can produce about 70,000 tons of hydrogen if it is powered entirely through an external source of energy.[72] For a facility to be self-sufficient (effectively needing no external energy input), about 30% of the syngas produced in the gasification step of hydrogen production is needed.[73] In this case, for every million tons of CO_2 produced, only about 50,000 tons of hydrogen is produced.[74] Whether and to what degree produced syngas or external energy sources are used depends on the relative cost of available energy sources, and the marketplace value of green hydrogen. If green hydrogen is far more valuable than other energy sources, facilities may use electricity or other fuels to produce the hydrogen, so they can sell as much of what they generate as possible. If prices are relatively equivalent, or green hydrogen prices decline to be cheaper than other fuels, facilities will likely opt to use some of the generated hydrogen to power the facility.

Most of the energy needs for biomass hydrogen production are used to attain the necessary heat and pressure to gasify the organic feedstock. The exact amount of required heat energy is difficult to ascertain, as the process is still relatively new, and most technical information regarding any individual gasification technique is proprietary. The fact that most facilities meet this energy need with their own supply of syngas, also leads to its often being unreported. Regardless of the scale of heat energy requirements, if solar-sourced energy were used, it would need to be paired with heat batteries, which likely would make it uneconomical compared to utilizing a portion of the syngas. As for the electricity demands, most facilities either pursue a grid connection as back-up or set up their own solar panels to meet any electrical demand. For a facility capturing 1 million metric tons of CO_2, the estimated solar capacity would be 135 MW, occupying ~945 acres, just to meet the electricity needs.[75]

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[67] IEA (2019) The Future of Hydrogen. p. 43. [37]

[68] EIA (May 1, 2023) FAQ: How much gasoline does the United States consume? [25]

[69] IEA (2019) The Future of Hydrogen. p. 43. [37]

[70] Hydrogen Program (no date) Hydrogen Conversion Factors. p. 1. [35]

[71] Our World in Data (no date) USA Electricity Generation. [60]

[72] Wu *et al.* (2023) Carbon capture in hydrogen production by biomass gasification. Supplementary Table S4. [85]

[73] Wu *et al.* (2023) Carbon capture in hydrogen production by biomass gasification. p. 3. [85]

[74] This estimate is consistent with yield estimates from an industry representative, personal communication, September 8, 2022.

[75] Industry representative, personal communication, September 8, 2022.

For SMR + CCS, there is no expected electricity demand, as the SMR process can be driven using internally generated waste heat, but there is a requirement of 3.4 kilograms of natural gas (methane) input per kilogram of hydrogen generated.[76] If waste heat is not employed to support the heat necessary for the SMR and water-gas shift reactions, then additional natural gas (methane) may be needed to meet the heat energy requirements.

6.1.4.3 Other operational requirements

Waste disposal requirements

During electrolysis, two gaseous products are created: hydrogen gas (H_2) and oxygen gas (O_2). Most electrolyzer plants choose to release their oxygen gas directly into the atmosphere,[77] but the oxygen could hypothetically be packaged and sold for use in metal processing, stone and glass production, chemical manufacturing, or for medical uses.[78] If these uses were pursued, the oxygen would likely need to be compressed and given warehouse space before it could be shipped to end users.

If the water source for electrolysis is not delivered at the necessary purity to go straight into an electrolyzer, then it may require additional on-site filtration, which produces minerals (mostly salt) that will need to be disposed of.[79] For a plant generating 45 metric tons of hydrogen gas daily using water directly from municipal supplies, the estimated weekly mineral production was about one dumpster worth of material for disposal.[80,81] A 100 MW hydrogen electrolysis facility, which produces slightly more H_2 (about 50 metric tons daily),[82] would need just over one dumpster per week. In the long term, another category of expected waste will be the electrolyzer stacks themselves, which typically require replacement on a 7 to 11 year timescale depending on the electrolyzer type.[83]

For hydrogen production via biomass gasification, all of the reaction products—hydrogen, CO_2, biochar—can be sold for use or permanently sequestered. It is only equipment that should require a waste disposal strategy at end-of-life, which will be component specific, depending on whether it can be recycled or needs to be landfilled. Further information about gasification products and disposal can be found in Section 4.1.4.2 of this report.

For hydrogen production via SMR + CCS, the picture is similar to biomass gasification—once all of the steps have been completed, the only process outputs should be hydrogen,

[76] Katebah *et al.* (2022) Analysis of production costs in Steam-Methane Reforming. p. 9. [41]
[77] Plug Power (no date) STAMP Green Hydrogen Production Site. p. 1. [64]
[78] Lenntech (no date) Oxygen. [44]
[79] Plug Power (no date) STAMP Green Hydrogen Production Site. p. 2. [64]
[80] Governor Kathy Hochul (October 20, 2021) Construction Start at Largest Green Hydrogen Plant in North America. [34]
[81] Plug Power (no date) STAMP Green Hydrogen Production Site. p. 2. [64]
[82] Hydrogen Program (no date) Hydrogen Conversion Factors. p. 1. [35]
[83] UK Department of Business, Energy & Industrial Strategy (2021) Hydrogen Production Costs. p. 19. [77]

CO_2, and a small amount of heat.[84] None of these products require waste disposal, unless there are any impurities in the methane gas stream that would result in small amounts of gaseous waste.[85] The hydrogen and CO_2 can be packaged for sale or sequestration, and the heat would ideally be cycled back into the process or directed towards a co-located industry for use. Again, only equipment that requires replacement should need separate waste disposal practices.

Warehousing requirements

For all methods of hydrogen production, the most likely warehousing requirement will be a site to compress and store the hydrogen for transport once formed. Both hydrogen production via biomass gasification and via SMR + CCS will also create CO_2 that must be compressed and transported off-site, ideally to geologic storage, to minimize environmental impacts.

Hydrogen production via electrolysis may require similar infrastructure to store oxygen if they plan to sell it instead of releasing it.

For hydrogen production via biomass gasification, a facility will need biomass on hand to gasify (i.e. Figure 6.3), and these facilities often have drying warehouses on-site to prepare the biomass for processing.[86] Since these facilities will generate other byproducts, like biochar, that can be sold, it is likely that they will need other buildings to process and store these products for shipment.

Transportation requirements

Over short distances, hydrogen can be transported via pipeline, truck, or rail.[87] With that said, pure hydrogen gas is extremely hard to transport. It can be compressed, liquefied, or converted temporarily into a metal hydride (fuel cell) in order to be transported.[88] Given that hydrogen is the lightest and smallest element in the universe, hydrogen gas is the lowest density gas. Hydrogen gas is also extremely flammable when mixed with even small amounts of air, so leaks or other malfunctions in transport could be extremely hazardous.[89] As such, it would be an extensive challenge to retrofit existing transport methods for safe use with hydrogen. Rather, new, dedicated infrastructure (pipelines, hydrogen compression or conversion technologies, and appropriately designed tanker and shipping vessels) will need to be developed. Technologies to scale up the cooling and compressing of hydrogen for commercial-scale transport are still in the research and development phase.[90] Based on the current state of the industry, consensus is that mass transport of

[84] Student Energy (no date) Steam Methane Reforming. [74]
[85] EERE (no date) Hydrogen Production: Natural Gas Reforming. [59]
[86] Zafar (July 25, 2022) Everything you should know about biomass storage methods. [86]
[87] Pascal (June 20, 2022) Different methods of storing, transporting, and distributing hydrogen. [61]
[88] Brown (April 27, 2022) The next frontier. [13]
[89] Brown (April 27, 2022) The next frontier. [13]
[90] Brown (April 27, 2022) The next frontier. [13]

hydrogen by sea will not be commercially viable until the mid-2030s,[91] limiting viable hydrogen markets over the next decade to those accessible by onland routes.

Currently, long-distance transport of hydrogen is conducted by converting hydrogen into chemical intermediates and then moving the intermediates to a final destination, where it can then be converted back into hydrogen gas for use. The intermediates used as energy carriers will likely be compounds like methylcyclohexane (organic hydride).[92] Methylcyclohexane can be imported and exported globally and is less dangerous to transport than pure hydrogen, as it remains a liquid at standard temperature and pressure and is chemically stable.[93, 94] The Chiyoda Corporation has already successfully demonstrated this process, using a mixture of toluene and hydrogen to generate methylcyclohexane in Brunei, transporting the methylcyclohexane over sea using a chemical tanker to Japan, and then using a dehydrogenation process on Japanese shores to supply the hydrogen for industrial facilities.[95]

In short, because of its molecular structure, hydrogen gas will require development of entirely new transportation networks and usage infrastructure than that used in our existing natural gas economy.[96] This new infrastructure will need to develop at a significant pace in order to ensure the economic viability of any large-scale hydrogen production facility.

Pipeline requirements

In the United States, there are approximately 1,600 miles of hydrogen pipelines[97] under the regulation of the federal Pipeline & Hazardous Materials Safety Administration (PHMSA).[98] Regulating hydrogen pipelines in the United States has been under the purview of the U.S. Department of Transportation (DOT), PHMSA's parent agency, since 1970 due to 49 CFR Part 192.[99]

Although hydrogen can be moved alongside natural gas at concentrations up to 15% hydrogen with only minor modifications required in a natural gas pipeline, moving hydrogen at higher concentrations of purity will require more substantial modifications or new pipeline infrastructure.[100]

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[91] Brown (April 27, 2022) The next frontier. [13]
[92] Shibata (2015) Hydrogen Production from Variable Renewables. p. 27. [70]
[93] Shibata (2015) Hydrogen Production from Variable Renewables. p. 27. [70]
[94] Kurosaki (2018) Introduction of Liquid Organic Hydrogen Carrier. p. 4. [43]
[95] FuelCellWorks (February 10, 2022) Hydrogen Transportation in the Form of MCH by Chemical Tanker. [32]
[96] Bossel, Eliasson (no date) Energy and the Hydrogen Economy. p. 1. [9]
[97] EERE (no date) Hydrogen Pipelines. [56]
[98] PHMSA (no date) Hydrogen. [63]
[99] PHMSA (no date) Hydrogen. [63]
[100] EERE (no date) Hydrogen Pipelines. [56]

6.1.5 Carbon Capture Potential

The carbon capture potential associated with hydrogen production differs depending on the process under consideration.

To generate hydrogen via electrolysis, no CO_2 should be produced unless the energy to sustain the reaction is sourced from a non-renewable resource. As we are only considering electrolysis conducted with renewable resources—like wind or solar—in this analysis, this production process should not be generating carbon for capture. It would exist as a clean energy industry, rather than a carbon management industry.

To generate hydrogen via biomass gasification, CO_2 will be created as a byproduct of hydrogen production. However, recovery rates of these carbon emissions are quite high (over 90%),[101] allowing nearly all the CO_2 produced onsite to be compressed and transported for permanent underground storage. Between 50,000 to 70,000 tons of hydrogen can be generated via biomass gasification per every 1 million tons of CO_2 produced, depending on how the facility's energy needs are met.[102]

To generate hydrogen via SMR + CCS, CO_2 will be created through multiple stages of production in both the initial SMR reaction and the subsequent water-gas shift reaction.[103] Given that gray hydrogen production (SMR without CCS) produces about 9 kilograms of CO_2 per kilogram hydrogen, while the estimate for blue hydrogen production (SMR + CCS) is 1-5 kilograms of CO_2 per kilogram hydrogen, the carbon capture and storage potential of SMR + CCS should range from 4-8 kilograms CO_2 per kilogram hydrogen produced.[104] This would correspond to a capture rate of 44-88% of the CO_2 emissions generated by hydrogen production via SMR. Some recent models have stated that carbon capture from SMR has a maximum removal capacity of 90%.[105]

6.2 Societal Impacts

6.2.1 Job creation potential

6.2.1.1 Number and types of jobs

There are no average industry estimates across types of hydrogen production methods, and no public methodology for arriving at these estimates. Some studies have projected that nationwide, hydrogen-related jobs in the United States could number almost one million by 2030, but these jobs are expected to disproportionately benefit highly-skilled and

[101] Patrizio *et al.* (2021) CO_2 mitigation or removal. p. 1-2. [62]
[102] Wu *et al.* (2023) Carbon capture in hydrogen production by biomass gasification. p. 6. [85]
[103] Student Energy (no date) Steam Methane Reforming. [74]
[104] Simon *et al.* (August 13, 2021) Economics of Hydrogen Energy. [71]
[105] Katebah *et al.* (2022) Analysis of production costs in Steam-Methane Reforming. p. 9. [41]

well-paid technical and professional workers.[106] Thus training workers to take on these new positions in the workforce will be essential to keeping jobs within local communities.

There are a few specific case studies we can use to approximate job creation potential in hydrogen production. Air Products, for their planned SMR + CCS facility in Louisiana designed to capture over 5 million tons of CO_2 annually, has projected the creation of 170 permanent jobs with an average salary of $93,000.[107] For hydrogen production via biomass gasification, this study assumes that the number and type of jobs will not vary significantly from other biomass gasification facilities covered in Section 4 of this report—for specifics on those job figures, please see Section 4.2.1.1. A similar case study reporting jobs for a large scale electrolysis facility has not been found.

6.2.2.2 Training pipelines

A U.S. Department of Energy (DOE) study on the implementation of a hydrogen economy between 2020 and 2050 found that many American workers would need new skills for the hydrogen economy, and that training and retraining programs would need to be established to fill this gap.[108] Unfortunately, the DOE's reporting does not provide depth on what training would be necessary or the likely occupations (and anticipated earnings) associated with the growth of hydrogen production.[109]

A wide range of skill levels are expected to engage with the hydrogen economy at-large (including hydrogen production, transport, and use), with experts anticipating that the hydrogen economy will include experts with graduate education, but also "include jobs that require associate's degrees, long-term on-the-job training, or trade certifications – and lead to jobs that pay higher than US average wages."[110] Furthermore, Plug Power, a company currently constructing electrolyzer facilities in the United States, has specifically referenced that a skilled workforce in the region was desirable for planning where to locate electrolyzer plants.[111] Setting up programs at local community colleges and universities to provide specialized training to take on roles in hydrogen production is a crucial way to support these nascent industries and ensure new, high-paying jobs in the region benefit local community members. By establishing local programs to train workers in these skills, it could attract hydrogen investment opportunities to the overall region; existing regional benefits for Kern County specifically are explored in Section 6.4.3.

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[106] Bezdek (2019) The hydrogen economy. [8]

[107] Air Products (no date) Louisiana Clean Energy Complex. [4]

[108] Bezdek (2019) The hydrogen economy. [8]

[109] Bezdek (2019) The hydrogen economy. [8]

[110] Bezdek (2019) The hydrogen economy. [8]

[111] Plug Power (no date) STAMP Green Hydrogen Production Site. p. 1. [64]

6.2.2 Quality of Life

6.2.2.1 Location

Hydrogen production via electrolysis is generally a quiet process—a facility in western New York describes the actual electrolyzer as "silent."[112] The loudest equipment on site are the compressors, used to cool hydrogen post-production to prepare for transport. The impact of the compressor noise can be mitigated by placement inside a building far from the site boundary, allowing the sound to disperse over distance.[113]

Hydrogen generated via biomass gasification will have more components that can generate noise, as well as some outdoor equipment (ex. conveyor belts to transport biomass) that would be hard to dampen except with distance from population centers. The loudest components of the operation—such as the engine and compressor—should be housed in insulated materials to dampen the machinery noise.[114] Other equipment like blowers and coolers inside the plant can also contribute noise, as well as any noise from equipment to transport biomass to the site and transport co-products off-site for distribution.[115] For a facility capturing 1 million tons of CO_2 annually, about 1,800 tons of feedstock (~90 tractor-trailer truckloads) need to be delivered each day,[116] which could contribute to noise and traffic in nearby communities. As a result, anticipated overall site noise can be a determining factor in siting a new biomass gasification facility.[117]

SMR processes can be quite loud, with on-site noise near the reformer loud enough to cause ear damage and fatigue to personnel.[118] Ensuring there is adequate hearing protection available for workers, as well as that noise level surveys for the site and surrounding area do not exceed local regulations, is essential for any proposed SMR + CCS site.[119]

The full life-cycle of hydrogen production, transport, and use can generate a range of pollutants, which may have health impacts for nearby populations – the full spectrum of these emissions is explored in Section 6.3.2.

[112] Plug Power (no date) STAMP Green Hydrogen Production Site. p. 2. [64]
[113] Plug Power (no date) STAMP Green Hydrogen Production Site. p. 2. [64]
[114] IEE (2009) Guideline for Safe and Eco-friendly Biomass Gasification. p. 41. [36]
[115] IEE (2009) Guideline for Safe and Eco-friendly Biomass Gasification. p. 22. [36]
[116] EPA (no date) Biomass Preparation. p. 23. [26]
[117] IEE (2009) Guideline for Safe and Eco-friendly Biomass Gasification. p. 29. [36]
[118] EIGA (no date) Combustion Safety for Steam Reformer Operation. p. 13. [29]
[119] EIGA (no date) Combustion Safety for Steam Reformer Operation. p. 13. [29]

6.2.2.2 Multi-use potential

Currently, most hydrogen is produced on the same site where it is used, making hydrogen a key co-location opportunity for heavy, heat-reliant industries and transportation hubs like train depots, airports, and shipping ports.

The multi-use potential of hydrogen production sites for community spaces is more narrow—with both biomass gasification and SMR + CCS being relatively hot and requiring stringently-controlled conditions to maximize efficiency, opportunities for community use on-site are unlikely. Hydrogen production via electrolysis may offer multi-use potential, as the production process is relatively quiet, making it potentially an attractive prospect for school field trips for scientific demonstration.

However, the risks of hydrogen could make such facilities intrinsically a poor candidate for multi-use opportunities. If handled improperly, hydrogen can cause fires or explosions, and since hydrogen gas is very light and odorless, leaks can be exceedingly difficult to detect before hydrogen concentrations exceed its lower flammability limit in air.[120] This risk can be reduced by designing hydrogen facilities with key features (like sloped and vented roofs) that leave hydrogen space to escape, so it is not trapped to mix with air in a sealed space.[121] Overall, since hydrogen gas will need to be handled carefully on-site to protect workers, permitting other uses or untrained people to the site could be logistically difficult.

6.3 Environmental Impacts

The environmental impacts of hydrogen production are significant, particularly given that most hydrogen production taking place today is derived from natural gas and coal (gray, black and brown hydrogen). Annual global CO_2 emissions from hydrogen are equivalent to the combined annual CO_2 emissions of the United Kingdom and Indonesia, or approximately 830 million metric tons of CO_2 a year.[122] For reference, in 2021, the United States emitted approximately 5 billion metric tons of CO_2,[123] so current hydrogen production would be equal to about 16.6% of annual CO_2 emissions in the United States. Implementing less carbon-intensive methods of hydrogen production is important for reducing emissions and air pollution, regardless of the potential uptake of hydrogen as a fuel. Building a sustainable future relies upon diversifying the energy sources used to generate hydrogen and utilizing less carbon-intensive production practices than the industry currently uses.[124]

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[120] OSHA (no date) Green Job Hazards - Hydrogen Fuel Cells: Fire and Explosion. [53]

[121] Plug Power (no date) STAMP Green Hydrogen Production Site. p. 2. [64]

[122] IEA (2019) The Future of Hydrogen. p. 14. [37]

[123] Richie, Roser (no date) United States: CO_2 Country Profile. [67]

[124] IEA (2019) The Future of Hydrogen. p. 17. [37]

6.3.1 Water requirements

6.3.1.1 Minimum volume requirements

For hydrogen production via electrolysis, the volume requirements of water are proportional to the output of hydrogen generated in the facility. As such, large hydrogen electrolyzers correspond to large water requirements by volume. For every two molecules of water put in an electrolyzer, two molecules of hydrogen (H_2) are created, assuming 100% efficiency.[125] However, real-world electrolyzers will suffer inefficiencies that means this 1:1 ratio will not hold in reality, and given the vast difference in molecular weight and size of a water molecule and a hydrogen gas molecule, put in terms of mass, water to hydrogen ratios are significantly higher than 1:1. Published estimates of the theoretical minimum water demand for electrolysis are as low as 9.1 liters (or 2.4 gallons) of water per kilogram of hydrogen.[126] In practice, electrolyzer operators have found that it takes approximately 12 liters (or 3 gallons) of water to produce every kilogram of hydrogen created via electrolysis.[127]

Although experts are working to reduce the water requirements needed for hydrogen production via biomass gasification, currently, water is used to perform the water-gas shift reaction to generate hydrogen and purify the gaseous products. Some forms of gasification rely on steam or supercritical water, which can increase the overall water demand. The most conservative facilities use about equal quantities of biomass and water in their process.[128] There is some potential for water reuse; water is used to purify gas, allowing contaminants like SO_x or NO_x to dissolve into aqueous species. Once H_2 and CO_2 streams have been purified, the water is separated from them, carrying contaminants with them as dissolved components that can settle out. That water is typically stored in evaporation ponds on site, and could be treated for reuse with appropriate equipment.[129] Currently, the estimated water use for a biomass hydrogen facility capturing a million metric tons of CO_2 per year ranges between 266 and 1840 acre-feet of water each year.[130] That equates to about 15.0-103.6 liters (or about 3.9-27.4 gallons) of water needed to produce one kilogram of hydrogen via biomass gasification.*

A full life-cycle analysis for hydrogen production via SMR + CCS found that per kilogram of hydrogen generated, the process consumed 6 to 13 liters (or 1.6-3.4 gallons) of water.[131]

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[125] LibreTexts (August 9, 2022) 23.9: Electrolysis of Water. [46]

[126] Katebah *et al.* (2022) Analysis of production costs in Steam-Methane Reforming. p. 10. [41]

[127] Valdez (August 11, 2022) Electrolyzers and Water. [79]

[128] Industry representative, personal communication, September 8, 2022.

[129] Industry representative, personal communication, September 8, 2022.

[130] See the Comparative Analysis spreadsheet.

* This calculation uses a ratio of estimated hydrogen output to water usage derived from data obtained in an interview with an industry representative, personal communication, September 8, 2022.

[131] Valdez (August 11, 2022) Electrolyzers and Water. [79]

This is corroborated by other studies, which placed the water demand for SMR and the subsequent water-gas shift reaction combined at 9.7 liters (or 2.6 gallons) of water per kilogram of hydrogen produced.[132]

Given these relatively high water use figures across production methods, hydrogen production may be a poor fit for water-stressed regions like Kern County, as freshwater is already overallocated.[133] The strain on local water resources could be reduced if highly purified, reclaimed or recycled water could help meet this need, a subject that is explored in Section 8 of this report on water treatment.

6.3.1.2 Minimum quality requirements

For electrolysis, the water quality threshold is extremely high—the water used in electrolyzers "needs to be as pure as possible."[134] The water used in an electrolyzer should be distilled and/or deionized, to preserve the efficiency and lifetime of the equipment.[135] Membrane-based electrolyzers require water to be of type II purity, though operate better with water of type I purity, which is even more filtered.[136]

6.3.2 Air quality

An electrolyzer itself does not produce gaseous emissions other than H_2 and O_2. Any emissions associated with electrolysis will therefore come from its power supply. A full life-cycle analysis study of electrolyzer options fueled by different energy sources in Colombia found that wind-powered electrolysis was the most air quality-friendly option when looking at methane (CH_4), CO_2, NO_x, SO_x, and particulate matter emissions.[137] Any fossil-free, renewable energy supply will minimize emissions for electrolysis, with remaining life cycle emissions profiles reflecting third-order, upstream (manufacturing and construction) and downstream (end-of-life) related emissions.

In contrast, generating hydrogen via biomass gasification can create direct air pollutants, including carbon monoxide (CO), NO_x, methane (CH_4), and a small amount of soot (particulate matter[138]),[139] although if the feedstock source for gasification is agricultural waste, forest waste or municipal waste that would otherwise have degraded through crop burning, wildfire or landfill decomposition, the net effect of using gasification on air quality

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[132] Katebah *et al.* (2022) Analysis of production costs in Steam-Methane Reforming. p. 9. [41]

[133] IEA (2019) The Future of Hydrogen. p. 43. [37]

[134] Valdez (August 11, 2022) Electrolyzers and Water. [79]

[135] Spiegel (November 7, 2017) Introduction to Electrolyzers. [72]
[Note: this information derives from a response provided in the comment section by the Fuel Cell Store account.]

[136] Jonsson, Mässgård (2021) An Industrial Perspective on Ultrapure Water Production for Electrolysis. p. 17. [40]

[137] Ullman, Kittner (2022) Environmental impacts associated with hydrogen production. [78]

[138] Weidman, Marshall (August 10, 2012) Soot Pollution 101. [83]

[139] Ahmed *et al.* (2019) Emissions factors. p. 221. [1]

is likely to be an improvement. There are few published studies comparing emissions from biomass gasification to combustion (what happens in bioenergy generation plants) or open burning, but what information is available suggests a significant reduction in criteria pollutants with gasification. Examples include a comparative study of coal gasification versus traditional coal-fired powerplants by the National Energy Technology Laboratory.[140] Their study showed a significant decrease in SO_x, NO_x, particulate matter and CO_2 emissions in gasification relative to traditional combustion. While the feedstock is different, the organic matter in coal and the organic matter in biomass can be expected to respond similarly to thermochemical processing. Another study found that less NO_x, CO, CH_4, CO_2 and soot was emitted from small scale biomass gasification plants, when compared to open burning.[141] And finally, the planned San Joaquin Renewables facility (described in Section 4.1.2.7) anticipates the emissions impact of their gasification facility will be far more favorable than open pile burning (commonly employed in the San Joaquin Valley today) —with a minimum of a 95% reduction in VOCs, 96% reduction in NO_x, 99% reduction in CO, and 99% reduction in particulate matter released relative to biomass burning.[142]

Blue hydrogen from SMR with CCS also produces both criteria air pollutants and greenhouse gasses aside from CO_2.[143] These emissions included VOCs, NO_x, CO, SO_2 and both large (PM_{10}) and small ($PM_{2.5}$) particulate matter* in the criteria air pollutants, and CH_4 and nitrous oxide (N_2O) as additional greenhouse gasses.[144] Researchers found that VOC, NO_x, and CO emissions per kilogram of hydrogen produced decreased as facility size increased, with an anticipated cause that larger facilities (in terms of expected hydrogen output) may have emissions control technologies that capture different pollutants.[145] Other emissions, though, showed little correlation with the facility size by anticipated hydrogen output, making it difficult to gauge how much other emissions categories can be effectively minimized.[146]

Finally, recent has identified some risk of using hydrogen as a fossil-alternative fuel, due to hydrogen's ability to act as an indirect greenhouse gas, warming the atmosphere on short-term (years to decadal) timescales.[147] When combusted, hydrogen reacts with oxygen to form water vapor, which in the stratosphere, can trap heat. Hydrogen that leaks from operations or is offgassed can also drive production of other greenhouse gasses, including

[140] NETL (no date) Emissions advantages of gasification. [49]

[141] Ahmed *et al.* (2019) Emissions factors. p. 221. [1]

[142] San Joaquin Renewables (no date) The Project. [69]

[143] Sun *et al.* (2019) Criteria Air Pollutants and Greenhouse Gas Emissions. p. 4. [75]

* Particulate matter emissions are often reported in terms of the size of the particles—PM_{10} refers to particles smaller than 10 micrometers (μm), and $PM_{2.5}$ to particles smaller than 2.5 μm.

[144] Sun *et al.* (2019) Criteria Air Pollutants and Greenhouse Gas Emissions. p. 4. [75]

[145] Sun *et al.* (2019) Criteria Air Pollutants and Greenhouse Gas Emissions. p. 16. [75]

[146] Sun *et al.* (2019) Criteria Air Pollutants and Greenhouse Gas Emissions. p. 16. [75]

[147] Ocko, Hamburg (2022) Climate consequences of hydrogen emissions. p. 9349. [54]

methane, ozone, and water vapor in the atmosphere, mostly through indirect pathways.[148] Although both hydrogen via electrolysis and hydrogen via SMR + CCS will have significant climate benefits compared to fossil fuel systems on 100-year timescales by reducing the amount of CO_2 released to the atmosphere, some studies suggest that in the short term (first 20 years after adoption), green hydrogen via electrolysis may only halve the impact of emissions from fossil-fuel use and blue hydrogen via SMR + CCS could potentially worsen immediate climate impacts by increasing emissions of methane and hydrogen in the short term.[149]

When used as a fuel, hydrogen can also generate NO_x in the atmosphere. During hydrogen combustion, enough heat is present to cause atmospheric nitrogen and oxygen to form NO_x in an endothermic reaction.[150] Atmospheric NO_x can have detrimental effects for humans, including respiratory symptoms like the development of asthma, as well as environmental harms, including acid rain and nutrient pollution in waterways and coastal areas.[151] NO_x emissions from hydrogen boilers or engines can be minimized by controlling combustion conditions or by scrubbing NO_x from post-combustion flue gasses.[152]

Ultimately, any project sited in Kern County, California, including those developed in a carbon management park like that examined here, would be considered through a public process, where the environmental impacts specific to the technologies and fuels being used in any given facility will be reviewed and mitigated in accordance with the California Environmental Quality Act (CEQA).

6.3.3 Other potential impacts

In many cases, hydrogen fuel is not the most effective solution for reducing greenhouse gas emissions—if a technology can run directly on clean energy or renewable electricity, that is typically a much more efficient power source.[153] However, for industries and processes that are difficult to electrify, hydrogen could be an excellent alternative to fossil fuels. Hydrogen has been explored as a fuel for heavy-duty transport (planes, freight rail, or trucking) or to produce the heat necessary to create products like ceramics, steel, and concrete.[154,155,156] In the context of a carbon management business park, where several industries could be co-located, on-site production of hydrogen may provide a valuable industrial heat energy source. However, a detailed techno-economic and environmental

[148] Ocko, Hamburg (2022) Climate consequences of hydrogen emissions. p. 9350. [54]
[149] Ocko, Hamburg (2022) Climate consequences of hydrogen emissions. p. 9349. [54]
[150] Douglas *et al.* (2022) NO_x Emissions from Hydrogen-Methane Fuel Blends. p. 2. [23]
[151] EPA (August 2, 2022) Basic Information about NO2. [27]
[152] Lewis (2021) Optimising air quality co-benefits in a hydrogen economy. p. 201. [45]
[153] Bottorff (January 4, 2022) Hydrogen: Future of Clean Energy or a False Solution? [10]
[154] Gitlin (2022) Forget passenger cars. [33]
[155] Baxter *et al.* (November 16, 2020) Which sectors need Hydrogen, which don't. [7]
[156] Roberts (January 31, 2023) This climate problem is bigger than cars and much harder to solve. [68]

impact analysis will be crucial when considering whether hydrogen is the most cost-effective and environmentally-efficient fuel option for such industries.

6.4 Economic Impacts

6.4.1 Business Model

Hydrogen is the primary product of electrolysis, biomass gasification and SMR with CCS, and in the future will most likely be sold primarily as a fuel product for transportation and industrial uses. Today, the infrastructure required for such end-use applications is not yet well established. Thus, most hydrogen currently produced goes to other purposes, such as in oil refining, to remove sulfur from natural gas distribution streams or in the production of synthetic fertilizers.[157, 158] Global demand for hydrogen has been steadily rising since 1975, both for direct applications (in oil refining and ammonia production) and indirect applications (methanol, synthetic fuels, and direct reduced iron steel production).[159]

Currently, the costs of hydrogen production are cheapest for more environmentally destructive processes like gray hydrogen, with blue and green forms of hydrogen being the most expensive. In 2020, the cost to generate a kilogram of hydrogen was $0.70 for SMR with no CCS (gray hydrogen), $1.30 for SMR with CCS (blue hydrogen), and $3 for solar-powered electrolysis (green/yellow hydrogen).[160] The cost differential is primarily due to the significantly higher energy demand (and thus energy cost) of electrolysis relative to steam methane reforming.[161] Any opportunities to lower the energy costs of electrolysis can therefore help this technique become cost competitive with gray hydrogen production. For example, when created using excess renewables from the grid, the production cost goes down to about $1.60 per kilogram (in 2020 dollars).[162] Depending on the availability of excess renewable resources in coming years, green hydrogen could become cost competitive with blue hydrogen within the next decade.[163] If a carbon tax were to be imposed, nationally or internationally, on CO_2 emitting power generation processes, like gray hydrogen, that could also equalize the cost differential between production methods, by penalizing the more environmentally destructive gray hydrogen production.[164]

Currently, the high cost of green hydrogen is considered to be the "brick wall" for global hydrogen production—it does not make sense to scale up production or end-use infrastructure until there are efficient and cheap ways to generate hydrogen that also do

[157] Cunningham (no date) The economics of hydrogen in a carbon constrained world. [22]
[158] IEA (2019) The Future of Hydrogen. p. 17. [37]
[159] IEA (2019) The Future of Hydrogen. p. 18. [37]
[160] Simon *et al.* (August 13, 2021) Economics of Hydrogen Energy. [71]
[161] Simon *et al.* (August 13, 2021) Economics of Hydrogen Energy. [71]
[162] Simon *et al.* (August 13, 2021) Economics of Hydrogen Energy. [71]
[163] Simon *et al.* (August 13, 2021) Economics of Hydrogen Energy. [71]
[164] Climate Now (October 18, 2021) Pricing carbon around the globe. 01:21. [17]

not contribute to greenhouse gas emissions, and solutions to the barriers to reaching commercial scale and competitive market costs in this space have yet to be realized.[165] In the United States, a tax incentive designated in the Inflation Reduction Act (IRA) of 2022 could change this picture by making environmentally-friendly hydrogen production methods more economically favorable. Under the new tax incentive, producers of hydrogen with 'near-zero emissions' can earn $3 per kilogram of hydrogen produced with no cap on the number of kilograms the producer can receive the incentive for.[166] This is exceptionally good news for hydrogen generated via electrolysis with renewable energy, as $3/kilogram is about the average cost of production, so any sales of their hydrogen would be profit. The exact structure of these benefits, however, will depend on rules that are still being written by the Treasury Department; until they have developed a clear definition for 'near-zero emissions,' it is difficult to guess what standards a producer would need to meet to be eligible for the $3/kilogram incentive.[167] In a worst-case scenario, the benefits could flow to companies that are still releasing large amounts of greenhouse gas emissions in the hydrogen production process, either via using methane as a feedstock or relying on grid electricity generated by fossil fuels to meet the high energy demands of electrolysis or gasification.[168]

Two other potential revenue streams are worth noting. First, in California, Low Carbon Fuel Standard credits (LCFS, see Section 2) are designed to promote switching from fossil fuels to low-carbon fuels in the transportation sector, and could provide an additional revenue stream for green hydrogen projects (from electrolysis or biomass). However, any hydrogen produced from fossil fuels—including blue hydrogen formed from SMR + CCS—would be ineligible for LCFS credits.[169] From 2018-2022, the LCFS credit has ranged from $62-218.[170] Second, federal incentive 45Q provides a tax benefit for CO_2 capture and storage processes other than direct air capture (DAC) of $85 per ton stored, for which green hydrogen via biomass gasification and SMR + CCS could be eligible. Hydrogen producers would need to choose between the 45Q and 45V federal tax credits; they cannot receive both.[171]

6.4.2 Business Costs

6.4.2.1 Cost to build (upfront costs)

The cost and efficacy of electrolyzers is projected to become more favorable in the near-term future, given that this field has seen greater investments in research and development

[165] Bezdek (2019) The hydrogen economy. [8]
[166] Pontecorvo (December 12, 2022) Subsidy for 'green hydrogen' could set off a carbon bomb. [65]
[167] Pontecorvo (December 12, 2022) Subsidy for 'green hydrogen' could set off a carbon bomb. [65]
[168] Pontecorvo (December 12, 2022) Subsidy for 'green hydrogen' could set off a carbon bomb. [65]
[169] Bezdek (2019) The hydrogen economy. [8]
[170] Neste (no date) California Low Carbon Fuel Standard Credit price. [52]
[171] Webster (September 20, 2022) The Inflation Reduction Act will accelerate clean hydrogen adoption. [82]

and economies of scale.[172] There are a wide range of levelized cost estimates available, but costs for large electrolysis facilities are poorly established. Additionally, these cost estimates vary widely based on capacity and the type of electrolyzer in question. A small PEM electrolyzer generating one cubic meter of hydrogen (≈11.126 kg H_2) per hour would likely be less than $8,000, but a commercial-scale facility would require a much larger capacity, either by running a lot of small units or building specialized large electrolyzers.[173] A compilation from the International Council on Clean Transportation (ICCT) of levelized capital cost estimates for different types of electrolyzers as a function of their price per kW and price per kg H_2 is presented in Table 6.1.[174] In general, alkaline electrolyzers are the cheapest to purchase upfront, primarily because they do not require any precious metals to operate.[175,176] Alkaline electrolyzers have a longer expected lifetime than PEM electrolyzers as well.[177]

Another study, which focused only on PEM electrolyzers, is consistent with the ICCT's meta-analysis. They provide an estimated total levelized cost of production that incorporates capital and energy costs. Depending on whether grid energy, solar, or wind is used, production costs of electrolysis facilities with existing technology varied between $4.22 and $6.27 per kilogram of hydrogen produced.[178]

For AE electrolyzers, the largest share of the capital cost is devoted to the electrolyzer stack, accounting for 50% of the estimated capital costs.[179] Although large alkaline electrolyzers have been built before in North America, Africa, Asia, and Europe, most large facilities were decommissioned in the late 20th century, so there are large uncertainties in projecting current costs for a new alkaline electrolyzer facility based on the costs of existing stock.[180] For PEM electrolyzers, about 60% of the capital cost is associated with the electrolyzer stack.[181]

Costs for electrolyzers are expected to decline sharply with advances in the electrode and membrane materials and improvements in manufacturing.[182,183] Additional, economies of scale resulting from significant increases in production capacity are expected to further

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[172] IEA (2019) The Future of Hydrogen. p. 16. [37]
[173] Lichner (March 26, 2020) Electrolyzer overview. [47]
[174] Christensen (2020) Costs from Electrolysis. p. 18. [16]
[175] IEA (2019) The Future of Hydrogen. p. 43. [37]
[176] Lichner (March 26, 2020) Electrolyzer overview. [47]
[177] IEA (2019) The Future of Hydrogen. p. 44. [37]
[178] Vickers *et al.* (2020) Cost of Electrolytic Hydrogen Production with Existing Technology. p. 1. [80]
[179] IEA (2019) The Future of Hydrogen. p. 46. [37]
[180] IEA (2019) The Future of Hydrogen. p. 43. [37]
[181] IEA (2019) The Future of Hydrogen. p. 46. [37]
[182] IEA (2019) The Future of Hydrogen. p. 46-47. [37]
[183] Vickers *et al.* (2020) Cost of Electrolytic Hydrogen Production with Existing Technology. p. 3. [80]

reduce electrolysis costs by 20-40%. The chart below illustrates the expected cost declines for both alkaline and PEM electrolyzers.[184]

Table 6.1. Anticipated capital cost estimates for hydrogen from electrolysis.[a]

Electrolyzer type	2020 $/kW	2020 $/kg H_2[b]	Sources
Capital costs for development in 2020			
Alkaline electrolysis (AE)	$500-1268	$1.90-4.80	IEA (2019) The Future of Hydrogen,[185] IRENA (2019) Renewable Energy Perspective,[186] BloombergNEF (2019) H2 from Renewables,[187] ICCT (2020) Costs from Electrolysis.[188]
Proton exchange membrane (PEM)	$385-2068	$1.50-7.90	
Solid oxide electrolysis (SOE)	$677-2800	$2.60-10.60	
Capital costs for development in 2030			
Alkaline electrolysis (AE)	$400-1208	$1.50-4.60	IEA (2019) The Future of Hydrogen, IRENA (2019) Renewable Energy Perspective, BloombergNEF (2019) H2 from Renewables, ICCT (2020) Costs from Electrolysis.
Proton exchange membrane (PEM)	$365-1968	$1.40-7.50	
Solid oxide electrolysis (SOE)	$647-2175	$2.50-8.30	
Capital costs for development in 2050[c]			
Alkaline electrolysis (AE)	$80-1090	$0.30-4.10	IEA (2019) The Future of Hydrogen, IRENA (2019) Renewable Energy Perspective, BloombergNEF (2019) H2 from Renewables, ICCT (2020) Costs from Electrolysis.
Proton exchange membrane (PEM)	$150-1781	$0.60-6.80	
Solid oxide electrolysis (SOE)	$500-1968	$1.90-7.50	

a. Adapted from ICCT (2020) Costs from Electrolysis.
b. 1kW ≈ 263kg H_2
c. For IEA (2019), cost estimates described as 'long term.'

For biomass gasification that generates hydrogen and CO_2, the capital cost of a facility that could capture 1 million tons of CO_2 would be ~$278 million to $328 million.[189] If the facility operated for 30 years, the capital costs over the lifetime of the facility would be ~$24-52 per

[184] IEA (2019) The Future of Hydrogen. p. 47. [37]

[185] IEA (2019) The Future of Hydrogen. [37]

[186] IRENA (2019) Hydrogen: A renewable energy perspective. [39]

[187] Hydrogen: The Economics of Production From Renewables. Bloomberg New Energy Finance, Technical Report, September 2019. (Data available through Christensen (2020) Costs from Electrolysis.)

[188] Christensen (2020) Costs from Electrolysis. p. 18. [16]

[189] Wu *et al.* (2023) Carbon capture in hydrogen production by biomass gasification. p. 6. [85] Note: In figures in Wu, Lan, and Yao (2023), these estimates appear lower (approximately $241 to $285 million) as they correspond to a facility capturing 868,000 metric tons of CO_2 per year (see the supplementary material, Table S4 for CO_2 capture rates by scenario). In this report, all Wu, Lan, and Yao (2023) estimates are presented in-text as scaled figures for a million ton facility, to ensure consistency between carbon management industries when possible.

ton of CO_2 (assuming a capital recovery factor of 7.5-12.5%; see Section 3.4.3.1 for details).[190] Both capital and operating costs for biomass-based hydrogen production vary depending on the energy source, which varies across plant designs. In general, self-sustaining plants—which can meet their own energy needs—are the most expensive to build, but have the lowest operational costs.[191] Plants that receive some or all of their energy from external sources are typically cheaper to construct, but more expensive to operate and maintain.[192] It is worth noting that the cost range for most biomass plants, as outlined in Section 4.4, exceeds the range presented here. As the cost estimates here are derived from a single study, and it is likely that hydrogen production via biomass gasification will closely resemble other biomass-based plants, considering the larger variability in capital costs of biomass-conversion facilities in general may be worthwhile.

For SMR facilities in general (gray and blue hydrogen), there are a large number of constituent parts required to contain the entire reaction sequence and limit the escape of pollutants like particulate matter and NO_x.[193] Adding CCS equipment to the SMR process (blue hydrogen) generally results in an estimated capital cost increase of 50%.[194] When also accounting for the operation and maintenance of a facility over its lifetime, however, the distributed cost addition of carbon capture to SMR is anticipated to result in a ~13% increase in total levelized production cost.[195] A recent techno-economic study of hydrogen production for SMR + CCS estimated a levelized capital cost of $0.28/kg hydrogen.[196] This model assumes that SMR without CCS emits 8.5 kilograms CO_2 per kilogram hydrogen but SMS with CCS emits only 1.2 kilograms of CO_2. Thus, we can estimate that for every kilogram of hydrogen produced via SMR + CCS, 7.3 kilograms of CO_2 will be captured.[197] If we assume a facility capturing 1 million metric tons of CO_2 per year, it will generate about 137,000 tons (or 137 million kg) of hydrogen per year. For a capital recovery factor (crf) between 7.5 and 12.5% (see Section 3.4.2.1),[198] the cost to build such a facility would be about $300-510 million USD.

This estimate is relatively well-aligned with planned investment in the Air Products facility currently being constructed in Louisiana. Air Products states that it will cost about $4.5 billion to build, own, and operate their facility with a capture capacity of over 5 million tons of CO_2 annually.[199] Scaling capital expenditures of $300-510 million USD/ton CO_2 to a 5

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[190] Adapted from: Carbonplan DAC cost calculator.

[191] Wu *et al*. (2023) Carbon capture in hydrogen production by biomass gasification. p. 6. [85]

[192] Wu *et al*. (2023) Carbon capture in hydrogen production by biomass gasification. p. 6. [85]

[193] Simon *et al*. (August 13, 2021) Economics of Hydrogen Energy. [71]

[194] IEA (2019) The Future of Hydrogen. p. 42. [37]

[195] Katebah *et al*. (2022) Analysis of production costs in Steam-Methane Reforming. p. 9. [41]

[196] Katebah *et al*. (2022) Analysis of production costs in Steam-Methane Reforming. p. 9. [41]

[197] Katebah *et al*. (2022) Analysis of production costs in Steam-Methane Reforming. p. 9. [41]

[198] Calculated using: Levelized capital expenditure ($/kg$H_2$) = (Cost to build/Annual capacity of the facility)*crf

[199] Air Products (no date) Louisiana Clean Energy Complex. [4]

million ton facility, suggests that capital costs will represent one third to over half of the total investment costs, the remainder presumably coming from operation, maintenance and the cost of the feedstock methane.

6.4.2.2 Operational costs

For an electrolyzer, the stacked membranes inside the machine must be replaced about every 7 to 10 years.[200] The British government estimates the replacement period for electrolyzer membrane stacks varies with the technology type, with alkaline stacks requiring replacement every 9 years, PEM stacks requiring replacement every 11 years, and SOE stacks requiring replacement every 7 years, assuming a 30-year facility lifetime.[201] Fixed operational costs will also include labor, administrative costs, maintenance, insurance, and taxes.[202] Alkaline electrolysis systems also have relatively high maintenance costs throughout their lifetimes due to the variety of equipment needed to pump, clean, and store the electrolyte solution and to filter out and clean the hydrogen.[203] The ICCT economic analysis of electrolysis states that most techno-economic models estimate fixed operational costs (labor and maintenance) as 1-3% of capital expenditures. Based on the range of capital costs summarized in Table 6.1, fixed operation costs of modern electrolyzers are about \$4-84 USD/kW (or \$0.02-\$0.32 USD/kg H_2), with their preferred operating cost estimate of \$40-50 USD/kW (\$0.15-0.19 USD/kg H_2).[204] Variable costs will largely be electricity costs, which can vary considerably over time (and even be zero, if a facility is using excess energy from renewables or the grid). The ICCT model estimates variable operating costs of \$0.08 USD/kg H_2.[205]

For a biomass gasification plant, operational costs are expected to range from approximately \$60 million to \$101 million for a facility capable of capturing a million metric tons of CO_2 annually.[206] The feedstock costs—amounting to approximately \$44 million annually—are the largest share of the operating costs.[207] If these costs were reduced, it would lower the annual operating expenses notably. The next big cost categories come

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[200] Simon *et al*. (August 13, 2021) Economics of Hydrogen Energy. [71]

[201] UK Department of Business, Energy & Industrial Strategy (2021) Hydrogen Production Costs. p. 19. [77]

[202] UK Department of Business, Energy & Industrial Strategy (2021) Hydrogen Production Costs. p. 19. [77]

[203] Lichner (March 26, 2020) Electrolyzer overview. [47]

[204] Christensen (2020) Costs from Electrolysis. p. 18. [16]

[205] Christensen (2020) Costs from Electrolysis. p. 18. [16]

[206] Wu *et al*. (2023) Carbon capture in hydrogen production by biomass gasification. p. 6. [85] Note: In figures in Wu, Lan, and Yao (2023), these estimates appear lower (approximately \$52 to \$88 million) as they correspond to a facility capturing 868,000 metric tons of CO_2 per year (see the supplementary material, Table S4 for CO_2 capture rates by scenario). In this report, all Wu, Lan, and Yao (2023) estimates are presented in-text as scaled figures for a 1 million ton facility, to ensure consistency between carbon management industries when possible.

[207] Wu *et al*. (2023) Carbon capture in hydrogen production by biomass gasification. p. 6. [85]

from chemical, material, and utility costs, while labor, maintenance, and waste treatment make up a relatively small amount of the operating expenses.[208] These operational costs, combined with capital costs, result in a total levelized cost of about $2.50-$3.60 per kilogram of hydrogen produced, which translates to an estimated range of $125-257 per metric ton of CO_2 captured.

Finally, for any SMR plant, the majority of operational costs are variable; they depend on the cost of methane (natural gas) in the market at a given time, and can account for 45-75% of overall production costs (including capital costs).[209] However, the addition of a carbon capture component also adds additional operating costs and maintenance responsibilities for an operator.[210] In modeling SMR + CCS with a 90% carbon capture rate, the estimated variable operating cost (the energy costs for running the facility) amounted to $0.88 per kilogram of hydrogen,[211] and the additional costs for carbon capture, including separation, purification, compression, pipeline transport, and injection add up to about $0.60/kg hydrogen,[212] or $82 USD/ton CO_2.[213] Translated to total annual operating costs for a facility capturing one million metric tons of CO_2 each year, these amounts should come out to approximately $120 million USD and $82 million USD, respectively, and combined with the estimated capital expenditures, the total levelized production cost of SMR + CCS is ~$1.76 USD/kg H_2.

6.4.3 Regional benefits

California is already among the top three hydrogen-producing states in the U.S.[214] Additionally, the hydrogen market is strong in California—the state is home to 71% of all fuel cell EVs in the county and maintains the largest number of hydrogen fueling stations by far.[215] California also hosts a wide variety of industries that would be hard to fully electrify (such as cement and concrete manufacturing), thus making them prime candidates to transition to alternative fuels like hydrogen.[216] A large amount of credit for the growth of the hydrogen market in California is due to the state's carbon cap-and-trade program, which incentivizing the growth of hydrogen through a carbon credit marketplace.[217] With

[208] Wu *et al*. (2023) Carbon capture in hydrogen production by biomass gasification. p. 6. [85]
[209] IEA (2019) The Future of Hydrogen. p. 42. [37]
[210] IEA (2019) The Future of Hydrogen. p. 42. [37]
[211] Katebah *et al*. (2022) Analysis of production costs in Steam-Methane Reforming. p. 9. [41]
[212] Simon *et al*. (August 13, 2021) Economics of Hydrogen Energy. [71]
[213] Given the ratio of 1 kg H_2 production resulting in 7.3 kg CO_2 capture. From Katebah, Al-Rawashdeh, and Linke (2022) Analysis of hydrogen production costs in Steam-Methane Reforming.
[214] AFDC (no date) Hydrogen Production and Distribution. [6]
[215] AltaSea (October 28, 2022) Sustainable Green Hydrogen Market. [5]
[216] AltaSea (October 28, 2022) Sustainable Green Hydrogen Market. [5]
[217] Magill (February 23, 2021) California And Texas Vie To Be America's Hydrogen Capital. [48]

existing demand already in the region and sector-wide growth anticipated, Kern County is a promising locale for companies looking to develop hydrogen fuels.

6.4.3.1 Proximate feedstocks

For hydrogen produced via biomass gasification, Kern County's agricultural waste could become a supply of feedstock to generate hydrogen and capture CO_2. This theme is touched upon at greater length in Section 11.2.1 on the potential relationship between local agriculture and biomass-based carbon management facilities. For SMR+CCS, Kern County is home to the state's largest oil and gas fields and produces 78% of the state's total natural gas production.[218]

6.4.3.2 Proximate consumers

As mentioned above, one of the strengths of locating in the region would be a proximate consumer base. All of the approximately 15,000 consumer cars in the U.S. that are fuel cell EVs are located in California, which is the only state with a network of retail hydrogen fueling stations to make them usable.[219] Kern County's proximity to the port of Los Angeles, the busiest shipping port in North America,[220] also holds promise for the hydrogen industry - both as an access point for international trade, and because hydrogen holds potential as a fossil-free fuel source for the shipping industry.[221]

6.4.3.3 Co-location advantages

Locating alongside carbon management industries could have benefits for a hydrogen production facility. If generating hydrogen via electrolysis, an electrolyzer could utilize water generated as a byproduct of some carbon management industries, such as S-DAC (Section 3), depending on the water quality.

If generating hydrogen via steam reforming and CCS, co-location could have multiple benefits. Steam reforming and the water-gas shift reaction could similarly use water generated from other industries in their production process, and the transport and sequestration needed for permanent underground storage of CO_2 could be shared infrastructure with other carbon management industries in the park.

6.4.3.4 Other

For hydrogen production via electrolysis, which relies on renewable energy to avoid carbon emissions, California and the American Southwest is a highly promising region to bring down production costs, given the extremely high solar and wind energy potential in the region (Figure 6.5). Given the significant impact that electricity costs have on the market

[218] KEDF (2021) The economic contribution of the oil and gas industry in Kern County. p. 1. [42]
[219] Voelcker (September 26, 2022) Hydrogen Fuel-Cell Vehicles. [81]
[220] Port of Los Angeles (no date) The Port of Los Angeles. [66]
[221] Climate Now (May 2, 2022) The bottom line on sustainable shipping. 23:29. [18]

competitiveness of green hydrogen from electrolysis, the renewable energy potential of Kern County and the surrounding region is a remarkable asset for this industry.

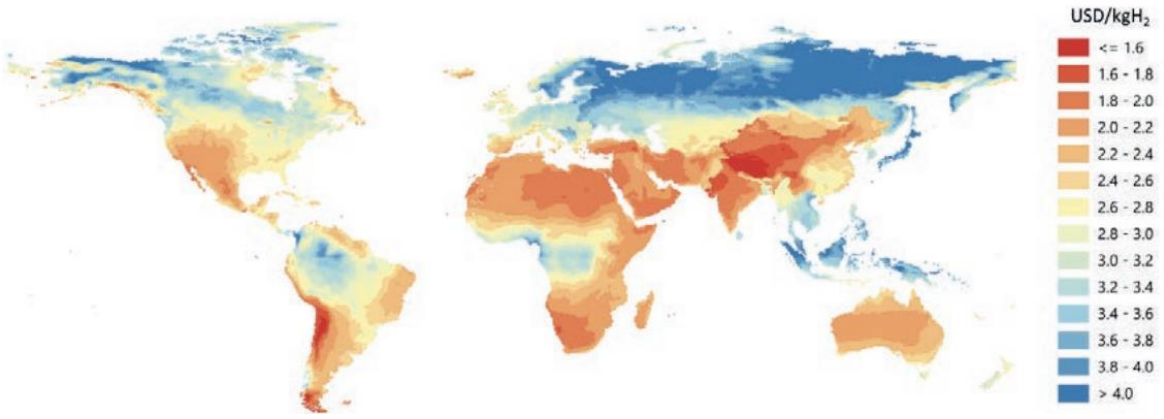


Figure 6.5. Global map demonstrating the cost viability of locations where renewable energy generation (wind or solar energy) and hydrogen production via electrolysis are co-located.[222] The California coast, as well as the American Southwest, show promising cost estimates for electrolysis-generated hydrogen. Image credit: International Energy Agency.

[222] IEA (2019) The Future of Hydrogen. p. 49. [37]

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7. Battery and Energy Storage Solutions

TECHNOLOGY AT A GLANCE

- Energy storage solutions come in a wide variety of form, many of which are fully commercial, and others of which are still in early research and development stages.[1]
- Lithium-ion batteries are currently the most widely used technology for utility-scale energy storage.
- Installation of large energy storage facilities is unlikely to create many jobs, but can produce a variety of societal benefits, like eliminating the need of fossil-based peaker power plants, and providing increased grid reliability.
- Adding energy storage to solar or wind power supplies increases the cost by ~$5-39, but the cost of batteries has decreased 97% in the last 3 decades, and is projected to continue becoming less expensive.
- Key advantages of this technology to Kern County: it ensures a continuous clean energy supply to any industries sited in a carbon management park, and potentially to the local grid, and can provide a fossil-free source of industrial heat to industries that require it.
- Key concerns for this technology in Kern County: environmental and safety risks vary by battery type, and further assessment to identify the optimal storage approach for the region and needs of the carbon management park will be necessary.

[1] Values in this section are summarized from the suite of references cited herein, and are explained in further detail in each subsequent section.

7.1 Technology Summary

Since 2020, wind and solar energy have become the cheapest form of electricity generation in most parts of the world, and their costs have continued to decrease year over year.[2,3] The sunny and arid climate of Kern County is particularly well suited for these renewable energy sources, and as such is host to the largest commercial solar project and among the largest commercial wind energy projects in the United States.[4] Such abundant, fossil-free energy is particularly attractive to carbon management industries for two reasons. First, many carbon management industries are energy intensive, with energy costs representing their largest operational expense. Thus, minimizing the price per kWh of electricity used is critical to ensuring facilities are economically viable. Second, most carbon management industry's business model depends on the *net* amount of CO_2 removed or prevented from entering the atmosphere, which means that if such industries are powered by carbon-emitting fuels, their carbon capture efficiency (and thus potential for revenue) is reduced.[5]

Wind and solar are examples of variable renewable electricity (VRE) – they only generate electricity when the sun is shining or the wind is blowing, and the intensity of the electricity the generate depends on weather conditions.[6] Battery storage solutions are a way to smooth fluctuations in energy supply, by storing excess energy generated by renewables during highly productive periods and then releasing that energy to meet electricity or heat demands during periods of lower productivity.[7] For solar energy, for example, this could mean storing excess energy during the day and releasing it at night, when the sun is not out to generate additional power.

To support renewables and decarbonization objectives, the International Energy Agency (IEA) predicts that globally, energy storage will need to scale up to 266 GW of storage capacity by 2030—in 2017, global energy storage capacity was 176.5 GW—to keep climate change under 2°C of warming.[8] To support the development of a clean energy and carbon management industrial park in Kern County, it is worth assessing the degree to which energy storage solutions would need to be integrated with local renewable energy generation in order to provide sufficient, continuous power that meets the needs of any industries locating within the park.

7.1.1 Description: How it works

In this report, we define energy storage technologies as devices that take in any form of renewable energy, store that energy in various forms, and then release energy as electricity

[2] Masterson (July 5, 2021) Renewables were the world's cheapest source of energy in 2020. [33]
[3] Lazard (2021) Levelized cost of energy. [28]
[4] CSUB (no date) Energy in Kern County. [5]
[5] National Academies of Sciences, Engineering, and Medicine (2019) Research Agenda. p. 222. [36]
[6] IRENA (2017) Electricity Storage and Renewables. p. 10. [26]
[7] MIT (2022) The Future of Energy Storage. p. xi. [32]
[8] EESI (February 22, 2019) Fact Sheet | Energy Storage. [20]

or heat to be used on demand. A summary of the more widely used energy storage technologies are listed in Table 7.1, along with the characteristics of each storage type that typically define its most suitable applications.

As the aim here is to understand storage solutions that could support a carbon management park in Kern County, we will focus on off-grid technologies with rechargeable, industrial-scale potential that can provide intermediate to longer-duration storage, and will produce energy in the form of electricity or in the form of heat. Some energy storage solutions are eliminated based on Kern's geography and resources. For example, pumped-storage hydropower (PSH) systems have been used in the United States for a century, and currently constitute 95% of energy storage facilities nationally, but are a poor fit for Kern given its largely arid climate.[9] This section will also cover hydrogen-based batteries, with the assumption that the hydrogen utilized for this energy storage is produced through low-carbon processes—for more on hydrogen production, please refer to Section 6 of this report.

Table 7.1. Characteristics of selected energy storage types.[10]

	Max Power Rating (MW)	Discharge Time	Max Cycles or Lifetime	Energy Density (Wh/l)	Round-Trip Efficiency
Pumped hydro	3,000	4h - 16h	30-60 years	0.2-2	70-85%
Compressed air	1,000	2h - 30h	20-40 years	2-6	40-70%
Molten salt (thermal)	150	hours	30 years	70-210	80-90%
Li-ion battery	100	1min - 8h	1,000-10,000 cycles	200-400	85-90%
Lead-acid battery	100	1min - 8h	6-40 years	50-80	80-90%
Flow battery	100	hours	12,000-14,000 cycles	20-70	60-85%
Hydrogen	100	mins - week	5-30 years	600 (at 200bar)	25-45%
Flywheel	20	secs - mins	20,000-100,000 cycles	20-80	70-95%

7.1.1.1 Electricity storage

Most of the batteries discussed in this report rely on the same basic electrochemical process: reduction-oxidation (redox) reactions. In redox reactions, electrons move between one molecule and another molecule; the substance losing electrons is oxidized and the substance gaining electrons is reduced.[11] It may sound counterintuitive that the substance

[9] EESI (February 22, 2019) Fact Sheet | Energy Storage. [20]
[10] EESI (February 22, 2019) Fact Sheet | Energy Storage. [20]
[11] Chemistry LibreTexts (July 1, 2019) Batteries. [9]

gaining electrons should be 'reduced', but reduction is referring to the overall charge of a particle, not how many electrons it has. Because electrons are negative, the overall charge of the substance gaining electrons will be a less positive number; it will be reduced.[12]

In a battery system, the site where oxidation (electron loss) occurs is called the anode, and the site where reduction (electron gain) occurs is called the cathode.[13] These processes occur simultaneously in a redox reaction, and the electrons lost in one part of a battery system will be the same as the electrons gained in another part of the system. When these redox processes occur with a wire to capture the electric charge, it constitutes an electrochemical (or Galvanic) cell—the basic principle of most electric batteries.[14] Here, we explore three types of electrochemical batteries: lithium-ion, flow, and molten salt. While the constituent parts of each of these electric batteries can look quite different, they all share the components shown in Figure 7.1: in addition to the cathode and anode, there is an electrolyte, separator, and two current collectors.[15] The role of each of these components when a battery charges or discharges can be described in the context of each of the four battery types that are detailed below.

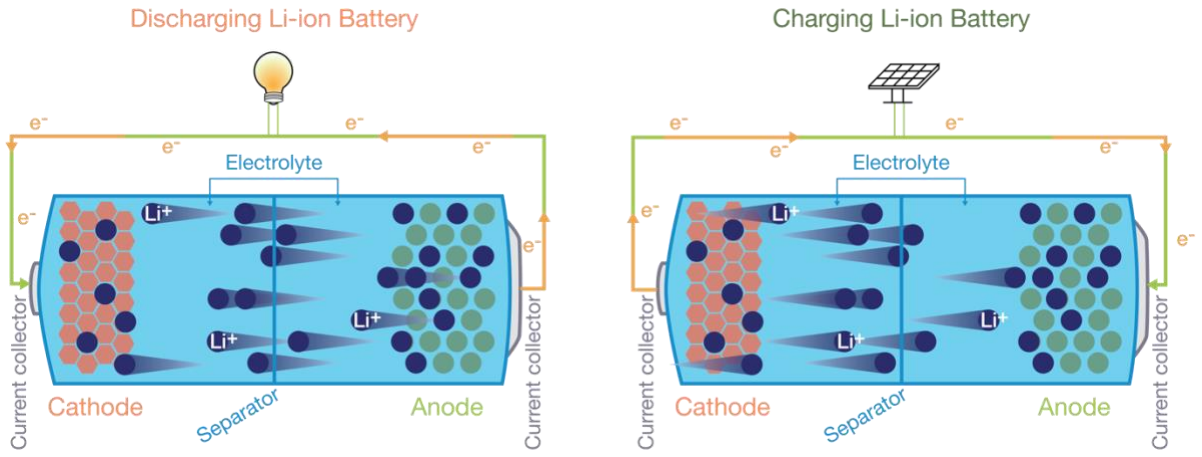


Figure 7.1. Schematic of lithium-ion electric battery storage.[16]

Lithium-ion batteries

Lithium-ion (Li-ion) batteries are what are typically used for mobile energy storage applications, such as in consumer electronics like cell phones, and in electric vehicles.[17]

[12] Chemistry LibreTexts (July 1, 2019) Batteries. [9]
[13] Chemistry LibreTexts (July 1, 2019) Batteries. [9]
[14] Chemistry LibreTexts (July 1, 2019) Batteries. [9]
[15] Minos (February 28, 2023) How lithium-ion batteries work. [35]
[16] Minos (February 28, 2023) How lithium-ion batteries work. [35]
[17] EESI (February 22, 2019) Fact Sheet | Energy Storage. [20]

During a discharge cycle (when energy is being released from the battery), lithium that is stored in the anode gets ionized, meaning it converts to a lithium ion (Li^+) and an electron.

$$Li^o \rightarrow Li^+ + e^- \quad \text{(R7.1)}$$

The lithium ion is carried through the battery via the electrolyte, a liquid solution containing dissolved salts, to the cathode. A porous separator allows the lithium ions to pass through the electrolyte solution towards the cathode, but prevents the passage of electrons within the battery structure. Thus, the cathode becomes concentrated with positively charged lithium ions, and the electrons collect near the negative current collector. The charge differential drives the electrons to travel along the external electrical circuit, creating an electric current that can provide electricity to an external device. Electrons are collected at the positive current collector, and recombined with the lithium ions, to form elemental lithium that is stored in the cathode. When all the lithium has migrated from the anode to the cathode, the battery is "empty" and needs to be recharged. Charging the battery works in the reverse direction of discharging: lithium ions are released by the cathode and received by the anode.[18,19]

$$Li^+ + e^- \rightarrow Li^o \quad \text{(R7.2)}$$

Advantages of the Li-ion battery is that it is highly efficient and energy dense (Table 7.1), being able to discharge as much as 90% of the energy used to charge, and able to provide a large amount of power from a relatively small battery, which is why these are particularly advantageous for mobile applications like phones, laptops and cars. Typically, these types of can supply a charge for a few hours, and they can go through the discharge/recharge cycle about 1,000-10,000 times,[20] meaning they usually need to be replaced within ~10 years.[21]

Flow batteries

Flow batteries can exist in a variety of forms and designs, but are primarily distinguished from standard rechargeable batteries (like Li-ion batteries) because the electroactive materials in a flow battery are dissolved within electrolyte solutions, rather than stored within one or the other electrode as they are in conventional rechargeable batteries (Figure 7.2).[22]

In a flow battery, the electrolyte solution is stored in two separate tanks, with an anolyte tank replacing the anode and a catholyte tank replacing the cathode in a standard electrochemical cell.[23] These tanks are separate from regenerative cell stacks (or the reaction unit), wherein electrolytes are pumped in from the tanks to charge and discharge

[18] Minos (February 28, 2023) How lithium-ion batteries work. [35]
[19] Clean Energy Institute (no date) What is a lithium-ion battery and how does it work? [8]
[20] EESI (February 22, 2019) Fact Sheet | Energy Storage. [20]
[21] Le (August 4, 2020) Flow Batteries. [29]
[22] IRENA (2017) Electricity Storage and Renewables. p. 86. [26]
[23] IRENA (2017) Electricity Storage and Renewables. p. 86. [26]

the system using reversible chemical reactions.[24] The separate tanks can remain charged for long periods without experiencing degradative effects, making them an appealing solution for long-term energy storage.[25]

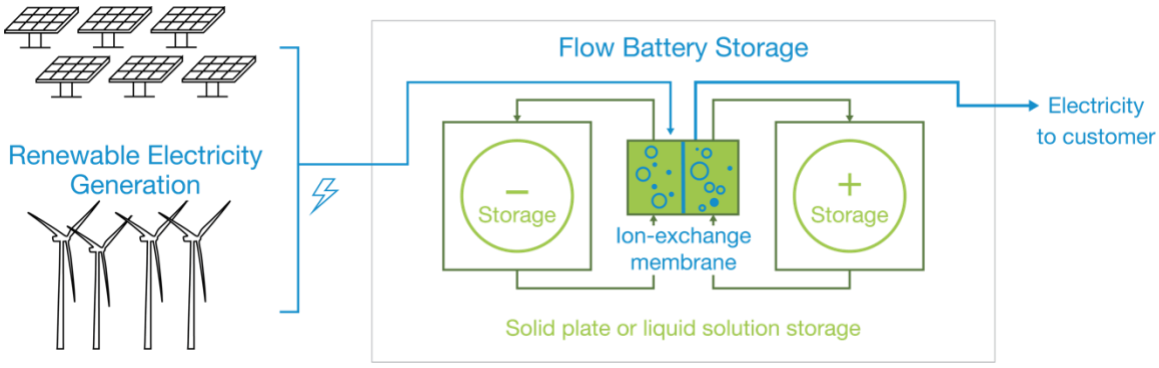


Figure 7.2. Schematic of flow battery electricity storage.

A flow battery is considered 'pure flow' if both the anolyte and catholyte are stored outside the cell stacks and only flow in during operation; if one or more of the electrolyte materials are stored within the cell stacks, then the flow battery is considered to be a 'hybrid' flow battery.[26] Within this overarching split between pure and hybrid flow, there are other subcategories defined by the materials used or the physical state of the active materials, as seen in the IRENA categorization below (Figure 7.3).[27]

Flow batteries are attractive for stationary applications as they are 100% recyclable, nonflammable, easily rechargeable, and approach the same high efficiency of Li-ion batteries, but with much longer lifetimes.[28] Many battery storage providers are looking to scale up their flow battery capacities, particularly flow batteries that rely on vanadium,[29] a material that is abundant and does not degrade through charge/recharge cycles.[30] Canadian company CellCube has deployed vanadium flow batteries in Australia, Vietnam, and South Africa, and British company Invinity is working with the Energy Superhub Oxford to create the UK's largest flow battery system.[31]

[24] IRENA (2017) Electricity Storage and Renewables. p. 86. [26]
[25] Le (August 4, 2020) Flow Batteries. [29]
[26] IRENA (2017) Electricity Storage and Renewables. p. 86-87. [26]
[27] IRENA (2017) Electricity Storage and Renewables. p. 87. [26]
[28] Le (August 4, 2020) Flow Batteries. [29]
[29] Le (August 4, 2020) Flow Batteries. [29]
[30] Rapier (October 24, 2020) Why vanadium flow batteries may be the future. [47]
[31] Le (August 4, 2020) Flow Batteries. [29]

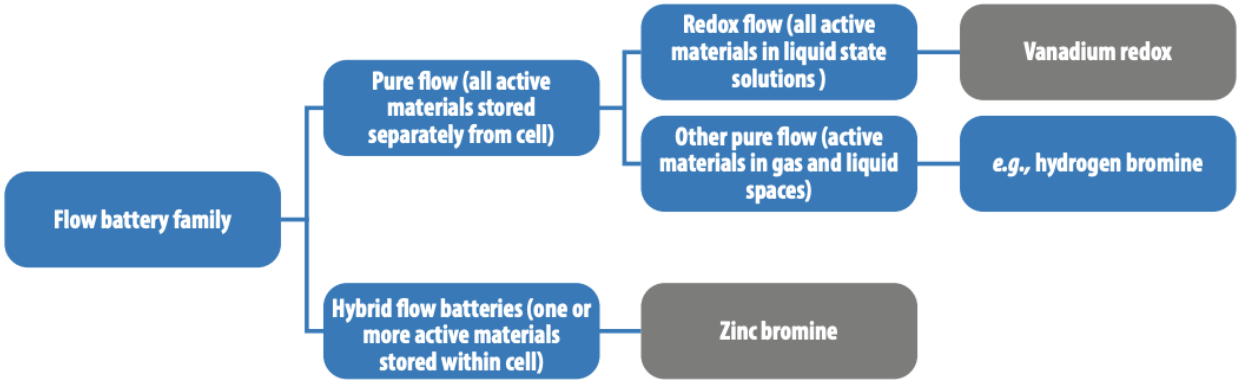


Figure 7.3. Categories of flow battery systems. Image credit: IRENA (2017).[32]

Molten salt batteries

As the name implies, molten salt batteries use a salt, in a liquid, molten state to act as the electrolyte in an electrochemical battery. These systems are often called high-temperature batteries, as high temperatures are necessary to keep the active materials in a liquid state.[33] When the temperature is lowered, the molten salt "freezes," or solidifies, allowing them to store their charge in an inactive state for up to months at a time.[34] Molten salt technologies are the most common kind of "thermal electricity storage", currently accounting for about 75% of global thermal storage capacity.[35] (Although these batteries operate at high temperatures, they deliver energy as electricity rather than heat, hence their categorization as electricity storage rather than as heat storage.)

In one example of the molten salt battery – the sodium beta battery – the anode is molten sodium while the cathode (and membrane) is constructed of beta-aluminum (β''-Al_2O_3).[36] The system works by using sodium ion transport across the membrane to store or release energy from the battery.[37]

A similar iteration of the high-temperature battery replaces the beta-aluminum with molten sulfur as the cathode and is known as the sodium sulfur (NaS) battery.[38*] The anode and cathode are separated by a solid ceramic of sodium alumina, which only allows positively-

[32] IRENA (2017) Electricity Storage and Renewables. p. 87. [26]
[33] IRENA (2017) Electricity Storage and Renewables. p. 95. [26]
[34] Dhar (April 15, 2022) Molten-salt battery freezes energy over a whole season. [14]
[35] IRENA (2017) Electricity Storage and Renewables. p. 21. [26]
[36] IRENA (2017) Electricity Storage and Renewables. p. 95. [26]
[37] IRENA (2017) Electricity Storage and Renewables. p. 95. [26]
[38] IRENA (2017) Electricity Storage and Renewables. p. 95. [26]
* Element S can be spelled as sulfur (American English) or sulphur (British English). In this report, all references have been standardized to American spelling, but the original source uses British spelling. Both spellings refer to the same element.

charged sodium ions to pass through its surface.[39] Operation relies on the system maintaining temperatures of 300-350°C to keep the active materials liquid, which can make it difficult for these batteries to operate intermittently.[40] However, these systems are highly efficient, with an average efficiency of 89%.[41] Sodium sulfur batteries are already installed at dozens of sites in Japan and Abu Dhabi, assisting with voltage control and power reliability.[42]

Currently, molten salt tanks (while molten) lose about 1% of their stored heat per day—after two weeks, their capacity has gone down to about 85%.[43] Research conducted at Pacific Northwest National Laboratory (PNNL) demonstrated that freezing and thawing molten salt creates a rechargeable battery that stores energy more effectively and inexpensively for weeks or months on end.[44] If scaled up, these research findings could help make the most of the high efficiency of these batteries by extending the timespan they can effectively store energy for future use.

7.1.1.2 Compressed Air Energy Storage (CAES)

Compressed air energy storage (CAES) systems do not rely on a chemical process, but rather in storing energy through pressurized air that can then be deployed as necessary. It does this by compressing ambient air (or another gas) and storing it at high pressure underground—when additional electricity generation is required, the compressed air is heated and expanded in a turbine connected to a generator, producing power.[45]

Utility-scale CAES was first deployed in the 1970s, at capacities of around 290 MW, so the technology is well-established and understood even for large-scale storage needs.[46] CAES systems now encounter high costs associated with storing compressed air and relatively low capacities for these systems, with research and development efforts for this technology focused on addressing these obstacles.[47] Estimated efficiencies for CAES range from 40-70%.[48]

7.1.1.3 Thermal/heat storage

Energy does not always need to be stored, or delivered, in the form of electricity. For some industrial and commercial facilities, storing heat energy is more important for sustaining

[39] ESA (no date) Batteries. [18]
[40] ESA (no date) Batteries. [18]
[41] ESA (no date) Batteries. [18]
[42] ESA (no date) Batteries. [18]
[43] MIT (2022) The Future of Energy Storage. p. 122. [32]
[44] Blaustein (May 6, 2022) Rechargeable Molten Salt Battery. [2]
[45] ESA (no date) Why Energy Storage - CAES. [19]
[46] ESA (no date) Why Energy Storage - CAES. [19]
[47] Xiaotao *et al.* (2017) Performance Study of Salt Cavern Air Storage. p. 1. [61]
[48] EESI (February 22, 2019) Fact Sheet | Energy Storage. [20]

their operations. This includes steel, iron, cement, and chemical manufacturing, which all require high heat to fuel their primary processes.[49] Globally, about half of the world's energy consumption is in the form of heat energy.[50]

Most thermal energy storage systems rely on heating a medium—like water, salt, or rocks—and then placing this material in an insulated environment so it retains heat.[51] The type of medium used to store energy determines the system's classification: sensible (water and rock), latent (water, ice, or salt hydrates), and thermochemical reactions (i.e. chemical reactions and sorption processes).[52] In sensible storage, when heat is needed, cold water is pumped onto the heated material to generate steam (Figure 7.4).[53,54] Depending on the needed energy use, the steam can be used directly to heat a facility, or indirectly to turn turbines and generate electricity.[55] If the heat is converted back into electricity for use, the system averages only 47% round-trip efficiency (i.e. only 47% of the power put into the system as electricity will come back out as electricity).[56] In contrast, delivering stored energy in the form of heat can have a round-trip efficiency as high as 90%.[57] Thus, using the heat directly is ideal where possible, but relies on the industrial heat needs of co-located processes.

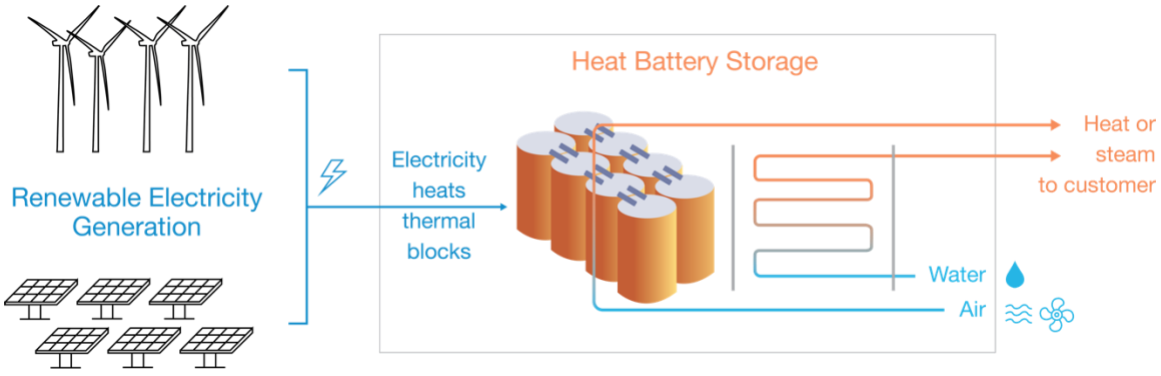


Figure 7.4. An example of sensible thermal storage, modeled after the operational design of Rondo Energy (see Section 7.1.2.1).

Whereas sensible storage relies on changing the temperature of the storage medium to release or absorb heat as needed, latent systems change the phase of the material without

[49] MIT (2022) The Future of Energy Storage. p. 4-5. [32]
[50] Celsius (August 17, 2020) Thermal Energy Storage. [7]
[51] EESI (February 22, 2019) Fact Sheet | Energy Storage. [20]
[52] Celsius (August 17, 2020) Thermal Energy Storage. [7]
[53] EESI (February 22, 2019) Fact Sheet | Energy Storage. [20]
[54] Celsius (August 17, 2020) Thermal Energy Storage. [7]
[55] EESI (February 22, 2019) Fact Sheet | Energy Storage. [20]
[56] MIT (2022) The Future of Energy Storage. p. 114. [32]
[57] EESI (February 22, 2019) Fact Sheet | Energy Storage. [20]

changing the temperature to release energy—both a phase change and temperature change can occur in the same material concurrently, though.[58] The last system type, thermochemical, relies on chemical reactions taking place on the surface of a material to release or absorb heat. These systems can adapt renewable energy into heat to be stored and released, or capture waste heat for use in other processes.[59]

Utility-scale heat storage systems can balance energy supply and demand across timescales from daily to seasonally,[60] making them a versatile solution for both short- and long-term needs. Since most of the processes addressed in this report require heat rather than cooling, we emphasize the capacity of this technology to store heat energy, but the process can work conversely, to provide residential or industrial cooling.[61]

7.1.1.4 Hydrogen Fuel Cells

Fuel cells are another energy storage solution that can be deployed to support energy needs in a range of sectors, including transportation, commercial and residential buildings, and for industrial-scale energy storage.[62] Fuel cells operate similarly to batteries, but rather than cycling back and forth between discharging and recharging the energy stored, fuel cells thermochemically transform fuel to produce electricity and heat. Therefore, fuel cells – much like a gasoline-powered car – can only produce energy for as long as fuel is being supplied. Although fuel cells can use a wide range of fuels to operate, most focus has been directed towards the potential of using hydrogen in fuel cells, given that their only byproducts are electricity, heat, and water.[63]

Like a standard chemical battery, fuel cells have an anode and a cathode placed on either side of an electrolyte.[64] Fuel is introduced at the anode and air is introduced at the cathode. The fuel molecules are separated to create positively charged ions (protons in the case of hydrogen) and electrons; the positively charged ions migrate across the electrolyte to the cathode, while the electrons move towards the cathode via an external circuit, creating an electric current. At the cathode, the positive ions and electrons reunite and react with oxygen from the air stream to form a new molecule in an exothermic (heat-generating) reaction.[65] For the case of hydrogen fuel, the reaction progresses as follows:

$$\tfrac{1}{2}O_2 + 2e^- + 2H^+ \rightarrow O^{2-} + 2H^+ \rightarrow H_2O + \textit{heat} \qquad \text{(R7.3)}$$

[58] Celsius (August 17, 2020) Thermal Energy Storage. [7]
[59] Celsius (August 17, 2020) Thermal Energy Storage. [7]
[60] Celsius (August 17, 2020) Thermal Energy Storage. [7]
[61] Celsius (August 17, 2020) Thermal Energy Storage. [7]
[62] EERE (no date) Fuel Cells. [41]
[63] EERE (no date) Fuel Cells. [41]
[64] EERE (no date) Fuel Cells. [41]
[65] EERE (no date) Fuel Cells. [41]

Over traditional combustion engines, fuel cells have many advantages—they operate at higher efficiencies, have fewer (sometimes zero) emissions, are quiet to operate, and do not form air pollutants on-site that harm human health.[66]

Currently, fuel cells are rarely used for utility-scale energy storage applications, although research and development programs, both publicly and privately supported, aim to increase the longevity and reliability of fuel cell systems, so that they can become a technologically and economically viable option.[67,68] The primary area of interest for utility-scale storage with renewable energy sources is *reversible* hydrogen fuel cells. Just like other hydrogen fuel cells, they generate electricity and heat using air and hydrogen fuel.[69] However, the systems can also function in reverse—when there's excess renewable energy available, these cells can store that energy in the form of hydrogen by using the excess renewable energy to break apart water into hydrogen and oxygen, a process known as electrolysis.[70] Then, this hydrogen can be used to fuel the cell when the intermittent renewable energy source declines,[71] helping to balance out energy production and energy use schedules. (A full exploration of hydrogen production via electrolysis is available in Section 6.1.1.2 of this report.)

Technological progress still needs to be made before reversible hydrogen fuel cells are commercially ready. One issue is that commercial-scale fuel cells and electrolyzers currently deploy different catalysts to support the electrolysis/combustion reactions. For one piece of equipment to do both jobs, a new device would need to be developed to get around these catalytic differences.[72] One has been developed, called a proton conducting fuel cell (PCFC), but the device cannot yet maintain the power output needed for most practical applications.[73]

7.1.2 State of Development

The state of development for these technologies is mixed, with some utility-scale batteries already having been commercially available for decades while others are still in the research and development space. Pumped hydropower storage and compressed air energy storage (CAES) are two examples of energy storage solutions that have existed for many decades.[74] The majority of newly-deployed utility-scale projects are focused on lithium-ion

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[66] EERE (no date) Fuel Cells. [41]
[67] EERE (no date) Fuel Cells. [41]
[68] Service (March 12, 2019) New fuel cell could help fix the renewable energy storage problem. [53]
[69] EERE (no date) Types of Fuel Cells. [42]
[70] EERE (no date) Types of Fuel Cells. [42]
[71] EERE (no date) Types of Fuel Cells. [42]
[72] Service (March 12, 2019) New fuel cell could help fix the renewable energy storage problem. [53]
[73] Zhang, Hu (2021) Progress in proton-conducting oxides as electrolytes. p. 995-997. [62]
[74] Irving (April 29, 2021) World's largest compressed air grid "batteries" will store up to 10GWh. [27]

batteries.[75] For those technologies that are still in development, the U.S. Department of Energy (DOE) is working to accelerate innovation, so that they can quickly reach commercial scale operations and contribute to national and international goals of rapidly decarbonizing the economy.[76] A summary compiled by the Massachusetts Institute of Technology (MIT) of development statuses for a variety of energy storage technologies, as well as the ancillary industries that support them (mining and processing of critical minerals, battery recycling or up-cycling, and development of infrastructure to support the production and distribution of hydrogen for fuel cells) is given in Table 7.2. Most technologies fall in a range of developmental stages because of ongoing innovations aimed at optimizing and scaling energy storage.

Table 7.2. Status of development for energy storage + ancillary industries, as of 2022.[77]

	Current Innovation Status[a]				
Technology	**Idea creation**	**R&D**	**Pilot scale**	**Demonstration**	**Deployment**
Li-ion batteries		■		■	■
Flow batteries (inorganic)		■		■	■
Flow batteries (organic)	■	■	■		
NaS batteries				■	■
Metal-air batteries		■	■		
Pumped hydro storage				■	■
Thermal storage		■	■	■	
Hydrogen		■			
Ancillary Industries					
Critical materials supply chain	■	■	■		
Battery recycling	■	■	■	■	
H_2 production, transport, storage	■	■		■	

a. Shaded region(s) denote one or more technology types in the relevant stage of readiness. Because there are several battery types in each technology category, more than one current innovation status may exist.

One energy storage technology that we have not explored extensively in this report due to its still being in very early stages of development are metal-air batteries, in which electricity is released through the spontaneous oxidation of a common metal (i.e. zinc, iron,

[75] IEA (September 2022) Grid-Scale Storage. [25]
[76] Blaustein (May 6, 2022) Rechargeable Molten Salt Battery. [2]
[77] MIT (2022) The Future of Energy Storage. p. xiv. [32]

aluminum) by air.[78] A spontaneous reaction is one that is thermodynamically favorable - it will progress naturally without external forcing (like the addition of heat or pressure). As a corollary to other electro-chemical redox batteries, here the metal is the anode material during discharge and the cathode is a porous material that allows the air to pass through and react with the electrolyte to form hydroxyl ions. The hydroxyl ions react with the metal, producing oxidized metal and free electrons. For example:

$$FeO_{metal} + OH^- \rightarrow FeO(OH)_{goethite} + e^- \quad \text{(R7.4)}$$

Although a zinc-based metal-air battery was first proposed in 1878, they are most commonly used today in small, often disposable, consumer electronics, and their deployment for utility-scale storage has yet to be proven.[79] If metal-air batteries can be scaled, they would have key advantages over other battery types: their theoretical specific energies exceed standard lithium-ion batteries by magnitudes of 5 to 50, depending on the type of metal used, and do not have the same overheating risks as lithium-ion battery cells (see Section 7.2.2).[80] While, attaining these high specific energies has not yet been achieved in practice, and currently, these systems are not cost-competitive with most other types of electrochemical battery storage,[81] this example of the potential for innovation and development is worth keeping in mind. With the speed at which new technologies are evolving in the battery space, the utility-scale battery storage options that seem most practical now may look very different even in a few years.

7.1.2.1 Example projects

Electrical Storage: Fluence, headquarters in Arlington, Virginia

Fluence is an energy storage technology and service provider that is run by Siemens and AES. The company was launched in 2018.[82] Fluence provides grid-scale and industrial-strength energy storage solutions, with scalable energy capability ranging from 2 MW to >500 MW and discharge duration of 6+ hours. Their advanced lithium ion sealed cells come in modular packaging, pre-installed with the necessary battery racks and modules, heating and cooling system, power supply, controllers, and safety components.[83] Fluence offers both short- and long-duration units ("cubes") that can be configured and combined on a site; a short-duration cube is approximately 2.5 x 2.5 x 2.2 m, while a long-duration cube is 2.5 m x 2.5 m x 2.1 m.[84]

[78] MIT (2022) The Future of Energy Storage. p. 35. [32]
[79] MIT (2022) The Future of Energy Storage. p. 37. [32]
[80] MIT (2022) The Future of Energy Storage. p. 35-36. [32]
[81] MIT (2022) The Future of Energy Storage. p. 36-37. [32]
[82] Fluence (no date) Fluence Energy. [21]
[83] Fluence (2022) Gridstack - Technical Specifications. [22]
[84] Fluence (2022) Gridstack - Technical Specifications. [22]

Heat Storage: Rondo Energy, Alameda, California

Rondo Energy converts wind and solar energy—either directly from the source or indirectly through the grid—into heat energy that can be stored and deployed as needed (see Figure 7.4).[85] This is an example of a sensible thermal energy system. When wind or solar energy is available, either through the grid or in an off-grid system, Rondo's process uses electric heating elements (called Joule heaters) to turn that electrical energy into high-temperature heat energy. The heating elements are placed near bricks, warming them to temperatures up to 1500°C (~2730°F). These bricks can store heat very effectively for long periods, with thermal losses of less than 1% per day. To release the heat for use, air is directed through the heated bricks, where it rises to temperatures over 1000°C (~1830°F)—the release of heat into the system can be easily adjusted by controlling the air flow out of the brick stack. This heat can then be delivered to a facility as superheated air or superheated steam, with temperatures, pressures, and heat medium (air or water) optimized to meet a facility's specific needs.[86]

7.1.3 Operational Needs

7.1.3.1 Physical footprint

Most energy storage sites report their size in terms of megawatt (MW) capacity, rather than a physical footprint. A good rule of thumb in the field is that per megawatt hour (MWh), the estimated land use for battery storage is 1,000 square feet.[87] The size will scale accordingly. Most energy storage applications require less than 10 acres of total land use.[88]

A battery storage facility called Saticoy, opened by Averon Asset Management in Ventura County in 2021, represents what a typical battery storage site in southern California would look like (Figure 7.5). It houses a 100 MW (or 400 MWh) energy storage system, enough to power the entirety of Ventura County for half an hour or the city of Oxnard for four hours.[89] The system is made up of 142 Megapacks, Tesla's utility-scale battery units, with performance management software from Power Factors.[90]

Another facility, Crimson Storage, is located on 2,000 acres of Bureau of Land Management (BLM) land in Riverside County, California (Figure 7.6).[91] As of the writing of this report, it

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[85] Rondo Energy (no date) The Rondo Heat Battery. [50]

[86] Rondo Energy (no date) The Rondo Heat Battery. [50]

[87] Convergent (no date) Landowner Partnerships. [12]

[88] Merritt (no date) Energy Storage Investment Opportunities. [34]

[89] Wagman (June 29, 2021) Averon opens 100 MW/400 MWh battery energy storage facility in California. [60] Note: For reference, Ventura County, California has a population of about 843,000 people, according to the U.S. Census Bureau's 2020 Census figures. Oxnard, California has a population of about 202,000 people, according to the U.S. Census Bureau's 2020 Census figures.

[90] Wagman (June 29, 2021) Averon opens 100 MW/400 MWh battery energy storage facility in California. [60]

[91] Lewis (October 19, 2022) The world's largest single-phase battery. [30]

is the largest single-phase battery storage facility, and the second largest operating energy storage facility, in the world, with a capacity of 350 MW or 1400 MWh.[92]



Figure 7.5. Saticoy 100 MW battery storage facility, Ventura County, California. Image credit: Averon Asset Management.[93]



Figure 7.6. Crimson Storage 350 MW battery storage facility, Riverside County, California. Image credit: Bureau of Land Management.

[92] Lewis (October 19, 2022) The world's largest single-phase battery. [30]

[93] Wagman (June 29, 2021) Averon opens 100 MW/400 MWh battery energy storage facility in California. [60]

The world's largest energy storage facility is Vistra Energy's Moss Landing Energy Storage Facility, with a capacity of 400 MW or 1600 MWh, also located in California (Monterey County).[94] In this project, battery units were stacked into a retrofitted turbine building in an old power plant that is approximately three football fields long.[95] Moss Landing is an interesting example of reusing existing energy infrastructure to meet new needs and the ability to stack battery units to reduce the land footprint of these facilities, both features that could inform the development of new energy storage projects.

7.1.3.2 Energy requirements

When assessing energy requirements for energy storage, the necessary metric to consider is round-trip efficiency. Not all of the energy that is stored in a battery can be used later—some amount of the energy is lost in the process. Depending on type of battery storage, the round-trip efficiency varies between 40-90% (Table 7.1), meaning that somewhere between 40% and 90% of the energy put into the battery can be withdrawn later for use.[96] Efficiencies can also alter over time for the same system. Aging systems generally have lower efficiencies due to degradation of the battery itself.[97] Systems can also decline in efficiency depending on the length of time that energy is stored in a particular medium before it is discharged; for example, molten salt batteries lose an estimated 1% of their stored energy every day.[98] For relatively short-term storage needs, molten salt could be incredibly efficient, but meeting longer-term needs could require other battery types or trying novel ideas, like freezing the entire molten salt system to hold the energy.[99] Thus, intended usage needs to be a determining factor for the type of storage chosen—large-scale battery storage systems are designed differently to meet short-term needs as opposed to long-term ones.

The storage duration – or how long an energy storage solution can supply energy to the user – depends upon the system's rated power capacity and the energy capacity. Most sites describe themselves in terms of rated power capacity, or the maximum rate of power discharge that a battery system can attain from a full charge expressed in kilowatts (kW) or megawatts (MW).[100] However, the total amount of power that can be stored by a battery system is the energy capacity, which is expressed in kilowatt-hours (kWh) or megawatt-hours (MWh). For a system rated 1 MW of power capacity storing 4 MWh of usable energy capacity (i.e. holding 4 MWh that can be released from the system with its efficiency), the

[94] Colthorpe (October 18, 2022) Crimson Energy Storage 350MW/1,400MWh battery storage plant. [11]
[95] Patel (January 14, 2021) Vistra Energizes Massive 1.2-GWh Battery System at California Gas Plant. [46]
[96] Roberts (July 21, 2018) Batteries have a dirty secret. [49]
[97] NREL (no date) Battery Lifespan. [37]
[98] MIT (2022) The Future of Energy Storage. p. 122. [32]
[99] Blaustein (May 6, 2022) Rechargeable Molten Salt Battery. [2]
[100] Greening the Grid (September 2019] Grid-Scale Battery Storage. p. 2. [24]

storage duration of the system would be 4 hours.[101,102] Determining the correct battery storage system for different applications will rely on matching up typical energy usage with battery characteristics in terms of the rated power capacity and the energy capacity.

7.1.3.2 Other operational requirements

Waste disposal requirements

Day-to-day, waste disposal requirements are generally not needed for energy storage systems. Most systems can run and rerun using the same materials thousands or tens of thousands of times (Table 7.1). The end-of-life disposal for these systems is often opaque, though. For example, utility-scale use of lithium-ion batteries has been growing rapidly, but there are no standardized disposal guidelines for these batteries, which only have a 15-20 year lifetime.[103] These batteries also cannot be disposed of in traditional landfills; not only would it be wasteful of expensive and finite materials, but elements within the battery like cobalt, manganese, and nickel can harm soil and groundwater.[104] Battery recycling is not as advanced as battery production, but it is quickly growing into a large scale industry of itself, as demand for the critical materials that compose batteries increases. For example, in 2023, the U.S. Department of Energy granted Redwood Materials, a lithium-ion battery recycling company based in Carson City, Nevada, a conditional $2 billion USD loan to build out its battery recycling campus. The expansion is expected to 1,600 full-time employees and support the production of more than 1 million electric vehicles per year.[105]

Warehousing requirements

Energy storage technologies are essentially warehouses for electricity and/or heat. Some forms of energy storage may benefit from (or require) housing within a building, but as the only feedstock and product is energy, the need for ancillary on-site warehousing is highly unlikely.

Transportation requirements

Transportation requirements for battery energy storage systems should involve the transfer of electricity from a power source (e.g. wind or solar), and when needed, to an electricity or heat user. Electricity will be transported in the form of power lines. Heat can be transported as steam or hot air. The length of these transport lines is minimized the closer energy source, storage system, and end user are sited together, which is one of the key benefits of Kern County for carbon management industry development. High efficiency renewable energy and storage systems could be sited adjacent to a large-scale business park, reducing technical hurdles and costs of energy transfer.

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[101] Greening the Grid (September 2019] Grid-Scale Battery Storage. p. 2. [24]
[102] NREL (2022) Utility-Scale Battery Storage. [38]
[103] Semeniuk (October 12, 2020) The Future of Energy Storage Needs a Disposal Plan. [52]
[104] Semeniuk (October 12, 2020) The Future of Energy Storage Needs a Disposal Plan. [52]
[105] LPO (February 9, 2023) LPO offers conditional commitment to Redwood Materials. [31]

7.1.3 Carbon Capture Potential

Energy storage systems do not capture or sequester carbon dioxide emissions. However, these technologies are expected to play a key role in transitioning from carbon-intensive energy sources—like coal, oil, and natural gas—to lower-carbon renewables like wind and solar. This is because traditional fossil fuel energy infrastructure can operate continuously and consistently, but renewable sources like wind and solar can be more intermittent in their supplies. To ensure reliable operation of any technology requiring heat or electricity, battery storage is required alongside renewables to sustain continuous or on-demand operations.

It is worth noting that battery storage is not inherently carbon-neutral, and over its life-cycle (manufacture to end-of-life) can emit CO_2 and other greenhouse gasses. How much it emits depends on the *indirect* emissions that occur during production of the energy that it stores (batteries can store energy indiscriminately of the source). If it's cheapest to store and then deploy energy that originates from a fossil fuel facility, then batteries will actually enable a very carbon-intensive energy mix. Currently, most incentives for battery storage expansion do not require the energy to be sourced from renewable resources, meaning that battery storage deployment has actually *increased* carbon emissions relative to a national grid with no storage.[106]

This is relevant to a carbon management industry that uses CO_2 credits (either from public incentives like the federal 45Q tax credit, or from the private carbon credit market) for revenue, because they can only receive income for the *net* CO_2 that they remove from the atmosphere (or prevent from being emitted). If their energy source is carbon-emissions-intensive, that will reduce the viability of their business model. Thus, battery storage needs to be coupled with low-carbon energy sources—sources that are much less carbon-intensive than existing energy sources—to produce maximum revenue potential as well as maximum climate benefits.[107]

7.2 Societal Impacts

7.2.1 Job creation potential

7.2.1.1 Number and types of jobs

By 2050, it is estimated that between research and development, manufacturing, installation, and operation and maintenance, the energy storage industry is expected to create 370,000-450,000 jobs in North America, or nearly 2,000 jobs for every GW of storage capacity installed.[108] Of these roles, only installation and maintenance jobs will be

[106] Roberts (July 21, 2018) Batteries have a dirty secret. [49]
[107] Roberts (July 21, 2018) Batteries have a dirty secret. [49]
[108] ACPA (2021) Clean Energy Labor Supply. p. 18. [1]

necessarily sited at energy storage facilities, and only maintenance jobs will be permanent, long-term, on-site roles. Given that a primary design goal for energy storage is high durability, and low maintenance, there would likely be very few permanent maintenance jobs created.

In terms of installation jobs, the Crimson Energy Storage Project - a 350MW battery storage facility in Riverside County (Figure 7.6) created 140 jobs during peak construction.[109] A 45MW energy storage facility planned in Massac County, Texas, anticipates the creation of 100 short-term jobs during construction.[110]

Sectors of the energy storage industry that have the largest growth potential are manufacturing (38% of all industry job growth) and project development (25%), which includes services like consulting, finance, research, legal support, architecture, engineering, and other specialized design services.[111] Battery recycling is also likely to experience significant growth (see Section 7.1.3.2). While project development jobs could locate onsite, local policies that incentivize or mandate energy storage companies to hire local workers to fill as many roles as possible is a strong driver for expanding the community benefits of these kinds of projects.[112] Manufacturing and recycling do not need to be co-located with installation sites, but given their job growth potential, an assessment of the benefits and risks of encouraging these types of facilities to locate in the region warrants further investigation.

7.2.2.2 Training pipelines

A training needs assessment for energy workforce development conducted by the New York State Energy Research and Development Authority (NYSERDA), identified a suite of thirteen technical, business, manufacturing, and general training needs to create a strong workforce in the energy storage sector.[113] Most of these needs, such as fundamental knowledge of energy storage technology, technical skills training for installation and maintenance, electrician training, regulatory and permitting processes, advanced manufacturing skills, interconnection processes, and safety training, can be learned through on-the-job training, apprenticeships, professional association training programs, or trade schools. Some skills such as engineering, system design expertise, and business and finance modeling, will require advanced post-secondary degrees.

An assessment of job growth potential across the entire clean energy sector (wind, solar and storage) by the American Clean Power Association reported average wages for clean energy occupations to range from $33,710-$158,100 (in 2020 USD), with higher paying

[109] Denos (October 18, 2022) BLM announces completion of Crimson Energy Storage Project. [13]
[110] Vistra (April 6, 2021) Joppa power plant to close in 2022. [58]
[111] ACPA (2021) Clean Energy Labor Supply. p. 18. [1]
[112] Garcia (October 6, 2021) FAQ: Community-Level and Large-Scale Battery Energy Storage. [23]
[113] NYSERDA (2021) Energy Storage Workforce Development. [39]

positions requiring advanced degrees.[114] They projected that 65% of job-years created across these occupations would have an annual average wage higher than the national average of $56,310 (in 2020 USD).[115]

7.2.2 Quality of Life

7.2.2.1 Location

Battery storage facilities can be beneficial to communities, especially ones that are heavily reliant on variable energy sources, prone to extreme weather conditions, and/or suffer from transmission issues or grid unreliability. Battery storage facilities can replace "peaker plants"—typically fossil fuel-reliant power plants that run intermittently to meet peak demand on the grid.[116] Peaker plants are frequently located in disadvantaged communities, where they release greenhouse gasses and other emissions, some of which harm human health. Energy storage facilities can also replace aging facilities on the grid in need of decommissioning (such as the Moss Landing Energy Storage Facility, Section 7.1.3.1), which reduces the burden for ratepayers on paying for necessary infrastructure updates.[117] Because battery storage solutions can meet multiple needs, be deployed at a variety of scales, and utilize different storage technologies, there is a good deal of flexibility in ensuring the benefits of storage are realized by local communities.

Battery storage facilities do not locally emit any pollutants that cause harm to human health.[118] This is part of why battery storage solutions generally make a favorable replacement to traditional peaker plants—they can help meet periods of high energy demand without emitting harmful pollutants into local communities.

In general, battery storage systems are described as being "no louder than the average residential home air conditioning system."[119] The noise is derived from inverters, transformers, and fans needed to keep the equipment running,[120] though the exact equipment parts and their noise levels will differ between types of battery storage systems. With a planned 56 inverters, 56 transformers, and 40 HVAC units, the total noise level at a 1,000-foot distance from a 125MW facility operating at maximum sound level was 59.2 dB,[121] about as loud as normal conversational voices when people are standing about 3 feet apart.[122]

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[114] ACPA (2021) Clean Energy Labor Supply. p. 27-29. [1]
[115] ACPA (2021) Clean Energy Labor Supply. p. 24. [1]
[116] PNNL (no date) Energy Storage for Social Equity Initiative. [45]
[117] PNNL (no date) Energy Storage for Social Equity Initiative. [45]
[118] Garcia (October 6, 2021) FAQ: Community-Level and Large-Scale Battery Energy Storage. [23]
[119] Convergent (no date) Landowner Partnerships. [12]
[120] Burns & McDonnell (2019) Battery Energy Storage System Sound Study. p. 23. [3]
[121] Burns & McDonnell (2019) Battery Energy Storage System Sound Study. p. 23. [3]
[122] OSHA (no date) Occupational Noise Exposure. [40]

Light pollution is uncommon for battery storage sites, but is something that would need to be evaluated based on the site-specific needs and the facility type.

Battery storage does come with some risks that will impact both on-site workers and, to a lesser extent, quality of life for nearby residents. Utility-scale battery storage sites can be a fire and explosion risk.[123] For example, with lithium-ion batteries, there is the risk of *thermal runaway*, wherein one battery pack overheats, leading to a domino effect causing other units to overheat, which can create a fire or explosion within or across battery packs. If the battery packs catch fire, toxic gasses including carbon monoxide, hydrogen fluoride, and hydrogen chlorine can be released. If batteries are damaged during disposal, they can have similar hazards. With diligent on-site management and strong federal and state regulation, these hazards can be minimized to protect workers and nearby communities.[124]

7.2.2.2 Multi-use potential

Most battery storage systems can be easily co-located with other facilities, as exemplified by the diversity of sites upon which they already exist in urban, residential and remote environments, including private homes. One multi-use example comes from Duke Energy, which is planning to build a solar microgrid and battery storage facility next to Johns Hopkins Middle School in Pinellas County, Florida.[125] The 2.5 MW battery is designed to store energy from the solar microgrid to be deployed to support the school, which also acts as a hurricane shelter, or to the local power grid.

7.3 Environmental Impacts

7.3.1 Water requirements

7.3.1.1 Minimum volume requirements

Water intake amounts vary across battery types, and the relationship between water use (by volume) and capacity to store and release energy is not well reported, to the best of our knowledge, for any industry other than pumped hydropower storage facilities that rely on water from a nearby river being moved into a reservoir with a power station and then released back into the river (in this case, the net water use is very small).[126]

Many energy storage systems require water as a solution medium—redox flow batteries rely on aqueous (water-based) solutions to store the salts needed to generate electricity,[127] but the extent to which that water needs to be replenished (and thus the water demand of

[123] Garcia (October 6, 2021) FAQ: Community-Level and Large-Scale Battery Energy Storage. [23]
[124] Garcia (October 6, 2021) FAQ: Community-Level and Large-Scale Battery Energy Storage. [23]
[125] Duke Energy (August 25, 2020) Three new battery storage sites. [15]
[126] Casey (November 30, 2022) Underground Water Battery. [6]
[127] MIT (2022) The Future of Energy Storage. p. 29. [32]

such batteries over time) is not well reported. CAES facilities often need water to be pumped underground to dissolve the salts in underground storage caverns, which become a reservoir to store the compressed air for the system.[128] This generates brackish water that needs to be removed from the ground and treated before reuse (see Section 8 on water treatment techniques).[129]

Current lithium-ion batteries do not require water—in fact, most perform better in very dry conditions—but some teams are working on new lithium-ion batteries that can absorb water or use liquid materials instead of being a 'dry-cell' battery.[130]

7.3.2 Other potential impacts

For an industry as diverse as this, it is not possible to clearly outline all potential environmental impacts (positive or negative) in a region that develops utility scale storage. Even within the same category, different battery types do not carry same risks or potential environmental impacts.

Ultimately, any project sited in Kern County, California, including those developed in a carbon management park like that examined here, would be considered through a public process, where the environmental impacts specific to the technologies and fuels being used will be reviewed and mitigated in accordance with the California Environmental Quality Act (CEQA).

Two general points, however, can be made. First, battery and other energy storage systems do not generate criteria air pollutants.[131] In fact, because battery storage facilities often replace emergency generators or traditional power plants that run on fossil fuels, battery storage can serve to improve local air quality by replacing energy facilities that do emit pollutants.[132] Second, on a more global scale, battery production does have environmental impacts resulting from the extraction of critical materials (like lithium and cobalt) used to manufacture batteries, and from their disposal. As energy storage technologies scale up, a significant focus of research and development is on optimizing battery longevity and efficiency, and on improving mining practices and identifying raw materials that can replace critical minerals whose sourcing is often unsustainable and/or ethically fraught.[133]

[128] MIT (2022) The Future of Energy Storage. p. 94. [32]
[129] MIT (2022) The Future of Energy Storage. p. 94. [32]
[130] Sagoff (May 2, 2022) Water containing battery electrolyte. [51]
[131] Garcia (October 6, 2021) FAQ: Community-Level and Large-Scale Battery Energy Storage. [23]
[132] Garcia (October 6, 2021) FAQ: Community-Level and Large-Scale Battery Energy Storage. [23]
[133] Le (August 4, 2020) Flow Batteries. [29]

7.4 Economic Impacts

7.4.1 Business Model

The global energy storage market size is currently valued at $59 billion, and is anticipated to grow by at least 900% by 2035.[134] This is due primarily to the dramatic increase expected in our reliance on variable renewable energy (VRE) sources like wind and solar. In 2020, VREs provided 9% of global energy supplies. It is projected to rise to almost 70% of global energy supplies by 2050,[135] due both to commitments by nations and municipalities to reduce their carbon emissions, and to the fact that since 2020, onshore wind and solar power have been the least expensive forms of energy generation to build.[136]

Business models for utility-scale battery storage typically relies on the mismatch between energy supply and demand. With variable renewable electricity (VRE) sources like wind and solar, energy production highs and lows are based on the weather. Battery facilities buy electricity during periods of high VRE availability, when electricity is the cheapest, and then sell and distribute the electricity when VRE availability is low for a higher price.[137] This system enables battery facilities to generate consistent profits, while also providing a few co-benefits. First, implementing battery storage reduces demand for peaker plants, which are typically sustained using fossil fuels, to meet peak periods of electricity demand, thereby reducing CO_2 and other types of emissions. Second, it levels out energy costs for ratepayers from industrial to household scale. In California, as more battery facilities have come online, the variability between minimum and maximum energy prices has decreased, introducing greater consistency to energy pricing (Figure 7.7).[138]

The build-out of energy storage systems is not always driven by pure economics—rebates and other government incentives can drive additional uptake by making the economics more favorable, and mandates can ensure broad uptake, even when the economics are unfavorable. For example, in 2018, the Federal Energy Regulatory Commission (FERC) mandated that regional transmission organizations (RTOs) begin to adopt energy storage practices and that energy storage facilities are classed as "generation facilities."[139] In December 2020, the U.S. Congress passed the Better Energy Storage Technology Act, authorizing over USD 1 billion over five years to support the research and commercialisation of a range of storage technologies, with a focus on multi-hour distribution (balancing daily variation in VRE availability, and long-duration storage, that addresses seasonal VRE variability.[140] Although more regulatory changes will be necessary

[134] Le (August 4, 2020) Flow Batteries. [29]
[135] MIT (2022) The Future of Energy Storage. p. 271. [32]
[136] Lazard (2021) Levelized cost of energy. [28]
[137] CEC (November 2021) Buy Low, Sell High. [4]
[138] CEC (November 2021) Buy Low, Sell High. [4]
[139] Shim (November 13, 2018) Enthusiasm for Energy Storage. [54]
[140] St. John (December 22, 2020) Congress passes spending bill. [55]

to keep pace with expected changes in the energy grid, these policies offer a promising groundwork to remove unnecessary regulatory barriers and encourage greater participation of energy storage in the national electricity market.[141]



Figure 7.7. As more batteries have entered the California energy market, the highest and lowest energy prices have both moderated. Image credit: California Energy Commission.[142]

7.4.2 Business Costs

7.4.2.1 Cost of energy: Installed cost of storage

When considering the cost of energy storage, there are a few key takeaways:

1. Storage cost is dependent on the storage technology and energy capacity.
2. The price of energy has dropped significantly in the last few decades, and is expected to continue dropping.
3. The capital and operational costs associated with storage development do not translate to a levelized cost of energy in the same way that other energy commodities do, because energy storage is not a stand alone energy provider - it only operates in conjunction with an energy source.

We will unpack these takeaways in this, and the following section.

[141] Shim (November 13, 2018) Enthusiasm for Energy Storage. [54]
[142] CEC (November 2021) Buy Low, Sell High. [4]

Determinants of installed cost of storage

A 2022 study undertaken by the Pacific Northwest National Laboratory (PNNL)[143] examined commercially available energy storage technologies, with the aim of assessing how their costs varied as a function of power capacity (the amount of energy they can provide at a given time, in MW or kW) and energy capacity (the total amount of energy they can store on a single charge, in MWh or kWh), and how these costs are likely to evolve by 2030. Their comparison was across two variables: installed cost and levelized cost of storage (LCOS). Installed cost is addressed here, and LCOS is discussed in Section 7.4.2.2.

Table 7.3. Installed cost of energy storage in 2021.[144]

Battery Type[a]	Power Capacity Range (MW)	Installed Cost ($/kWh)	Installed Cost ($/kW)	Operating Costs ($/kW-yr)	Decommis-sioning Costs ($/kWh)
Lithium-Ion (LFP)[b]	1-10	$360-519	$922-9,128	$2.79-23.30	$2.65
Lithium-ion (NMC)[c]	1-10	$410-576	$1,031-10,405	$6.18-29.59	--
Lead Acid	1-10	$412-607	$1,090-10,457	$4.05-31.46	$16.89-33.28
Vanadium Redox Flow	1-10	$356-836	$1,522-$9,054	$4.85-26.48	$22.95-59.27
Zinc	1-10	$440-631	$1,172-10,798	$10.56-27.65	--
CAES	100-1,000	$16-295	$1,087-1,784	$9.82-18.56	--
Pumped storage hydropower	100-1,000	$221-511	$1,716-2,625	$15.58-28.19	--
Gravitational	100-1,000	$190-731	$1,706-7,600	$14.28-34.37	--
Thermal	100-1,000	$130-595	$1,568-3,944	$6.95-42.77	--
Hydrogen	100-1,000	$126-295	$2,949-3,033	$16.89-23.90	--

a. The most commonly utilized battery types are described in this report. For details on all battery types, see Viswanathan et al. (2022) PNNL energy storage cost assessment.
b. Lithium-ferrophosphate
c. Nickel-manganese-cobalt

Installed costs comprise the net of capital expenses (raw materials, project development, engineering, procurement, construction and grid integration). These costs are detailed in Table 7.3, along with operating costs (fixed operations and maintenance, losses associated with round-trip efficiency (RTE),[145] and in some cases a warranty) and decommissioning costs (disconnection, removal, site remediation and recycling/disposal), and are given as

[143] Viswanathan *et al.* (2022) PNNL energy storage cost assessment. [59]

[144] Viswanathan *et al.* (2022) PNNL energy storage cost assessment. [59]

[145] Note: round-trip efficiency (RTE) is the percentage of the energy used to charge a storage system that is released during discharge. See Table 7.1 for typical RTEs by battery type.

ranges that reflect cost variation as function of power capacity (specified by storage type) and storage duration, in hours.

For any of these technologies, installation costs in terms of energy capacity ($/kWh) decrease with increasing storage duration (see Figure 7.8), but in terms of power capacity ($/kW) and operating costs, they increase with storage duration.[146] Installation costs also decrease with increasing power capacity, due to economies of scale.[147]

Projected decreases in battery costs

The outlook for rapidly decreasing costs for energy storage is quite promising, on the basis of historical trends. Since 1991, the price of lithium-ion batteries has decreased 97%.[148] Like other technological innovations (such as solar and wind power), economies of scale and learning by doing have driven significant, systematic decreases in the cost of production with every doubling of installed capacity. For lithium-ion batteries, this 'learning rate' has been a price decline of about 18.9% for every cumulative capacity doubling.[149] Using this learning rate, as well as anticipated growth in energy storage installation capacity, it is possible to make projected estimates of what costs will be in the future. A cost analysis from MIT estimated that by 2050, lithium ion batteries may have decreased an additional 37-74% in price, while less developed technologies could see even greater cost decreases (up to 91% for flow batteries and up to 97% for metal-air batteries).[150]

7.4.2.2 Cost of energy storage: Levelized cost of storage

The cost of energy is often assessed as a levelized cost, that is incorporating capital, operational, labor and feedstock costs, what is the total cost of producing energy ($/kWh or $/MWh) for a given facility, over the lifetime of that facility?[151] Assessing the levelized cost of storage is slightly more complicated, as it requires not only consideration of the above factors, but also how much the storage system would be used annually (annual hours discharged), the cost of energy needed to charge the energy storage system and the round-trip efficiency (RTE). These variables are combined to calculate the levelized cost of storage (LCOS) as follows:

$$LCOS = [(fcr \times CapEx) + O\&M_{fixed})/AH + ECC, \quad \text{(E7.1)}$$

where fcr = the fixed charge rate (%), CapEx is the present value of capital expenditures, $O\&M_{fixed}$ are fixed operating and maintenance costs, AH is the annual hours discharged, and ECC is the electricity charging cost (purchased energy [$/kWh] divided by RTE [%]).[152]

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[146] NREL (2022) Utility-Scale Battery Storage. [38]

[147] Viswanathan *et al.* (2022) PNNL energy storage cost assessment. f.ex. p. 24-25. [59]

[148] Ritchie (2021) Price of batteries has declined by 97%. [48]

[149] Ritchie (2021) Price of batteries has declined by 97%. [48]

[150] MIT (2022) The Future of Energy Storage. p. 19. [32]

[151] Lazard (2021) Levelized cost of energy. [28]

[152] Viswanathan *et al.* (2022) PNNL energy storage cost assessment. p. 120-121. [59]

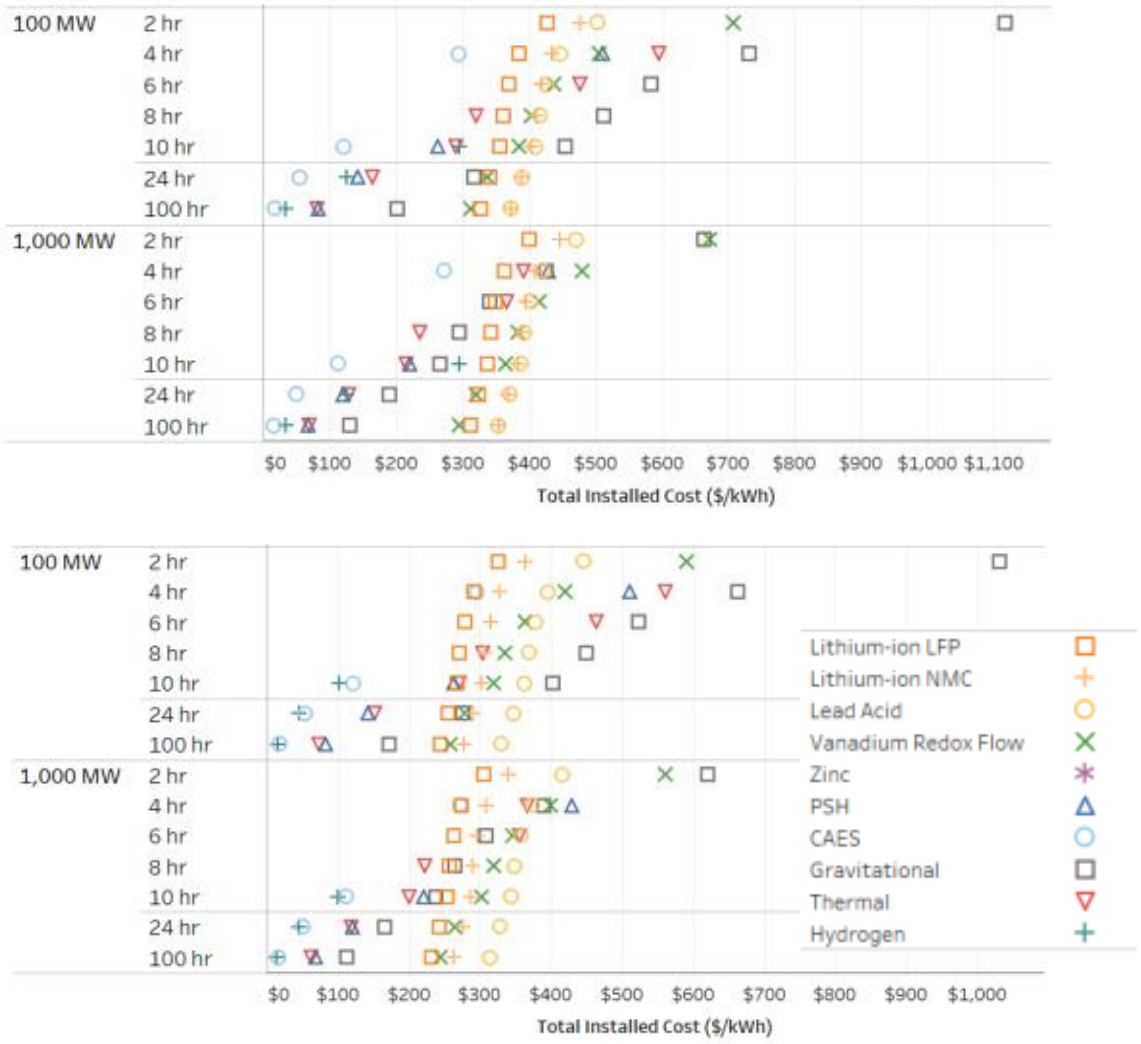


Figure 7.8. Total installed cost of energy solutions, as a function of storage duration and power capacity, showing estimated 2021 values (a) and projected 2030 values (b). Values are shown for power capacities of 100 and 1,000 MW. Data and image credit: Pacific Northwest National Laboratory.[153]

The energy system cost assessment from PNNL (2022) included an LCOS analysis of all studied energy storage systems, and found that levelized costs ranged from about $0.10-1.30 USD/kWh for large (100-1,000 MW) storage systems, with most costs falling between $0.10 and $0.40 (the higher costs were associated with systems that had 100 hr storage duration).[154] For comparison, grid electricity in California is about $0.12-0.65 USD/kWh.[155] It is also important to note that battery storage does not work alone - it operates in tandem with an energy source, like wind or solar - with the direct energy source supplying power sometimes (to the grid and the storage system) and the energy storage system supplying

[153] Viswanathan *et al.* (2022) PNNL energy storage cost assessment. p. ix-x. [59]
[154] Viswanathan *et al.* (2022) PNNL energy storage cost assessment. p. 130. [59]
[155] EIA (February 2023) Average price of electricity. [16]

power other times. Therefore it is most useful to think of how energy storage adds to the levelized cost of energy production from wind or solar, which is about $0.03-0.05 USD/kWh.[156]

The National Renewable Energy Laboratory reports added costs per MWh (= 1,000 x kWh) of $5-39 for energy storage (from their own models and the published literature), with much of the range reflecting the inclusion or omission of tax credits. In a practical example, during a 2018 bidding war for new energy capacity for electricity provider Xcel Energy in Colorado, the median price for energy storage and wind was $21/MWh, and it was $36/MWh for solar and storage. This compares to $18/MWh and $29.50/MWh, respectively, for wind and solar solutions without storage.[157]

7.4.3 Regional benefits

California leads the nation in energy storage, with 215 operational projects providing ~4,200 MW of energy,[158] and plans to grow. Among utility-scale facilities, about 75% of planned development between 2022 and 2025 is concentrated in California and Texas.[159] As such, there are already companies active in the energy storage space with a sizable presence in the California market.

Local laws and regulations in California also make it an attractive location for utility-scale energy storage projects. The California Energy Commission (CEC) predicts that to meet the requirement of Senate Bill 100 for a carbon-free electricity system by 2045, 49,000 MW of battery storage capacity will need to be integrated into the electricity grid.[160] To reach these goals, new state legislation has removed some of the subdivision and zoning requirements that extended project timelines, making it more straightforward to develop a battery energy storage facility in California.[161]

7.4.3.1 Proximate feedstocks

Battery storage systems have minimal feedstocks in the traditional sense. These systems need inputs and catalysts to fuel the redox reactions that support most electrical storage, but these materials can often be reused for many charge/discharge cycles. Thus, having local supplies of materials to meet this need is not a major concern—depending on the battery type, replacement of component chemicals may not be necessary for a decade or longer.

Depending on the system type, water intake will be the most important feedstock consideration. For aqueous systems like redox flow batteries, water is necessary for

[156] Lazard (2021) Levelized cost of energy. p. 9. [28]
[157] Svaldi (January 16, 2018) Xcel Energy receives shockingly low bids. [56]
[158] University of Michigan (no date) U.S. grid energy storage factsheet. [57]
[159] EIA (December 8, 2022) U.S. battery storage capacity will increase significantly by 2025. [17]
[160] CEC (November 2021) Buy Low, Sell High. [4]
[161] Colthorpe (August 31, 2022) California zoning exemption granted. [10]

sustained operation. However, some forms of redox flow batteries have optimized reuse of the liquid electrolyte solutions, with vanadium redox flow batteries having a liquid electrolyte with near-100% recyclability.[162] As a result, this water requirement can vary greatly, even within the same family of batteries, due to the material differences between electrolyte solutions, catalysts, and other components.

Other battery types—like standard dry-cell lithium-ion batteries—are corroded by water,[163] so locating them in arid regions, a common feature in Kern County, could be a great locational fit based on the region's climate and the battery's optimal operating conditions.

7.4.3.2 Proximate consumers

Battery storage has multiple benefits for carbon management and clean energy industries. Many of these processes require energy input to capture carbon or generate other products, but given the goals of the carbon management park, would need to find ways to meet this energy demand while minimizing their operational carbon output. Battery storage can serve to smooth out energy supply availability by storing solar energy during peak production periods and releasing it while the solar supply is negligible (i.e. at night), so facilities can maintain continuous operation. Thermal batteries can also convert renewable energy solar and wind energy into high temperature heat, which is needed in some carbon management industries, particularly L-DAC (Section 3) and steel (Section 5).

7.4.3.3 Co-location advantages

There will already be a large amount of renewable energy resources around to support the carbon management and clean energy industries on-site; batteries bridge the gap between supply and need imbalances.

If the system is entirely off-grid, a battery storage provider could secure procurement agreements directly with park facilities. If the system has a grid connection, the battery storage provider could also secure procurement agreements with local utility companies.

[162] Ondrey (April 1, 2021) Recycling electrolyte from vanadium RFBs. [43]
[163] Sagoff (May 2, 2022) Water containing battery electrolyte. [51]

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8. Water Treatment

TECHNOLOGY AT A GLANCE

- Industry has wide-scale public implementation: globally, 48% of wastewater is treated, with 11% destined for reuse.[1] In the U.S., an estimated 91.1% of wastewater is safely treated.[2]
- Water treatment is energy-intensive[3] and varies in size and complexity based on the amount and quality of water received and the necessary quality for use after treatment.[4]
- Key advantages of this technology in Kern County: regional water supply is already overallocated[5] and subject to frequent drought conditions.[6] Water reclamation and reuse could support new industries while minimizing impacts on existing agricultural and residential water use.
- Key concerns of this technology in Kern County: Water treatment is well-understood and highly regulated for safety. Facilities should be sited where odors, light, and noise pollution will not bother communities and implemented in the context of a sustainable regional water use plan.

[1] Utrecht University (February 8, 2021) Half of global wastewater treated. [79]
[2] Alabaster *et al.* (2021) Progress on Wastewater Treatment. p. 92. [1]
[3] Lund (September 2017) Plant Earns LEED Recognition. [55]
[4] CDC (no date) Water Treatment. [16]
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8.1 Technology Summary

Water use is a critical consideration in the design of any new industrial center, especially in California, which is in the midst of a multi-decadal megadrought.[7] State policies require restoration of the groundwater aquifers[8] that have been traditionally relied upon to compensate for shortages in surface water resources, further exacerbating the need for water conservation.[9] In Kern County, industries requiring abundant fresh water would directly compete with regional agriculture, municipalities and existing industries. However, the state of California produces more than 3.4 million acre-feet of wastewater annually[10] (see below for definitions) that has the potential to be remediated and repurposed for industrial use. The viability of such an option is dependent upon interest, cost, and needs of the envisioned park, which will vary depending upon the types of industries that choose to locate on-site. In this section, we provide a general overview of water treatment facilities, and how they differ as a function of the purity needs of treated water. For readers unfamiliar with industrial scale water treatment and use, relevant key terms and policies are outlined here.

Acre-foot is a standard measurement for large volumes, representing the amount of water needed to cover one acre of land with one foot of water. One acre-foot is equivalent to 326,000 gallons of water.[11] For reference, it would take the average household in California between six months and two years to use this volume of water.[12]

Alternative water is a catch-all term for water sources that are not surface or standard groundwater collection. According to the U.S. Department of Energy (DOE), this includes "Harvested rainwater, stormwater, sump-pump (foundation) water; Graywater [also spelled greywater or grey water]; Air-cooling condensate; Rejected water from water purification systems; Reclaimed wastewater; [and] Water derived from other water reuse strategies."[13] Graywater and reclaimed wastewater are of particular interest here. **Graywater** constitutes water lightly used for domestic or industrial use aside from toilets, and typically requires less processing than wastewater.[14] **Wastewater** is a broader category, including sewage, water used in heavier industrial processes, and stormwater as

[7] James (February 14, 2022) Western megadrought is worst in 1,200 years. [48]

[8] Escriva-Bou *et al*. (2021) Groundwater recharge in California. [33]

[9] Chappelle *et al*. (2017) Groundwater in California. [17]

[10] California Water Boards (no date) Volumetric annual reporting of waste water and recycled water. [15]

[11] Bland (August 4, 2021) Water is life. [9]

[12] Bland (August 4, 2021) Water is life. [9]

[13] EERE (no date) Net Zero Water Building Strategies. [58]

[14] Ghaly *et al*. (2021) Greywater Sources, Characteristics, Utilization and Management Guidelines. p. 128. [39]

well as graywater; it can contain a wider range of pollutants and thus requires more processing, depending on the quality necessary for reuse.[15]

Influent refers to the water entering a treatment plant, and **effluent** refers to the same water after it has undergone treatment and is leaving a treatment plant.[16] The quality and volume of influent and effluent will vary across facilities.

8.1.1 Description: How it Works

Wastewater processing works utilizing a well-established model, though the steps may differ based on the quality of the influent, amount of water processed, and age of the facility. There are a few consistent steps across models, however, with one exception that distinguishes the two primary types of plants: conventional treatment, in which a sedimentation tank is part of the treatment process, or direct filtration, which does not use a sedimentation step.[17] The list below describes **primary treatment**, typical for all wastewater treatment plants. Depending on the quality of the influent water and the necessary quality of effluent flow, secondary or tertiary systems can be implemented to further clean the supply.

- **Preliminary treatment**: influent water passes through coarse screening and grit removal processes to remove large materials, like manmade objects, rocks, or gravel.[18]
- **Coagulation**: chemicals are added to the water to "stick" small particulates together.[19]
- **Flocculation**: as particulates begin to clump together, water is added to large tanks with slowly-mixing paddles, which bring particles together to form floc.[20]
- **Sedimentation**: the water slowly passes through a sedimentation tank, where the floc settles at the bottom of the tank to be pumped out while the water moves out of the tank.[21,22] Direct filtration systems skip this step.[23]
- **Filtration**: the water enters a filter, typically a concrete box with sand and gravel supported on an underdrain structure, which removes remaining suspended particles.[24]

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[15] DES – Queensland (no date) Wastewater. [24]
[16] Pulsar Measurement (no date) Influent and Effluent Flow Monitoring. [61]
[17] College of the Canyons (November 22, 2020) Water Treatment Facilities. [22]
[18] Pescod (1992) Wastewater treatment. [60]
[19] College of the Canyons (November 22, 2020) Water Treatment Facilities. [22]
[20] College of the Canyons (November 22, 2020) Water Treatment Facilities. [22]
[21] College of the Canyons (November 22, 2020) Water Treatment Facilities. [22]
[22] EPA (1998) How Wastewater Treatment Works. p. 3. [29]
[23] College of the Canyons (November 22, 2020) Water Treatment Facilities. [22]
[24] College of the Canyons (November 22, 2020) Water Treatment Facilities. [22]

- **Disinfection**: prior to discharge, water is often treated with chlorine gas or a mix of chlorine and ammonia in a process called chloramination to kill microorganisms.[25] The maximum residual disinfectant level (MRDL) for effluent water leaving the plant is 4.0mg/L, and most effluent averages free and total chlorine concentrations "between 2.5 and 3.5 mg/L" when leaving a treatment facility.[26]

While these steps are common to nearly all water treatment facilities, some can be removed or other steps can be introduced, depending on the water quality and planned destination for effluent flow. The flowchart in Figure 8.1 provides an example, demonstrating the water treatment process used at the Granollers Wastewater Treatment Plant, built in Spain in 1992.[27] This system includes far more intermediary steps to clean its water before discharge. The figure also details the steps necessary to process sludge (raw primary biosolids), a byproduct of water treatment.[28]

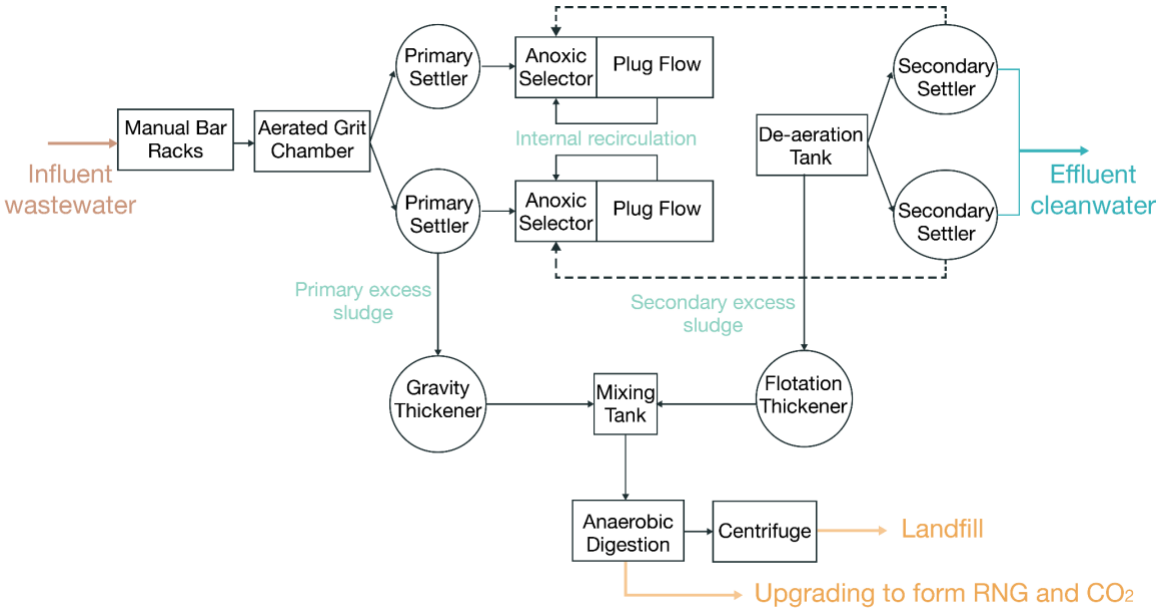


Figure 8.1. Flow chart demonstrating some typical steps of a wastewater treatment process; adapted from Vidal et al. (2002) and other sources.[29]

Cleaning water for industrial use may be less intensive than is required for a wastewater treatment plant producing drinking water quality effluent. The European Union's guidelines for water reuse, which draws on existing best practice, outlines that "industrial water reuse

[25] College of the Canyons (November 22, 2020) Water Treatment Facilities. [22]
[26] College of the Canyons (November 22, 2020) Water Treatment Facilities. [22]
[27] Vidal *et al.* (2002) Design of Wastewater Treatment Plants. p. 4994. [81]
[28] EPA (1998) How Wastewater Treatment Works. p. 3. [29]
[29] Vidal *et al.* (2002) Design of Wastewater Treatment Plants. p. 4994. [81]

is highly determined by the exact quality needs of the individual industrial process and/or product as well as the costs of producing water of the required quality compared to other suitable sources."[30] Thus, there are few 'industry standards' that can be used to define the necessary processes (and costs) of industrial water reuse—it will depend on the types of industries that could be located within the park and the water volume and quality necessary to operate a given facility.

Another freshwater alternative for industrial water (or drinking or irrigation water) is desalination, which is the process of stripping dissolved salts from seawater or other brines. As Kern County is within 100 miles of the Pacific Ocean, desalination of seawater would provide an effectively limitless volume of water for industrial development, albeit at a high price. Desalination is up to four or five times the cost per gallon for treatment, when compared to graywater or wastewater treatment plants.[31] It is considered in this study for the purpose of comparison with treatment of graywater or wastewater, and as a point of consideration for future development in the region, given that freshwater resources are anticipated to become ever more scarce with climate change.[32]

There are two main techniques for desalination, each reviewed briefly here. In reverse osmosis (RO), influent is passed through a series of semi-permeable membranes in order to remove the salts and other impurities found in seawater, as shown schematically in Figure 8.2.[33,34]

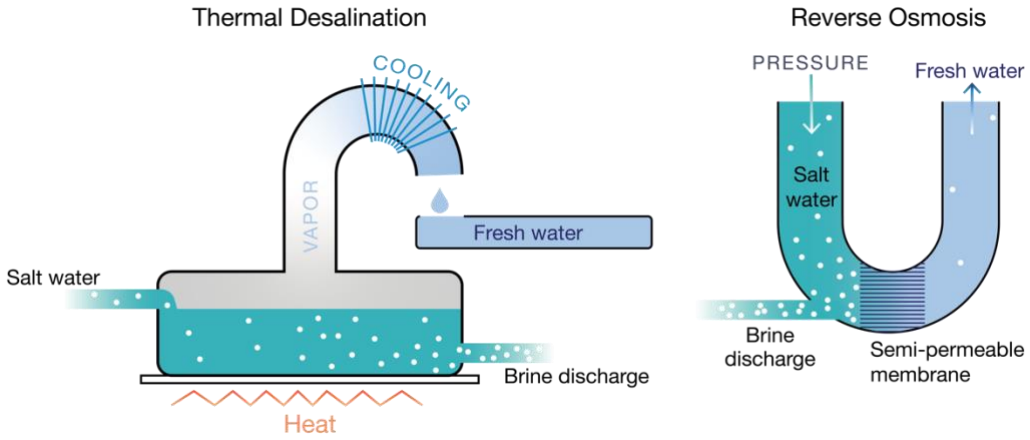


Figure 8.2. Thermal desalination and reverse osmosis are two techniques for producing fresh water from saline waters like seawater or brines. Adapted from the Texas Comptroller of Public Accounts.[35]

[30] EU Water Directors (no date) Common Implementation Strategy. p. 24. [35]
[31] Climate Now (April 19, 2022) Solve the Global Water Crisis? 6:30-6:42. [20]
[32] Hanak (January 9, 2023) Adapting to a Water-Scarce California. [44]
[33] IDE Technologies (no date) What is Desalination? [46]
[34] Ang *et al.* (2015) Integrated/Hybrid Membrane Processes. [3]
[35] Texas Comptroller of Public Accounts (no date) Texas Water Tour: Desalination. [73]

In thermal desalination, heat is used to evaporate seawater, creating pure water vapor and a briny residue. The vapor is subsequently condensed into fresh liquid water. Waste heat from power plants or refineries is often used to supply the heat source.[36] Thermal desalination can be accomplished through vapor compression (VC), in which heat derived from mechanically compressed vapor is used to drive evaporation of the seawater influent. Alternatively, multi-stage flash distillation (MSF) and multi-effect distillation (MED) employ multi-step evaporation/condensation processes, taking advantage of how the boiling point of water varies as a function of salinity to optimize energy efficiency. Steam or the seawater influent itself is used as the carrying agent for the heat, which boils seawater in a series of vessels (or "effects"), producing vapor and a more salty brine. The brine is moved to the next vessel, which induces boiling at a higher temperature, producing more vapor and a saltier brine, that is transferred to the next vessel, and so forth, iterating as many times as is desired.[37,38]

8.1.2 State of Development

Water treatment and transport has been employed for centuries,[39] and are a common feature of public drinking water systems throughout the United States[40] (and the world). But new technologies that are particularly important in water-scarce regions like Kern County, such as desalination of seawater or wastewater treatment that provides water effluent that is clean enough for irrigation or drinking purposes, are not yet widely used on a commercial scale in the United States. Only about 1% of water is recycled in the U.S.,[41,42] and less than 3 gallons of every 1 million gallons of water used each day in the U.S. comes from desalination.[43]

For the purposes of this investigation, we have examined two water treatment facilities that are typical for water reuse in irrigation or landscaping, and a small set of facilities across the nation that fall within the 1% of plants that are designed to generate usable water to directly meet local needs and increase water circularity. Water treatment facilities specifically designed to meet the needs of an industrial park are not well-covered in the literature, given the vast diversity of requirements that might entail. However, lessons gleaned from existing facilities can provide a general sense of the parameters, needs, impacts and benefits of a water treatment or desalination facility to nearby industries or communities.

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[36] IDE Technologies (no date) What is Desalination? [46]
[37] IDE Technologies (no date) What is Desalination? [46]
[38] Tzen (no date) Desalination Technologies (I). [75]
[39] EPA (2000) The history of drinking water. [31]
[40] CDC (no date) Water treatment. [16]
[41] WaterReuse.org (no date) Water Reuse 101. [84]
[42] USGS (no date) How much water is used by people in the United States? [77]
[43] Tonner (November 2, 2021) Desalination in America. [74]

8.1.2.1 Example projects

Bee Ridge Water Reclamation Facility, Sarasota County, Florida[44]

This facility in Sarasota County has a capacity of 12 million gallons per day (GPD), making it the largest of the county's water treatment plants. Wastewater is moved to the site through a series of underground pumps and lifting stations. Once at the site, the influent water goes through four major cleaning steps: screening for inorganic materials, biological processing, filtration, and disinfection. Biosolids removed during the treatment process are separated out and composted.

Effluent water that leaves the Bee Ridge facility after processing is reclaimed water that is suitable to meet commercial and residential needs for landscaping and irrigation. This reduces the demand to use potable water—which could be used in homes for cooking and cleaning—for outdoor use.

Lancaster Water Reclamation Plant, Lancaster, California[45]

This facility in Lancaster, just south of Kern County, has a capacity of 18 million GPD. It employs primary, secondary, and tertiary processing, so the facility can generate reclaimed water suitable for agricultural, municipal, industrial, and parkland uses, including maintenance of water levels in regional parks and migratory bird ponds. An estimated 12.6 million gallons per day of reclaimed water is used from the Lancaster facility every day.

The Lancaster facility also saves its byproducts; biosolids are dried and can be used for compost or soil additives. The methane (biogas) generated on-site from processing wastewater is used to meet the heat requirements of the anaerobic digesters.

Direct potable reuse (DPR) water treatment demonstration facilities, United States

Although it is possible to generate reused water at the quality necessary for safe drinking water, few states allow treated wastewater to be pumped directly into homes—currently, only Texas and (on a case-by-case basis) Arizona allow direct distribution of treated water as potable tap water (direct potable reuse, or DPR).[46] Both Big Spring and Wichita Falls, in Texas, have used DPR to support local water supplies, with Wichita Falls relying on the practice to generate 5 million gallons of treated water per day to support the city during the end of a 5-year drought.[47]

In California, cities like San Diego and Los Angeles have begun to consider the implementation of DPR to diversify their own water supplies.[48] The State Water Control Resources Board is expected to release updated regulations this year that would allow DPR

[44] Sarasota County (no date) Bee Ridge Water Reclamation Facility. [68]
[45] LACSD (no date) Lancaster Water Reclamation Plant. [54]
[46] Constantino (August 19, 2022) What's in your drinking water? [23]
[47] Constantino (August 19, 2022) What's in your drinking water? [23]
[48] Constantino (August 19, 2022) What's in your drinking water? [23]

in the state.[49] To prove the viability and safety of DPR to the public, San Diego ran a demonstration advanced purification facility from 2009 to 2013 allowing the public to tour the plant and try the water, but avoided any legal trouble by not sending any of the DPR water to taps.[50] Los Angeles plans to undertake a similar demonstration facility in 2024 to act as "proof of concept" for city residents about the safety of DPR.[51] Experts estimate that California has the potential to triple its current water reuse rate to 2.8 million acre-feet annually.[52]

8.1.3 Operational Needs

8.1.3.1 Land use requirements

Water treatment plants can have large land use requirements. The physical footprint of a facility can comprise a series of open ponds and/or buildings, depending on facility scale and local regulations.[53] Quality of the influent and effluent can also shape facility size—more intensive treatment can introduce additional filtration steps requiring extra equipment or ponds—and facilities often locate, when possible, on larger sites than needed to both leave room for future expansion and avoid bothering nearby communities with any noise, light, or odor pollution from the treatment plant.[54]

It is important to note that facility acreage and facility capacity (the amount of water a treatment plant can process) are not strongly correlated. In the United States, the largest treatment plants by capacity have maximum physical footprints of about one square kilometer (~247 acres), with an average size of around 0.6 square kilometers (~148 acres).[55] For a regionally representative example, the Bakersfield Wastewater Treatment Plant No. 2, processing 13.7 million gallons per day or about 15,345 acre-feet of water per year,[56] occupies ~645 acres of land.[57]

Design plans also differ considerably, depending on how much of the processing equipment is visible from the outside of the facility. An advantage of water treatment facilities relative to other industries included in this report, is the wide potential for alternative uses, including natural or open spaces, or public use spaces (see Section 8.2.2). An image demonstrating the potential appeal in the landscape and for nearby residents is shown in Figure 8.3.

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[49] Water Education Foundation (no date) Water Recycling. [83]
[50] Constantino (August 19, 2022) What's in your drinking water? [23]
[51] Constantino (August 19, 2022) What's in your drinking water? [23]
[52] Water Education Foundation (no date) Water Recycling. [83]
[53] USA SHADE (no date) Water Treatment Facility Design Guide. [76]
[54] USA SHADE (no date) Water Treatment Facility Design Guide. [76]
[55] Wikipedia (August 2, 2022) List of largest wastewater treatment plants. [86]
[56] City of Bakersfield (no date) Wastewater Treatment Plants. [18]
[57] Measured via Google Earth.



Figure 8.3. The Newtown Creek Wastewater Treatment Plant in is located on a 52-acre site and has been designed to exist alongside residential development.[58] Blue and white lighting at the plant seek to provide enough light to work safely at night, without constituting an ecological or community hazard of light pollution.[59] Image credit: Victoria Belanger / Flickr

8.1.3.2 Energy requirements

Water treatment is an extremely energy-intensive process, using approximately 650 MWh per acre-foot of treated water.[60] Electricity costs alone can account for 25% to 40% of a water treatment facility's annual operating budget,[61] and within most municipal areas, wastewater treatment facilities are the largest single electricity consumer.[62] Energy requirements for water treatment depend on the quality of influent water being processed, considering both the type of contaminants involved, and their concentration in the influent. These factors determine the technologies and methods used to treat the water and are thus highly correlated with energy consumption.[63] The most energy intensive practices are generally also the most expensive, with seawater desalination requiring more electricity than cleaning wastewater or graywater.[64]

Aside from treatment facilities themselves, transporting water before or after treatment also requires a great deal of energy, simply because water is heavy to move. For reference, one acre-foot of water weighs 1,360 U.S. tons (~1,233 metric tons).[65] In California, the State Water Project – a suite of canals, pipelines, reservoirs, and hydroelectric power facilities that serve as a freshwater delivery system across the state[66] – is "the state's single largest user of electricity" as the infrastructure needed to support pumping water between regions is highly energy intensive.[67]

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[58] L'Observatoire International (no date) Newtown Creek. [53]
[59] L'Observatoire International (no date) Newtown Creek. [53]
[60] Hamilton *et al.* (2009) Driving energy efficiency in the U.S. water & wastewater industry. [43]
[61] Lemar, de Fontaine (2017) Energy Data Management Manual. p. 2. [51]
[62] Lemar, de Fontaine (2017) Energy Data Management Manual. p. 5. [51]
[63] Energy Star (no date) Energy Use in Wastewater Treatment Plants. p. 2. [26]
[64] Fort, Nelson (2012) Pipe Dreams. p. 21. [36]
[65] Fort, Nelson (2012) Pipe Dreams. p. 3. [36]
[66] California Department of Water Resources (no date) State Water Project. [14]
[67] Fort, Nelson (2012) Pipe Dreams. p. 3. [36]

Innovative state and federal programs are helping facilities to reduce their energy consumption through improvements in energy recovery, benchmarking usage, and efficiency upgrades to onsite equipment.[68] Scientists and engineers are even optimistic that ambitious wastewater treatment plants could become net energy creators, rather than users, in the future.[69] This is primarily due to their ability to use the biogas and thermal heat produced on-site more efficiently with measures like co-digestion and fuel cell systems.[70] However, given the present average energy requirements of water treatment facilities (650 MWh/acre-foot), approximately 1.6 acres of solar energy would be required to treat an acre-foot of water.* Water needs from the various carbon management systems explored in this report range from less than 0 acre-feet per million metric tons of CO_2 captured (S-DAC and some forms of BiCRS), to as much as ~16,000 acre-feet of water needed per million tons CO_2 (L-DAC, see Figure 8.4). The high-end estimate translates to about 25,312 acres of solar panels needed to support sufficient water treatment.

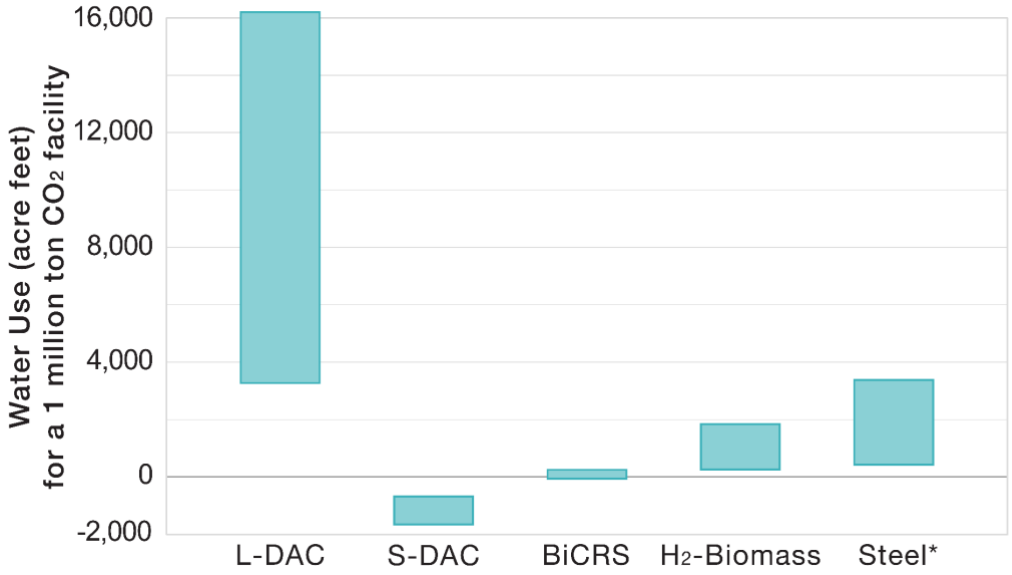


Figure 8.4. Water use across carbon management industries, based on this study (see Sections 3, 4 and 5). Hydrogen production via biomass, steel and particularly L-DAC technologies are water-intensive practices, using as much as 16,200 acre-feet of water annually, that could be sourced from treated graywater or (less economically) desalinated seawater.

[68] Lemar, de Fontaine (2017) Energy Data Management Manual. p. 4. [51]

[69] Gandiglio *et al.* (2017) Enhancing the Energy Efficiency of Wastewater Treatment. p. 1. [38]

[70] Gandiglio *et al.* (2017) Enhancing the Energy Efficiency of Wastewater Treatment. p. 1-2. [38]

* Please see Section 3.1.3.2 of this report to see the equation and solar capacity factor used to derive this estimate.

8.1.3.3 Other operational needs

Waste disposal requirements

Wastewater treatment plants generate bio-solids and methane gas as byproducts of the water purification process.[71] According to the EPA, the methane produced on-site is frequently used by water treatment plants as fuel, rather than being disposed of or sold.[72] However, the methane produced can be sold as renewable natural gas (RNG) to other firms as long as its production and storage meets necessary federal and state standards.[73] This could encourage circularity within a water treatment plant or within a carbon management industrial park at large, particularly given the potential for generating electricity plus CO_2, or hydrogen fuel plus CO_2, through oxy-fuel combustion or methane steam reforming, respectively (see Sections 4 and 6).

Biosolids are another byproduct that are produced by physically and chemically treating the solids separated out during the water purification process to generate a nutrient-rich, semisolid product.[74] These solids can be used productively on agricultural and mining sites to improve soil structure, add nutrients, and improve water reuse, with secondary benefits including reduced landfilling and reduced use of synthetic fertilizers.[75] If not reused, biosolids must be disposed of by surface disposal methods, such as landfilling or incineration.[76]

Warehousing requirements

To store influent prior to treatment and effluent before it is sent to customers, water treatment facilities typically require a large amount of onsite storage. Water awaiting treatment is often held in ground lakes or pools.[77]

Because treated water is also often stored onsite until it can be transported to a customer, facilities can require millions of gallons worth of space to store cleaned water.[78] Onsite storage helps to regulate water supply to align with demand, both of which can vary seasonally.[79] Furthermore, onsite storage serves to further reduce the amount of nitrogen, microorganisms, and suspended solids present in treated water, so water leaving storage can also be cleaner than when it first leaves the treatment plant.[80] Depending on the

[71] City of Bakersfield (no date) Wastewater Treatment Plants. [18]
[72] EPA (no date) Methane Generated on Site. [30]
[73] EPA (no date) Methane Generated on Site. [30]
[74] EPA (no date) Basic Information about Biosolids. [28]
[75] EPA (no date) Basic Information about Biosolids. [28]
[76] EPA (no date) Basic Information about Biosolids. [28]
[77] College of the Canyons (November 22, 2020) Water Treatment Facilities. [22]
[78] College of the Canyons (November 22, 2020) Water Treatment Facilities. [22]
[79] Pescod (1992) Wastewater treatment. [60]
[80] Pescod (1992) Wastewater treatment. [60]

location and quality, effluent can be directly discharged into 'receiving waters' such as nearby rivers or streams, removing the need to store effluent flow for distribution.[81]

Transportation requirements

The influent and effluent from any water treatment plant would need to move between potential sources – agricultural fields, commercial or industrial facilities, or the ocean – to the plant, and then into the carbon management park. Depending on the yield of the plant and the park's water usage, additional infrastructure may be necessary to transport water to alternate consumers or to nearby aquifers in need of replenishment.

In California, water is typically transported using open canals, aqueducts, or pipelines.[82] The size of this equipment, as well as its operating needs and costs, will depend on the anticipated load.[83] Moving water can be energy-intensive over any topographical features, as pumps will be necessary to accommodate any increases in altitude along the route; as a result, the most efficient pipelines would move water near flat or declining geography to benefit from gravity.[84] A good example of this type of infrastructure operating without energy-intensive pumps is the nearby Los Angeles aqueduct, which runs through the eastern portion of Kern County.[85, 86]

Pipeline requirements

Pipeline requirements would depend upon a facility's size and anticipated influent and effluent flows. A low intensity project may only require polyvinyl chloride (PVC) pipes, while larger projects would require steel pipes.[87] Investing in durable and easily-repairable equipment is generally the most cost-effective option in the long run by minimizing future repair and maintenance costs.[88]

8.1.4 Local Context - Current Water Use

Given the overall focus of this report on the potential development of a carbon management industrial park, an entire segment on water use—including the viability of on-site water treatment options—may appear to be out of scope. However, water is often critical to ensuring sustained and successful facility operations, thus the local context of water availability in Kern County is worth examining.

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[81] EPA (1998) How Wastewater Treatment Works. p. 4-5. [29]

[82] Bland (August 4, 2021) Water is life. [9]

[83] Resourcefulness (no date) Transporting Water. [64]

[84] Resourcefulness (no date) Transporting Water. [64]

[85] Fort, Nelson (2012) Pipe Dreams. p. 23. [36]

[86] Library of Congress (1908) Topographic map of the Los Angeles aqueduct and adjacent territory. [52]

[87] Frankel (November 10, 2021) Wastewater Treatment System Cost? [37]

[88] Frankel (November 10, 2021) Wastewater Treatment System Cost? [37]

California is in a state of drought, having experienced a series of such dry years since at least 2000, that the few wet years in between have not been enough to replenish groundwater or support plant regeneration.[89] Currently, over 80% of Kern County is experiencing 'exceptional drought' conditions.[90]

In Kern County, precipitation is low due to the arid climate—the county seat of Bakersfield receives an average of 6.49 inches of rain per year.[91] Yet the area uses water to support a diverse range of communities, industries, and farms; in an average year, agriculture receives 2,294,000 acre-feet of water and municipalities and industry receive 166,000 acre-feet of water across Kern County.[92] Only about one-quarter of the water used originates from local surface sources, like the Kern River or smaller streams.[93] Most of the region's water is derived from underground reservoirs or is brought in from the State Water Project (via the California Aqueduct) or the federal Central Valley Project (via the Friant-Kern Canal).[94]

Water is overallocated across California when compared to supply, with a 2014 study from University of California researchers finding that "[in] the state's major river basins, water rights account for up to 1000% of natural surface water supplies."[95] For the Kern River, this figure stood at 631%.[96] Additionally, overpumping of underground aquifers as an alternative water source has led to land subsidence, with approximately half the land in the San Joaquin Valley experiencing significant land subsidence (over one foot in surface ground level change) by 1970.[97] In this context, land subsidence occurs when water is removed from under the ground and the land at the surface drops down as a result.[98] These environmental changes have caused significant concern, and the state has sought to resolve these impacts of reduced aquifer replenishment and land subsidence with laws like the Sustainable Groundwater Management Act (SGMA) of 2014.[99]

Given this regional context, any ways in which newly developing industries in Kern County can make use of non-freshwater sources, like treated graywater or desalinated seawater, or in which industries that produce water as a byproduct of carbon management (S-DAC and some forms of BiCRS) could co-locate with more water intensive industries, warrant examination.

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[89] Wigglesworth (April 18, 2021) Is California suffering a decades-long megadrought? [85]
[90] NDMC (October 13, 2022) Kern County, California. [57]
[91] WAKC (no date) Water in Kern County. [82]
[92] WAKC (no date) Water in Kern County. [82]
[93] WAKC (no date) Water in Kern County. [82]
[94] WAKC (no date) Water in Kern County. [82]
[95] Grantham, Viers (2014) California's water rights system. p. 1. [41]
[96] Grantham, Viers (2014) California's water rights system. p. 5. [41]
[97] USGS (October 17, 2018) Land Subsidence. [78]
[98] USGS (October 17, 2018) Land Subsidence. [78]
[99] SWRCB (no date) The Sustainable Groundwater Management Act. [71]



Figure 8.5. Image of the Los Angeles Aqueduct, which does not require energy for pumping, demonstrating what large-scale water pipelines look like in the local environment. Image credit: Mavens Notebook / Flickr.

8.2 Societal Impacts

8.2.1 Job creation potential

8.2.1.1 Number and types of jobs

Water management will likely generate relatively few jobs past any necessary construction phases; however, the initial construction of any treatment facilities or canals would be labor-intensive endeavors.[100]

California's water supply is heavily monitored and managed by existing staff attempting to balance demands from industry, agriculture, and power generators, in addition to communities and natural habitats.[101] Any additional permanent jobs created in this sector will likely be skilled jobs to remotely manage flows, supplies, and make executive decisions during periods of drought.[102]

There could be some full-time, on-site jobs generated by a water treatment facility. The majority of these would likely require vocational training, but would not require extensive secondary education, as 85% of national water-related occupations are filled by workers

[100] Kane, Tomer (2018) Renewing the water workforce. p. 17. [50]
[101] Escriva-Bou, A. *et al.* (2019) Dams in California. p. 1. [34]
[102] California Department of Water Resources (no date) Careers. [13]

who have less than a bachelors degree.[103,104] Furthermore, water infrastructure jobs are generally good jobs, with an average wage that exceeds the national average and equates to a livable wage in most of the country.[105]

For a large water treatment facility, staffing needs would likely be around a few dozen employees. For reference, Bakersfield's Wastewater Treatment Plants 2 and 3, processing 13.7 and 17.3 million gallons per day of influent water (or approximately 15,346 and 19,378 acre-feet per year), support 11 and 19 jobs, respectively.[106]

8.2.2.2 Training pipelines

Anyone with a high school diploma or GED with appropriate experience can become certified to fill most water treatment roles.[107] All states set their own guidelines for certification for water operators.[108]

Most training for working with water infrastructure relies on developing skills and knowledge through applied learning, rather than emphasizing traditional postsecondary education.[109] Some specialized jobs within the water workforce—including architects, environmental engineers, and computer systems managers—typically require a postsecondary degree and earn higher pay.[110]

8.2.2 Quality of Life

8.2.2.1 Location

Light pollution is a frequent complaint regarding water treatment sites close to communities.[111] Since the facilities process water continuously, the site must be well-lit at all hours of the day for the safety of its employees, who are walking around and operating large equipment. Newly-designed plants have taken on a variety of innovative features to try and address light pollution concerns. The Newtown Creek plant (seen in Figure 8.3) has used a mixture of blue and white lighting to provide both an artistic and safe amount of light without disturbing residents.[112] A LEED-certified wastewater treatment plant located in Dryden, Ontario optimized their design to use the lowest possible light levels whilst still

[103] Bureau of Labor Statistics (October 4, 2022) Water and Wastewater Treatment Plant. [12]
[104] Kane, Tomer (2018) Renewing the water workforce. p. 21. [50]
[105] Kane, Tomer (2018) Renewing the water workforce. p. 19-20. [50]
[106] City of Bakersfield (no date) Wastewater Treatment Plants. [18]
[107] AWWA (no date) Water Operator Certification Explained. p. 13. [2]
[108] AWWA (no date) Water Operator Certification Explained. p. 13-14. [2]
[109] Kane, Tomer (2018) Renewing the water workforce. p. 22. [50]
[110] Kane, Tomer (2018) Renewing the water workforce. p. 20. [50]
[111] ACE (2005) Washington Aqueduct: Environmental Impact Statement. p. 5-13. [4]
[112] L'Observatoire International (no date) Newtown Creek. [53]

meeting security requirements.[113] Another facility in Adelaide, Australia is using infrared lighting to monitor all the external features and security gates of their water plant, so only the inside of buildings require visible lighting for operation.[114] Although light pollution is a serious concern, there are innovative options available to protect worker safety and reduce light pollution for any nearby residents.

Noise complaints are another frequent issue with locating water treatment plants close to residential areas.[115] Given the fans, motors, pumps, and compressors needed to run the plant, noise can build up.[116] The most common problem is not just an increase in ambient noise, but different parts of equipment that produce unique but similar tones, creating a 'pulsating' effect for human ears that can be perceived as doubling the sound coming from the plant.[117] Designing the plant to accommodate for noise can resolve most of these problems. Construction plans should locate large equipment away from residential areas, minimize the potential openings in the building for sound to escape, and include necessary sound-dampening materials like acoustical louvers and HVAC duct silencers.[118] Recent software developments, namely variable frequency drives (VFD), can adjust the speed of rotation for devices based upon the required load, which can dramatically lower the sound pressure generated.[119]

If the water being processed involves any raw sewage, as is true of most wastewater plants, odor becomes another concern for the plant. Depending on the chemicals and processes used to cope with biological waste, the resulting biosolids may also release a noticeable smell, typically due to "ammonia, amines, and reduced sulfur-containing compounds" present in the biosolids.[120] Odors can be mitigated with intentional design. At the Dryden plant (Figure 8.4), a fan is placed over the influent flow entrance to draw off air into a set of biofilters and charcoal, leaving most of the facility odor-free to house offices and other space for workers.[121]

8.2.2.2 Multi-use potential

Multi-use projects with water treatment plants are rare, likely due to their size and high potential for noise pollution. Although plants like the Newtown Creek treatment facility have been designed with unique tanks, lighting, and glass walkways to draw visual interest

[113] Lund (September 2017) Plant Earns LEED Recognition. [55]
[114] Raytec (July 14, 2014) RAYMAX IR Protects Australian Water Plant. [63]
[115] Goodfriend, Bontomase (June 1, 2007) Can Water Treatment Plants be Quiet? [40]
[116] Goodfriend, Bontomase (June 1, 2007) Can Water Treatment Plants be Quiet? [40]
[117] Goodfriend, Bontomase (June 1, 2007) Can Water Treatment Plants be Quiet? [40]
[118] Goodfriend, Bontomase (June 1, 2007) Can Water Treatment Plants be Quiet? [40]
[119] Goodfriend, Bontomase (June 1, 2007) Can Water Treatment Plants be Quiet? [40]
[120] EPA (no date) Basic Information about Biosolids. [28]
[121] Lund (September 2017) Plant Earns LEED Recognition. [55]

from passersby, akin to an art exhibit, these designs are uncommon and do not involve any nontraditional users on the actual site.

There are some unique water treatment facilities that have evolved for multi-use purposes. The R.C. Harris Water Treatment Plant in Toronto, Ontario processes about 30% of the city's drinking water, but also is a notable Art Deco building with public access to the grounds and has served as a frequent filming location for TV and movies.[122] The plant used to be fully open for public access until security concerns arose in the early 2000s, but still allows some public access for special events.[123] Similarly, water treatment plants in China and the United States have managed to incorporate both indoor and outdoor botanical gardens for public enjoyment.[124,125]

8.3 Environmental Impacts

8.3.1 Water requirements

8.3.1.1 Minimum volume requirements

For graywater and wastewater treatment plants, the volume of influent and effluent hardly differs. By weight, wastewater is 99.9% water, with only the remaining 0.1% of organic and inorganic compounds, as well as microorganisms, being removed by the filtration process.[126] Thus the yield of water that will be released as effluent is quite high. There is no minimum volume requirement to operate a water treatment plant, though efficiency varies—both in terms of maximizing water reuse and equipment lifetime—if the plant is processing much more or much less water than it was designed to handle.[127]

For desalination specifically, the technology used to remove salts from seawater will determine the minimum volume requirements necessary. Using reverse osmosis (RO), approximately half of the initial volume of water run through the process can be desalinated—the remainder is returned to the water source.[128] This is considered a relatively good yield for desalination processes.

The salient question for volume requirements—what will the average daily water needs of the carbon management park look like—is also the most difficult to answer, as different technologies exhibit a vast range of water consumption patterns. For biomass-based

[122] City of Toronto (no date) Fast Facts about the City's Water Treatment Plants. [19]
[123] Mok (no date) The historic R.C. Harris Water Treatment Plant. [56]
[124] Engineering News-Record (September 25, 2019) Wusong Wastewater Plant Upgrade - Botanical Garden. [27]
[125] Smith (June 2019) Landscape With a Purpose. [69]
[126] Buchanan, J. R. (no date) Wastewater Basics 101. [11]
[127] Tchobanoglous, G. *et al.* (2021) Rationale for constant flow to optimize wastewater treatment. p. 1238-1239. [72]
[128] Beswick *et al.* (2021) Does the Green Hydrogen Economy Have a Water Problem? p. 3168. [8]

processes (BiCRS and BECCS), facilities can typically run close to neutral on water use. Some processes are even net-positive on water and can generate water as a reaction byproduct at a quality suitable for agricultural use.[129] Other technologies, like hydrogen production via electrolysis, require water to generate any output. 9 kg of water must be used to generate a single kg of hydrogen fuel (Section 6), with some companies reporting that in the field, the best estimate is 12 kg per kg of hydrogen produced due to water vapor loss.[130, 131]

8.3.1.2 Minimum quality requirements

Water quality needs are dependent on the intended use of the treated water. For agricultural uses or industrial cooling needs, water can typically be less filtered than would be necessary for drinking water. To use water in chemical processes like electrolysis, the water must meet high standards of purity (i.e. be distilled and/or deionized) to preserve the efficiency and lifetime of the equipment.[132] Membrane-based electrolyzers require water to be of type II purity, though operate better with water of type I purity, which is even more filtered.[133]

8.3.3 Other potential impacts

Redirecting water use in any way may impact existing usage covenants, or harm the well-being of local communities, farms, or wildlife. Given the exceptional drought conditions in Kern County discussed in Section 8.1.4, directing already-purified water for industrial use from existing sources that are already stretched for existing and new housing would be difficult.

In terms of environmental impact, generating more usable water for the park from otherwise undesirable sources, including graywater, stormwater, seawater, or wastewater, can be construed as a net positive. If a water treatment facility can purify otherwise unusable water to be clean enough for industrial, agricultural, or residential uses, and in excess of the quantities needed by members of the carbon management park, this water can help alleviate shortages in the county's current supplies. Excess purified water could be traded through California's water markets to help keep agricultural producers in business during dry years. It could even be stored in the area's underground aquifers to replenish the over-drained supply and prevent continued land subsidence in the southern San Joaquin Valley. Further, excess energy generation from other industries (such as electricity from oxyfuel combustion of biomass, or waste heat from BiCRS or steel

[129] San Joaquin Renewables (no date) The Project. [67]

[130] Beswick *et al.* (2021) Does the Green Hydrogen Economy Have a Water Problem? p. 3167. [8]

[131] Valdez (August 11, 2022) Electrolyzers and Water. [80]

[132] Spiegel (October 18, 2022) Introduction to Electrolyzers. [70]
Note: this information derives from a response provided in the comment section by the Fuel Cell Store account.

[133] Jonsson, Mässgård (2021) An Industrial Perspective on Ultrapure Water Production. p. 17. [49]

industries) could be used as a cost-effective and carbon-free energy source for treating alternative waters for regional use.

8.4 Economic Impacts

8.4.1 Business Model

The profitability of water is a complex question due to the array of existing regulations and allocations involved and the unusually low price of water.[134] Low tariffs on water use are intended to protect economically vulnerable residential consumers, but also effectively undercharge all users—including those in industry and agriculture—for their current water use.[135] This system means that despite scarcity, water is generally undervalued, and thus rarely conserved or reused.[136] At the macro scale, investing in large facilities for generating more clean water from less pure sources is seen as an expensive and unnecessary investment when water access is currently cheap in monetary terms. However, as scarcity increases, there is a "huge opportunity" to adopt reuse and recycling practices for industrial water that will mitigate risks associated with climate change as the American West becomes more arid.[137]

Because of the high costs associated with these projects, the federal government offers a range of funds, loan guarantees, and grant programs that can provide funding for projects aiming to increase water reuse, reclamation, and efficiency.[138] Most programs emphasize community or local government leadership, and may be ineffective options for an industrial park—more research would be needed to determine the viability of pursuing federal water reuse funding for a specific project. Likely, policy intervention or necessity due to scarcity will be the levers that encourage more widespread adoption of water conservation, reuse, and desalination within California.[139]

Finally, under California law, water is a public resource, although its use can be subject to private rights.[140] Presumably, the revenue potential of a water treatment facility within a carbon management industrial park would depend on how projects were permitted and funded. If the County itself owned a water treatment plant, it could presumably sell the water (within the park or outside of it) or store it in aquifers. It is less clear whether there is a profitable model for a privately owned and operated water treatment plant. California does operate a water market where a purifier could recuperate costs by selling water,

[134] Climate Now (November 16, 2021) Water Strategy. 9:25-9:55. [21]
[135] Climate Now (November 16, 2021) Water Strategy. 11:07-11:58. [21]
[136] Climate Now (November 16, 2021) Water Strategy. 11:07-11:58. [21]
[137] Climate Now (2022) Solve the Global Water Crisis? 4:42-6:10. [20]
[138] EPA (no date) Water Reuse Infrastructure Funding Programs. [32]
[139] James (August 11, 2022) California expected to lose 10% of its water within 20 years. [48]
[140] Green (no date) A Primer on California's Water Issues. [42]

though most of the water traded in California originates from surface sources.[141] 46% of all water traded in California is done between buyers and sellers in the same county.[142] In the last decade, farmers in the San Joaquin Valley and cities have been the largest buyers in the water trading market, so it is likely that there would be substantial interest in Kern County around purchasing any water generated from industrial park activity or from treatment of alternative waters, not to mention the potential of selling to industrial players within the park to support their operations.[143]

8.4.2 Business Costs

Capital and operational costs for water treatment can be difficult to ascertain. First, there is currently no federal or non-federal standard for what factors should be included or excluded when reporting estimated capital or operating expenses.[144] Furthermore, both the capital and operational costs are dependent upon changeable factors; for example, for capital costs, this includes the volume and quality of the influent water and for operating costs, this includes the costs of labor and electricity.

8.4.2.1 Cost to build (upfront costs)

Costs to build a facility depend upon its capacity (usually measured in gallons per day, hereafter GPD) and purity of the influent. Wastewater treatment centers capable of processing 150,000 GPD for industrial use typically cost $500,000 to $1.5 million upfront.[145] For reference, 150,000 GPD is equivalent to 168 acre-feet of water treated per year, and water-intensive carbon management facilities investigated in this report could require up to 16,200 acre-feet per million tons of CO_2 captured (Figure 8.4).

Depending on the other technologies needed to filter and process the water and the level of purity required for the effluent, costs can grow significantly—up to many millions in additional upfront costs. Reverse osmosis (RO), a desalination process, and ion exchange (IX), which can remove minerals and ions to generate deionized water for chemical processes like electrolysis,[146] both would add an estimated capital cost of under $5 million for smaller GPD systems.[147] Complete distillation and purification via zero liquid discharge (ZLD)—essentially, a water treatment plant that does not release water with any solid or liquid contaminants into the natural environment, like streams or groundwater, instead

[141] Hanak *et al*. (2021) California's Water Market. p. 1. [45]
[142] Hanak *et al*. (2021) California's Water Market. p. 1. [45]
[143] Hanak *et al*. (2021) California's Water Market. p. 2. [45]
[144] Dundorf *et al*. (2017) Quantifying the Cost of Water Treatment. [25]
[145] SAMCO (October 12, 2017) Industrial Water Treatment System Cost? [66]
[146] Atlas Scientific (October 31, 2022) Ion Exchange in Water Treatment. [5]
[147] SAMCO (October 12, 2017) Industrial Water Treatment System Cost? [66]

recycling the water routinely on-site[148]—would be considerably more expensive, running up to $10 million for systems capable of handling GPD in the thousands.[149]

8.4.2.2 Operational costs

Operational costs for water treatment vary considerably based upon influent quality,[150] and are dependent upon material costs, electricity costs, labor costs, and costs from third-party services.[151]

Treating graywater and other wastewater is less cost-intensive than treating seawater or other brackish water via desalination. To generate the same quantity of usable water, the costs of operation for desalination are typically two to four times higher than for wastewater treatment.[152] In a study of treatments to recycle irrigation water for greenhouses, researchers found that the costs ranged from $0.07 to $1.00 to treat 1,000 gallons of water, depending on the treatment method,[153] equating to between $38,325 and $547,500 per year for a 150,000 GPD facility. That's over a tenfold increase between the lowest and highest cost treatment option, and irrigation water generally has less impurities requiring treatment compared to wastewater or seawater, suggesting operational costs would be higher for a wastewater treatment facility or desalination plant.

8.4.3 Regional benefits

With population increases and a decades-long cycle of droughts afflicting the American West, innovative projects to generate more usable water should be drawn to locations like Kern County, with its abundance of open land to locate a facility and steady mix of agricultural, industrial, and residential water consumers.

8.4.3.1 Proximate feedstocks

Within Kern County, the largest water users are in the agricultural sector.[154] Agriculture produces substantial runoff of graywater, as up to half of the water used in crop irrigation evaporates or becomes runoff.[155] If captured and reused, this graywater would constitute an existing and accessible source of water for the carbon management park.

The western edge of Kern County is located less than 100 miles from the Pacific coastline, making it a potential site for desalination projects. A desalination facility could also be

[148] Saltworks (January 15, 2018) What is Zero Liquid Discharge & Why is it Important? [65]
[149] SAMCO (October 12, 2017) Industrial Water Treatment System Cost? [66]
[150] Frankel (November 10, 2021) Wastewater Treatment System Cost? [37]
[151] Bluefield Research (October 9, 2018) Operating Expenditures. [10]
[152] Climate Now (April 19, 2022) Solve the Global Water Crisis? 6:30-6:42. [20]
[153] Raudales *et al.* (2017) How much does it cost to sanitize your water? [62]
[154] WAKC (no date) Water in Kern County. [82]
[155] Balsom (September 28, 2020) Water Usage In The Agricultural Industry. [7]

located on the coast and utilize pipelines or canals to transport water into Kern County for industrial or agricultural uses.

8.4.3.2 Proximate consumers

In addition to potential users within a carbon management industrial park, treated water could be utilized by residents as drinking water or for agricultural use, depending on the quality of water available and the amount produced in excess of the carbon management park's needs. For water that is not purified to drinking water standards, underground storage to replenish regional aquifers would be an option. As groundwater, the water would be purified further within the aquifers, making it usable to consumers above the surface in the future.[156]

8.4.3.3 Co-location advantages

Kern's existing supply of clean energy from wind and solar—amounting to over half of California's total renewable energy supply—may be appealing for water treatment plants, which are energy-intensive operations.[157] Similarly, depending on the energy and heating needs of a facility, locating on-site in the carbon management park may be a good way to reuse heat or energy that would otherwise be lost from other processes, like converting biomass or steel production.

[156] Balke, Zhu (2008) Natural water purification and water management by artificial groundwater recharge. [6]
[157] Oviatt (July 15, 2022) Why is California punishing our alternative energy leader? [59]

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9. Carbon Dioxide Transport

TECHNOLOGY AT A GLANCE

- Industry is well established: CO_2 pipelines have been in operation in the U.S. for more than 50 years.[1]
- Pipelines are typically the most cost-effective option for overland transport of CO_2. Average levelized cost for pipeline transport is $10-20 per metric ton CO_2, but values can be higher or lower depending on length of pipeline, pipeline capacity, and siting logistics (terrain, securing rights-of-way, urbanization, etc.).
- CO_2 pipelines are typically constructed ~3 feet below the surface, so they do not create a visual or sound impact at the surface, and can co-locate with other land uses.
- Key advantages of this technology in Kern County: Would provide a cost-effective solution for transporting CO_2 between producer(s) in the region and sites that are permitted for injecting CO_2 underground for the purpose of permanent geologic storage.
- Key concerns for this technology in Kern County: Safety hazards related to leaks or ruptures of pipelines are exceedingly rare, but if a large rupture occurs, CO_2 can pose a health risk in the immediate vicinity. Siting pipelines in remote areas and following all federal and state regulations regarding monitoring and emergency response protocols in event of a leak are critical. Additionally, regulatory

[1] Values and information in this section are summarized from the suite of references cited herein, and are explained in further detail in each subsequent section.

frameworks for construction of CO_2 pipelines in California are not yet well-established.

9.1 Technology Summary

Between any potential carbon dioxide source or production and sequestration, safe transport is required. Pipelines, rail cars, trucks, and ships are all available forms of transport for carbon dioxide. In most cases, pipelines are the most cost-efficient choice,[2] especially for moving long or routine distances over land. These pipelines compress the carbon dioxide into a single phase (it can be gaseous, liquid, dense-phase or supercritical, depending on pipeline specifications) and then maintain controlled temperature and pressure conditions to safely deliver the carbon dioxide to its end use.[3] For the carbon management industrial park being examined here, that end use would be permanent geologic storage, taking place deep underground in nearby sequestration sites that have been appropriately permitted for such use, with the possible exception of some CO_2 utilized by other co-located industries (see Section 10).

9.1.1 Description: How It Works

Pipelines are the standard transportation choice for moving large volumes of carbon dioxide for extended distances (on the order of hundreds to thousands of miles) along overland routes,[4] especially when the sources and sinks are located at fixed points, as they are intended to be for proposed projects in Kern County. CO_2 pipelines are made from externally coated steel line pipe[5] and operate at high pressures to transport carbon dioxide between sources and sequestration sites.[6] There is also an external cathodic protection applied to prevent corrosion on the outside of the pipe.[7]

Because impure CO_2 streams (containing traces of NO_x, SO_x, O_2 or H_2O) can have corrosive effects on alloys and polymers,[8] non-steel or composite metal pipelines are not permissible to transport carbon dioxide under California law without an exemption approved by the federal Pipeline and Hazardous Materials Safety Administration (PHMSA).[9] Pipelines are more complex than a single steel tube, though. They have a range of parts, including "valves, compressors, booster pumps, pig launchers and receivers, batching stations and instrumentation, metering stations, and Supervisory Control and Data Acquisition (SCADA)

[2] Roussanaly *et al.* (2021) Comparison of CO_2 shipping options. p. 20-22. [31]
[3] Lu *et al.* (2020) Carbon dioxide transport via pipelines. p. 5-6. [19]
[4] Roussanaly *et al.* (2021) Comparison of CO_2 shipping options. p. 20-22. [31]
[5] EEIA (no date) Key Excerpts on CO2 Transport. p. 4. [7]
[6] Lu *et al.* (2020) Carbon dioxide transport via pipelines. p. 7. [19]
[7] EEIA (no date) Key Excerpts on CO2 Transport. p. 4. [7]
[8] Paul *et al.* (2012) Selection of materials for high pressure CO2 transport. [23]
[9] PSD (June 8, 2022) Carbon Dioxide Pipeline FAQs. [28]

systems."[10] The number and complexity of these constituent parts is dependent on the pipeline's length, topography of the pipeline route, the need to adjust for pressure along-route pressure variability, and safety monitoring requirements.

Before pipeline transport, carbon dioxide must be dehydrated and not surpass certain oxygen or hydrogen sulfide (H_2S) concentrations to avoid internal corrosion of the pipeline or constituent parts, or cause stress cracking in the steel.[11] When necessary, there are coatings designed for the inside of pipelines in addition to the standard external coating.[12] Theoretically, corrosion-resistant pipeline could be designed that allowed for the transportation of carbon dioxide with higher concentrations of water or H_2S present.[13] However, given the high risks of H_2S to human health if a pipeline were to rupture or leak, purifying the carbon dioxide prior to transport is likely to remain a necessity.[14]



Figure 9.1. Installation of the Cortez Pipeline, a 30" diameter carbon dioxide pipeline located in New Mexico, during a maintenance upgrade conducted and documented by STATS Group. Image credit: STATS Group.

Finally, carbon dioxide needs to be condensed prior to transport, which requires specialized compressors.[15] Although similar compressors have been utilized in the natural gas industry, the unique properties of carbon dioxide require some design, material and sizing modifications.[16] Once compressed, carbon dioxide can be transported as a gas, liquid,

[10] Forbes *et al*. (2008) CCS Guidelines. p. 46. [12]
[11] EEIA (no date) Key Excerpts on CO2 Transport. p. 4. [7]
[12] Forbes *et al*. (2008) CCS Guidelines. p. 46. [12]
[13] Doctor *et al*. (2018) Transport of CO_2. p. 181. [6]
[14] Pipeline Safety Trust (2022) CO_2 Pipelines. p. 4. [29]
[15] EEIA (no date) Key Excerpts on CO2 Transport. p. 3. [7]
[16] EEIA (no date) Key Excerpts on CO2 Transport. p. 3. [7]

solid, dense phase substance, or supercritical fluid (Figure 9.2), depending on the pipeline length, requirements, and location.[17] The most common pipelines constructed in the United States are intended for liquid or dense phase carbon dioxide transport, with liquid being more common near population centers and dense phase more common in sparsely populated regions.[18] Although it can be transported in a variety of physical states, for a given pipeline, operators need to keep the carbon dioxide in the same state for all steps of transportation, as two-phase flows can interfere with compressors or other key equipment, increasing the odds of pipeline failure.[19] Optimizing CO_2 pipeline transport relies upon reducing impurities and controlling temperature and pressure to avoid unexpected pressure drops.[20] Since carbon dioxide exhibits nonlinear patterns of compressibility and density, pipeline operators typically develop point-by-point estimations of fluid properties along the pipeline's length using computational modeling.[21]

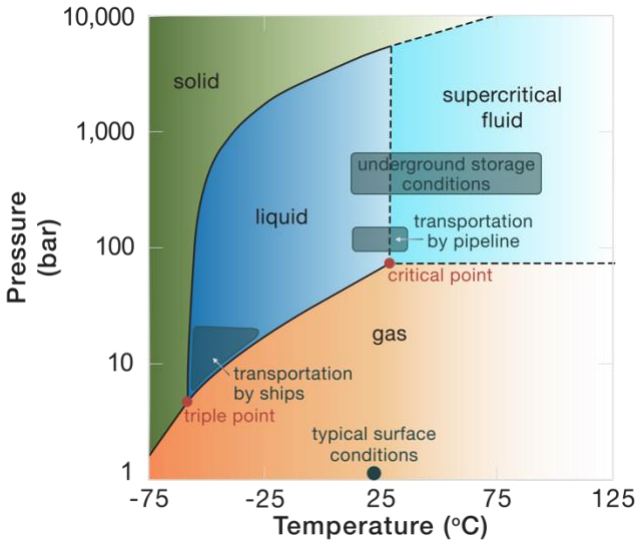


Figure 9.2. CO_2 is a gas at standard surface temperatures and pressures. When transported for permanent underground storage via pipeline, pipeline pressure and temperature is controlled to keep CO_2 in a denser phase. Dense phase liquids and supercritical fluids demonstrate properties of both a fluid and a gas - they can flow easily like a gas, but their high density allows for high flow capacity. Adapted from Paul et al. (2012).[22]

Commercial carbon dioxide pipelines, in which CO_2 is in a dense liquid phase or supercritical fluid phase for the entire journey, typically operate at pressures between 1,200 pounds per square inch gauge (psig) and 2,200 psig (83-152 bar), though some pipelines have higher maximum pressures in the 2,500 to 2,800 psig (172-193 bar) range.[23] These higher pressures allow the operator to minimize costs by increasing flow capacity for the

[17] Lu *et al*. (2020) Carbon dioxide transport via pipelines. p. 5. [19]

[18] Lu *et al*. (2020) Carbon dioxide transport via pipelines. p. 6. [19]

[19] Forbes *et al*. (2008) CCS Guidelines. p. 44. [12]

*For reference, a *two-phase flow* occurs when the carbon dioxide in the pipeline exists at two physical states simultaneously (ex. liquid and gas).

[20] Lu *et al*. (2020) Carbon dioxide transport via pipelines. p. 5. [19]

[21] Forbes *et al*. (2008) CCS Guidelines. p. 45. [12]

[22] Paul *et al*. (2012) Selection of materials for high pressure CO2 transport. [23]

[23] EEIA (no date) Key Excerpts on CO2 Transport. p. 3. [7]

pipeline.[24] To ensure that the CO_2 remains in a dense phase state along the entire pipeline length, pumps are used to recover any pressure losses that can occur due to friction of elevation changes.[25] The allowable temperature range for the pipeline will differ between projects, with the minimum set based upon the winter ground temperature and the maximum set by the compressor-station output temperature and any temperature limits imposed by the pipeline coating composition.[26] A standard temperature range for carbon dioxide pipeline operation falls between 55 and 110°F.[27]

Pressure and temperature are not the only factors which impact carbon dioxide behavior. For example, the fluid flow rate responds to changes in pipeline diameter—for larger pipeline diameters, the fluid flow rate decreases, which should result in fewer pressure drops within the pipeline.[28] Extensive modeling is required to determine the most efficient and cost-effective balance of pipeline size, number of compressors, and route design.[29]

In general, CO_2 pipelines will need to be purpose-built to handle carbon dioxide, especially when intended for transporting large quantities of carbon dioxide or covering long distances. Pipelines designed to transport natural gas, for example, are in a different class according to the American National Standards Institute (ANSI)—they are not built to the same maximum pressure rating necessary for transporting carbon dioxide.[30] Some pipelines built for other energy purposes have been retooled to transport carbon dioxide at lower flow rates and/or for distances shorter than 100 miles.[31] Federal requirements for pipeline construction are set by PHMSA and are covered at greater length in Section 9.1.4.

9.1.2 State of Development

Carbon dioxide pipelines already constitute a small but growing industry. The United States is a global leader in the area, having established some of the first carbon pipelines in the 1970s.[32] As of 2015, the U.S. had over 4,400 miles of active carbon dioxide pipelines, with that figure growing every year.[33]

The vast majority of carbon dioxide pipeline projects support enhanced oil recovery (EOR) in Texas and the American West; the number currently deployed for sequestration is

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[24] EEIA (no date) Key Excerpts on CO2 Transport. p. 3. [7]
[25] EEIA (no date) Key Excerpts on CO2 Transport. p. 3. [7]
[26] Forbes *et al*. (2008) CCS Guidelines. p. 44. [12]
[27] Forbes *et al*. (2008) CCS Guidelines. p. 44. [12]
[28] Forbes *et al*. (2008) CCS Guidelines. p. 45. [12]
[29] Forbes *et al*. (2008) CCS Guidelines. p. 45. [12]
[30] EEIA (no date) Key Excerpts on CO2 Transport. p. 4. [7]
[31] EEIA (no date) Key Excerpts on CO2 Transport. p. 4. [7]
[32] Doctor *et al*. (2018) Transport of CO_2. p. 182. [6]
[33] Peletiri *et a*l. (2018) CO_2 Pipeline Design. p. 3. [24]
** This figure has been converted to miles; in Peletiri et al., this figure is given as 7200 kilometers.*

smaller.[34] However, because the technical and regulatory requirements for safely and efficiently moving carbon dioxide are the same regardless of end use, pipelines developed for EOR can be used as a case study for new pipeline systems being constructed for permanent CO_2 sequestration.

9.1.2.1 Example projects

Pipeline companies: Kinder Morgan, Houston, TX and Trimeric, Buda, TX

Installation of pipelines are typically performed by third parties, rather than carbon management companies, sequestration companies, or even pipeline operators.[35] Kinder Morgan is the largest transporter of carbon dioxide in North America, although they also operate many of their pipeline systems. They have capacity to transport as much as 1.5 billion cubic feet (>77,000 metric tons) of CO_2 daily.[36] Although their operations are mostly sourcing CO_2 from natural source fields and delivering it to oil and gas operations for the purpose of enhanced oil recovery, the logistics of pipeline transport are the same for CO_2 sourced from capture industries and transported for the purpose of injection and permanent storage. Kinder Morgan's largest pipeline is 500 miles long and spans from Colorado to Texas.

Trimeric is another example of a third party company that could support pipeline development. They design CO_2 purification and compression facilities, and their company has served as technical experts and design engineers on a wide range of research programs supported by the U.S. Department of Energy, and for carbon dioxide pipeline projects in the United States.[37] Their process engineers have worked on all stages of the CO_2 transportation and storage process, including dehydration, cooling, pumping, liquefaction, compression, purification, and sequestration pumping.[38]

South West Hub Project, Western Australia

The South West Hub project, which broke ground in 2012, is designed to connect point source carbon emissions in industrial centers south of Perth to sequestration sites underneath the Lesueur sandstone formation in saline aquifers.[39] Publicly available video and conference papers largely emphasize the research conducted on validating Lesueur's feasibility as a sequestration site—the pipeline infrastructure needed for the project is less emphasized.[40] However, its overall model matches well with Kern's potential projects, where a number of known carbon producing or capturing sites within a carbon

[34] Jones, Lawson (2022) Carbon Capture and Sequestration (CCS) in the United States. p. 8. [16]
[35] George Peridas (LLNL) personal communication, July 6, 2022.
[36] Kinder Morgan (no date) CO_2 operations overview. [18]
[37] Trimeric (no date) CO_2 Capabilities. [38]
[38] Trimeric (no date) CO_2 Capabilities. [38]
[39] Sharma, Van Gent (2018) The Australian South West Hub Project. p. 2. [32]
[40] Sharma, Van Gent (2018) The Australian South West Hub Project. p. 12-14. [32]

management park will be directly connected with a sequestration site using the same pipeline infrastructure.

The South West Hub also presents an interesting form of management, as the project originated as a collaboration between the Western Australia Department of Mines, Industry Regulation and Safety, acting as the project lead, and industrial producers in the energy and chemicals space.[41] This project may be valuable as a type example for private-public partnership in carbon management projects.

9.1.3 Operational Needs

9.1.3.1 Land use requirement

Most carbon dioxide pipelines are relatively small, ranging from 12-28 inches in diameter,[42] and operate similarly to pipelines used for decades in the oil and natural gas industries, though they often operate at higher pressures.[43] On land, pipelines are typically buried 3 to 4 feet beneath ground level—thus at surface level, the physical footprint of the pipeline is invisible, except at metering or pumping stations.[44]

The siting of a pipeline is determined by state authorities; federal authorities are only implicated if a project crosses federal lands, uses federal funding, or if a project sought federal intervention to grant eminent domain.[45] Pipeline operators who operate as public utilities or common carriers may have greater flexibility over their siting options, as state and federal authorities can grant the powers of eminent domain to these projects to acquire land,[46] and because of existing rights-of-way utilities possess for other pipeline systems, like natural gas.[47] In lengthy pipeline projects, it is near impossible to site a project without exercising eminent domain.[48]

9.1.3.2 Energy requirements

Condensing the carbon dioxide gas into a dense state for transport requires a large energy input to reach appropriate pressurization, ranging from 90-120 kWh per metric ton of CO_2,[49] about the same amount of energy needed to power a home for 3-4 days.[50] CO_2 compressors can be fueled by "electricity, natural gas or diesel engines, steam, or a combination of

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[41] Department of Mines, Industry Regulation, and Safety (no date) South West Hub Project. [5]

[42] Molag, Dam (2011) Modelling accidental CO_2 pipeline release. p. 2301. [21]

[43] EEIA (no date) Key Excerpts on CO2 Transport. p. 3-4. [7]

[44] Forbes *et al.* (2008) CCS Guidelines. p. 46. [12]

[45] DOE (2017) Siting and Regulating Carbon Capture. p. 31. [4]

[46] Forbes *et al.* (2008) CCS Guidelines. p. 49. [12]

[47] Industry representative, personal communication, February 10, 2023.

[48] Fish, Martin (2010) California Carbon Capture and Storage Review Panel. p. 2. [11]

[49] Jackson, Brodal (2018) A comparison of the energy consumption for CO_2 compression process alternatives. p. 1. [15]

[50] EIA (October 12, 2022) How much electricity does an American home use? [8]

these,"[51] and could be the responsibility of either the pipeline operator or the capturing industry. For industries like DAC and steel, compression represents between 25% and <1% of the energy needs for CO_2 capture.[52]

Maintaining constant pressure and flow specifications along the length of the pipeline also requires energy input (using compression or pumps), although it is a small fraction of the energy needed for compression, and can be minimized through intentional route designs that take advantage of gravity to maintain flow through the pipeline.[53,54] Choosing between compressors or pumps to maintain constant pressure conditions within the pipeline depends on the intended physical state for transport—compressors are needed for gas, whereas pumps can be used for liquid or dense phase carbon dioxide.[55,56] Given the park's goal of carbon management, using low-carbon energy sources to power initial CO_2 compression and any additional pumps or compressors along the length of the pipeline should be a priority.

9.1.3.3 Other operational needs

Waste disposal requirements

There should be no waste disposal requirements for regular operation and maintenance of CO_2 pipelines, unless the pipeline or monitoring equipment requires replacement. Then, the old equipment would need to be disposed of or recycled accordingly.

The carbon dioxide itself often needs to be dehydrated and treated to reach a certain purity percentage (generally 95%) for efficient and safe transport, so preparing CO_2 for transport will likely produce some byproducts to dispose or reuse, like water and hydrogen sulfide (H_2S).[57] It is important to remove water from CO_2 streams because it can react with carbon dioxide to form carbonic acid (H_2CO_3) in the pipeline, which can cause corrosion. Similarly, hydrogen sulfide can interact with any remaining water to form sulfuric acid, another corrosive compound. Additionally, because H_2S is toxic to humans at any concentration exceeding 200 parts per million (ppm), for the safety of any communities located near a CO_2 pipeline, both water and H_2S should be restricted to reduce the likelihood and resulting risk of a pipeline rupture.[58] Water could be filtered and reused onsite in the industrial park (see Section 8). The most common disposal method for hydrogen sulfide is injection into deep geologic storage, as surface storage of sulfur generally constitutes a liability for the

[51] EEIA (no date) Key Excerpts on CO2 Transport. p. 3. [7]
[52] Appendix D
[53] Suter *et al.* (2022) Carbon Capture, Transport, & Storage. p. 21. [35]
[54] EEIA (no date) Key Excerpts on CO2 Transport. p. 3. [7]
[55] Lu *et al.* (2020) Carbon dioxide transport via pipelines. p. 6. [19]
[56] Lu *et al.* (2020) Carbon dioxide transport via pipelines. p. 5. [19]
[57] Pipeline Safety Trust (2022) CO_2 Pipelines. p. 4. [29]
[58] Forbes *et al.* (2008) CCS Guidelines. p. 43. [12]

producer.[59] However, this purification process would likely be the responsibility of a different party—i.e. the company capturing or generating carbon dioxide within the carbon management park—rather than the pipeline operator, and for many types of CO_2 capture explored in this report (BiCRS, DAC, oxy-fuel combustion), H_2S is not known to be a significant contaminant.

Warehousing requirements

There are no inherent warehousing requirements for transporting carbon dioxide, but the value of housing some carbon outside of the pipeline to maintain a constant supply, and therefore pressure, is likely advantageous.

9.2 Societal Impacts

9.2.1 Job creation potential

9.2.1.1 Number and types of jobs

Monitoring and upkeep of a local pipeline network will likely create between 8-20 high-wage permanent jobs.[60] CCS initiatives are also projected to generate indirect employment, as new pipeline manufacturing projects and administrative staff will be necessary in addition to jobs created on-site.[61] These indirect jobs may not be locally concentrated, however.

9.2.1.2 Training pipelines

Jobs in CO_2 transport require a mix of skill levels but overlap considerably with skills in other pipeline management or engineering jobs (like those in the oil and gas industry) and other heavy industries.[62]

9.2.2 Quality of Life

9.2.2.1 Location

Unlike transport via rail, truck, or ship, there is no noise or light pollution from a pipeline that would disturb nearby communities. Additionally, because CO_2 pipelines are buried, they produce no significant visual disturbances to the landscape. The primary issue relevant to locational justice is both the real and perceived risks of a pipeline leak or rupture.

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[59] Forbes *et al*. (2008) CCS Guidelines. p. 43. [12]

[60] Carbon Capture Coalition (no date) Jobs and Project Development Status. p. 4. [3]

[61] Townsend *et al*. (2020) Thought Leadership. p. 15. [37]

[62] Carbon Capture Coalition (no date) Jobs and Project Development Status. p. 4. [3]

We explore this issue here, first in the context of general public's attitudes towards pipeline safety, and then with a focus on the actual risks associated with transporting CO_2.

Pipelines related to the energy sector have a long history of generating locational justice concerns, primarily for the environmental, health and safety hazards that they can bring. Some key examples from the oil and gas sector where locational justice has become a widespread public concern because of risk to local ecosystems, water resources and safety include the Dakota Access Pipeline,[63] Enbridge's Line 3,[64] and the Coastal GasLink project in Canada.[65] Given the historically large public debates around these major pipeline projects, the idea of placing any new pipelines in or near a community could drive resistance among local residents and environmental groups, even though piping carbon dioxide has a different purpose, and carries different risks (and safety mitigation measures) than piping oil or natural gas. For example, regional chapters of environmental organizations are already organizing against the construction of new carbon dioxide pipelines in other parts of the country. The Iowa chapter of the Sierra Club has been resisting three proposed pipelines primarily because the carbon transported has an unclear end-of-life—there has been varied messaging about whether it will be sequestered or used for EOR.[66]

Addressing the general public's hesitancy or resistance to development of pipeline networks requires open communication and education about the real hazards associated with CO_2 pipelines, how they differ from other types of pipelines, what mitigation strategies ensure low safety risks associated with these kinds of pipeline, and the current and developing regulatory frameworks that are designed to assess and monitor pipeline safety standards.

Safety risks associated with CO_2 pipelines

Unlike natural gas and other fossil fuels, carbon dioxide is not flammable or explosive, and if leaked in small quantities, will dissipate into the air without creating a hazardous situation.[67] But, in large quantities (over 40,000 ppm, or comprising more than 4% of inhaled air) it acts as an asphyxiant,[68] and if released quickly from the pressurized conditions of a dense phase or supercritical phase pipeline, can cause flash freezing - producing temperatures immediately around a pipeline rupture that are well below freezing, which can cause brittle failure of the remaining pipeline and exacerbate further

[63] Environmental & Energy Law Program (no date) The Dakota Access Pipeline (DAPL). [9]
[64] MPR News (October 1, 2021) The Line 3 oil pipeline project: What you need to know. [20]
[65] Simmons (November 8, 2022) 'You will be arrested'. [34]
[66] Sierra Club Iowa Chapter (no date) Carbon Dioxide Pipelines - Say NO to CO2 pipeline projects. [33]
[67] Thomley, Kammer (2023) CO_2 pipeline safety. [36]
[68] FSIS (2020) Carbon dioxide health hazard information sheet. [13]

rupturing.[69] This means that small leaks present little health or safety risk,[70] and in fact, over the 50 years that CO_2 pipelines have operated in the U.S. there has been only one reported injury and no deaths related to pipeline operation.[71,72] A significant pipeline rupture, however, could pose a safety hazard. If a breach were to occur, carbon dioxide could be released into the atmosphere in high concentrations; because CO_2 is more dense than ambient air, rather than dissipating as it is released, it can concentrate in low-lying areas, risking the health of any residents in the area.[73]

Although leaks are uncommon, a significant event did occur near a population center in 2020. That year, a carbon dioxide pipeline ruptured near Satartia, Mississippi, sending 49 residents to the hospital. Residents reported seeing an eerie green cloud that left them "nauseated and dazed."[74] Carbon dioxide itself is odorless and colorless—the green shade of the gas reported in Satartia is thought to be due to high amounts of hydrogen sulfide in the supply, which likely worsened the health impacts on residents.[75] The Satartia rupture is thought to be the first outdoor CO_2 mass exposure event resulting from a pipeline failure globally.[76] However, as pipeline mileage increases in the future, potential for these types of accidents could grow. The federal Pipeline and Hazardous Materials Safety Administration, or PHMSA (responsible for pipeline safety and monitoring), has responded to the Satartia leak by promising additional regulations for CO_2 pipeline safety, with a focus on emergency preparedness.[77]

Mitigation options for CO_2 pipelines

To reduce public concerns about pipelines in general, other hazardous materials transported via pipeline – like natural gas – are typically odorized, so residents can identify a gas leak and evacuate. In theory, the same practice is possible for carbon dioxide moved through pipelines, although there are currently no requirements in place to odorize carbon dioxide prior to transport for the purpose of public safety.[78] There are some promising contenders for odorants, like disulfides or thioethers, although they increase pipeline operation costs and dilute the purity of the carbon dioxide stream.[79]

Compared to other types of pipelines, carbon dioxide pipelines are more susceptible to longitudinal running fractures, which can be a brittle or ductile weakness in the pipeline,

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[69] Vree *et al.* (2015) Rapid depressurization of a CO_2 pipeline. [39]
[70] Forbes *et al.* (2008) CCS Guidelines. p. 48-49. [12]
[71] Thomley, Kammer (2023) CO_2 pipeline safety. [36]
[72] Doctor *et al.* (2018) Transport of CO_2. p. 182. [6]
[73] Doctor *et al.* (2018) Transport of CO_2. p. 188. [6]
[74] Zegart (August 26, 2021) Gassing Satartia. [40]
[75] Zegart (August 26, 2021) Gassing Satartia. [40]
[76] Zegart (August 26, 2021) Gassing Satartia. [40]
[77] PHMSA (May 26, 2022) New Safety Measures. [27]
[78] Doctor *et al.* (2018) Transport of CO_2. p. 190. [6]
[79] Forbes *et al.* (2008) CCS Guidelines. p. 48. [12]

causing it to "unzip" several hundred meters.[80] To mitigate the severity of a potential rupture, propagation of these kinds of fractures can be inhibited with the placement of fracture arrestors along the pipeline. The arrestors are typically placed every 500 meters (545 yards) along the length of the pipeline, minimizing the distance a fracture can spread.[81,82]

Additionally, a variety of monitoring fixtures, both internal and external, can be used to ensure the pipeline is secure, or provide warning for emergency response if a rupture occurs. Meters can be placed along the pipeline to conduct computational pipeline monitoring (CPM) leak-detection, though this is not yet a regulatory requirement as it can be technically difficult to implement.[83] Other types of monitoring—including pressure point analysis or aerial and visual surveys—can also be used to identify potential leaks.[84]

Finally, the most effective safety measure for CO_2 pipelines is siting them far from urban or residential areas. Because CO_2 settles rather than dissipates, any impact from a pipeline leak will occur in the vicinity of the pipeline, although determination of safe distances from pipelines that experience an accidental rupture remains ongoing.[85]

Regulatory authority and monitoring

The Occupational Health and Safety Administration (OSHA) imposes safety regulations that impact carbon dioxide pipeline operators, including workplace safety laws that ban carbon dioxide exposure exceeding 5,000 ppm.[86] Requirements for pipeline construction and management have also been standardized by PHMSA within the U.S. Department of Transportation,[87] and operators that fail to meet standards of environmental safety can be issued with notices and fined.[88]

In response to the Satartia pipeline rupture, PHMSA initiated new rulemaking processes to strengthen regulations on carbon dioxide pipeline safety, including updating standards on emergency preparations and response, that may impose new requirements for the safe construction, maintenance, and operation of future pipelines.[89] As of the writing of this report, PHMSA has not released any new regulations determined from this rulemaking process. Currently, PHMSA regulations only apply to pipelines transporting supercritical carbon dioxide at a minimum of 90% purity. Projects where the carbon dioxide is in a liquid

[80] Lu *et al*. (2020) Carbon dioxide transport via pipelines. p. 4. [19]
[81] Doctor et al. (2018) Transport of CO_2. p. 184. [6]
[82] Forbes *et al*. (2008) CCS Guidelines. p. 46. [12]
[83] Forbes *et al*. (2008) CCS Guidelines. p. 46. [12]
[84] Forbes *et al*. (2008) CCS Guidelines. p. 46. [12]
[85] Molag, Dam (2011) Modelling accidental CO_2 pipeline release. p. 2301. [21]
[86] Forbes *et al*. (2008) CCS Guidelines. p. 47. [12]
[87] EEIA (no date) Key Excerpts on CO2 Transport. p. 3. [7]
[88] PHMSA (May 26, 2022) New Safety Measures. [27]
[89] PHMSA (May 26, 2022) New Safety Measures. [27]

or gas state, as well as lower-purity pipelines, remain less regulated.[90] Furthermore, PHMSA's current guidelines do not regulate maximum concentrations of water or hydrogen sulfide contaminants in CO_2,[91] despite their presence making pipelines more susceptible to corrosion and failure, and the added health risk of H_2S if a leak occurs.

In the state of California, the Pipeline Safety Division (PSD) of the Office of State Fire Marshal regulates supercritical and hazardous liquid pipelines (including CO_2 pipelines) following the 49 Code of Federal Regulation (CFR), Part 195 and the Elder California Pipeline Safety of 1981.[92] However, in 2022, the California state legislature passed law SB-905, stating that no new CO_2 pipelines can be built until the federal government updates its CO_2 pipeline policies with stronger safety regulations, or until state lawmakers can develop their own pipeline standards, based on recommendations from the California Natural Resources Agency (CNRA).[93] To this end, CNRA submitted a proposal to the California legislature in March 2023 for establishing a state framework and standards for intrastate CO_2 pipelines, which is now being considered.[94] Such a framework is critical not only for ensuring the safe handling and transportation of CO_2 for permanent sequestration, but also for ensuring public acceptance of nascent carbon management industries.

9.2.2.2 Multi-use potential

Since onshore pipelines are typically beneath the surface once installed, the land surface above a pipeline can still be used for a variety of purposes. Some forms of agriculture that require ample underground space for plant roots may be inappropriate, but myriad other applications should be sustainable on overlapping land, while keeping in mind the advantage of siting CO_2 far from human activity for safety reasons.

9.3 Environmental Impacts

9.3.1 Water requirements

No references were found identifying any water requirements for the operation of CO_2 pipelines. Given the technology, it is unlikely that water is necessary for operation beyond that generally required for construction.

[90] Pipeline Safety Trust (2022) CO_2 Pipelines. p. 2. [29]
[91] Pipeline Safety Trust (2022) CO_2 Pipelines. p. 5. [29]
[92] OSFM (no date) Carbon Dioxide Pipeline. [22]
[93] Phillis, Ronayne (February 23, 2023) Pipeline debate at center of California carbon capture plans. [25]
[94] CNRA (2023) Proposal for CO_2 pipeline state policy framework. [2]

9.3.2 Other potential impacts

California's Central Valley is naturally susceptible to seismic activity, and small earthquakes in the region are common and larger-scale seismic events are possible. This environmental stressor will exacerbate external pressure on any pipelines constructed and will need to be accounted for in construction and operational monitoring plans, as is done for all pipeline systems in the region.

9.4 Economic Impacts

9.4.1 Business Model

Business models for the operation of carbon dioxide pipelines can be flexible from project to project, based upon the operator's structure. For example, the owner or operator of the transport infrastructure could charge either CO_2 suppliers or CO_2 purchasers a tariff for using the pipeline network.[95] Given the proposed setup of a carbon management park as a putative CO_2 source and a sequestration well operator as a CO_2 "purchaser," both avenues of tariffs seem possible—either charging a tariff to members of the park to sequester their carbon dioxide off-site, or a transport tariff being covered as part of a carbon offset payment or other arrangement where an external company would act as a carbon purchaser.

Under either scheme, the pipeline operator can choose between different tariff calculation models. The two most common options are charging based upon the distance moved, by summing the specific costs per segment of pipeline traveled, or determining a system average cost to charge all users of the network (i.e. a flat rate per ton CO_2).[96] Based upon the current end-to-end structure of the pipeline that would be built for this project (modeled as a single business park producing CO_2 and supplying it to a single site for sequestration), a system average cost and total distance traveled would likely come out to near-identical tariffs. However, if the carbon management park model proves successful, there could be multiple parks in different locations, sharing a single pipeline system, in which case a preferred tariff model would have to be determined across parties.

The time horizon for profitability of a CO_2 pipeline network will depend upon the tariff rate and the total capital cost—without external incentives, it would likely take a few years before tariffs offset the millions spent on permitting, construction, and monitoring.

[95] Abramson *et al.* (2020) Transport Infrastructure for CCS. p. 31. [1]

[96] Abramson *et al.* (2020) Transport Infrastructure for CCS. p. 31. [1]

9.4.2 Business Costs

9.4.2.1 Cost to build (upfront costs)

Upfront costs are a substantial hurdle to constructing CO_2 pipelines. In general, costs depend on the terrain, environment, and existing regulations around right-of-way.[97] Shorter pipelines requiring few bends and avoiding existing features in the built environment constitute the cheapest conditions for pipeline construction,[98] as does avoiding heavily built areas like cities and suburbs. The Greencore Pipeline in Montana, which spans private ranches as well as state and federal public lands was built for $68,635 per diameter inch mile; meanwhile, the Webster Pipeline built in the industrial and suburban districts south of Houston, Texas cost $199,176 per diameter inch mile to construct.[99] According to a 2018 IPCC report, population density and terrain are the largest determinants of cost: "Onshore pipeline costs may increase by 50 to 100% or more when the pipeline route is congested and heavily populated. Costs also increase in mountains, in nature reserve areas, in areas with obstacles such as rivers and freeways, and in heavily urbanized areas because of accessibility to construction and additional required safety measures."[100] Pipeline right-of-ways can amount to 4%-25% of the overall pipeline construction costs, with estimates at the lower end of this range in rural areas and higher end of this range in suburban or urban areas.[101]

In 2020, the Great Plains Institute developed a techno-economic analysis of building national CO_2 transport infrastructure to support near- and medium-term carbon capture and storage capacity at a national scale. They modeled how much of a variety of pipelines (distinguished by diameter, and therefore CO_2 flow rate capacity) would be necessary to capture CO_2 from the most economically feasible point sources of carbon dioxide existing today, and determined capital, labor and operation and maintenance costs of pipeline infrastructure as a function of pipe diameter and length. A summary of their analysis is detailed in Table 9.1, for the purpose of illustrating a few key points.

First, reducing the pipeline's length by siting the carbon source (like a carbon management park) and sequestration well projects close together, drastically lowers all costs (capital, labor and maintenance) for the pipeline operator.[102] Second, while smaller pipe diameters do result in lower costs per mile, due to lower material costs, large diameter pipelines are ultimately more cost efficient, as long as they are operating at capacity. The more CO_2 that is transported through the pipeline systems, the lower the effective cost per ton of CO_2.[103] The calculated costs of CO_2 transport per ton-mile (how much it costs to move one ton of

[97] Doctor *et al*. (2018) Transport of CO_2. p. 189-190. [6]
[98] Peletiri *et al*. (2018) CO_2 Pipeline Design. p. 4. [24]
[99] EEIA (no date) Key Excerpts on CO2 Transport. p. 3. [7]
[100] Doctor *et al*. (2018) Transport of CO_2. p. 190. [6]
[101] Peletiri *et a*l. (2018) CO_2 Pipeline Design. p. 4. [24]
[102] Abramson *et al*. (2020) Transport Infrastructure for CCS. p. 23. [1]
[103] Abramson *et al*. (2020) Transport Infrastructure for CCS. p. 29. [1]

CO_2 one mile) is lower than most summative estimates of the levelized cost of CO_2 transport (usually ~ $10-20 per ton of CO_2 from source to sink, see below), because most point sources of carbon would be unable to provide enough CO_2 for the pipeline to operate at capacity. For example, the calculations in Table 9.1 indicate that a 100 mile, 24" pipeline operating at full capacity would cost $1 per ton of CO_2 transported. However, that requires that the pipeline is transporting 25 million tons of CO_2 annually. The largest facility capturing CO_2 for the purpose of sequestration (not EOR) in the US today is the Illinois Industrial ethanol plant (operated by Archer Daniels Midland Co.),[104] which is capturing CO_2 at a rate of about 500,000 tons annually.[105] At that rate, it would cost over $50 per ton of CO_2 to pipe it for 100 miles in a 24" pipeline, and $15 per ton of CO_2 in an 8" pipeline. Such sensitivity to CO_2 capacity demonstrates the value of developing concentrated sources for large amounts of CO_2, such as could be achieved by co-locating CO_2-emitting industries and/or carbon removal industries like DAC or BiCRS/BECCS in a single business park.

Table 9.1. Capital and operating costs of CO_2 pipelines as a function of pipe diameter and segment length[106]

Pipe diameter	Segment capacity	Segment length	Capital costs	Labor costs	Annual O&M costs	Cost per Mile[a]	Cost per tCO_2-mile[b]
(inches)	($MtCO_2$/yr)	(miles)	(million USD)			(million USD)	(US cents)
8"	<5	8,560	$3,436	$3,672	$72.6	$1.1	1.8 ¢
12"	3-7	5,834	$4,195	$2.928	$49.5	$1.5	1.6 ¢
16"	6-11	2,675	$2,888	$1,777	$22.7	$2.0	1.5 ¢
20"	10-16	1,790	$2,704	$1,498	$15.2	$2.6	1.4 ¢
24"	15-25	59	$99	$63	$0.5	$3.0	1.0 ¢
30"	24-33	16	$34	$23	$0.1	$3.8	0.97 ¢

a. The sum of capital, labor and annual O&M costs (assuming a 30 year lifespan), divided by segment length.
b. The sum of labor and annual O&M costs normalized to maximum segment capacity and pipeline lifespan with the levelized capital cost, divided by the segment length. (Modeled for a 30 year lifespan and capital recovery factor of 12.5%.)

Another report which performed cost-benefit analyses of nation-wide decarbonization plans - Princeton's Net-Zero America report - calculated regionally specific building costs for CO_2 pipeline networks. To build a main CO_2 pipeline fully across the region of southern California, the report estimates a cost of $1.2 billion for 239 miles[107] of a 36" diameter

[104] Rassool *et al.* (2021) CCS in the circular carbon economy. [30]
[105] EPA (no date) Archer Daniels Midland Co. Emissions Data. [10]
[106] Data from Abramson et al. (2020) Transport Infrastructure for CCS. p. 23, 29. [1]
[107] Email correspondence with Chris Greig and Andrew Pascale, January 24-25, 2023.

pipeline, or $139,470 per diameter inch mile.[108,109] The cost per user (whether CO_2 supplier or buyer) for this pipeline could be reduced by incorporating other carbon dioxide pipelines into this system, creating a regional network in southern California to connect carbon producers or capture sites to sequestration sites in Kern County. The best layout for a hypothetical hub system to connect multiple sources with a single sink—whether it be "tree with branches" or "hub and spoke" (Figure 9.3)—would depend upon angles the pipelines from the sources are placed at relative to each other.[110]

Innovative financing could also reduce the overall capital needed to sustain regional scale pipeline networks. Financing options, including private activity bonds (PAB) or master limited partnerships (MLP), should be explored by any potential operator to reduce the direct capital required to start up operations.[111]

In addition to construction costs, it is also critical to consider the time needed for an onshore pipeline to go from development to deployment – estimated at four to six years.[112] Opening of a pipeline this decade, for instance, would require setting an ambitious project timeline now to be able to clear all the regulatory requirements needed, complete construction, and pass safety and environmental quality checks prior to deployment.

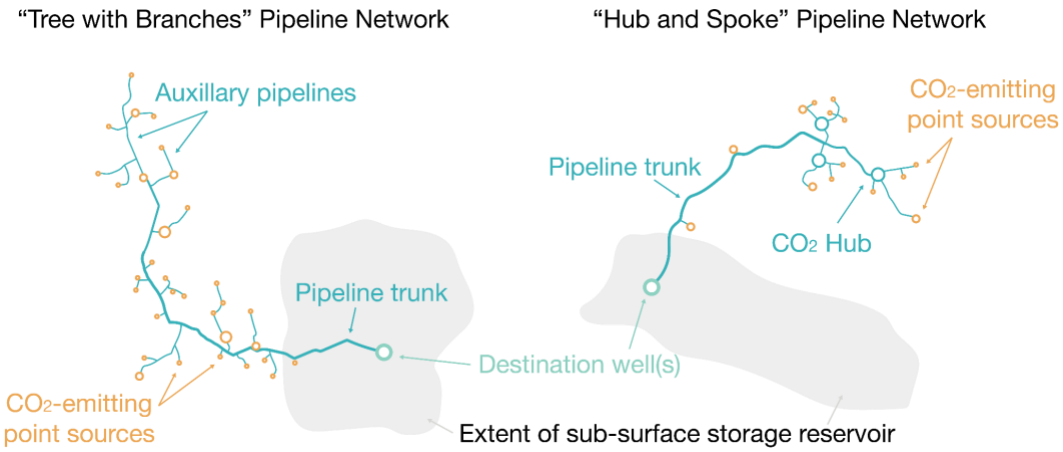


Figure 9.3. CO_2 transport pipelines are most cost-effective when built as a network, connecting multiple CO_2 sources to an underground storage site. The two most common pipeline network designs are a 'tree with branches' model, which has a single main line with many small, single-input offshoots, and a 'hub and spoke' model, where CO_2 sourced from several small facilities ('spokes') are combined in a 'hub' before being joined to a main pipeline.

[108] Greig, Pascale, Wagner (2021) Net-Zero America Annex I. p. 25-26. [14]

[109] The conversion to diameter inch miles was possible due to additional information provided by the primary authors on Net-Zero America Annex I via email on January 25, 2023.

[110] Peletiri *et al*. (2018) CO_2 Pipeline Design. p. 6. [24]

[111] Abramson *et al*. (2020) Transport Infrastructure for CCS. p. 29. [1]

[112] ZEP (no date) The Costs of CO2 Transport. [41]

Finally, it is worth noting that the expense of building and maintaining a CO_2 pipeline is not typically a significant portion of the cost of carbon capture and storage projects. Up to 90% of carbon management project costs come from the capture process itself, and the energy needed for CO_2 compression.[113] Transport is a relatively small portion of the overall cost of capturing CO_2 for the purpose of permanent underground storage.

9.4.2.2 Operational costs

Operation and management (O&M) costs of a pipeline vary by industry, as they are dependent on the required maintenance and monitoring technology. One estimate of O&M and labor costs – from the Great Plains Institute[114] – is given in Table 9.1. Such costs are often estimated to be between 4 and 7% of the original capital cost.[115] In scenarios explored by Princeton's Net-Zero America study, which looked at potential paths to get to net-zero nationwide by 2050, the estimated average cost to move a ton of CO_2 – considering capital as well as O&M costs – would range between $10-20, depending on the location.[116] For long distances or CO_2 derived from low-capacity sources (see Section 9.4.2.1), the cost would increase, but approximately 90% of carbon dioxide moved throughout this hypothetical national network could be moved for under $20/ton CO_2.[117]

As discussed above, there are additional safety considerations for an operator with locating pipelines near population centers, thus siting pipelines too close to communities can result in both higher upfront and heavier monitoring costs for operators.

9.4.3 Regional benefits

Any carbon management business park of the form considered in this study would likely find pipelines to be the most cost-effective form of CO_2 transport to locations suited for permanent underground storage. Additionally, regions like Kern County, where there is suitable geology and growing industry interest in developing CO_2 sequestration sites (as of the writing of this report, three companies have applied for permits from the EPA to construct Class VI wells for the purpose of CO_2 sequestration), development of a pipeline network is crucial. If a large carbon management park was developed within Kern County to act as the primary CO_2 source, pipeline distances could be exceptionally short by industry terms, requiring tens to a few hundred miles of pipeline, rather than hundreds to thousands (the county is 180 miles across at its widest point). Not only would short distances reduce the costs of construction and maintenance, but all of construction, monitoring, and taxation would fall under the same set of state and county regulations for the entire length of the pipeline, reducing regulatory or bureaucratic hurdles.

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[113] Peletiri *et al*. (2018) CO_2 Pipeline Design. p. 2. [24]

[114] Abramson *et al*. (2020) Transport Infrastructure for CCS. p. 23. [1]

[115] Abramson *et al*. (2020) Transport Infrastructure for CCS. p. A6. [1]

[116] Greig, Pascale, Wagner (2021) Net-Zero America Annex I. p. 34. [14]

[117] Greig, Pascale, Wagner (2021) Net-Zero America Annex I. p. 33-34. [14]

9.4.3.1 Proximate consumers

As Kern County is already pursuing permits for a sequestration site and investigating the feasibility of a carbon management park, transport of carbon dioxide will be necessary to link these two distinct projects to fulfill their potential.

When applying for LCFS (Low Carbon Fuel Standard) or CARB (California Air Resources Board offset) credits, there will need to be a new legal arrangement drawn up between the supplier, the sequesterer, and the transporter about who will claim the credits and how they will be divided amongst parties within this relationship.[118]

9.4.3.2 Co-location advantages

The primary advantage of a carbon management park that can act as a 'hub' is particularly evident when dealing with transport. Pipelines are time-consuming to design and permit, expensive to safely build and monitor, and require meeting a range of regulations and environmental quality checks. Any company developing a pipeline project would want to ensure that there would be steady interest in carbon dioxide transport; the occupants of a carbon management park, who are either generating or capturing carbon dioxide, would be of substantial appeal because they would constitute a reliable source of carbon to transport. As for members of the industrial park, having another player provide the pipeline infrastructure can reduce overall costs and risks of their operation, as they can focus on the carbon capture and purification, but leave the transportation and sequestration portion to other companies. Thus co-locating has the appeal of distributing risk across a set of players.

9.4.3.3 Other

Although technically tricky to accomplish due to the differences between the material and safety requirements of oil pipelines versus carbon dioxide pipelines, there are operational projects that have retrofitted existing oil pipelines to transport carbon dioxide. In the Netherlands, the OCAP pipeline has been transporting carbon dioxide since 2004 using a retrofitted oil pipeline that had been out of commission for 25 years.[119] The right pipeline operator may be able to reuse existing oil and natural gas pipelines[120] in Kern County by upgrading them to the necessary specifications to safely move carbon dioxide, which could be less costly than constructing a new pipeline and reduce the burdens of permitting and obtaining right-of-ways. If such re-purposing is deemed unsafe for CO_2 transport be the ongoing assessment of state safety regulations,[121] it is worth investigating whether existing right-of-ways for these pipeline systems could be used for CO_2 transport as well, minimizing the time and expense of identifying and purchasing rights to new right-of-ways.

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[118] Internal conversation with DOE Technical Team, August 29, 2022.

[119] Kenton, Silton (no date) Repurposing Natural Gas Lines. [17]

[120] PHMSA (no date) National Pipeline Mapping System. [26]

[121] CNRA (2023) Proposal for CO_2 pipeline state policy framework. [2]

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10. Carbon Dioxide Utilizing Industries

TECHNOLOGY AT A GLANCE

- There are a diverse suite of industries that can incorporate CO_2 into their production process or their final products. Most industries are in pilot or early demonstration phases of CO_2 integration. The exception is the food and beverage industry, which uses about 15 million tons of CO_2 annually.[1]
- The most promising industries for scaling up CO_2 utilization to the million-ton scale are in cement and concrete manufacturing, building materials manufacturing, synthetic carbon fuels, and plastics, polymers and other chemical manufacturing.
- Significant investment in research and development (± policy incentives) will be needed to bring costs down relative to competing, non-CO_2 utilizing products.
- Key advantages of these technologies to Kern County: co-location within a carbon management industrial park and near abundant clean solar and wind power will reduce operational costs and make CO_2-utilizing products more economically viable.
- Key concerns for this technology in Kern County: each CO_2-utilizing industry has its own suite of impacts and benefits, which warrant further investigation. Additionally, most CO_2-utilizing industries do not permanently store CO_2; it is (re)-released to the atmosphere on the order of months to years. Case by case life cycle analyses of the carbon removal benefit of a CO_2-utilizing practice will be necessary to understand whether it provides any climate benefit, and whether it is eligible for state or federal carbon removal incentives.

[1] Values and information in this section are summarized from the suite of references cited herein, and are explained in further detail in each subsequent section.

10.1 Technology Summary

Interest from governments,[2] companies[3] and scientists[4] around the growth of the carbon management industry is primarily for the purpose of carbon dioxide removal: pulling CO_2 from the atmosphere (through processes like DAC or BiCRS) or preventing CO_2 emissions from point sources (like steel mills), and storing that CO_2 permanently and safely underground to reduce the impacts and mitigate the costs of climate change. However, until the U.S. Inflation Reduction Act that passed in 2022 increased financial incentives for carbon sequestration, carbon capture for the purpose of permanent storage was, for the most part, not financially feasible.[5] As an alternative, several researchers and companies have explored options for using CO_2 in products, in ways that would either remove it from the atmosphere on timescales of decades to centuries, or replace products or feedstocks that would otherwise produce more greenhouse gas emissions.[6]

Even with the increased cost effectiveness of carbon management for the purpose of removal and storage, the research and innovations of recent decades in CO_2 utilization has seeded or expanded potential commercial markets for CO_2 that could complement sequestration programs, and those markets could grow in scale to using as much as tens of millions of tons of CO_2 annually by mid-century.[7]

The primary industries expected to use CO_2 are food & beverages, concrete & other building materials, fuels, and chemical manufacturing opportunities, and in this section, we provide a review of each of these sectors and how CO_2-utilization can be integrated into their products or supply chains. Because this section is an examination of several different nascent industries, and detailed evaluation of each is beyond the scope of this report, rather than presenting CO_2-utilizing industries in the format common to other industries examined here (through technological, societal, environmental and economic lenses), we will provide brief descriptions of each category of CO_2-utilizing industries, examining their state of development and describing example projects (Section 10.1), and then will consider the potential of these industries from a business model standpoint (Sections 10.2 and 10.3).

Note that the industries described in this section are not necessarily exhaustive examples of uses for CO_2. For example, it can be used to increase agricultural productivity or in cleaning or medical processes – but these uses are either addressed in other sections of the larger report or are negligible in the context of how much CO_2 they would utilize. As such, these uses are not explored in this section. Finally, one application of CO_2-utilization

[2] WRI (December 22, 2022) Carbon removal in the BIL and IRA. [57]

[3] Brigham (June 28, 2022) Why Big Tech is pouring money into carbon removal. [5]

[4] Harvey (April 5, 2022) Carbon removal 'unavoidable' as climate dangers grow, new IPCC report says. [26]

[5] Climate Now (February 18, 2022) How to scale up carbon capture and storage with Sheila Olmstead. [18]

[6] IEA (2019) Putting CO_2 to Use. [34]

[7] IEA (2019) Putting CO_2 to Use. p. 1. [34]

is not addressed in this section at all: Enhanced Oil Recovery, or EOR. While globally, EOR is by far the largest market for CO_2, it is not a relevant market to consider for the purpose of a carbon management business park in Kern County, given that state law SB-905 prohibits operators from injecting CO_2 produced in a carbon management project into the subsurface for the purpose of enhanced oil recovery.[8]

10.1.1 Types of Industries

CO_2 can be used in its pure state for several purposes – an example many are familiar with is beverage carbonation. Currently, most commercial processes that rely on CO_2 use it directly.[9] However, if the goal of CO_2 utilization is to create a measurable impact in the reduction of atmospheric greenhouse gases, it will have to be adopted by industries that would use tens or hundreds of millions of tons of CO_2 annually. These types of industries – concrete, fuels, plastics and polymers, and other chemicals – require chemical or biological conversion of the CO_2 into usable products, which can be technologically complex and energy intensive. A summary of the wide range of industrial applications for CO_2 is shown in Figure 10.1, adapted from a comprehensive report on CO_2 utilization from the International Energy Agency (IEA),[10] to which the reader is referred for further information on the topic.

The CO_2 utilization market is relatively small (currently, about 25-35 million tons of CO_2 are used in non-EOR industries),[11,12] and likely to remain so in the short term, as carbon management companies that could cost-effectively source CO_2 are still in nascent stages of development, and the markets most likely to be large consumers of CO_2 (building materials and fuels) will require years of testing to ensure they meet regulatory and safety standards.[13] Additionally, adoption of CO_2 utilization practices will require either 1) a clear economic benefit compared to current techniques for an industrial activity or product development, or 2) a clear and measurable climate benefit to the utilization of CO_2 that adds enough value to its use that additional costs can be offset. For most CO_2-utilizing industries, neither of these goals has been clearly achieved yet – more expansive and improved methods to analyze the life-cycle emissions of CO_2-utilizing products will be necessary to inform the best policy and investment decisions for the future.[14] In the following sections, we provide a brief summary of the state of the art for CO_2 utilization in the food and beverage, concrete, building material, fuel, plastic & polymer, and chemical industries.

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[8] OpenStates (no date) SB 905. [48]

[9] IEA (2019) Putting CO_2 to Use. p. 3. [34]

[10] IEA (2019) Putting CO_2 to Use. [34]

[11] IEA (2020) CCUS in Clean Energy Transitions. p. 109. [36]

[12] Note: About 70-80 million tons of CO_2 is used for EOR, and ~125 $MtCO_2$/yr is used by the fertilizer industry. However, fertilizer facilities produce and use their own CO_2, so they do not need to buy it externally. (IEA (2020) CCUS in Clean Energy Transitions. [36])

[13] IEA (2019) Putting CO_2 to Use. p. 1. [34]

[14] IEA (2019) Putting CO_2 to Use. p. 2. [34]

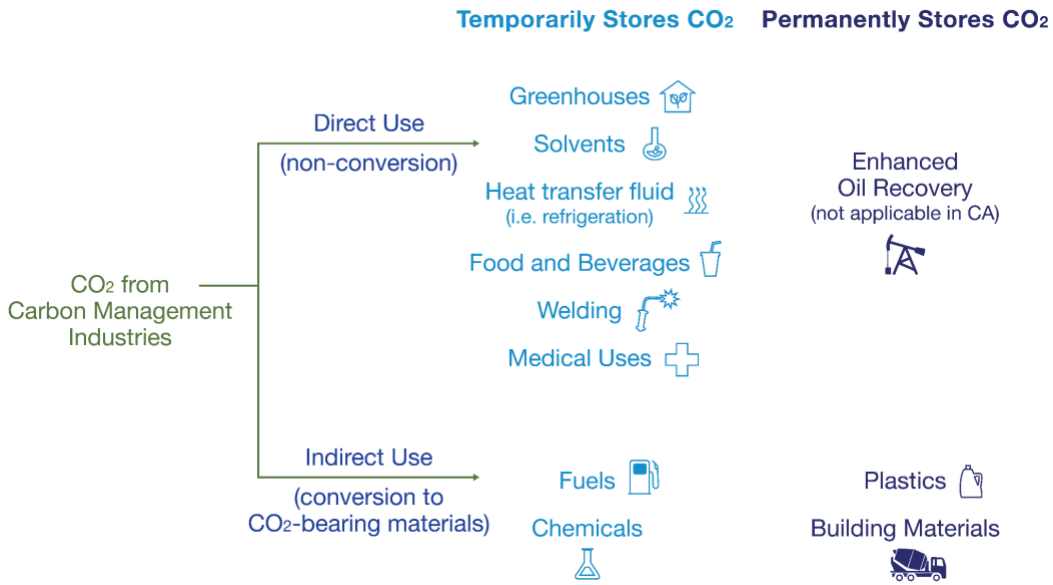


Figure 1. A summary of direct uses of CO_2 (including in greenhouses, in food and beverages and solvents) and indirect uses of CO_2 (including fuels, plastics, and building materials). Adapted from IEA (2019).[15]

10.1.1.1 Food & Beverages

Currently, the largest industry for CO_2 utilization (excluding EOR and fertilizers, see notes above) is the food and beverage industry, which purchases about half of the CO_2 on the market – approximately 15 million tons in 2015.[16,17] Carbonated beverages comprise about half of the use in the food and beverage industry,[18] but CO_2 is also used as a produce preservative, a freezing agent for meat, or to keep food items cold in transport as dry ice.[19] Food and beverage opportunities for CO_2 utilization are among the least useful in terms of atmospheric carbon dioxide removal; the CO_2 that is utilized will only be stored temporarily in the product before returning to the atmosphere.[20] However, it is one of the more well-established CO_2-utilization industries, with captured CO_2 already used on a commercial scale.

Another promising avenue of food and beverage applications is associated with chemical manufacturing opportunities. For example, sodium bicarbonate, or baking soda, can be formed through the chemical conversion of CO_2 (its chemical formula is Na_2CO_3). Baking soda is both widely used in commercial baked goods and sold directly to consumers.[21]

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[15] IEA (2019) Putting CO_2 to Use. p. 7-8. [34]
[16] GlobalNewsWire (January 7, 2021) The Largest User Of The Carbon Dioxide Market. [25]
[17] IEA (2019) Putting CO_2 to Use. p. 6. [34]
[18] IEA (2019) Putting CO_2 to Use. p. 6. [34]
[19] nexAir (no date) Carbon Dioxide in Food and Beverage. [44]
[20] Budinis (January 31, 2020) Going carbon negative. [6]
[21] IEA (2019) Putting CO_2 to Use. p. 49. [34]

Chemical compounds formed by converting CO_2 are explored at large in Section 10.1.1.6 on chemical manufacturing.

Example Project: Coca-Cola HBC Switzerland, Switzerland

A Coca-Cola franchised bottler in Switzerland purchased captured CO_2 from the first commercially operating DAC facility in the world for use in beverage carbonation for its Valser sparkling water.[22] Climeworks' first generation Hinwil DAC facility supplied CO_2 to the bottling company from 2017 until the retirement of the facility in January 2023.[23] Presently, Coca-Cola is considering ways to expand its use of captured CO_2 across its products and Climeworks is looking to expand their CO_2 utilization offerings beyond Switzerland as their operations grow.[24, 25]

Example Project: Air Company, New York, New York

Air Company is a carbon utilization company that uses CO_2 conversion technology to produce carbon negative alcohol products, such as vodka, as well as personal care products including perfume and hand sanitizer.[26] Air Company's technology obtains CO_2 from point-source capture sources, then combines that CO_2 with green hydrogen (hydrogen via electrolysis) to create an alcohol mixture that is distilled and forms the basis for their product offerings.[27] They also rely wholly on clean energy (wind and solar) to support their processes.[28]

Air Company is planning to add fuel products to their commercial-scale offerings, namely sustainable aviation fuels, ethanol, and methanol (see Section 10.1.1.4).[29] Their aviation fuels have been successfully used by the U.S. Air Force in pilot-scale tests, and the company is currently in the process of scaling their operation to a commercial demonstration phase.[30] If expanded to all potential areas of business that Air Company has scoped (food, personal care and fuels), they anticipate their technology "could avoid 10.8% of global CO_2 emissions, the equivalent of more than 4.6 billion tons of CO_2 annually."[31]

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[22] Johnston (September 6, 2021) Inside the Facility. [37]

[23] Climeworks (January 24, 2023) Climeworks completes the commercial operation of its 1st gen technology. [20]

[24] Johnston (September 6, 2021) Inside the Facility. [37]

[25] Kotecki (January 15, 2019) Sparkling water made with carbon dioxide captured from the atmosphere. [39]

[26] Air Company (no date) Transforming CO_2. [3]

[27] Air Company (no date) AIR Eau de Parfum. [1]

[28] Air Company (no date) AIR Eau de Parfum. [1]

[29] Air Company (no date) Transforming CO_2. [3]

[30] Air Company (no date) AIRMADE™ SAF. [2]

[31] Air Company (no date) Transforming CO_2. [3]

10.1.1.2 Concrete

Concrete production is very carbon-intensive, accounting for at least 8% of global CO2 emissions.[32] Moreover, concrete demand is quickly accelerating—we use three times more concrete than we did 40 years ago, and as more nations industrialize, demand growth is expected to continue.[33] Thus decarbonizing concrete production has a clear positive impact on reducing global greenhouse gas emissions. There are already small-scale manufacturing facilities developing lower-carbon concrete, but it will require immense scaling and regulatory reforms before these products can replace traditional concrete.[34]

In general, CO_2 utilization in concrete production falls into two categories: 1) replacing water for curing, or 2) as a raw material within the concrete mixture. Both uses represent examples of CO_2 utilization that provide sequestration on the order of decades, so could benefit from carbon offset marketplaces or regulatory incentives for CO_2 storage.[35] CO_2 curing is both a mature and particularly promising avenue for CO_2 use, as it provides the co-benefits of decreasing water use, decreasing the production time for curing, and producing a higher-strength concrete. Additionally, the amount of CO_2 necessary for concrete curing is relatively minimal, so does not add significant manufacturing costs to cement production, even with the still relatively high costs of capture CO_2. Meanwhile, using CO_2 directly in the production process is a developing area of technology. Injecting CO_2 directly into concrete changes its material composition and could affect its properties—at this early stage of development, it is not yet clear to what degree. CO_2-rich concrete could have material properties that are essentially the same – or better – than conventional concrete.[36]

In terms of market readiness, barriers for CO_2-rich concrete are cost- and policy-related. One way to keep costs low while the industry (and availability of CO_2) evolves, is by injecting CO_2 into precast concrete materials, like concrete bricks, at a central facility rather than incorporating captured CO_2 into onsite concrete mixing or curing of concrete at building sites (see example projects below).[37]

In terms of policy barriers, all types of concrete are highly regulated for safety reasons. As such, extensive testing and regulatory reforms are necessary before any CO_2-utilizing concrete could be used for high-stability purposes. Thus, early market opportunities will likely rely on less-intensive concrete uses, like paving roads or poured concrete floors.[38]

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[32] *Nature* (September 28, 2021) Concrete's colossal carbon footprint. [43]

[33] *Nature* (September 28, 2021) Concrete's colossal carbon footprint. [43]

[34] IEA (2019) Putting CO_2 to Use. p. 12. [34]

[35] The federal tax credits 45Q provides a reduced tax-credit for industrial uses of CO_2 (compared to permanent storage) as long as emissions reductions can be clearly demonstrated. From: IEA (November 4, 2022) Section 45Q credit for carbon oxide sequestration. [35]

[36] IEA (2019) Putting CO_2 to Use. p. 12, 54-55. [34]

[37] IEA (2019) Putting CO_2 to Use. p. 55-56. [34]

[38] IEA (2019) Putting CO_2 to Use. p. 12. [34]

Although developers are working on promising new industrial processes in this field, experts anticipate that the hurdles in scaling and deploying CO_2-utilizing concrete will be regulatory, rather than technical, in nature.[39]

Example Project: Carbicrete, Montreal, Quebec

Canadian company Carbicrete has developed a new process to reduce their carbon emissions that both changes the constituent parts of the concrete to be less carbon intensive and relies on CO_2 to cure its final concrete product.[40] Rather than mixing cement with aggregates and water to generate their concrete, they replace the cement with steel slag, which is incorporated into the mixture on industry standard equipment—removing the requirement for cement altogether.[41] Then, they mold precast concrete blocks that are cured with CO_2 in a specialized chamber, taking 24 hours to reach their full strength.[42] In testing, they have found their concrete has up to 30% higher compressive strength, improved freezing and thawing resistance, and the same water absorption properties of traditional concrete.[43]

Across Carbicrete's production process, more CO_2 is absorbed in the concrete than is emitted in manufacturing, making their concrete production carbon negative.[44] Currently, Carbicrete relies on captured industrial point-source emissions for its CO_2, but it is hoping to move to using CO_2 from Direct Air Capture (DAC) facilities in the future so they are actively removing existing CO_2 from the atmosphere.[45]

Example Project: CarbonCure, Halifax, Nova Scotia

CarbonCure's process relies on incorporating CO_2 directly into the concrete mix, where the CO_2 reacts with calcium ions within the cement (composed primarily of lime, or CaO and $Ca(OH)_2$) in order to form calcium carbonate ($CaCO_3$).[46] They market a range of products from their technology, including ready concrete mix, concrete bricks, precast concrete, and reclaimed water.[47] Their technology decreases both the water and carbon intensity of their concrete in comparison to traditional concrete.[48]

It's expected that over the next 30 years, about half of the emissions from new construction will come from embodied carbon, which is the carbon emitted during the manufacture of

[39] IEA (2019) Putting CO_2 to Use. p. 58. [34]
[40] Carbicrete (no date) Technology. [11]
[41] Carbicrete (no date) Technology. [11]
[42] Carbicrete (no date) Technology. [11]
[43] Carbicrete (no date) End Users. [10]
[44] Carbicrete (no date) Carbicrete - About the Process Video. 0:31-0:36. [9]
[45] Fairs (June 27, 2021) Carbon Revolution. [24]
[46] CarbonCure (no date) Innovative CO_2 Technologies. [14]
[47] CarbonCure (no date) Innovative CO_2 Technologies. [14]
[48] CarbonCure (no date) Innovative CO_2 Technologies. [14]

building materials.[49] CarbonCure's goal is that with their associated products, they could remove 500 million metric tons of embodied CO_2 from the environment by 2030, equivalent to taking 100 million cars off the road.[50]

Example Project: Solidia Technologies, San Antonio, Texas

Solidia Technologies is developing two processes for reducing CO_2 emissions associated with concrete production: one is to adjust the chemistry of the cement mix and the other - like other companies - is to use a CO_2 curing process.[51] Their cement formula is more silica-rich and less lime-rich than the most common cement recipe, Portland cement. Because lime production (converting limestone rock ($CaCO_3$) to lime (CaO and $Ca(OH)_2$) is an energy intensive process that releases CO_2 in the atmosphere, a cement chemistry with less lime has the effect of lowering the CO_2 emissions, energy requirements, and raw materials intensity of the cement and subsequent concrete products.[52]

The lime-poor cement is combined with sand granules to generate their concrete, which undergoes CO_2 curing. In the CO_2 curing process, the CO_2 reacts with the cement in the concrete to form calcium carbonate ($CaCO_3$), strengthening the material and chemically trapping the CO_2.[53] This process makes the concrete higher performing, reduces production costs, and drastically reduces the curing time to less than 24 hours, compared to a full 4 weeks for traditional concrete.[54]

If implemented globally, Solidia anticipates that their technologies could reduce carbon emissions from concrete production by up to 70%.[55]

10.1.1.3 Building Materials

CO_2 can be utilized for building materials other than concrete as well, with most applications involving the remediation of metal waste materials into carbonates that can be used as aggregates in construction.[56] Fly ash and steel slag are two examples of alkaline wastes - materials that have high concentrations of reactive metals like calcium and magnesium. These kinds of metals chemically bond with CO_2 to form solid carbonate materials ($CaCO_3$ and $MgCO_3$) that permanently bind the carbon. Carbonation of 1 ton of fly ash can sequester about 0.07-0.25 tons CO_2, and carbonation of 1 ton of blast furnace slag from steel operations requires about 0.26-0.38 tons CO_2. Not all of the CO_2 used is bound up in the product, but the cost of CO_2 input encourages recycling the CO_2 such that the majority of the CO_2 input will be sequestered. Producing carbonates from metal waste is a

[49] CarbonCure (no date) 500 Million Tonne CO_2 Reduction. [13]
[50] CarbonCure (no date) 500 Million Tonne CO_2 Reduction. [13]
[51] Solidia Technologies (no date) Solutions. [52]
[52] Solidia Technologies (May 2021) The Science Behind Solidia. [53]
[53] Solidia Technologies (no date) Solutions. [52]
[54] Solidia Technologies (no date) Solutions. [52]
[55] Solidia Technologies (no date) Impact. [51]
[56] IEA (2019) Putting CO_2 to Use. p. 59. [34]

relatively new industry, and life-cycle assessments of the CO_2-reduction potential of carbonated waste products are limited and often not transparent – substantial analytical work is still needed to establish the climate benefits possible from these processes.[57]

However, a co-benefit of metal-waste carbonation is that it binds harmful metals that could leach into the environment and cause harm, and it helps eliminate the costs of tailings or hazardous waste disposal in mining and industrial applications.[58] Thus, these practices have the potential to reduce the environmental impact of existing industrial sites requiring remediation and protect industrial communities from future environmental harm.

Carbonation of metallic wastes for construction aggregates does face economic hurdles before significant scaling can take place. Since building materials are readily and cheaply available, it is difficult for materials generated from waste to be economically competitive in the marketplace.[59] As a result, early markets are likely to appear only where there are large amounts of waste to process and tightening regulations incentivize safe remediation of that waste. Examples include regions around the world that are increasing regulations around disposing bauxite residue (informally called "red mud") from aluminum production,[60] and regions where industrial waste disposal is expensive, like the European Union (EU).[61] Regulations can also present hurdles, however; for example, EU law currently prohibits the integration of waste into commercial products, which could present challenges for bringing a carbonated aggregate generated from waste into the European market.[62]

Example Project: Carbon8, United Kingdom

In the UK, Carbon8 works to capture CO_2 from industrial sources and then, at the same site, react that CO_2 with residues and byproducts that would otherwise be destined for landfilling.[63] Once formed, these carbonated materials can be used for "a variety of applications including in cement blocks, road filler and green roofing substrate."[64] Carbon8's technology is notable because it can sequester CO_2 for long periods and has a relatively short production time, with an estimated time for its carbon capture and storage process of 20 minutes.[65]

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[57] IEA (2019) Putting CO_2 to Use. p. 59-62. [34]
[58] IEA (2019) Putting CO_2 to Use. p. 59. [34]
[59] IEA (2019) Putting CO_2 to Use. p. 60. [34]
[60] Srivastava *et al.* (2023) Challenges, regulations, and case studies on sustainable management. [54]
[61] IEA (2019) Putting CO_2 to Use. p. 61. [34]
[62] IEA (2019) Putting CO_2 to Use. p. 62. [34]
[63] Carbon8 (no date) Our Solution. [12]
[64] Carbon8 (no date) Our Solution. [12]
[65] Carbon8 (no date) Our Solution. [12]

10.1.1.4 Synthetic Carbon Fuels

Another budding industrial opportunity for CO_2 use is to incorporate captured CO_2 into new carbon fuels. These fuels could replace conventional fuels in use today, including gasoline, aviation fuels, methane, and methanol.[66] This prospect has clear potential: by volume, synthetic carbon fuels rank as the biggest use potential for CO_2, with the ability to provide a lower-carbon fuel option for industries with few non-carbon fuel alternatives, like the aviation industry, or by replacing fossil fuels with an option that is simpler to use and store than pure hydrogen fuels. However, synthetic carbon fuels come with challenges as well: generating fuels from CO_2 is very energy-intensive, and existing fuel standards may be difficult to meet with synthetic CO_2-derived fuels. Additionally, upon combustion of these fuels, CO_2 will be re-released into the atmosphere, and so these products are not pathways for permanent CO_2 removal and storage, and thus not eligible for carbon credits, or policies that incentivize carbon removal.[67]

Production of synthetic carbon fuels can be carried out through one of two pathways, either direct or indirect.[68] Both pathways involve combining CO_2 and H_2 for chemical conversion, summarized by this simplified reaction:

$$CO_2 + H_2 \text{ (or } H_2O) + \text{energy} \rightarrow \text{Hydrocarbon fuel} + O_2 \qquad \text{(R10.1)}$$

The direct pathway relies on hydrogenation, and the indirect pathway on a reverse gas-water shift process followed either by a Fischer-Tropsch (FT) or methanol synthesis process. Not all of these processes are equally ready for commercial deployment. Hydrogenation, FT, and methanol synthesis are all mature processes, but the reverse water-gas shift is still at the demonstration scale.[69] Other processes that develop CO_2-derived fuels via chemical or biological pathways are still in the research and development phase.[70]

Regardless of production pathway, producing synthetic carbon fuels is an energy intensive process, which significantly contributes to their high cost relative to fossil fuels. For example, in creating CO_2-derived methane and methanol, electricity accounts for 40-70% of production costs and is the primary reason that production costs exceed traditional methane and methanol by 2 to 7 times.[71] With improvement, CO_2-derived methanol may become price-competitive in the marketplace, but other fuels produced from CO_2 – methane, diesel, gasoline, and aviation fuel – are expected to require policy interventions

[66] IEA (2019) Putting CO_2 to Use. p. 9. [34]
[67] IEA (2019) Putting CO_2 to Use. p. 7-10. [34]
[68] IEA (2019) Putting CO_2 to Use. p. 10. [34]
[69] IEA (2019) Putting CO_2 to Use. p. 18. [34]
[70] IEA (2019) Putting CO_2 to Use. p. 9. [34]
[71] IEA (2019) Putting CO_2 to Use. p. 10. [34]

to compete with traditional fuels.[72] Some of the policy avenues that could precipitate this change in demand are explored in Section 10.3.2.

The energy demand of synthetic carbon fuels is intuitive - production of these fuels is essentially a reversal of the combustion reaction we use to obtain energy:

$$\text{Hydrocarbon fuel} + O_2 \rightarrow CO_2 + H_2O \text{ (or } H_2\text{)} + \text{energy} \quad \text{(R10.2)}$$

Thus, synthetic carbon fuels will only have value if the energy used to create them produces less CO_2 than would come from simply combusting fossil fuels. For example, using electricity generated from a coal-fired power plant to create synthetic carbon fuel could emit more CO_2 than it avoids. Thus, for any production facility, a full life-cycle analysis would be necessary to examine how beneficial these CO_2-derived fuels are when compared to traditional fuels.

Example Project: Carbon Engineering - Air to Fuels, British Columbia, Canada

Carbon Engineering is one of two leading companies in the development of Direct Air Capture (the other being ClimeWorks, see Section 3), having operated a pilot Liquid Direct Air Capture (L-DAC) facility in Sqamish, British Columbia since 2015.[73] In addition to their work in capturing CO_2 for the purposes of underground sequestration, the company's Air to Fuels program develops synthetic fuels that are drop-in compatible with existing infrastructure and engines. Their process involves reacting CO_2 captured from the air with green hydrogen derived from electrolysis (see Section 6) to create hydrocarbons that can be converted into synthetic gasoline, diesel or jet fuel.[74] In 2019, the reported cost to produce these fuels was ~ $4 USD per gallon.[75]

Example Project: George Olah Renewable Methanol, Svartsengi, Iceland

The George Olah Renewable Methanol facility, located in Svartsengi, Iceland, is the first industrial scale operation converting captured CO_2 to methanol fuel.[76] The facility was commissioned in 2011 and reuses 5,500 metric tons of CO_2 annually. It relies on captured CO_2 from a nearby geothermal power plant (point-source capture) to synthesize methanol via a catalytic reaction with H_2.[77]

Example Project: Air Company, New York, New York

Air Company is developing a variety of products utilizing CO_2, including alternative fuels, and is described in detail in Section 10.1.1.1.

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[72] IEA (2019) Putting CO_2 to Use. p. 10. [34]

[73] Carbon Engineering (no date) Our Story. [16]

[74] Carbon Engineering (no date) Air to Fuels™. [15]

[75] Conca (October 8, 2019) Carbon Engineering – Taking CO_2 right out of the air to make gasoline. [21]

[76] IEA (2019) Putting CO_2 to Use. p. 18. [34]

[77] Carbon Recycling International (no date) George Olah renewable methanol plant. [17]

10.1.1.5 Plastics & Polymers

Today, fossil fuels are not only used for energy production, but are a primary feedstock in the production of a variety of plastics, polymers and their derivatives: materials that are collectively described as the *petrochemical* industry. In the long term, decarbonization efforts would ideally reduce fossil fuel use in petrochemicals in addition to the energy sector, and to this end, plastics and polymer production is an industry with a strong potential for reusing captured CO_2 to create new products.[78]

A clear benefit to incorporating CO_2 into plastics and polymers is that it requires relatively low energy input, making it cost-competitive with many traditional manufacturing practices, and it reduces the raw materials necessary from fossil fuels.[79] However, this is not a fix-all solution—at least currently, CO_2 can only replace part of the raw material from fossil fuels necessary to form plastics or polymers, up to approximately 50% of the final products' mass.[80] Full life-cycle analyses would be necessary to quantify the degree to which CO_2-utilization reduces the emissions associated with polymer production. Additionally, while the longevity of CO_2-derived plastics and polymers could provide an environmental benefit in the form of long-term storage sites for CO_2, the accumulation of non-degradable plastic waste creates a different environmental hazard that needs to be considered.[81]

Example Project: Econic, United Kingdom

UK manufacturer Econic is using CO_2 to produce polyurethane, which is used in foam, coatings, sealants, elastomers and other products.[82] Their process relies on replacing a percentage of the material's polyols—cross-linking agents—with carbon dioxide, which serves not only to bind the CO_2 but also replaces a highly expensive standard polyol material, propylene oxide.[83] As a result, Econic estimates that their process will not only lower carbon emissions, but also save money for manufacturers.[84] Econic products are in development - with full scale production of their polyol technology planned to begin in 2024.[85]

10.1.1.6 Chemical Development

Most of the products discussed in the previous sections involved some form of chemical conversion of CO_2 into a new product. However, there are other ways to chemically convert CO_2 that does not fit clearly into these large, existing industrial sectors, like fuels, building

[78] Vilcinskas (March 2020) Carbon dioxide-based polymers. [56]
[79] IEA (2019) Putting CO_2 to Use. p. 11. [34]
[80] IEA (2019) Putting CO_2 to Use. p. 11. [34]
[81] Parker (June 7, 2019) The world's plastic pollution crisis explained. [49]
[82] Cormier (no date) Turning carbon emissions into plastic. [22]
[83] Cormier (no date) Turning carbon emissions into plastic. [22]
[84] Cormier (no date) Turning carbon emissions into plastic. [22]
[85] Econic (January 12, 2023) Econic Technologies Named on the 2023 Global Cleantech 100. [23]

materials or plastics. This section encompasses products of CO_2-conversion that are outside of the previously described sectors, as well as some processes of chemical conversion that are in early stages of laboratory testing, but could have promising future applications.

Through processes described as biological conversion, CO_2 can be converted into fatty acids, amino acids, and proteins.[86] Synthetic amino acids and proteins can be used in animal feed or, in the future, to generate meat alternative products.[87]

Electrochemical conversion of CO_2 could produce a wide variety of products, including carbon monoxide and carbon nanomaterials.[88] Some products, like methanol and formic acid, can be generated through thermochemical or electrochemical conversion of CO_2.[89] These products are exceedingly versatile and useful. Carbon monoxide is used in the formation of an array of other chemical materials, including long-chain hydrocarbons for fuel and methanol. Carbon nanomaterials, depending on their specific shape and characteristics, can be used in fuel cells, batteries, automotives, and water treatment.

Methanol can be formed with CO_2, CO, and H_2 molecules, and serves as a reactant for forming other chemical compounds, including acetic acid, formaldehyde, and long-chain hydrocarbons. It can also be used as a fuel (see Example Project: George Olah Renewable Methanol in Section 10.1.1.4) – although less energy-dense than gasoline, methanol can be used in some gas-powered engines with minor modifications.[90] Lastly, formic acid can be formed through a multi-step process, but has thus far been rarely commercialized as it relies on an expensive catalyst and can be difficult to separate out at the product end.[91] Formic acid (or CH_2O_2) can be used as a food additive, pesticide (depending on local regulations), in cleaning products, in dyeing or treating fabric and paper products, and as an organic reagent for chemists.[92]

10.2 Growth in CO_2-Utilizing Industries: Obstacles and Opportunities

The International Energy Agency (IEA) has identified four primary factors that will determine the market viability of a CO_2-utilizing technology: scalability, competitiveness, climate benefits, and the policy & regulatory framework in place.[93] The IEA's analysis of

[86] ten Have (December 20, 2022) Don't bury money. [55]
[87] ten Have (December 20, 2022) Don't bury money. [55]
[88] ten Have (December 20, 2022) Don't bury money. [55]
[89] ten Have (December 20, 2022) Don't bury money. [55]
[90] ten Have (December 20, 2022) Don't bury money. [55]
[91] ten Have (December 20, 2022) Don't bury money. [55]
[92] PubChem (no date) Formic Acid (Compound). [50]
[93] IEA (2019) Putting CO_2 to Use. p. 28. [34]

each of these factors are summarized briefly here, with additional focus given to national and state policies and funding opportunities that could impact growth of CO_2-utilizing industries in California.

10.2.1 Scalability

For new technologies, supply chains and infrastructure to produce new products take time to develop. In terms of CO_2-utilizing industries, key supply inputs are CO_2 and clean energy (and in some cases, hydrogen). For projects to grow from R&D testing scale to commercial production, large supplies of these inputs will be necessary, which requires either siting such industries close to input sources, or developing significant infrastructure (100% utility-scale energy and a large CO_2 (± H_2) pipeline networks). While these supply frameworks are in development, it will likely be several decades before such inputs are widely available.[94] Co-locating CO_2-utilizing industries in regions close to points of CO_2 capture, green hydrogen production, and abundant potential for clean, renewable energy, as would be the case in a carbon management business park in Kern County, would be highly advantageous, particularly before the infrastructure to support national supply chains is available.

Another critical determinant to scalability is marketplace demand, which varies widely across the products examined here. For example, demand for some of the sophisticated chemicals made with CO_2 will likely be constrained to chemical engineering firms, specialized labs, and other chemical industries. Meanwhile, demand for a product like concrete has grown exponentially over the last century,[95] and with applications across a wide variety of sectors that grow in tandem with population growth and social-economic development (residential, industrial, municipal, and commercial), is likely to continue such growth. Demand is also not fixed – new technologies may shift what materials are most in demand in ways that have not been considered here – but the ability to project future demand and revenue potential will certainly shape the types of initiatives that are pursued and funded within this early, exploratory phase. The IEA estimates that the five largest potential CO_2-utilization markets (fuels, chemicals, building materials from waste, building materials from minerals – essentially, concrete and cement, and CO_2 to boost plant yields – discussed in Section 11) each have the potential to scale up to tens of millions of tons of CO_2 use annually, on a global scale.[96]

10.2.2 Competitiveness

CO_2-utilizing products that will see success at a commercial scale are those whose use or CO_2-based production pathway can be easily implemented and have the lowest production costs, especially when ranked against alternatives. This will depend on the costs of the technology itself, the market price, and the cost of inputs—material, energy, labor. For

[94] Larson *et al.* Net-Zero America: Final Report Summary. [40]

[95] Andrew (2018) Global CO2 emissions from cement production. [4]

[96] IEA (2019) Putting CO_2 to Use. p. 1. [34]

example, plastics and polymers made with CO_2 reuse are expected to be quite competitive, as there's little additional equipment needed for production, the process can actually save money in material cost for manufacturers, and these products could be sold near the existing average market price for these plastic and polymer products.

In contrast, carbon-based synthetic fuels will need to compete against fossil fuels that have been historically abundant and heavily subsidized.[97] Building materials, like concrete, will need to compete on a global market where profit margins are low, so additional production costs are difficult to absorb without some kind of policy incentives.[98] Both of these types of CO_2-utilizing industries will likely need some kind of policy intervention to support their adoption during early stages of development (see Section 10.2.4).

10.2.3 Climate benefits

Life cycle emissions and other environmental benefits associated with products that utilize captured CO_2 is often difficult to characterize, but will be essential for quantifying the impact and cost-benefit of adopting products that utilize CO_2, as is determining the life cycle emissions of the products they displace. For example, for building aggregates that are developed from combining industrial waste (slag and tailings) with CO_2, there are clear benefits—not only does the construction industry have new aggregates to work with, the technology reduces wastes that could leach harmful metals into the environment. However, for an item like plastics or polymers, addition of CO_2 into the production process does not displace the need for raw materials from fossil fuels to create these products—the impacts are limited as current technologies do not fully displace the reliance on fossil fuels.

Benefits are also enhanced when the necessary energy to complete these processes is reduced through in the CO_2-utilization process compared to traditional methods, and/or if it supplied through clean sources near the production site. Depending on the region, this could include solar, wind, hydropower, geothermal, and/or nuclear energy sources.

Finally, the benefits of CO_2 reuse will be driven by the amount of time that the CO_2 is stored within the product. For building materials and concrete, this is on the order of years or decades; for beverages and fuels, this could be only a few weeks or months. Longer storage of the CO_2 within the product enhances the climate benefits by acting more as a CO_2 removal solution, whereas products with short storage spans only serve to recycle existing atmospheric CO_2, avoiding further CO_2 additions from fossil sources.

10.2.4 Funding Opportunities & Policy Support

To date, most of the investment in CO_2-utilization technologies has come from the private sector. Between 2008 and 2018, private investment in the form of venture capital and

[97] IEA (February 2023) Fossil Fuels Consumption Subsidies 2022. [32]

[98] Khung, Crete (2022) Life cycle assessment (LCA) and cost-benefit analysis for low carbon concrete. [38]

growth equity for start-ups in the CO_2-use space reached nearly $1 billion USD, globally.[99] It is worth noting that level of investment pales in comparison to other clean energy sectors. Global investment in electrified transport topped $139 billion dollars USD in 2020 alone, and $304 billion dollars USD were invested in renewable energy in the same year.[100] However, public funding and policy support is beginning to gain momentum within state and federal governments. The simplest and most direct policy support for CO_2-utilization is the development of incentives, guidelines or policies for using low-carbon products, or requiring products to stay below a maximum carbon-intensity (i.e. limit of how much CO_2 per unit product was emitted).[101] While politically less popular, another effective policy strategy is placing a price on carbon (a carbon tax), that reflects the cost of – and provides revenue for – mitigating climate change, while also encouraging the use of carbon-negative materials over carbon-intensive materials.[102]

As a climate leader within the nation, California has some statewide policies already informing practices in some CO_2 utilization areas. Federally, the United States supported research and development of CO_2 use through a variety of grant programs, and is beginning to develop additional policy incentives.

10.2.4.1 Relevant California State Policies

With a state-wide commitment to be carbon-neutral by 2045,[103] laws are being developed to directly address CO_2-emitting industries, many of which are industries that can use CO_2 (concrete and cement, fuels, plastics and chemicals). For example, California's SB 596, passed in 2021, requires the cement industry to reach net-zero carbon emissions by 2045, are changing the landscape by making climate improvements a necessity.[104,105] However, the high costs of decarbonizing some processes—like creating cement and concrete—have led operators to seek ways to work with the government to lower emissions.[106] California's Air Resources Board (CARB) is scheduled to release a comprehensive strategy to guide the state's cement industry to meet this goal by July 1, 2023, including defining metrics for greenhouse gas intensity, coordinating strategy with other state agencies, and incorporating ways to leverage state and federal incentives and market demand to promote low-carbon cement.[107]

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[99] IEA (2019) Putting CO_2 to Use. p. 25. [34]

[100] Bullard (January 28, 2021) In the race for investment dollars, cars are pulling ahead. [7]

[101] IEA (2019) Putting CO_2 to Use. p. 5. [34]

[102] Climate Now (October 18, 2021) Pricing carbon around the globe. [19]

[103] Office of Governor Gavin Newsom (November 16, 2022) California releases world's first plan. [46]

[104] Office of Governor Gavin Newsom (September 23, 2021) Governor Newsom Signs Climate Action Bills. [47]

[105] Lopez (June 27, 2022) Climate-friendly cement? [41]

[106] Lopez (June 27, 2022) Climate-friendly cement? [41]

[107] CARB (2022) SCOPING PLAN FOR ACHIEVING CARBON NEUTRALITY. p. 48. [8]

California's climate policies have also prevented the use of CO_2 for certain uses. SB 905 (2022) bans the use of captured CO_2 for enhanced oil recovery (EOR),[108] a process where CO_2 is injected into existing oil fields to extract hard-to-reach deposits, thereby extending the lifetime of oil fields.[109] SB 1314 (2022) effectively bans the use of CO_2 injection for EOR, explicitly citing that the state's support of CCUS technologies is driven by a desire to advance towards a carbon-neutral society rather than extending the lifetime of fossil fuel production facilities.[110]

10.2.4.2 Relevant United States Federal Funding Programs and Policies

At the federal level, funding in CO_2 utilization has primarily been in the form of grants for early-phase research and development (R&D). The 2009 American Reinvestment and Recovery Act (ARRA) invested $100 million USD in R&D projects focused on innovative CO_2 conversion projects,[111] notably in the building materials and chemical production industries.[112] From 2012-2017, a portion of the U.S. Department of Energy (DOE)'s Carbon Storage Program (between ~$1 and 10 million USD annually) funded an R&D portfolio of projects specifically in the space of carbon use and reuse.[113] A similar program (the Climate Innovation Research Opportunity investment program) launched in 2021, providing another $100 million USD grant program for low-carbon energy technologies, including those in the field of carbon capture and utilization.[114] The 2020 Energy Act authorized the Department of Energy to allocate nearly $7 billion USD in funds for various carbon management and removal programs, including carbon utilization.[115] Additional funding is planned from the 2021 Infrastructure Investment and Jobs Act, with $12 billion USD earmarked for investments in carbon capture, utilization and storage technology.[116]

Section 45Q in the tax code provides a credit for qualified uses of CO_2, most commonly used for EOR in the oil and gas sector, but other uses can qualify if they fall into certain categories. The language of Section 45Q(f)(5)(A) permits 45Q credits for processes that fix CO_2 via photosynthesis or chemosynthesis or chemical conversion that securely stores carbon, but other uses could become eligible if a commercial market exists and the use of qualified CO_2 is determined to be eligible for 45Q by the Secretary of Energy.[117]

In general, experts agree that governments need to develop more incentive structures to encourage CO_2 utilization, as well as more robust policies in place to quantify reduced or

[108] OpenStates (no date) SB 905. [48]
[109] FECM (no date) Enhanced Oil Recovery. [45]
[110] IEA (November 4, 2022) Enhanced Oil Recovery and CCUS (SB 1314). [31]
[111] IEA (August 24, 2021) American Reinvestment and Recovery Act - CCUS elements. [28]
[112] IEA (August 24, 2021) American Reinvestment and Recovery Act - CCUS elements. [28]
[113] NETL (2017) Carbon use and reuse program overview briefing. [42]
[114] IEA (July 8, 2021) Climate Innovation Research Opportunity investment program. [29]
[115] IEA (March 10, 2022) Energy Act of 2020. [30]
[116] IEA (April 18, 2022) Infrastructure and Jobs act. [33]
[117] IRS (no date) Request for Comments on Credit for Carbon Oxide Sequestration. p. 5-6. [27]

avoided emissions resulting from CO_2-utilizing products or production pathways. Underpinning any policies or incentives with transparent measurement, reporting, and verification standards will be crucial to ensuring that development of CO_2 utilization programs results in meaningful emissions reductions or carbon removal.[118] Although this sounds straightforward, developing these standards is difficult due to the range of products that can be developed utilizing CO_2, and the need to assess the life cycle impacts of CO_2-utilizing products as compared traditional manufacturing methods for those same kinds of products.[119]

Finally, adaptations in existing legislation and regulations will also be required for the widespread adoption of CO_2-utilizing materials, especially in long-lived products like concrete and building materials that, for public health and safety reasons, are highly regulated. Without a clear regulatory pathway to the adoption of CO_2-utilizing materials as replacements for the carbon-intensive products used today, continued development and commercial scaling of these technologies will not be possible.

[118] IEA (2019) Putting CO_2 to Use. p. 67. [34]
[119] IEA (2019) Putting CO_2 to Use. p. 67. [34]

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11. Connections with Regional Agriculture

OPPORTUNITIES AT A GLANCE

- Kern County's agricultural sector emits over 2 million tons of CO_2 annually, 65% of which comes from the degradation of agricultural waste, including livestock waste.[1]
- 482,000 tons of agricultural waste and 625,000 tons of livestock manure are produced in Kern County annually, and could be converted into renewable fuels, pure streams of CO_2, and/or a source of water.
- Conversion of 100% of Kern County's biomass waste could produce over 900 thousand metric tons of CO_2 annually.
- Biochar is a byproduct of BiCRS + BECCS processes, which could serve as a nutrient-adding alternative to fertilizer for regional croplands.
- Additional products of carbon management industries that could be useful to regional agriculture are water (depending on carbon management technology) and CO_2, which can be used to enhance greenhouse production.

[1] Values and information in this section are summarized from the suite of references cited herein, and are explained in further detail in each subsequent section.

11.1 Kern County's Agricultural Sector

Agriculture is a major industry throughout California's Central Valley, a region that produces about a quarter of the nation's food.[2] In Kern County alone, agricultural output is valued at over $8 billion annually,[3] making it the highest producing agricultural county in California by value in 2021.[4] The agriculture sector also leads the county in land use,[5] water use,[6] and employment,[7] providing nearly 1 in 5 county jobs directly, and supporting a variety of indirect jobs (i.e. sales of equipment, fertilizers, feed, and other supplies, or supplying food an beverage processing facilities). As such, understanding the ways in which carbon management and clean energy technologies can enhance, benefit from, or compete with this sector are worth considering.

A full examination of agriculture and its projected development in Kern County is beyond the scope of this report. Rather, in this section we will provide a brief overview of the current state of the industry, highlighting strengths, challenges and potential synergistic pathways between agriculture and the development of one or more carbon management business parks in the region.

11.1.1 The Current Agriculture Industry

Kern County's farmland is expansive, covering 2,295,497 acres of land according to the USDA's 2017 Census of Agriculture.[8] That means that farmland accounts for 44% of Kern county's land area of 5,206,176 acres.[9] Although over 80% of the county's sales are in crops, land use is more evenly distributed between livestock and crops, with 53% of farmland designated as pastureland and 42% of farmland designated as cropland.[10]

Agriculture requires more than land to flourish, though, and the water needed to irrigate Kern County's croplands is in jeopardy. In Kern County today, 2,294,000 million acre-feet of water is devoted to the agriculture industry.[11] That represents 93% of total municipal,

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[2] U.S. Geological Survey (no date) California's Central Valley. [45]

[3] Kern County Department of Agriculture and Measurement Standards (2022) 2021 Kern Agricultural Crop Report. [23]

[4] When compared to other county crop reports from the California Department of Food and Agriculture; accessed March 4, 2023 from https://www.cdfa.ca.gov/exec/county/CountyCropReports.html.

[5] NASS (no date) Agriculture Census: Kern County. [32]

[6] WAKC (no date) Water in Kern County. [47]

[7] State of California EDD (no date) California Labor Market Information Resources and Data. [42]

[8] NASS (no date) Agriculture Census: Kern County. [32]

[9] U.S. Census Bureau (no date) QuickFacts: Kern County, California. [44] (In this source, land area is given in square miles and has been presented here converted to acres.)

[10] NASS (no date) Agriculture Census: Kern County. [32] These percentages do not add to 100% as the Agriculture Census recognizes other categories (woodland, other) that are not discussed here.

[11] WAKC (no date) Water in Kern County. [47]

industrial and agricultural water use in the county. More than 70% of that water is sourced from reservoirs to the north of the county, or from groundwater in subsurface aquifers.[12] With more frequent droughts impacting the region and the implementation of laws like the 2014 Sustainable Groundwater Management Act (SGMA), which requires local water users to achieve sustainable groundwater use by 2040,[13] less water will be available for irrigation from rain and snowfall, and significantly less water will be available from underground aquifers.[14,15] The Public Policy Institute of California estimates the combined impact of climate change and the SGMA could result in as much as 900,000 acres of fallowed farmland in the San Joaquin Valley by 2040. The number can be lessened (but not eliminated) with improved water trading rules, infrastructure investments, and improved agricultural productivity.[16]

Development of carbon management business parks like that considered here, provide a potential revenue-generating alternative to agriculture in fallowed croplands, while carbon management itself directly combats the primary driver of climate change-induced droughts. Below, we explore how principles of carbon management – both in collaboration with some of the carbon management industries described in this report and applied directly to agricultural practices – could help farms transition under these new circumstances.

Table 11.1. Agriculture-related emissions in Kern County and California[a]

Emissions Source	Kern 2005[b]	CA 2005[c]	CA 2020[c]	% Change[d]
Livestock enteric fermentation	633,214	10.5 million	11.0 million	+5%
Livestock manure management	741,173	10.4 million	11.6 million	+12%
Crop growing & harvesting	575,572	8.2 million	6.8 million	-17%
Fuel combustion	74,511	4.6 million	2.3 million	-50%
TOTAL	**2,024,470**	**33.7 million**	**31.7 million**	**-6%**

a. In metric tons CO_2-equivalent.
b. Kern County Planning and Natural Resources Department (2012) Community GHG emission inventory final report.
c. CARB (2022) California greenhouse gas emissions for 2000 to 2020.
d. Relative change in state-wide emissions from 2005 to 2020.

[12] WAKC (no date) Water in Kern County. [47]
[13] Escriva-Bou *et al.* (2023) The future of agriculture in the San Joaquin Valley. [15]
[14] California Department of Water Resources (no date) Climate Change Basics. [9]
[15] Escriva-Bou *et al.* (May 14, 2020) Sinking Lands, Damaged Infrastructure. [16]
[16] Escriva-Bou *et al.* (2023) The future of agriculture in the San Joaquin Valley. [15]

11.1.2 Carbon Capture Potential

In 2012, the Kern County Department of Planning and Community Development created an inventory of community-wide greenhouse gas emissions, estimating the county's sector by sector emissions impact in 2005, in units of metric tons CO_2-equivalent (CO_{2e}). The agriculture sector sequestered ~400,000 metric tons of CO_{2e}, annually, through the process of photosynthesis and plant growth, but released over 2 million tons of CO_{2e} through enteric fermentation (digestive gasses of livestock), manure management, crop growing and harvesting, and fuel combustion (Table 11.1).[17] The report forecasted an ~30% increase in emissions by 2020, but no subsequent studies have been undertaken at the county level. At the state level, livestock related emissions have increased 5-12%, crop-related emissions have decreased 17%, and fuel combustion-related emissions have decreased 50%, with the net effect being very little change in agriculture sector emissions since 2020.[18] Of these emissions, some can be reduced through partnerships with biomass with carbon dioxide removal (BiCRS) technologies, detailed in Section 11.2, while others can be reduced through low carbon farming techniques, which are introduced briefly here. With sustainable practices and low-carbon techniques, farms can reduce their overall impacts on the environment. From low-till farms and crop cover to technical systems equipped to monitor water and nutrient levels, there are a variety of potential avenues to reduce the carbon intensity of farming.

About 28% of Kern County's agricultural emissions come from crop growing and harvesting, which includes fertilizer use, soil preparation and disturbance, and crop residue burning.[19] Many of these emissions can be reduced through the practice of *carbon farming*, a set of farming tactics that sequester carbon or reduce the GHG emissions of agriculture by focusing on the importance of CO_2 drawdown via photosynthesis as a carbon removal strategy.[20] An example is no-till farming practices, in which the topsoil is left undisturbed, preventing it from releasing its stored carbon into the atmosphere.[21] Other practices, like cover cropping, also serve to sequester carbon in soils and keep the ground nutrient-rich for other crops. With cover crops, new roots help feed the soil's ecosystem of fungi, bacteria, and other organisms over time, gradually increasing the soil's carbon levels.[22]

Currently, these practices are not standard for agricultural land in the region—the USDA found that in Kern County, less than 10% of farms are no-till or reduced-till and that only 2% of farms have cover crops.[23] However, interest has been rising in these practices nationally, and many feel there could be economic benefits as well as climate benefits

[17] Kern County Planning and Natural Resources Department (2012) Community GHG emission inventory. [24]
[18] CARB (2022) California greenhouse gas emissions for 2000 to 2020. [5]
[19] CARB (2022) California greenhouse gas emissions for 2000 to 2020. [5]
[20] Carbon Cycle Institute (no date) What is Carbon Farming? [10]
[21] Spears (June 24, 2018) What is No-Till Farming? [41]
[22] Clark (2015) Cover Crops and Carbon Sequestration. [11]
[23] NASS (no date) Agriculture Census: Kern County. [32]

associated with their adoption. Reporting from the USDA indicates that shifting from conventional to continuous no-till farming uses a third of the amount of diesel for farm equipment per acre, saves time in field maintenance, and can save money in future years as the more nutrient-dense soil requires less water and fertilizer to thrive.[24] Agricultural planners in Minnesota have reported that the net profit from farms earning $5.25 per acre with conventional farming can increase up to $112 per acre with a combination of no-till and cover cropping practices.[25]

More technologically driven carbon farming techniques include implementation of advanced monitoring equipment and automated systems, which can also help reduce water and fertilizer usage on agricultural lands. A variety of sensors are available to monitor farmland conditions: temperature sensors, electrochemical sensors for nutrient levels and pH, mechanical sensors to monitor soil compression or displacement, airflow sensors to test soil air penetration, and dielectric sensors for calculating soil moisture levels.[26] These systems can also be equipped to identify environmental threats like drought stress early, giving farmers more time to plan and mitigate such risks to their livelihood. [27]

11.2 Potential Relationships with a Carbon Management Business Park: Feedstocks and Products

11.2.1 Agricultural Waste as Carbon Management Feedstocks

Industries under the carbon management umbrella, though they all aim to sequester carbon, utilize different feedstocks and produce varied byproducts of capture. For biomass with carbon dioxide removal or biomass-to-energy with carbon capture and storage processes (collectively referred to as BiCRS, see Section 4), the feedstock is biomass. From an environmental perspective, the biomass source is ideally waste from existing agriculture or forest management practices. Examples specific to agriculture include plant residues (stalks, pits, shells) from harvest seasons, tree trimmings, or other discarded organic material. Obtaining BiCRS feedstocks from such sources solve two problems: they reduce the potential land and water use impacts of BiCRS that would result from producing dedicated feedstock crops, and they prevent the release of CO_2 that has already been trapped in that biomass material back to the atmosphere. Often, agricultural residues are left to decompose on the cropland,[28] releasing their carbon content as either methane (CH_4)

[24] Creech (August 3, 2021) Saving Money, Time and Soil. [14]
[25] Scharpe (January 11, 2020) Economics of no-till and cover crop; does it really pay off? [39]
[26] GeoPard Agriculture (no date) What types of sensors are used in precision agriculture? [17]
[27] GlobalNewsWire (February 12, 2020) Agricultural Sensors Market To Reach USD 2.56 Billion By 2026. [18]
[28] Lal (2005) World crop residues production and implications of its use as a biofuel. [26]

or CO_2 into the atmosphere, or are they burned.[29] The latter technique, common in orchards and vineyards, also releases air pollutants like SO_2, nitrous oxides, and particulate matter,[30] and are a particular health hazard to the regional community.[31]

In Kern County in 2021, 482,000 tons of almond hulls, almond shells and crop biomass were produced.[32] From 2000-2020, between 200,000 and 1,200,000 tons of agricultural waste were burned in the San Joaquin Valley each year.[33] The variation is due to increasing burn prohibitions from 2003-2011, which were relaxed over the following decade in response to drought-related fallowing of croplands. In 2021, the California Air Resources Board (CARB) renewed their plan to phase out agricultural burning entirely by 2024,[34] meaning disposal alternatives will be required for the region's agricultural waste. Currently, CARB is offering a grant program that incentivizes 'whole orchard recycling' as an alternative to burning.[35,36] Whole orchard recycling involves the chipping and grinding of waste material, which is then re-incorporated into the soil. It has the advantage of restoring soil nutrients, but may still release greenhouse gasses to the atmosphere as it decomposes into the soil. Another disadvantage is that it is a tax-funded program that may not run indefinitely. A more ideal solution to agricultural waste removal is identifying a buyer, for which BiCRS industries would be strong candidates.

Based on the average amount of carbon in organic feedstocks (~49% by mass of the dry tonnage),[37] the agriculture waste in Kern County alone could produce as much as 860,000 metric tons of CO_2 for geologic storage, depending on the BiCRS technique applied. If all of the San Joaquin Valley's agricultural waste were used for carbon management (approximating from the maximum rate of annual burning), as much as 2 million metric tons of CO_2 could be produced for geologic storage.

11.2.2 Renewable Natural Gas (RNG)

Another industry that relies heavily on biomass inputs is the renewable natural gas (RNG) industry. RNG relies on capturing the biomethane released from decomposing biomass, which can then be captured and compressed for use as natural gas.[38] A wide variety of

[29] CARB (2021) San Joaquin Valley agriculture burning assessment. [6]

[30] Andini *et al.* (2018) Impact of crop residue burning on air pollution and climate change. [3]

[31] Vaughan, Klein (September 6, 2022) Smoke from ag burning contributes to long-term health effects. [46]

[32] Kern County Department of Agriculture and Measurement Standards (2022) 2021 Kern Agricultural Crop Report. [23]

[33] CARB (2021) San Joaquin Valley agriculture burning assessment. [6]

[34] CARB (no date) San Joaquin Valley agricultural burning phase down. [7]

[35] Mayer (September 10, 2022) The goal is to end open-field burning by growers. [29]

[36] Klein, Vaughan (September 8, 2021) As air regulators phase out ag burning, what's the alternative? [25]

[37] Baker *et al.* (2020) Getting to Neutral. p. 31. [4]

[38] Murillo (August 8, 2022) A RNG Facility Will Be Opening Soon in Lost Hills. [31]

biomass can be used for RNG—agriculture waste and dairy manure are the most relevant for this section, but waste from food, wastewater, and landfills can also be used for RNG.[39]

Over the last decade, RNG has already been making inroads within Kern County. The CalBioGas cluster in Kern County is a joint venture wherein local dairy farmers use onsite dairy digesters to capture methane (CH_4), which is then shipped to a central upgrading facility run by California BioEnergy and Chevron that converts the methane into RNG.[40] A company described in detail in the BiCRS section of this report (Section 4), San Joaquin Renewables, is planning to site its first waste biomass-to-RNG facility in McFarland and will be producing RNG alongside its plans to capture and sequester CO_2.[41] Once active, their RNG will be transported using pipelines from regional energy provider SoCalGas.[42] SoCalGas has been actively embracing RNG as an energy alternative, with nine RNG projects currently connected to their system.[43] By 2030, SoCalGas is aiming to have 20% RNG in the natural gas supply that it sends to core customers.[44] Given these recent and upcoming projects, it appears that there is substantial interest in future RNG expansion in Kern County.

A significant contribution to the enthusiasm for RNG comes from economic incentives – under California's Low Carbon Fuel Standard (LCFS) program, in effect until at least 2030, RNG can qualify for LCFS credits in any situation where RNG is replacing "conventional transportation fuel in California,"[45] significantly subsidizing the cost of production (see Section 4). But there are carbon management incentives worth considering as well.

Anaerobic digestors, which are a typical first step in the conversion of biomass waste (particularly livestock manure) to RNG, produce *biogas*, which is a mixture of methane, CO_2 and other trace gasses.[46] About 18-27% of livestock manure solids (dry weight) will be converted to biogas.[47] Biogas is then *upgraded* to produce RNG (Figure 11.1),[48] by stripping the CO_2 and other gasses, leaving pure biologically-derived methane that can serve as a drop-in replacement anywhere methane is used. The ratio of CO_2 to CH_4 in the biogas is about 30-40 mol% CO_2 and 60-70 mol% CH_4.[49] That means that for the 625,000 tons of

[39] Murillo (August 8, 2022) A RNG Facility Will Be Opening Soon in Lost Hills. [31]
[40] California Climate Investments (2021) Capturing Methane to Create Renewable Fuels in Kern County. [8]
[41] San Joaquin Renewables (no date) The Project. [38]
[42] San Joaquin Renewables (no date) The Project. [38]
[43] SEMPRA (February 24, 2022) RNG in SoCalGas Pipelines. [40]
[44] SEMPRA (February 24, 2022) RNG in SoCalGas Pipelines. [40]
[45] Psihoules, Toro, Gamache (December 8, 2021) LCFS credit for renewable natural gas. [37]
[46] Yentekakis, Goula (2017) Biogas management. [48]
[47] PennState Extension (March 12, 2012) Biogas from manure. [36] ~15% of livestock manure are solids. Of those, 91% are volatile (can be converted to biogas), and conversion efficacy is 20-30%.
[48] IEA (no date) Introduction to biogas and methane. [21]
[49] Yentekakis, Goula (2017) Biogas management. p. 3. [48]

livestock manure produced by Kern County in 2021,[50] about 150,000 tons of biogas can be produced, which can be separated into about 4 million cubic feet of RNG as well as 85,000 tons of CO_2 for geologic storage.[51]

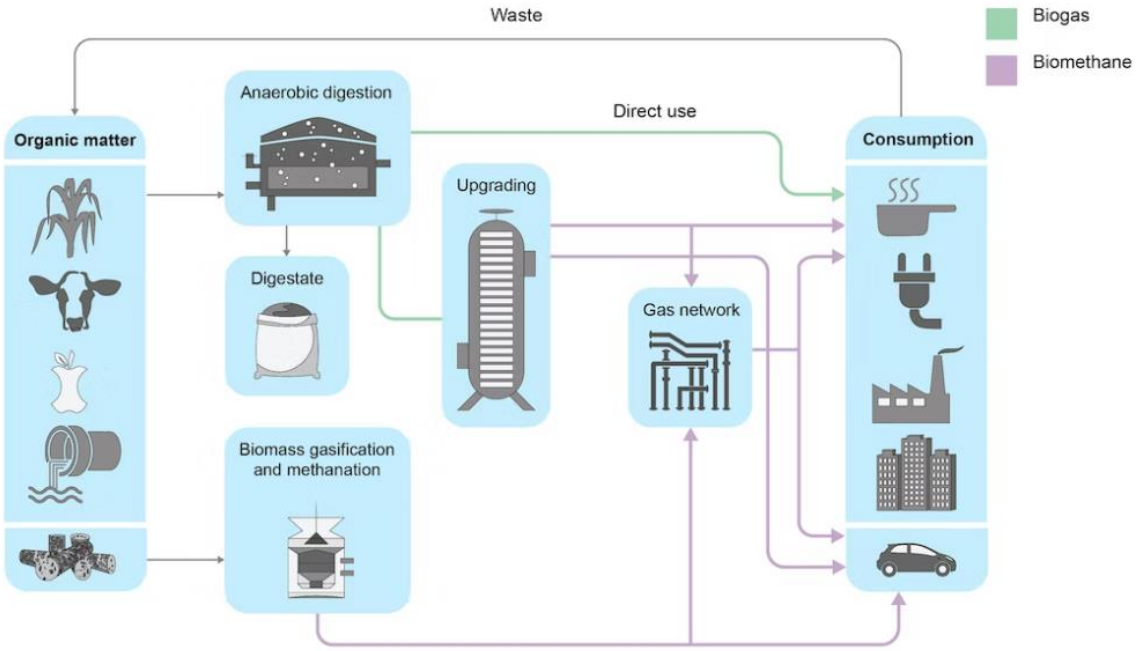


Figure 11.1. Schematic of RNG production. Image credit: International Energy Agency (IEA).[52]

11.2.2 Carbon Management Byproducts as Agricultural Supplements

Some BiCRS process used to convert biomass also generate useful byproducts for agriculture. For example, biomass processed via pyrolysis and gasification produces biochar, a soil additive that can support soil microorganisms, mitigate heavy metal toxicity, and raise soil pH.[53,54] Biochar can often be applied in place of traditional fertilizers, which has downstream benefits for the environment, as it prevents nitrogen runoff into

[50] Kern County Department of Agriculture and Measurement Standards (2022) 2021 Kern Agricultural Crop Report. [23] (Note: we are assuming dry tons. This is not explicitly stated in the report, but is consistent with the fraction of California's livestock farms located in Kern County and the state-wide dairy manure biomass estimate in Baker *et al.* (2020) Getting to Neutral. p. 32., which is listed in bone-dry tons.)

[51] Assumptions made in this calculation: Livestock manure was reported as dry tons, conversion factor to biogas is 25%, molar ratio of CO_2 to CH_4 is 30%:70%, 1 metric ton of methane at atmospheric pressure is 57,800 cubic feet.

[52] IEA (no date) Introduction to biogas and methane. [21]

[53] ARS (no date) What is Pyrolysis? [2]

[54] ARS (no date) Exploring the Benefits of Biochar. [1]

waterways and the release of excess nitrous oxide (N_2O) into the atmosphere—a greenhouse gas that warms the planet 300 times as much as CO_2.[55]

Additionally, some biomass gasification processes and S-DAC facilities generate water as a byproduct. The biomass gasification for San Joaquin Renewables uses local wood waste and nut shells to generate water along with biochar, renewable natural gas (RNG), and CO_2 for sequestration.[56] Clean Energy Systems, which has an existing test facility at Kimberlina in Kern County,[57] and purchased the idle Delano biomass facility, also in Kern, with plans to develop it into a BiCRS facility (still in the pre-permitting and assessment phase),[58] also produces water as a byproduct of their oxy-fuel combustion system (Section 4). Though utilizing an entirely different process, Climeworks' solid direct air capture (S-DAC) system also generates water alongside CO_2, generating 0.8-2 tons of water per ton of CO_2 captured.[59]

11.3 Other Collaborative Opportunities

11.3.1 Multi-Use Potential

Another potential opportunity for symbiosis between regional agriculture and carbon management industries is to share resources—primarily land, but potentially water as well—with local agriculture.

If water resources become increasingly scarce and farmers are being required by new groundwater policies to make decisions to permanently fallow unproductive land, then land could be rented or sold to carbon management companies, who may have large land use requirements to operate facilities (especially if they rely on solar power). In this arrangement, the land would continue to be profitable through the rents paid. Additional funding could be raised if farmers sold water to carbon management industries to operate. Some companies in the green energy and carbon management space are explicitly looking for landowners to partner with to deploy their processes, including NovoHydrogen, a company planning to develop local hydrogen fuels without degrading the land,[60] and InterEarth, looking for sites appropriate for their direct biomass burial method.[61]

Some technologies hold the promise of being able to operate with high mobility or to be decentralized, with nodal facilities spread out over large areas. In terms of high mobility, one example is Charm Industrial—their biomass pyrolyzer equipment can fit in the back of

[55] Manthiram, Gribkoff (July 15, 2021) Explainer - Fertilizer and Climate Change. [28]
[56] San Joaquin Renewables (no date) The Project. [38]
[57] Clean Energy Systems (no date) Site Locations. [12]
[58] Cox (December 4, 2021) Idle biomass plant near Delano would reopen. [13]
[59] Lebling *et al.* (May 2, 2022) 6 Things to Know About Direct Air Capture. [27]
[60] NovoHydrogen (no date) Partner with Us. [33]
[61] InterEarth (no date) For Farmers. [20]

a semi-trailer and can be driven directly to a site, so biomass doesn't have to be transported to a central processing facility.[62] Charm also pays farmers to be able to collect their biomass, and their unit can be temporarily stationed on the edge of a field during harvest season, when there is an abundance of waste biomass, and then offsite the rest of the year.[63] In terms of diffuse land use, direct air capture (DAC) is a prime example of technology that works well spread out across the land. Although DAC contactors can be placed anywhere (see Section 3), there is likely a minimum spacing of several hundred yards between contactors, to ensure the CO_2-free exhaust of one contactor fan does not directly feed into the next.[64] The space between contactors could be used for other land-intensive purposes, like farming or solar panels. However, there are uncertainties about how well crops would handle growing in between units that absorb CO_2 from the atmosphere, as plants also need to absorb CO_2 from the atmosphere to grow successfully.[65] This issue warrants further investigation.

11.3.2 Greenhouses

Greenhouses are experiencing a period of growth in California, driven primarily by drought conditions and an increasing consumer demand for organic and locally-grown produce.[66] This is because greenhouses promote higher productivity, even in less optimal environments: farming can take place on a smaller land footprint with lower water usage while still obtaining high crop yields.[67] Innovations like UC Santa Cruz's solar greenhouse, which uses transparent solar panels to filter light and help offset operational costs, are working towards the development of greenhouses that could be used "in most of California" rather than just along the coast.[68] Although these developments are still in pre-commercial stages, it presents another opportunity for the long-term future of agriculture in Kern County and California at large.

If greenhouses were implemented in Kern County, some of the CO_2 captured by carbon management industries could be supplied to the greenhouses to encourage plant growth. CO_2 must be very pure to not damage the plants,[69] but increasing the CO_2 concentration of the ambient air inside greenhouses can increase yields of some crops by up to 25-30% with CO_2 application.[70] Typically, greenhouses obtain CO_2 from combustion of natural gas, which also serves as a heat source for the facility. A retrofitted oil pipeline in the

[62] Temple (May 26, 2022) Charm Industrial's big bet. [43]
[63] Temple (May 26, 2022) Charm Industrial's big bet. [43]
[64] Herzog (February 4, 2021) Direct air capture: A process engineer's view. 16:05-16:34. [19]
[65] Ontario Ministry of Agriculture, Food, and Rural Affairs (August 2009) Carbon Dioxide in Greenhouses. [35]
[66] Murdock (July 23, 2018) Solar Greenhouse. [30]
[67] Murdock (July 23, 2018) Solar Greenhouse. [30]
[68] Murdock (July 23, 2018) Solar Greenhouse. [30]
[69] IEA (2019) Putting CO_2 to Use. [22]
[70] IEA (2019) Putting CO_2 to Use. [22]

Netherlands spanning over 180 miles demonstrates a viable alternative: the pipeline supplies 500,000 metric tons of CO_2 annually (captured from hydrogen production) to over 600 greenhouses in the region, and without the need of producing CO_2 from natural gas combustion, the greenhouses are able to switch to more sustainable heat sources.[71]

11.3.3 Other Potential Opportunities

This report is not comprehensive. There are other opportunities in the agribusiness space that may work symbiotically with carbon management technologies but were not identified to be good fits for Kern County at this time, and thus were not explored further here, although some examples are discussed in greater detail in other sections of the report. These include developing dedicated biomass crops to sustain BiCRS operations (also addressed in Section 3) or using CO_2 to promote algae growth to generate petroleum substitutes[72] (also addressed in Section 10).

A proposed component of the Carbon Management Business Park is a dedicated Research and Development Incubator, which would be an ideal setting for the exploration of new ways that local agriculture and carbon management industries could serve one another.

[71] OCAP (no date) Factsheet: Pure CO2 for Greenhouses. [34]

[72] IEA (2019) Putting CO_2 to Use. [22]

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Appendices

Appendix A. Existing commercial and industrial power facilities with CCS

Appendix B. Commercial and industrial power facilities with CCS in advanced development

Appendix C. Commercial and industrial power facilities with CCS in early development

Appendices A-C are summarized from the Global CCS Institute (GCCSI) CO_2RE Facilities Database, a list of all historical, active, and developing carbon-capture related projects worldwide. The database is maintained, and updated regularly to reflect status updates and new projects. The lists represented by Appendices A-C represent the status of the global carbon management industry as of the publication of this report. The database was sampled for this report on March 18, 2023.[1]

Appendix D. Comparative analysis of carbon management industries

A primary objective of this report is to provide an accessible resource for cost-benefit analysis of a variety of carbon management technologies that could hypothetically be developed in Kern County. We developed quantitative estimates of 6 key metrics across all 5 carbon management technologies examined in detail (L-DAC, S-DAC, BiCRS, green hydrogen from biomass, and steel with point source carbon capture):

- Land use
- Energy use
- Water use
- Job growth potential
- Cost to build (a proxy for potential county tax revenue)

[1] Global CCS Institute (GCCSI). CO_2RE Facilities Database. Published (no date). Accessed March 18, 2023 from https://co2re.co/FacilityData.

- Cost per ton CO_2 (a reflection of the competitiveness of the industry in the emerging carbon market)

Details of how each estimate was determined is given in the relevant section of the report, but how each industry compares with each other across these six metrics is shown visually in Appendix D across a suite of Figures D.1- D.6. The same figures are provided in the Comparative Analysis section of the companion website, at cmbp.kernplanning.com.

Appendix A. Existing commercial and industrial power facilities with CCS

Facility Name	Country	Operational	Industry
Terrell Natural Gas Processing Plant (formerly Val Verde)	USA	1972	Natural gas processing
Enid Fertilizer	USA	1982	Fertilizer production
Shute Creek Gas Processing Plant	USA	1986	Natural gas processing
MOL Szank field CO2 EOR	Hungary	1992	Natural gas processing
Sleipner CCS Project	Norway	1996	Natural gas processing
Great Plains Synfuels Plant and Wayburn-Midale	USA	2000	Chemical production
Core Energy	USA	2003	Natural gas processing
In Salah CO2 Storage	Algeria	2004	Natural gas processing
Petrobras Santos Basin Pre-Salt Oil Field	Brazil	2008	Natural gas processing
Snohvit CO2 Storage	Norway	2008	Natural gas processing
Arkalon CO2 Compression Facility	USA	2009	Ethanol production
Century Plant	USA	2010	Natural gas processing
Bonanza BioEnergy	USA	2012	Ethanol production
Yanchang Integrated CCS Demonstration	China	2012	Chemical production
Air Products Steam Methane Reformer	USA	2013	Hydrogen production
Coffeyville Gasification Plant	USA	2013	Fertilizer production
Lost Cabin Gas Plant	USA	2013	Natural gas processing
PCS Nitrogen	USA	2013	Fertilizer production
Boundary Dam Unit 3	Canada	2014	Power plant - coal
Karamay Dunhua Oil Technology	China	2015	Chemical production (Methanol)
Quest	Canada	2015	Hydrogen production
Uthmaniyah CO2-EOR Demonstration	Saudia Arabia	2015	Natural gas processing
Abu Dhabi CCS (Emirates Steel Industries)	UAE	2016	Iron/steel production
Illinois Industrial Carbon Capture and Storage	USA	2017	Ethanol production
Petra Nova Carbon Capture	USA	2017	Power plant - coal
CNPC Jilin Oil Field CO2 EOR	China	2018	Natural gas processing
Gorgon Carbon Dioxide Injection	Australia	2019	Natural gas processing
Qatar LNG	Qatar	2019	Natural gas processing
Alberta Carbon Trunk Line (ACTL) - Nutrien	Canada	2020	Fertilizer production
Alberta Carbon Trunk Line (ACTL) - Sturgeon Refinery	Canada	2020	Hydrogen production
Guohua Jinjie	China	2020	Power plant - coal
Orca	Iceland	2021	Direct air capture
Glacier Gas Plant	Canada	2022	Natural gas processing
Red Trail Energy	USA	2022	Ethanol production
Sinopec Qilu-Shengli CCUS	China	2022	Chemical production

Appendix B.

Commercial and industrial power facilities with CCS in advanced development

Facility Name	Country	Operational	Industry
Stockholm Exergi BECCS	Sweden	2025	BiCRS/BECCS
HeidelbergCement	USA	2023	Cement production (incl. lime)
Norcem Brevik Cement Plant	Norway	2024	Cement production (incl. lime)
Antwerp@C - BASF Antwerp	Belgium	2030	Chemical production
Lake Charles Methanol	USA	2025	Chemical production
Farley DAC	USA		Direct air capture
Mammoth	Iceland	2024	Direct air capture
Occidental, 1PointFive	USA	2024	Direct air capture
Aberdeen Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Atkinson Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Bushmills Biorefinery CCS	USA	2024	Ethanol production
Casselton Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Central City Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Fairmont Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Federated Co-operatives Limited	Canada	2024	Ethanol production
Galva Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Goldfield Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Grand Junction Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Granite Falls Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Heron Lake Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Huron Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Lamberton Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Lawler Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Marcus Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Mason Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Merrill Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Mina Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Nevada Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Norfolk Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
One Earth Energy facility	USA	2025	Ethanol production
Onida Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production

Facility Name	Country	Operational	Industry
Otter Tail Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Plainview Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Project Interseqt - Plainview Ethanol Plant	USA	2024	Ethanol production
Redfield Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Shenandoah Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Sioux Center Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Steamboat Rock Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Superior Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Watertown Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Wentworth Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Wood River Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
York Biorefinery Carbon Capture and Storage	USA	2024	Ethanol production
Wabash CO2 Sequestration	USA	2022	Fertilizer production
Air Liquide Refinery Rotterdam	Netherlands	2024	Hydrogen production
Air Products Net-Zero Hydrogen Energy Complex	Canada	2024	Hydrogen production
Air Products Refinery Rotterdam	Netherlands	2024	Hydrogen production
Baytown Low Carbon Hydrogen	USA	2027	Hydrogen production
Cliff Head CCS Project (Mid West Clean Energy Project)	Australia	2025	Hydrogen production
ExxonMobil Benelux Refinery	Netherlands	2024	Hydrogen production
Phillips 66 Humber Refinery	UK	2028	Hydrogen production
Polaris Carbon Storage	Norway	2024	Hydrogen production
Shell Refinery Rotterdam CCS	Netherlands	2024	Hydrogen production
Louisiana Clean Energy Complex	USA	2026	Hydrogen production
Federated Co-operatives Limited	Canada	2026	Hydrogen production (Oil refining)
Prax Lindsey Carbon Capture Project	UK	2028	Hydrogen production (Oil refining)
Abu Dhabi CCS (Natural gas processing plant)	UAE	2025	Natural gas processing
Bayu-Undan CCS	Timor-Leste	2027	Natural gas processing
Ghasha Concession Fields	UAE	2025	Natural gas processing
Lang Lebah	Malaysia	2026	Natural gas processing
Northern Delaware Basin	USA	2023	Natural gas processing
PTTEP Arthit	Thailand	2026	Natural gas processing
Guodian Taizhou Power Station	China	2023	Power plant - coal
Cal Capture	USA	Mid-2020's	Power plant - NG
Capital Power Genesee	Canada	2026	Power plant - NG

Facility Name	Country	Operational	Industry
Coyote Clean Power Project	USA	2025	Power plant - NG
Deer Park Energy Centre	USA		Power plant - NG
James M. Barry Electric Generating Plant	USA	2030	Power plant - NG
Mustang Station of Golden Spread Electric Cooperative	USA		Power plant - NG
Peterhead CCS Power Station	United Kingdom	2026	Power plant - NG
Plant Daniel Carbon Capture	USA		Power plant - NG
VPI Immingham power plant	United Kingdom	2027	Power plant - NG
Acorn Storage Site	United Kingdom	2025	Infrastructure
Bayou Bend CCS	USA	2025	Infrastructure
Bridgeport Energy Moonie CCUS Project	Australia	2023	Infrastructure
CODA Shipping	Iceland	2026	Infrastructure
CODA Terminal Onshore Infrastructure	Iceland	2026	Infrastructure
CODA Terminal Pipeline	Iceland	2026	Infrastructure
CODA Terminal Storage	Iceland	2026	Infrastructure
East Coast Cluster	United Kingdom	2025	Infrastructure
East Coast Cluster Humber Pipeline	United Kingdom	2025	Infrastructure
East Coast Cluster Teesside Pipeline	United Kingdom	Mid-2020's	Infrastructure
Endurance Storage Site	United Kingdom	2025	Infrastructure
Porthos - Compressor Station	Netherlands	2024	Infrastructure
Porthos - Offshore Pipeline	Netherlands	2024	Infrastructure
Porthos Storage	Netherlands	2025	Infrastructure
Project Greensand	Denmark	2025	Infrastructure
Prothos - Onshore Pipeline	Netherlands	2024	Infrastructure
Southeast Saskatchewan CCUS Hub - Storage	Canada		Infrastructure
Stockholm Exergi BECCS - Shipping Route	Sweden	2025	Infrastructure
Summit Pipeline	USA	2024	Infrastructure
Viking CCS Pipeline	United Kingdom	2027	Infrastructure
Viking CCS Storage Site	United Kingdom	2027	Infrastructure
Norcem Brevik - Shipping Route	Norway	2024	Infrastructure
Northern Lights - Storage	Norway	2024	Infrastructure
Copenhill (Amager Bakke)	Denmark	2025	Waste-to-energy
Hafslund Oslo Celsio-Truck Route	Norway	2025	Waste-to-energy
Hafslund Oslo Celsio	Norway	2024	Waste-to-energy

Appendix C.

Commercial and industrial power facilities with CCS in early development

Facility Name	Country	Operational	Industry
Clean Energy Systems BiCRS Plant - Madera County	USA	2027	BiCRS/BECCS
Clean Energy Systems Carbon Negative Energy Plant	USA	2025	BiCRS/BECCS
Cyclus Power Generation	USA		BiCRS/BECCS
Drax BECCS Project	UK	2027	BiCRS/BECCS
Mendota BECCS	USA	2025	BiCRS/BECCS
Air Liquide CalCC	France	2028	Cement production
CEMEX	Germany	2026	Cement production
GO4ECOPLANET	Poland		Cement production
HyNet North West - Hanson Cement	UK	2026	Cement production
K6	France		Cement production
LafargeHolcim Cement Carbon Capture	USA	Mid-2020's	Cement production
LafargeHolcim Ste. Genevieve Cement Plant	USA		Cement production
Antwerp@C - Borealis Antwerp	Belgium	2030	Chemical production
Antwerp@C - Exxonmobil Antwerp Refinery	Belgium	2030	Chemical production
Antwerp@C - Ineos Antwerp	Belgium	2030	Chemical production
Hackberry Carbon Sequestration Project (Sempra)	USA		Chemical production
The Illinois Clean Fuels Project	USA	2025	Chemical production
Velocys' Bayou Fuels Negative Emission Project	USA	2026	Chemical production
Nauticol Energy Net Zero Methanol	Canada	Mid-2020's	Chemical production (Methanol)
Acorn Direct Air Capture Facility	UK	2026	Direct air capture
FS Lucas do Rio Verde	Brazil		Ethanol production
Midwest AgEnergy Blue Flint Ethanol	USA	2022	Ethanol production
Project Interseqt - Hereford Ethanol Plant	USA	2023	Ethanol production
Barents Blue	Norway	Mid-2020's	Fertilizer production
CF Fertilisers Billingham Ammonia CCS	UK	2023	Fertilizer production
El Dorado	USA	2024	Fertilizer production
ExxonMobil Donaldsonville	USA	2025	Fertilizer production
PAU Central Sulawesi Clean Fuel Ammonia Production	Indonesia	Mid-2020's	Fertilizer production
Project Pouakai Hydrogen Production	New Zealand	2024	Fertilizer production
Yara Sluiskil	Netherlands	2025	Fertilizer production
Acorn Hydrogen	UK	2025	Hydrogen production
Air Liquide Normandy CCS	France	2025	Hydrogen production
Buxton Lime Net Zero	UK	2024	Hydrogen production
H2NorthEast	UK	2027	Hydrogen production
Hydrogen 2 Magnum	Netherlands	2024	Hydrogen production
Hydrogen to Humber Saltend	UK	2027	Hydrogen production

Facility Name	Country	Operational	Industry
HyNet Hydrogen Production	UK	2025	Hydrogen production
HyNet North West	UK	Mid-2020's	Hydrogen production
Killinholme Power Station	UK	2027	Hydrogen production
L10 Carbon Capture and Storage	Netherlands	2026	Hydrogen production
Net Zero Teesside	UK	2027	Hydrogen production
Northern Gas Network H21	UK	2026	Hydrogen production
Polaris CCS	Canada	Mid-2020's	Hydrogen production
Preem Refinery	Sweden	2025	Hydrogen production
Project Pouakai Hydrogen Production	New Zealand	2024	Hydrogen production
Zeeland Refinery Azur	Netherlands	2026	Hydrogen production
Sukowati CCUS	Indonesia	2028	Hydrogen production (Oil refining)
Vertex Hydrogen	UK	2025	Hydrogen production (Oil refining)
ArcelorMittal Texas (formerly voestalpine Texas)	USA		Iron/steel production
Caroline Carbon Capture Power Complex	Canada	Mid-2020's	Natural gas processing
G2 Net-Zero LNG	USA		Natural gas processing
Grand Forks Blue Ammonia Capture plant	USA		Natural gas processing
INPEX CCS Project Darwin	Australia	2026	Natural gas processing
NextDecade Rio Grande LNG	USA	2025	Natural gas processing
Novatek Yamal LNG	Russia	Late 2020's	Natural gas processing
Otway Natural Gas Plant	Australia	2026	Natural gas processing
Repsol Sakakemang Carbon Capture and Injection	Indonesia	2026	Natural gas processing
South East Australia Carbon Capture Hub	Australia	2025	Natural gas processing
Dave Johnston Plant	USA	2020's	Power plant - coal
Diamond Vault CCS	USA	2028	Power plant - coal
Dry Fork Integrated CCS	USA	2025	Power plant - coal
Korea-CCS 1&2	South Korea	2020's	Power plant - coal
Caledonia Clean Energy	UK	2025	Power plant - NG
Caroline Carbon Capture Power Complex	Canada	Mid-2020's	Power plant - NG
Damhead Powerstation	UK		Power plant - NG
Ervia Cork CCS	Ireland	2028	Power plant - NG
Illinois Allam-Fetvedt cycle power plant	USA	2025	Power plant - NG
Keady 3 CCS Power Station	UK	2027	Power plant - NG
Medway Power Station	UK		Power plant - NG
Net Zero Teesside - NET Power Plant	UK	Mid-2020's	Power plant - NG
Net Zero Teesside CCGT Facility	UK	2025	Power plant - NG
Pembroke Power Station	UK	2030	Power plant - NG
Project Pouakai Hydrogen Production	New Zealand	2024	Power plant - NG
Saskatchewan NET power plant	Canada	Mid-2020's	Power plant - NG
Whitetail Clean Energy	UK		Power plant - NG

Facility Name	Country	Operational	Industry
Cane Run CCS	USA		Power plant - NG
Acorn	UK	Mid-2020's	Infrastructure
Acorn CO2 Pipeline	UK	2026	Infrastructure
Arun CCS Hub	Indonesia	2029	Infrastructure
Borg CO2	Norway		Infrastructure
Burrup CCS Hub	Australia		Infrastructure
Carbon TerraVault I	USA	2025	Infrastructure
Cinfracap - Pipeline	Sweden	2026	Infrastructure
Cinfracap - Shipping Route	Sweden	2026	Infrastructure
Coastal Bend CCS	USA	2026	Infrastructure
Damhead Pipeline	UK		Infrastructure
Delta Corridor Pipeline Network	Netherlands	2026	Infrastructure
Fortum Oslo Varme - Shipping Route	Norway	2025	Infrastructure
Heartland Greenway Storage	USA	2025	Infrastructure
HyNet Pipeline	UK	2025	Infrastructure
Hynet Storage Site	UK	2025	Infrastructure
Isle of Grain LNG Terminal	UK	2026	Infrastructure
Jubail CCS	Saudia Arabia	2027	Infrastructure
Medway Hub - Esmond and Forbes Carbon Storage	UK		Infrastructure
Medway Hub Shipping	UK		Infrastructure
Northern Lights - Pipeline	Norway	2024	Infrastructure
Origins Project Carbon Storage Hub	Canada	2026	Infrastructure
Ravenna CCS Hub	Italy	2027	Infrastructure
River Bend CCS Louisiana Pipeline	USA	2026	Infrastructure
Net Zero Teesside	UK	2027	Waste-to-energy
Runcorn Carbon Capture	UK		Waste-to-energy
Tees Valley Energy Recovery Facility Project	UK	2026	Waste-to-energy

Appendix D.
Comparative analysis of carbon management industries

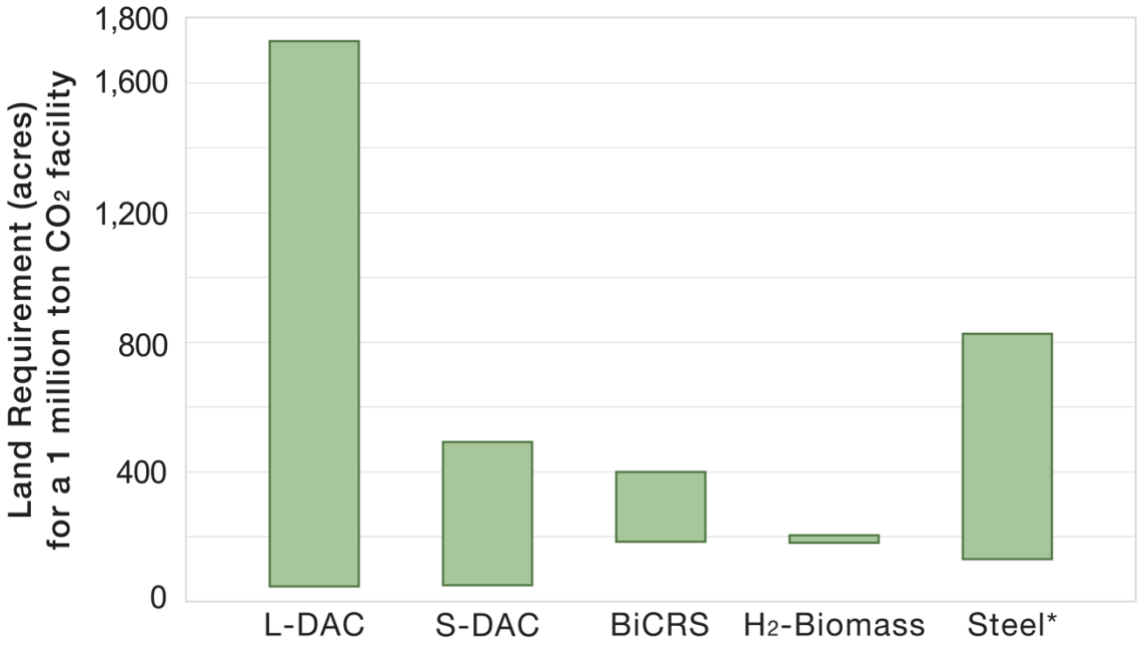


Figure D.1. Land Use. To capture 1 million metric tons of CO_2, the land use requirements of facilities vary considerably. Across the examined industries, estimated footprints range from 0.08 to 2.73 square miles (49-1730 acres). In cases where there is not an operational facility with the capacity to capture carbon at the million ton scale (L-DAC, S-DAC and green hydrogen from biomass) these footprints are industry-provided estimates of needed space. For established industries (steel and BiCRS), the range of values reflects the variability of existing facility footprints, most of which are not actively capturing CO_2. The range in land use is mostly due to availability and affordability of land, and the retrofitting of these types of facilities with carbon capture equipment would likely not result in a significant change in areal footprint. *A steel facility of the size modeled here could produce up to 1 million tons of CO_2, but it depends on the source of iron and type of energy used.

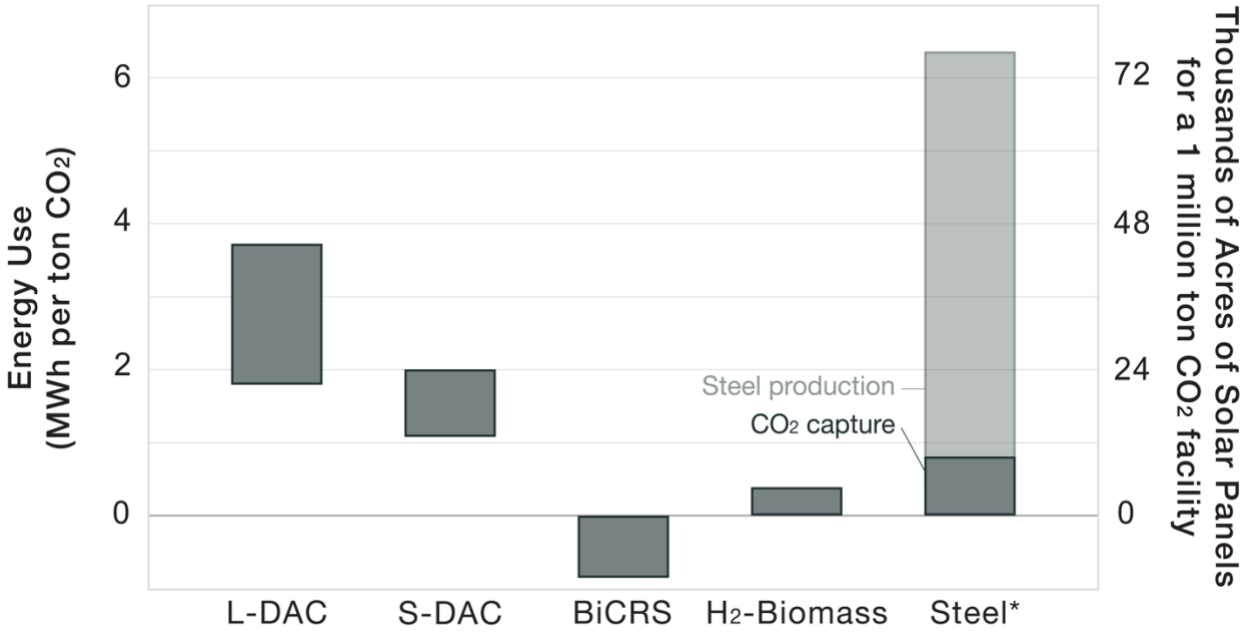


Figure D.2. Energy Use. Most carbon management industries (L-DAC, S-DAC, green hydrogen from biomass, and steel) are energy intensive, requiring both electricity and heat energy. DAC technologies require the largest amounts of energy per ton of CO_2 captured, whereas most of the energy demand for steel goes into steel production (the light shaded region) rather than CO_2 capture (the dark shaded region). Green hydrogen from biomass is less energy-intensive, and like steel, the energy needs also generate a different primary output: production of H_2 gas. Other forms of BiCRS (including BECCS) generate more energy than they consume, and are thus able to power their own production, with some facilities also selling energy to the grid. As a result, BiCRS facilities do not require an external energy supply unless it is more profitable to sell their output (i.e. biofuel, syngas) than to use it to operate the facility. An additional critical factor to note is that any facility using solar PV for their energy needs will also require electricity and heat storage (batteries) to ensure uninterrupted supply of electricity and that heat is provided at the required temperatures (100-1000°C, depending on industry). *A steel facility of the size modeled here could produce up to 1 million tons of CO_2, but it depends on the source of iron and type of energy used. The more power supplied by solar energy, the less CO_2 the steel mill would produce.

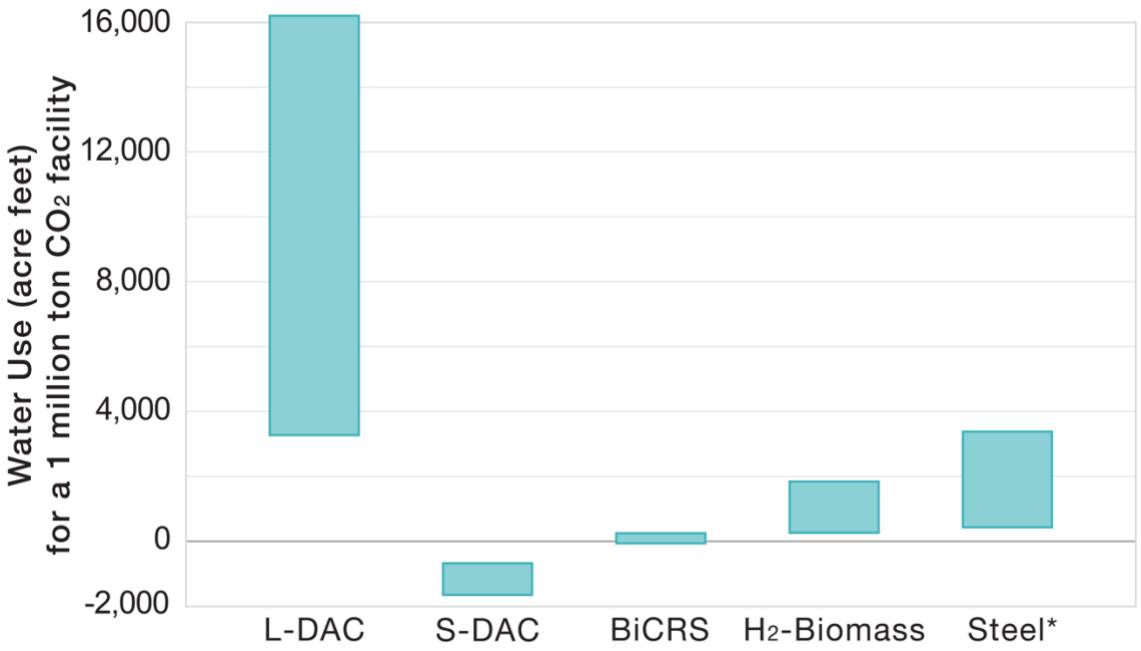


Figure D.3. Water Use. Water use is one of the most variable categories across carbon management industries. Hydrogen production via biomass, steel and particularly L-DAC technologies are water-intensive practices, using as much as 16,200 acre feet of water annually. Meanwhile, BiCRS and S-DAC technologies can actually generate excess water by capturing it from biomass feedstocks or the atmosphere. This water yield depends on the specific process a facility uses, but could be as much as 1,650 acre feet annually. Due to the arid environment in large parts of Kern County, mindfulness about the water intensity of these industries is crucial to ensure supplies can continue to meet a mixture of residential, agricultural, and industrial demands for decades to come. *A steel facility of the size modeled here could produce up to 1 million tons of CO_2, but it depends on the source of iron and type of energy used.

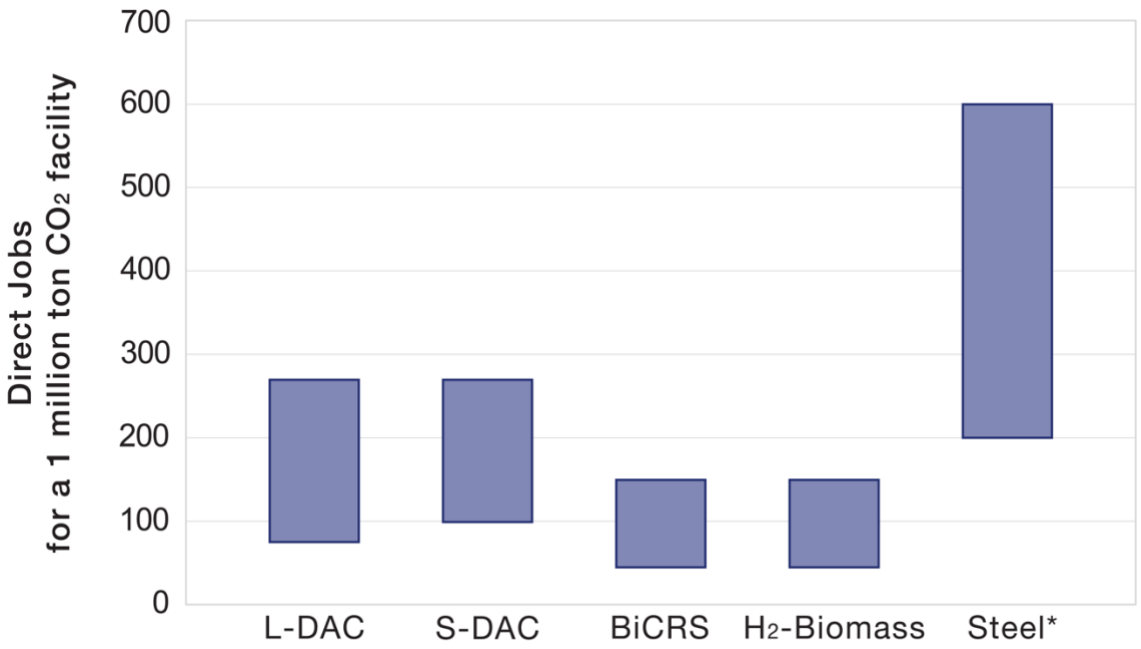


Figure D.4. Job Development Potential. The job growth potential of carbon management facilities can be difficult to quantify, as different companies rely on different processes—even within the same industry—that shapes their labor demands. Industries like BiCRS and hydrogen production via biomass expect to have lower labor demands, similar to that required to operate bioenergy power plants that do not utilize carbon capture. L-DAC and S-DAC have larger expected labor demands, mainly to monitor and maintain contactor units, although it is possible that some of these jobs could be performed remotely, and would not necessarily benefit the host community. Steel is likely to provide the most jobs. It is important to note that job growth potential for many of these industries was determined from the number of jobs at smaller facilities, and because the need for workers does not scale linearly with facility size, these are rough estimates. Furthermore, the possibilities of increased automation and remote monitoring means that steps should be taken in the planning and permitting process to ensure jobs for any new carbon management facility benefits local communities. *A steel facility of the size modeled here could produce up to 1 million tons of CO_2, but it depends on the source of iron and type of energy used.

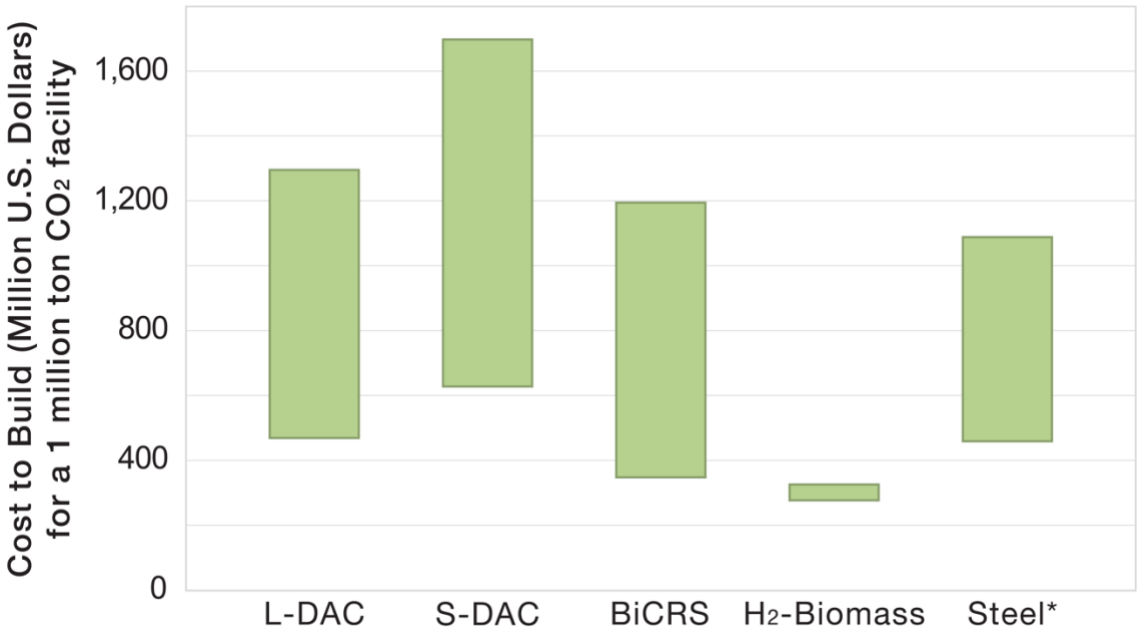


Figure D.5. Cost to Build. Building a new carbon management site comes with considerable expense—securing land, planning, engineering, permitting and zoning, environmental assessments, and other details will need to be handled before construction even begins. Across all of these carbon management industries, upfront costs range from $278 million to 1.7 billion. Costs are generally expected to be higher for the direct air capture industries (L-DAC and S-DAC) than for the biomass-based hydrogen production, BiCRS and steel facilities. However, many of these industries have never been built at a scale that could capture 1 million metric tons of CO_2 per year, which accounts for the large ranges of uncertainty in their upfront costs. *A steel facility of the size modeled here could produce up to 1 million tons of CO_2, but it depends on the source of iron and type of energy used.

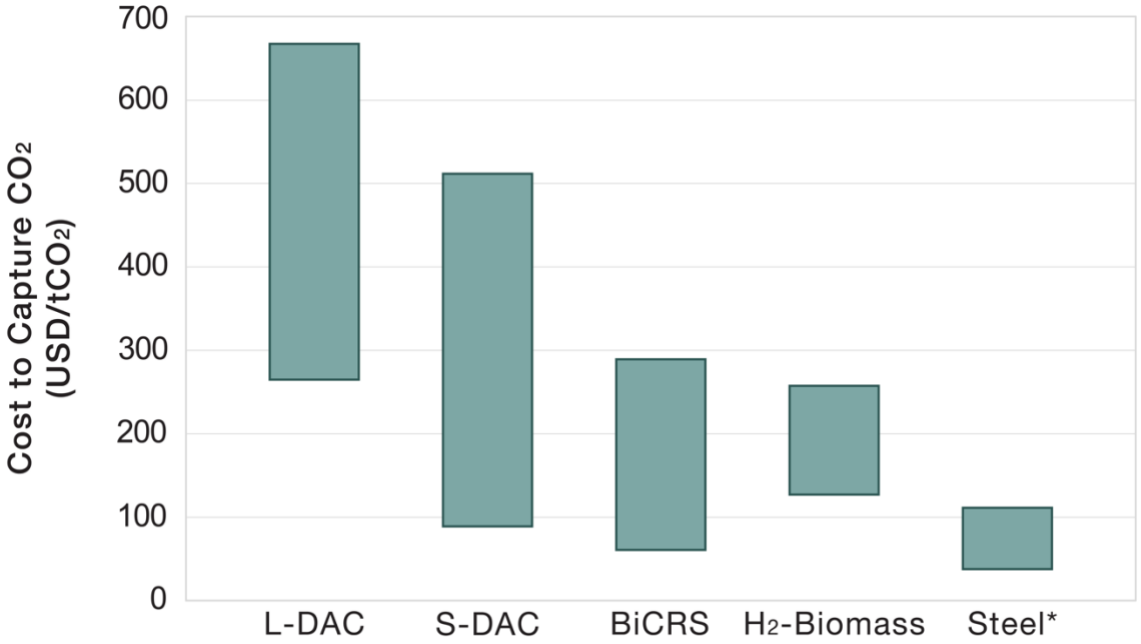


Figure D.6. Cost to Capture. The levelized cost per metric ton of CO_2 is a good way to consider overall costs—it accounts for the cost of building the facility (capital costs), the cost of maintenance and labor (operational costs), and the cost of energy (heat + electricity) over the lifetime of the plant. In these estimates, the plant lifetime has been fixed at 30 years to standardize estimates, though some of these facilities may have longer or shorter lifetimes. The cost of carbon capture is lowest for steel emissions, given the relatively high concentration of CO_2 in exhaust gases from this kind of facility, as well as the maturity of the technology. Biomass-based carbon capture (BiCRS or biomass hydrogen production) also generally have lower levelized cost estimate ranges than direct air capture (L-DAC and S-DAC). However, it is worth noting that 1) all of these costs are likely to decrease as carbon capture technologies mature, and 2) which of these industries is economically viable depends both on the levelized cost and on the potential sources of revenue to recoup that cost, which varies across industries. *The cost to capture CO_2 for the steel facility only considers the cost of building and operating the capture equipment. It does not incorporate the capital and operational costs of the steel mill itself.



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ANALYSIS OF POTENTIAL FISCAL AND ECONOMIC BENEFITS OF KERN COUNTY CARBON MANAGEMENT INDUSTRY

Prepared for:

KERN COUNTY PLANNING AND NATURAL RESOURCES DEPARTMENT
AND
KERN COUNTY ADMINISTRATIVE OFFICE

Prepared by:

THE NATELSON DALE GROUP, INC.

Telephone: (714) 692-9596
Fax: (714) 692-9597
Web: www.natelsondale.com

April 4, 2023

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1.0 INTRODUCTION

This report evaluates the potential fiscal and economic benefits that would be created by the development of a carbon management industry in Kern County. Specifically, the report quantifies the direct fiscal and economic impacts of the proposed Carbon Management Business Park (CMBP), and the indirect impacts that would be generated by related firms that the CMBP would support elsewhere in Kern County.

1.1. Categories of Benefits Evaluated

The study considers the following categories of fiscal and economic benefits:

Fiscal Benefits

- Property tax revenue accruing to the County of Kern General Fund and Fire Fund
- Sales tax revenue accruing to the County of Kern General Fund
- Property tax revenue accruing to city General Funds
- Sales tax revenue accruing to city General Funds

Broader Economic Benefits

- Jobs created
- Payroll created
- Total business activity (the dollar volume of "output") supported

Given the undefined nature of the indirect (offsite) benefits of the CMBP, the study does not attempt to quantify potential benefits to individual/specific cities (since the specific locations of supported businesses are unknown). Instead, potential city-level benefits are shown as aggregate numbers (i.e., for all cities combined).

1.2. Profile of Business Types in CMBP

As conceived by the Kern County Planning and Natural Resources Department, the proposed CMBP would encompass 4,200 acres in unincorporated Kern County. Although a specific site has not been identified yet, it is anticipated that the park would be developed on agricultural land that would be rezoned for industrial uses and the location would generally be west of Interstate 5.

The assumed mix of carbon management and related activities within the CMBP is as follows:

Business Type (Carbon Capture Technology)	Area
Liquid Direct Air Capture (L-DAC)	400 acres
Solid Direct Air Capture (S-DAC)	500 acres
Biomass Carbon Removal and Storage (BiCRS)	600 acres
Green Hydrogen (H2)	600 acres
Steel Micro Mill	600 acres
Research & Development Incubator Site	500 acres
Administrative Offices + Ancillary Clean Energy Industries	1,000 acres
Total (with 31 million square feet of industrial building space)	4,200 acres

1.3. Overview of Study Scope and Methodology

In completing this study, The Natelson Dale Group, Inc. (TNDG) has relied on industry profiles (for each of the above business types) prepared by Blue Engine for the CMBP project. In particular, the Blue Engine team has quantified the following economic variables for each CMBP component:

- Permanent (operational) jobs
- Operations and maintenance costs
- Capital costs

Blue Engine has also provided general descriptions of the types of carbon capture businesses that might be the "tenants" within each component of the park. From these descriptions, TNDG has selected specific industries (i.e., NAICS codes) representative of these business types for purposes of evaluating the projects fiscal and economic impacts.

The direct property tax impacts of the CMBP have been estimated by TNDG based on projected land re-assessment (from converting the underlying land from agricultural and industrial uses) plus anticipated improvement costs (based on the Blue Engine data). Indirect property taxes (i.e., from offsite businesses that would be developed as part of a countywide carbon management industry anchored by the CMBP) have been estimated using the IMPLAN model[1].

The IMPAN model has also been used to estimate direct and indirect sales tax revenue, as well as broader economic impacts such as job creation, payroll, and supported countywide business activity.

Due to the somewhat speculative nature of the CMBP (composed of industries that in many cases are still in early stages of development globally), the Blue Engine research is understood to provide general/

[1] This model was developed by researchers at the University of Minnesota and is widely used in economic impact analysis throughout the Country. This software is classified as an "Input-Output" (IO) model that computes all of the economic impacts of industries in a user-defined region (in this case, Kern County), including the estimated local expenditures of employees of both project-direct and supplier firms. The current version of the IMPLAN model divides the economy into 546 sectors that correspond to 4-digit and 5-digit NAICS codes.

approximate estimates of costs and employment. As such, the Blue Engine numbers are often expressed in broad ranges (e.g., the Liquid Direct Air Capture operation would support 75 to 270 permanent jobs per 1 million in CO2 captured annually). Since TNDG's analysis stems from the Blue Engine estimates, TNDG's numbers are expressed in terms of a "Low Scenario" and a "High Scenario" corresponding the Blue Engine's ranges.

2.0 EXECUTIVE SUMMARY

2.1. Fiscal Benefits of Carbon Management Industry

Table II-1, on the following page, summarizes the potential fiscal benefits of the proposed CMBP and the related countywide carbon management industry. All dollar amounts are expressed in 2023 dollars.

Fiscal Benefits to County of Kern. At full buildout, the CMBP and related offsite industries would generate total property tax income (General Fund plus Fire Fund) of $24.2 million (Low Scenario) to $56.2 million (High Scenario) per year.[2]

Total sales tax income to the County's General Fund is projected to range between $4.2 million and $7.9 million per year.[3]

Fiscal Benefits to Incorporated Cities. Whereas the direct impacts of the CMBP would occur in unincorporated Kern County (where the park would be located), the indirect impacts associated with the overall carbon management industry would potentially be spread throughout the county. Given the undefined nature of these indirect benefits, the study does not quantify potential benefits to individual/ specific cities (since the specific locations of supported businesses are unknown). Instead, potential city-level benefits are shown as aggregate numbers (i.e., for all cities combined).

The CMBP and related offsite industries would generate total property tax income to city General Funds of $4.5 million (Low Scenario) to $8.4 million (High Scenario) per year.

Total sales tax income (to city General Funds) is projected to range between $8.4 million and $15.6 million per year.[4]

[2] The projections of property tax generation are largely driven by the very substantial capital facility investments associated with carbon management projects. For purposes of this study, assessed valuation has been estimated based on total capital investments at the time facilities are completed and put into operation. To the extent these capital facility values are depreciated without offsetting capital reinvestments, property tax revenues from these facilities could decline over time.

[3] The sales tax projections are derived from the IMPLAN model; the IMPLAN estimates for Kern County have been adjusted by TNDG to reflect the recent passage of Measure K, which effectively doubles the County's local sales tax rate.

[4] A significant portion of the sales tax revenue projected in this analysis would be derived from indirect impacts (i.e., CMBP businesses making purchases at other Kern County firms) and induced impacts (i.e., CMBP employees spending their payroll incomes at local businesses). Since many of these indirect/induced expenditures would occur in incorporated cities, the CMBP would create larger sales tax impacts to city General Funds than to the County's General Fund.

Table II-1

POTENTIAL PROPERTHY TAX AND SALES TAX GENERATION
KERN CARBON MANAGEMENT BUSINESS PARK (CMBP)
INCLUDES DIRECT (ONSITE) + INDIRECT (OFFSITE) IMPACTS

LOW SCENARIO

	County		*Cities*	
Project Component	**Sales Tax**	**Property Tax**	**Sales Tax**	**Property Tax**
Liquid Direct Air Capture	$669,000	$3,163,700	$1,316,700	$709,500
Solid Direct Air Capture	$130,500	$4,326,800	$256,800	$138,400
Biomass Carbon Removal & Storage	$261,300	$1,836,800	$514,300	$277,200
Green Hydrogen	$84,600	$3,148,100	$166,400	$89,700
Steel Micro Mill	$111,800	$1,936,400	$220,000	$118,500
R&D Incubator Site	$581,400	$1,863,300	$1,144,200	$616,600
Ancillary Clean Energy Industries	$2,439,500	$7,895,100	$4,801,200	$2,587,200
Total CMBP and Offsite Support	$4,278,100	$24,170,200	$8,419,600	$4,537,100

HIGH SCENARIO

	County		*Cities*	
Project Component	**Sales Tax**	**Property Tax**	**Sales Tax**	**Property Tax**
Liquid Direct Air Capture	$1,226,500	$8,599,900	$2,413,900	$1,300,700
Solid Direct Air Capture	$344,000	$11,659,400	$677,000	$364,800
Biomass Carbon Removal & Storage	$1,835,900	$13,841,200	$3,613,300	$1,947,100
Green Hydrogen	$301,200	$4,124,200	$592,900	$319,500
Steel Micro Mill	$168,400	$4,406,800	$331,400	$178,600
R&D Incubator Site	$775,300	$2,681,300	$1,525,800	$822,200
Ancillary Clean Energy Industries	$3,252,600	$10,920,300	$6,401,400	$3,449,500
Total CMBP and Offsite Support	$7,903,900	$56,233,100	$15,555,700	$8,382,400

SOURCE: TNDG, based on Blue Engine research; IMPLAN.

Note: County Property Tax includes General Fund and County Fire Fund.

2.2. Broader Economic Benefits

Table II-2, on the following page, summarizes the broader economic benefits of the proposed CMBP and the related countywide carbon management industry. All dollar amounts are expressed in 2023 dollars.

Total business activity supported. The potential volume ("output") associated with the CMBP and related offsite activities is projected to range from $4.5 billion (Low Scenario) to $6.9 billion (High Scenario) per year.

Total jobs supported. At full buildout, the CMBP and related offsite activities would directly and indirectly support 13,500 to 22,000 permanent jobs.

Total payroll generated. The total direct and indirect payroll associated with these jobs is projected to range from $1.1 billion to $1.8 billion per year, representing an average annual wage of approximately $80,000.

Table II-2

POTENTIAL ECONOMIC IMPACTS
KERN CARBON MANAGEMENT BUSINESS PARK (CMBP)

LOW SCENARIO

Impact Measure	Employment	Employee Compensation	Value Added	Output
			$000s	
Liquid Direct Air Capture	197	$16,524	$117,945	$184,594
Solid Direct Air Capture	280	23,463	23,004	36,002
Biomass Carbon Removal & Storage	186	20,355	29,577	64,855
Green Hydrogen	368	43,675	32,989	74,886
Steel Micro Mill	500	36,999	30,400	119,439
R&D Incubator Site	325	30,073	47,059	85,755
Ancillary Clean Energy Industries	11,682	888,418	1,564,302	3,975,561
Total CMBP	13,540	$1,059,508	$1,845,277	$4,541,092

HIGH SCENARIO

Impact Measure	Employment	Employee Compensation	Value Added	Output
			$000s	
Liquid Direct Air Capture	711	$59,485	$184,714	$338,423
Solid Direct Air Capture	756	63,230	48,574	94,915
Biomass Carbon Removal & Storage	1,368	149,670	149,168	455,611
Green Hydrogen	1,228	145,583	88,822	266,780
Steel Micro Mill	1,501	110,998	37,973	179,934
R&D Incubator Site	876	81,043	99,760	231,094
Ancillary Clean Energy Industries	15,575	1,184,478	1,859,499	5,300,389
Total CMBP	22,014	$1,794,487	$2,468,510	$6,867,148

SOURCE: TNDG, based on Blue Engine research; IMPLAN.

Note: CMBP = Carbon Management Business Park

3.0 DETAILED SUMMARY OF FISCAL AND ECONOMIC IMPACTS

This section provides a detailed summary of the ongoing fiscal and economic impacts associated with the CMBP. For fiscal impacts, the analysis shows the ongoing property tax and sales tax revenues that would be generated for the County and incorporated cities in the County. For economic impacts, the analysis shows annually-recurring impacts related to employment, employee compensation, value added, and output (i.e., total dollar volume of business activity).

3.1. CMBP Sales Tax and Property Tax Impacts

Tables III-1 and III-2 (pages 9 and 10) show the direct and indirect sales tax and property tax impacts associated with each proposed CMBP component, along with the total for the entire proposed CMBP. Table III-1 shows the "low" scenario (reflecting more conservative direct employment and operating cost estimates), while Table III-2 shows the "high" scenario (reflecting higher direct employment and operating cost estimates).

3.2. CMBP Economic Impacts

Tables III-3 and III-4 (pages 11 and 12) show the direct and indirect/induced economic impacts associated with each proposed CMBP component, along with the total for the entire proposed CMBP. Table III-1 shows the "low" scenario (reflecting more conservative direct employment and operating cost estimates), while Table III-2 shows the "high" scenario (reflecting higher direct employment and operating cost estimates).

Table III-1

POTENTIAL PROPERTHY TAX AND SALES TAX GENERATION
KERN CARBON MANAGEMENT BUSINESS PARK (CMBP)
INCLUDES DIRECT (ONSITE) + INDIRECT (OFFSITE) IMPACTS

LOW SCENARIO

	County		*Cities*	
Impact Measure	**Sales Tax**	**Property Tax**	**Sales Tax**	**Property Tax**
Liquid Direct Air Capture				
Direct	$627,912	$3,014,656	$1,235,790	$665,920
Indirect	$41,089	$149,067	$80,867	$43,576
Total	$669,001	$3,163,723	$1,316,657	$709,496
Solid Direct Air Capture				
Direct	$122,465	$4,297,682	$241,023	$129,878
Indirect	$8,014	$29,073	$15,772	$8,499
Total	$130,479	$4,326,755	$256,795	$138,377
Biomass Carbon Removal & Storage				
Direct	$220,881	$1,689,984	$434,714	$234,251
Indirect	$40,461	$146,788	$79,631	$42,910
Total	$261,342	$1,836,772	$514,345	$277,161
Green Hydrogen				
Direct	$36,931	$2,975,317	$72,685	$39,167
Indirect	$47,626	$172,782	$93,732	$50,509
Total	$84,557	$3,148,099	$166,417	$89,676
Steel Micro Mill				
Direct	$58,109	$1,741,749	$114,364	$61,626
Indirect	$53,664	$194,688	$105,616	$56,912
Total	$111,773	$1,936,436	$219,980	$118,539
R&D Incubator Site				
Direct	$393,307	$1,180,952	$774,066	$417,115
Indirect	$188,070	$682,298	$370,140	$199,454
Total	$581,377	$1,863,251	$1,144,206	$616,569
Ancillary Clean Energy Industries				
Direct	$914,321	$2,361,905	$1,799,471	$969,666
Indirect	$1,525,172	$5,533,164	$3,001,683	$1,617,493
Total	$2,439,493	$7,895,069	$4,801,154	$2,587,159
Total Business Park Components				
Direct	$2,373,926	$17,262,245	$4,672,112	$2,517,624
Indirect	$1,904,095	$6,907,860	$3,747,441	$2,019,353
Total	$4,278,021	$24,170,105	$8,419,553	$4,536,977

SOURCE: TNDG, based on Blue Engine research; IMPLAN.

Note: County Direct Property Tax includes General Fund and County Fire Fund.

Table III-2

POTENTIAL PROPERTHY TAX AND SALES TAX GENERATION
KERN CARBON MANAGEMENT BUSINESS PARK (CMBP)
INCLUDES DIRECT (ONSITE) + INDIRECT (OFFSITE) IMPACTS

HIGH SCENARIO

	County		*Cities*	
Impact Measure	**Sales Tax**	**Property Tax**	**Sales Tax**	**Property Tax**
Liquid Direct Air Capture				
Direct	$1,151,171	$8,326,656	$2,265,614	$1,220,853
Indirect	$75,330	$273,290	$148,257	$79,890
Total	$1,226,501	$8,599,946	$2,413,871	$1,300,743
Solid Direct Air Capture				
Direct	$322,862	$11,582,788	$635,424	$342,406
Indirect	$21,127	$76,648	$41,581	$22,406
Total	$343,990	$11,659,436	$677,004	$364,812
Biomass Carbon Removal & Storage				
Direct	$1,551,707	$12,809,984	$3,053,907	$1,645,634
Indirect	$284,241	$1,031,197	$559,414	$301,447
Total	$1,835,948	$13,841,181	$3,613,320	$1,947,081
Green Hydrogen				
Direct	$131,568	$3,508,651	$258,939	$139,532
Indirect	$169,667	$615,535	$333,921	$179,937
Total	$301,236	$4,124,185	$592,860	$319,470
Steel Micro Mill				
Direct	$87,540	$4,113,513	$172,288	$92,839
Indirect	$80,845	$293,296	$159,110	$85,738
Total	$168,385	$4,406,809	$331,398	$178,578
R&D Incubator Site				
Direct	$524,473	$1,771,429	$1,032,214	$556,221
Indirect	$250,790	$909,841	$493,579	$265,971
Total	$775,264	$2,681,270	$1,525,793	$822,192
Ancillary Clean Energy Industries				
Direct	$1,219,061	$3,542,857	$2,399,229	$1,292,853
Indirect	$2,033,529	$7,377,432	$4,002,179	$2,156,622
Total	$3,252,590	$10,920,289	$6,401,407	$3,449,475
Total Business Park Components				
Direct	$4,988,384	$45,655,878	$9,817,614	$5,290,339
Indirect	$2,915,530	$10,577,239	$5,738,040	$3,092,012
Total	$7,903,914	$56,233,117	$15,555,654	$8,382,351

SOURCE: TNDG, based on Blue Engine research; IMPLAN.

Note: County Direct Property Tax includes General Fund and County Fire Fund.

Table III-3

POTENTIAL ECONOMIC IMPACTS
KERN CARBON MANAGEMENT BUSINESS PARK (CMBP)

LOW SCENARIO

Impact Measure	Employment	Employee Compensation	Value Added	Output
			$000s	
Liquid Direct Air Capture				
Direct	150	$12,163	$80,122	$120,000
Indirect/Induced	47	4,361	37,823	64,594
Total	197	$16,524	$117,945	$184,594
Solid Direct Air Capture				
Direct	213	$17,271	$15,627	$23,404
Indirect/Induced	67	6,192	7,377	12,598
Total	280	$23,463	$23,004	$36,002
Biomass Carbon Removal & Storage				
Direct	68	$10,986	$19,849	$46,500
Indirect/Induced	118	9,370	9,729	18,355
Total	186	$20,355	$29,577	$64,855
Green Hydrogen				
Direct	150	$25,978	$21,788	$53,333
Indirect/Induced	218	17,697	11,201	21,552
Total	368	$43,675	$32,989	$74,886
Steel Micro Mill				
Direct	235	$17,259	$14,950	$90,588
Indirect/Induced	265	19,741	15,450	28,851
Total	500	$36,999	$30,400	$119,439
R&D Incubator Site				
Direct	213	$21,587	$31,095	$57,322
Indirect/Induced	112	8,486	15,964	28,433
Total	325	$30,073	$47,059	$85,755
Ancillary Clean Energy Industries				
Direct	7,382	$563,778	$885,833	$2,727,538
Indirect/Induced	4,300	324,640	678,469	1,248,023
Total	11,682	$888,418	$1,564,302	$3,975,561
Total CMBP Components				
Direct	8,411	$669,022	$1,069,264	$3,118,686
Indirect/Induced	5,128	390,486	776,013	1,422,406
Total	13,540	$1,059,508	$1,845,277	$4,541,092

SOURCE: TNDG, based on Blue Engine research; IMPLAN.

Note: CMBP = Carbon Management Business Park

Table III-4

POTENTIAL ECONOMIC IMPACTS
KERN CARBON MANAGEMENT BUSINESS PARK (CMBP)

HIGH SCENARIO

Impact Measure	Employment	Employee Compensation	Value Added	Output
			$000s	
Liquid Direct Air Capture				
Direct	540	$43,786	$146,891	$220,000
Indirect/Induced	171	15,698	37,823	118,423
Total	711	$59,485	$184,714	$338,423
Solid Direct Air Capture				
Direct	574	$46,543	$41,198	$61,702
Indirect/Induced	182	16,687	7,377	33,213
Total	756	$63,230	$48,574	$94,915
Biomass Carbon Removal & Storage				
Direct	500	$80,777	$139,439	$326,667
Indirect/Induced	868	68,894	9,729	128,945
Total	1,368	$149,670	$149,168	$455,611
Green Hydrogen				
Direct	500	$86,594	$77,620	$190,000
Indirect/Induced	728	58,989	11,201	76,780
Total	1,228	$145,583	$88,822	$266,780
Steel Micro Mill				
Direct	706	$51,776	$22,523	$136,471
Indirect/Induced	795	59,222	15,450	43,464
Total	1,501	$110,998	$37,973	$179,934
R&D Incubator Site				
Direct	574	$58,174	$83,796	$154,472
Indirect/Induced	302	22,868	15,964	76,622
Total	876	$81,043	$99,760	$231,094
Ancillary Clean Energy Industries				
Direct	9,842	$751,653	$1,181,030	$3,636,471
Indirect/Induced	5,733	432,824	678,469	1,663,918
Total	15,575	$1,184,478	$1,859,499	$5,300,389
Total CMBP Components				
Direct	13,236	$1,119,305	$1,692,497	$4,725,783
Indirect/Induced	8,778	675,182	776,013	2,141,365
Total	22,014	$1,794,487	$2,468,510	$6,867,148

SOURCE: TNDG, based on Blue Engine research; IMPLAN.

Note: CMBP = Carbon Management Business Park

K.3 EPA Pamphlelt

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United States Environmental Protection Agency

How EPA's UIC Class VI Regulations Work to Ensure the Protection of Groundwater Resources

What is geologic sequestration?

Geologic sequestration (GS) of carbon dioxide (CO_2) is the injection of CO_2 deep underground to prevent it from entering the atmosphere, thereby helping to mitigate climate change. The CO_2 is injected through specially constructed wells that extend into deep rock formations. These formations have been tested and selected based on geologic characteristics indicating that they can safely contain the CO_2 for long-term storage.

How does the UIC program protect drinking water near geologic sequestration sites?

Under the Safe Drinking Water Act, EPA is tasked with protecting public health by regulating and overseeing the nation's public drinking water supplies. The EPA's Underground Injection Control (UIC) program regulates six classes of wells for the injection of fluids such as water, wastewater, brines, and CO_2 into the subsurface. *UIC regulations are designed to protect underground sources of drinking water (USDWs) by preventing the movement of contaminants out of injection formations and into USDWs. (The diagram on the second side of this pamphlet shows USDWs as the uppermost geologic formations in the figure.) Wells injecting CO_2 for GS are classified as UIC Class VI wells.*

The UIC program regulates all aspects of the injection wells of a GS project including project siting, well construction, injection operations, testing and monitoring, emergency response, financial responsibility, and eventual plugging and closure of the wells and injection sites. The UIC program implements the regulations through permitting, site inspections, required reporting, and compliance reviews to ensure that well owners/operators comply with the regulations. Regulations for Class VI wells are the most rigorous of the UIC program. **The sections below describe how UIC regulations for GS projects protect our underground drinking water resources, with additional details shown in numbered items on the diagram on the second page of this pamphlet.**

How can the public participate?

Public participation and transparency are important components of the UIC regulatory framework. Draft injection well permits for GS projects are published for public review. The public may comment on the draft permits, request and attend public hearings, and in some cases file appeals with the Environmental Appeals Board. Transparency is promoted through communications with communities and providing information from project start through closure.

What are key steps for planning GS projects, and how do they protect USDWs?

The Class VI regulations provide multiple safeguards to protect USDWs, beginning at the initial permitting stage. The owner/operator submitting a permit application for a Class VI well must:

- ***Evaluate the project site*** to document that the geology is suitable for GS and that CO_2 will not leak and migrate to USDWs. This includes identifying both a geologic confining layer to prevent the CO_2 from leaking upward (#1 in diagram on page 2) and an injection formation that can dependably hold and provide long-term storage of the injected CO_2 (see #2). Other geologic features (such as faults) are evaluated to confirm that they will not compromise storage and containment and affect USDWs (#3).
- ***Determine the Area of Review (AoR)***, which is the footprint on the land surface above the subsurface area that could be influenced by CO_2 injection. This is the area where owners/operators will take measures to protect USDWs by identifying other wells, and possibly remediating old or abandoned wells (#9) to ensure that CO_2 does not leak through them.
- ***Meet financial responsibility requirements*** that ensure that the private costs associated with a Class VI well are not passed along to the public and that funding is available to address any problems that could affect USDWs.

How is an injection well constructed and operated to be protective of USDWs?

- ***Construction requirements*** include multiple protective layers of corrosion resistant steel casing and cement (#7 and #8). These requirements help to ensure that CO_2 does not leak out of the well or out of the injection formation along the well itself and migrate to a USDW. The wells are tested for leaks and to confirm proper construction before injection begins. Wells are tested routinely during operations (#14),
- ***Operational requirements***, including safe injection pressure and rate (#6, #13), are established by testing prior to starting injection. Maintaining safe injection pressure and rate avoids fracturing the injection formation. This helps ensure that the injected CO_2 remains where intended and does not migrate to other formations, including those containing USDWs. Safe pressures and rates are set in permit conditions and are continuously monitored at the wellhead during operations (#15).

United States Environmental Protection Agency

What other activities are required for Class VI well operations that help protect USDWs?

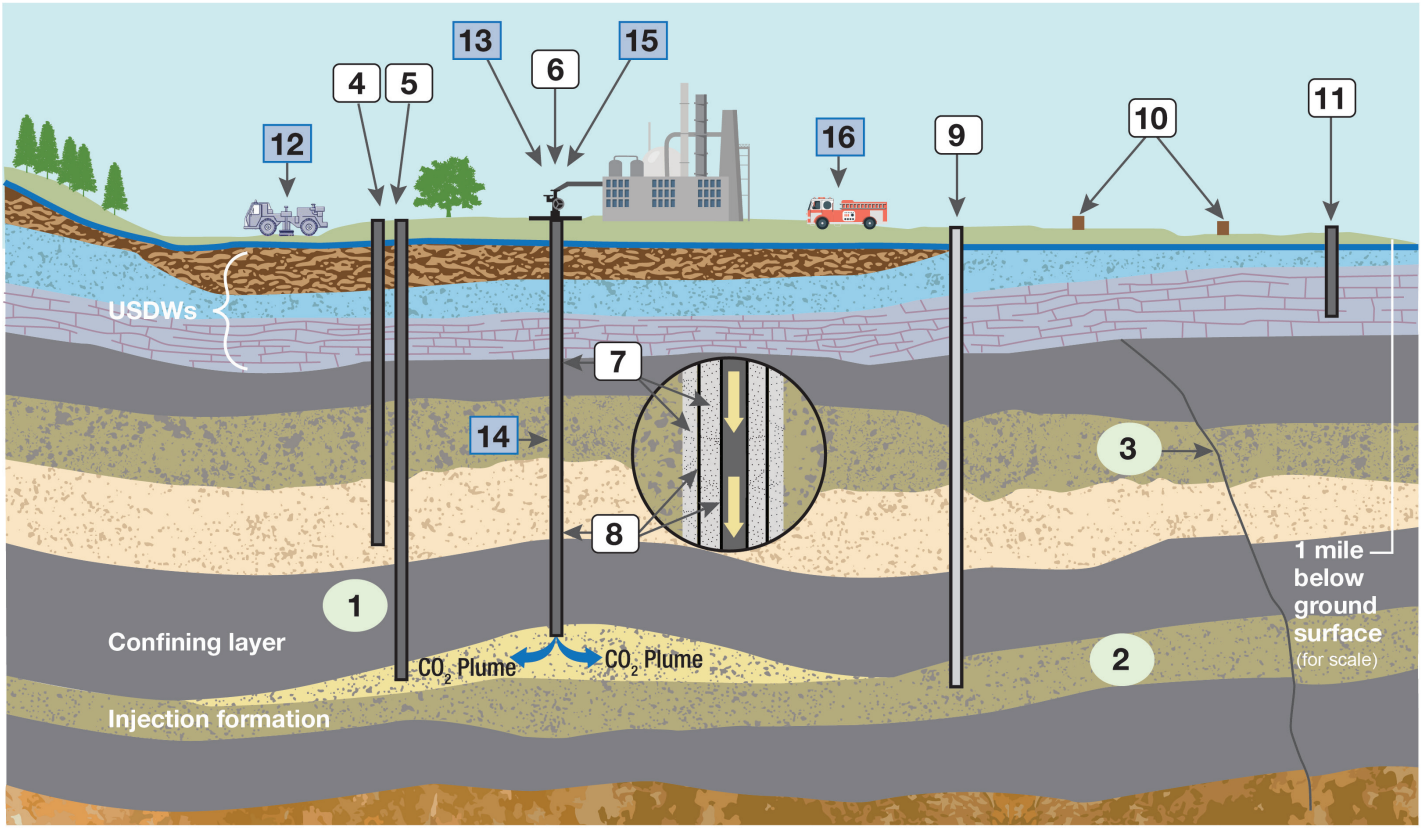
- ***Testing and monitoring*** will provide early warning or evidence in the event of well leaks, unexpected pressure changes, or movement of CO_2 out of the injection formation that could impact USDWs. The injection well is periodically tested for physical integrity and corrosion (#14). The owner/operator uses deep monitoring wells to measure the subsurface pressure and CO_2 in the injection formation (#5). Other monitoring wells are used to monitor groundwater quality above the confining layer (#4). Surface-based seismic surveys (#12) also help track the CO_2 plume.

- ***Emergency response*** requirements require that owners/operators report any evidence of potential dangers to USDWs within 24 hours, including evidence of CO_2 leakage, noncompliance with permit conditions, or malfunction of the injection system (#16).

What activities are required after injection is complete?

- ***Post-injection site care*** begins with well plugging according to an approved well plugging plan. This ensures that CO_2 will not migrate up through the injection well. Testing and monitoring continue according to an approved post-injection site care (PISC) plan. The default period of post-injection site care is 50 years, but the UIC Director can approve a shorter time if the owner/operator demonstrates no danger to USDWs.

- ***Site closure*** can take place when monitoring indicates that the plume and formation pressure are stable and there will be no danger to USDWs. Closure includes removal of surface equipment and site restoration (with grading, planting of vegetation) to conditions approved by the UIC Director. The UIC Director will not authorize the site to be permanently closed until data demonstrate no danger to USDWs.



Through the Underground Injection Control (UIC) program, EPA protects underground sources of drinking water (USDWs) by regulating the construction, operation, permitting, and closure of injection wells that are used for the underground storage or disposal of fluids. Class VI wells are specifically used to inject carbon dioxide (CO_2) into deep rock formations. The UIC permitting authority reviews Class VI permit applications to ensure that injected CO_2 will remain within deep, isolated formations, protecting human health and the environment.

KEY

Site geology
Injection, monitoring, and other wells
Drinking water resource protection practices
Water table

1 Thick, impermeable confining layer prevents CO_2 from leaking upward
2 Permeable injection formation will hold injected CO_2
3 Testing shows that the fault is inactive and sealed against movement of CO_2
4 Water quality is tracked in the permeable formation above the confining layer using a monitoring well
5 Pressure and CO_2 in the injection formation are tracked using a monitoring well
6 CO_2 injection well is permitted for safe operation with many safeguards
7 Cementing prevents CO_2 from moving outside of the well
8 Well materials are corrosion-resistant
9 Properly plugged and abandoned well prevents CO_2 movement between formations
10 Seismic activity is monitored using surface equipment as needed
11 Shallow groundwater well is isolated from the injection formation by multiple impermeable layers
12 Seismic surveys are used to study the geology and track the location of CO_2 through images of the subsurface
13 Safe CO_2 injection pressure avoids damaging the injection formation
14 Regular testing confirms the physical integrity of the well
15 Injection pressure and flow are continually monitored
16 Emergency response plan is in place and ready to be implemented

For general UIC questions, email safewater@epa.gov;
for Class VI questions, email UIC-ClassVI@epa.gov, or send a letter to:

U.S. Environmental Protection Agency
Underground Injection Control Program
Office of Water, Office of Ground Water and Drinking Water
1200 Pennsylvania Avenue, NW Washington, DC 20460

K.4 Source Identification Memo

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Source Identification Technical Memorandum

1. Overview

This memorandum describes additional carbon dioxide (CO_2) sources for the Carbon TerraVault I Project (CTV I) beyond the initial source identified in the Draft Environmental Impact Report (EIR) and Recirculated Draft EIR for CTV I (State Clearinghouse 2022030180). Through the addition of the CO_2 sources described herein, CTV I would serve as a "carbon hub," defined as the process of capturing and storing CO_2 in a defined geographic location, whereby more than one capture method or source is applied for maximized carbon capture and storage (CCS).

Source Limitations

CCS is a process that captures, compresses, transports, and stores large amounts of CO_2. This process is often paired with large greenhouse gas (GHG) emitting facilities and/or with facilities that directly capture CO_2 from the atmosphere. Any additional CO_2-emitting facilities added to the CTV I carbon hub would be limited to sources that are capable of mitigating criteria pollutants from the CO_2 capture and transportation process with no net increase for existing operations.

The project sources are limited in this analysis to the following areas:

- Location only within Kern County
- Blue hydrogen production
- Green hydrogen production
- Biomass carbon removal and storage (BiCRS)
- Cement production
- Green steel production (electric arc)
- Oilfield field gas streams
- Power plants
- Direct air capture
- Alternative fuel production

The listed allowable sources and the potential CCS strategies for CTV I are further discussed in Section 3, *Allowed Additional Carbon Sources,* below.

2. Specific Additional Carbon Sources

In the Recirculated Draft EIR for CTV I, Chapter 3, *Project Description*, Section 3.4.1, *CO_2 Capture Sites,* subsection *Future Sources – Identification*, details specific companies that have formally announced they have contracts or discussion with the applicant, California Resources Corporation (CRC), to send CO_2 to CTV I. All projects in unincorporated Kern County will require approval of the base industry in an appropriately zoned parcel with CO_2 capture and transport requiring an additional Conditional Use Permit (CUP) and EIR for compliance with the California Environmental Quality Act (CEQA). All CO_2 pipelines also require a CUP and EIR for compliance with CEQA. All CO_2 sources in any incorporated city

in Kern County must show compliance with the preparation of an environmental document, with Kern County as a Responsible Agency, and not an exemption from such review.

3. Allowed Additional Carbon Sources

This section identifies other CO_2 sources allowed by Kern County for storage in CTV I. All allowable CO_2 sources must be geographically located within Kern County. The section also discusses the various CCS strategies and associated industries that are allowable for future incorporation into CTV I. This discussion is predominantly guided by the commenters on the CTV I Draft EIR, the California Air Resources Board (CARB) 2022 Scoping Plan, and the technical document prepared for Kern County titled *Envisioning a Carbon Management Business Park* (BE 2023), provided as Appendix K-2 to the Draft EIR.

Oil and Gas Operations

While oil extraction in California has declined since 1986 from 402 million barrels per year to 6 million barrels per year in 2020, there is still demand for finished fossil fuels (gasoline diesel, and jet fuel), primarily for transportation (CARB 2022). The CARB 2022 Scoping Plan recognizes that California is a net exporter of finished fossil fuels and further provides that a phasedown of fossil fuel extraction should be managed with consideration of exports. If in-state extraction were to be phased out fully, the future petroleum demand by in-state refineries would be met through increased crude imports. This could lead to "leakage," as defined by Assembly Bill 32 (AB 32): "a reduction in emissions in GHGs within the state that is offset by an increase in emissions of GHGs outside the state."

Kern County produces approximately 70 percent of the state's oil (BE 2023). The geologic layers in Kern County meet the requirements for CO_2 storage and, therefore, position the County with a favorable opportunity for CO_2 capture at oil and gas refineries. Oil and gas operations, as noted by commenters on the Draft EIR for CTV I, would be an allowed source of CO_2 storage in CTV I, as these sources are within the County. Proposed oil and gas sources include the CRC Oil and Gas CUP Buena Vista, the CRC Oil and Gas CUP Elk Hills, and the Carbon Terra Vault Clean Energy Park.

Alternative Fuels

The Low Carbon Fuel Standard (LCFS) has successfully spurred demand for alternative fuels, such as renewable diesel, sustainable aviation fuel, biomethane, and electricity, as all have gained significant market share (CARB 2022). Currently, electricity and hydrogen are the primary fuels used for zero-emissions vehicles. Alternative fuel refineries can be repurposed from existing refineries and retrofitted to include various available CCS technologies. These sources would be eligible for LCFS credits.

Hydrogen Production

Hydrogen production is gaining traction as a clean energy fuel alternative because of its ability to power fuel cells in zero-emission vehicles (OEERE 2024). The demand for hydrogen is increasing due to other potential sector transitions as well, including industrial uses, transportation, power generation, energy storage, and grid balancing (DOE 2020). Today, hydrogen is mainly used for feedstock in ammonia, food, drug production, petrochemical, and refinery processing.

The types of hydrogen production being considered for the CTV I carbon hub involve the "splitting off" of hydrogen from carbon, which can be done using several different processes, as described below:

- **Thermochemical processes**: use energy in various resources such as gas, coal, or biomass to release hydrogen from their molecular structure. The resulting heat, in combination with closed-chemical cycles, produces hydrogen from feedstocks such as water.
- **Electrolytic processes**: use electricity to split water into hydrogen and oxygen molecules.
- **Direct solar water splitting processes**: use light energy to split water into hydrogen and oxygen molecules.
- **Biological processes**: use bacteria and microalgae to produce hydrogen through biological reactions using sunlight or organic matter. These methods are currently in the research and development phase, with some pilot demonstrations underway.

These methods have been further categorized into a color key system for productive research and discussions about the hydrogen industry and the various types of hydrogen production. It is important to note that hydrogen is a colorless gas and that the color system is simply a convenient notation device. No differences in visual, physical, or chemical properties are weighted when reviewing these different production methods. Green hydrogen and blue hydrogen are further discussed in this memo, as potential future sources would fall into these categories as acceptable carbon capture and removal industry practices for storage within CTV I.

Green Hydrogen

Green hydrogen production refers to production techniques that generate no GHG byproducts, mostly achieved by electrolysis from renewable resources. Renewable energy generation sources such as solar power and wind are dynamic and sometimes produce excess energy in times of low demand, and vice versa. Green hydrogen production has the potential to offer flexibility to shift production to match resource availability. This technology is well developed and available commercially.

Blue Hydrogen

Blue hydrogen refers to the production method of thermochemical process and electrolysis, whereby the conversion of methane (natural gas) to hydrogen relies on a process called steam reforming, which generates both hydrogen and CO_2. The CO_2 generated is captured via point source carbon technologies to be stored underground in perpetuity, reducing carbon emissions. The U.S. Department of Energy estimates that 99% of hydrogen production is sourced from fossil fuels, with 95 percent from natural gas reforming by steam-methane reforming (SMR) (DOE 2020). Natural gas reforming is the process of building upon existing natural gas pipeline delivery infrastructure for hydrogen production. This reform includes using existing natural gas facilities and the available methane from natural gas for hydrogen production. In the SMR process, the natural gas is heated with steam to generate hydrogen, with CO_2 byproducts that can be further captured for storage, collectively known as “blue hydrogen.”

How Blue Hydrogen Works

Blue hydrogen relies on the thermochemical processes method for splitting methane and water into hydrogen and oxygen. Sources used for this process are finite and include either methane or coal, plus water as a feedstock. This process is known as natural gas reforming, or SMR, discussed in further detail below. Unlike grey hydrogen (which uses the SMR process but does not include CCS to reduce emissions), blue hydrogen emits less carbon into the atmosphere, as it involves the deployment of a CCS system, storing the carbon in perpetuity below adequate geological layers. Because the production of

blue hydrogen is dependent on finite resources, including methane and coal, there is potential for retrofitting existing assets and pipelines while achieving lower carbon emissions.

Steam-Methane Reforming (SMR) + Carbon Capture and Sequestration (CCS)

SMR involves transforming methane (CH_4) and water into hydrogen and CO_2. In the first reaction, steam reacts with methane in a high-pressure container, which requires both a catalyst and heat (endothermic) in order to produce "syngas," a mixture of hydrogen, carbon monoxide, and CO_2. Large amounts of heat from this initial reaction (206 kilojoules of heat energy per mol of methane) are required for the reaction to proceed, which is a "water-gas shift reaction" wherein carbon monoxide generated reacts with more steam and a catalyst to form more hydrogen, CO_2, and small amounts of heat (OEERE, 2023). Finally, the last step is a "pressure-swing adsorption," which removes the CO_2 and other gases from the final products, leaving a pure stream of hydrogen gas.

1. Steam-methane reforming reaction

$CH_4 + H_2O$ (+ heat) → $CO + 3H_2$

2. Water-gas shift reaction

$CO + H_2O \rightarrow CO_2 + H_2$ (+ small amount of heat)

Once the CO_2 is separated from the gas stream, it can then be transported for permanent underground storage. The hydrogen can be packaged for sale, and the heat would ideally be cycled back into the process or redirected to a facility for further use. The transportation of CO_2 to the storage reservoir typically requires miles of pipeline for delivery. The storage of CO_2 underground is what differentiates blue hydrogen from grey hydrogen production, and it is estimated that at best, CCS capture efficiencies are expected to reach 85 to 95 percent, leaving 5 to 15 percent of the CO_2 to be emitted (IRENA 2020).

Summary of Blue Hydrogen

Blue hydrogen production has the potential to supply the demand in hydrogen by use of retrofitting existing natural gas pipelines. It is estimated that nationally, 95 percent of hydrogen production is derived from natural gas reforming, or SMR. However, blue hydrogen production has limitations in that it is dependent on fossil fuels and associated carbon emissions with point sources. Other criteria air pollutants may be released; however, researchers found that the amounts of volatile organic compounds, nitric oxide, and CO_2 decreased as the facility size increased, suggesting that larger facilities may have emissions control technologies that capture different pollutants (BE 2020).

While technological refinements and improvements are underway, significant water requirements needed to perform the water-gas shift reaction persist. Studies show that per kilogram of hydrogen generated, the SMR and water-gas shift reaction require 2.6 gallons of water per kilogram of hydrogen produced (BE 2023). As California grapples with record-year droughts, wastewater may be treated and repurposed for industrial use, but the viability of such an option is dependent on local interest, cost, and needs (BE 2023).

Carbon Dioxide Removal

Based on evidence cited in the CARB 2022 Scoping Plan, CO_2 removal will be necessary to achieve net negative emissions. Carbon removal can be nature-based or mechanical. Nature-based solutions involve enhancing natural and working lands for biological processes in vegetative material to remove and store

carbon from the ambient air. Another form of CO_2 removal is mechanical, which involves direct air capture (DAC).

Direct Air Capture

DAC technology typically involves a system wherein ambient air is pulled through a unit with a sorbent that first binds $C0_2$ to a compound, and later uses heat to break that bond for $C0_2$ separation. There are two types of DAC technologies—solid (S-DAC) and liquid (L-DAC)—distinguished by the type of sorbent material they use. Both involve passing air pulled from the atmosphere over the sorbent. In both techniques, the $C0_2$ derived from the air is chemically and temporarily bound into a new compound, only to be broken down into a pure stream of $C0_2$ for storage and the remaining original sorbent for reuse (BE 2023). Both technologies require electricity and heat for final outcomes.

Solid Direct Air Capture

S-DAC relies on a filtering process using dry amine-based chemical sorbents. This process happens through an adsorption/desorption process, whereby adsorption takes places at ambient temperature and pressure, and desorption occurs through a temperature vacuum swing process. Breaking the bonds of $C0_2$ and the sorbent requires temperatures of around 215 degrees Fahrenheit (^oF). This technique has the potential to capture several tens of tonnes of CO_2 per year. S-DAC plants are designed to be modular and can include as many units as needed.

Liquid Direct Air Capture

L-DAC typically uses hydroxide solutions (a liquid solvent) and is based on two chemical loops. The first loop takes place in what is called a contactor and brings atmospheric air into contact with an aqueous basic solution (such as potassium hydroxide) that captures the CO_2. Then, the second loop releases the CO_2 from the solution in a series of units operating at temperatures of 572 to 1,652 ^oF (IEA 2022). This temperature is difficult to reach using renewable sources, and if natural gas is used, CO_2 would need to be recaptured to offset further CO_2 emissions.

Direct Air Capture Technologies

DAC technologies are still emerging, and significant research and development efforts support the advancement of such technologies. A single unit for S-DAC technology has the ability to capture several tens of tonnes of CO_2 per year, and an S-DAC plant can be designed to include and operate as many units as feasible. These quantities are expected to increase as technologies emerge and costs are reduced.

Water needs for DAC technology vary depending on the technology used, ambient temperature, and humidity. L-DAC requires water for operations (50 tonnes of water per tonne of $C0_2$), while S-DAC can extract water from the air, alongside CO_2 (0.8 to 2 tonnes of water per tonne of CO_2 captured from the atmosphere). In dry climates S-DAC could provide water (for its own use or, for instance, to feed a water electrolyser to produce hydrogen and subsequently synthetic fuels together with the captured CO_2), whereas in humid climates, S-DAC may struggle to keep up with the amount of water to be removed from the atmosphere. Compared to other carbon removal methods, DAC requires a smaller land footprint (IEA 2022). Adequate geological layers for storing carbon are necessary for perpetual carbon sequestration.

Biomass Carbon Removal and Storage

BiCRS is an umbrella term for various technologies that utilize biomass, such as agricultural byproducts, for CCS. BiCRS includes a range of technologies that utilize the collection of naturally stored CO_2 in

biomass for breakdown. Biomass can be sourced from material that naturally stores and contains CO_2, including agricultural and forest byproducts, or industrial or municipal waste. This conversion of biomass can be divided into two categories: biochemical and thermochemical conversion.

Biochemical conversion involves using living microorganisms to convert biomass into biofuels, with the most common method being the biochemical conversion of corn to ethanol through fermentation. Other biomass sources require a modification to natural fermentation in order to break down more complex plant structures. This includes high-temperature deconstruction, wherein extreme heat and pressure are needed to break down biomass feedstocks.

Thermochemical conversion refers to the breakdown of biomass to be directly combusted to create steam or heat to be used as a direct source of energy. These types of bioenergy plants can be fitted with post-combustion carbon capture technology that scrubs CO_2 from gaseous byproducts to form a bioenergy with carbon capture storage (BECCS). BECCS is a distinct form of BiCRS, and primarily focuses on fuel and energy production from biomass, whereas CO_2 CCS neutralizes carbon emissions for the power generation industry.

Technological methods in BiCRS and the capture of CO_2 include retrofitting biomass power plants that convert biomass into carbon-negative electricity grid by using oxy-fuel combustion. The footprint necessary for these sources is considerable. According to *Envisioning a Carbon Management Business Park*, the estimated physical footprint for a facility capturing 1 million metric tons of CO_2 annually is 180 to 400 acres (BE 2023) (Appendix K-2). In addition, for BiCRS/BECCS, high temperatures are needed for the conversion, and energy requirements will depend on the plant's thermal efficiency.

Point Source Carbon Capture

Many of California's industries produce CO_2 as a byproduct of their processing activities—specifically, the combustion of fossil gas necessary for three broad industry needs: electricity, steam, and process heat. The industrial sector contributes significantly to the state's economy and includes a diverse range of facilities such as cement plants, refineries, glass manufacturers, oil and gas producers, paper manufacturers, mining operations, metal processors, and food processors (CARB 2022). While these industries collectively account for about half of global GHG emissions, many facilities can employ a technology known as "point source carbon capture," which scrubs CO_2 from points of exhaust prior to being released into the atmosphere. Unlike DAC and BiCRS, which remove CO_2 from the ambient air, point source capture *prevents* the release of CO_2 into the atmosphere.

Technologies for point source capture are available for cement plants, iron and steel manufacture, natural gas power plants and boilers, fertilizer development, and paper mills. According to *Envisioning a Carbon Management Business Park*, Kern County has 44 facilities that reported significant CO_2 emissions in 2021 (BE 2023) (Appendix K-2). The following point source facilities are divided into the following industries:

- 20 petroleum and natural gas systems or refineries
- 15 power plants
- Two waste facilities
- Two cement facilities
- One mine (boron mine and refinery)

Cement Plants

Cement plants are a significant source of CO_2 emissions as they require the combustion of fossil gas and processing, wherein combustion accounts for 40 percent of emissions. Due to the high heat required, cement plants are one of a few industries that are hard to decarbonize. Even if the sector were to operate using only zero-carbon fuels, process emissions are significant; thus, carbon capture is necessary to fully decarbonize manufacturing. Senate Bill 596 requires the CARB to develop a strategy for the state's cement sector to achieve net-zero emissions. In response, CARB aims for CCS on 40 percent of stone, clay, glass, and cement plants by 2035 and on all facilities by 2045 to minimize leakage and address emissions (CARB 2022).

With CCS at cement plants, full electrification using alternative fuels such as hydrogen could bolster hydrogen demand. With the state's carbon cap-and-trade program, the growth of hydrogen through a carbon credit marketplace is incentivizing.

Steel Plants – Electric Arc Furnaces

Steel forging requires high heat and onsite combustion, with few electrification options to replace fossil gas for high heat requirements, and as such is among the industries hard to decarbonize. Steel mills are technologically diverse and, depending on the type of production, they can produce as much as 2.4 tonnes of CO_2 for every ton of steel produced. A common, and now predominant, mill type is the mini mill, or micro mill, which uses a technology called "electric arc furnaces" (EAF) to re-melt andrefine alloy scrap steel, commonly direct reduced iron. These mills do not require raw materials and require less high heat to reduce iron ore. However, their growth potential is limited by the availability of scrap steel.

The EAF process involves using a high-current electric arc to melt steel scrap, which ultimately emits less CO_2 than steel making with basic oxygen furnaces. The steel scrap can be retrofitted with carbon capture to capture as much as 80 percent of CO_2 emissions. Some researchers propose powering EAF with natural gas via oxy-fuel combustion rather than grid or renewable sourced electricity. This would result in a mill that could produce low-carbon steel and CO_2 for capture.

Natural Gas Power Plants

Many techniques for carbon capture at point source are available today to capture CO_2 from the exhaust of coal and natural gas power plants. Most use a solvent-based approach, rather than directly emitting CO_2-bearing flue gas through exhaust chimneys of a plant or facility. This process utilizes an absorption tower, where it is mixed with a liquid solvent that physically attracts the CO_2, then drawn out of the flue gas and captured.

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